ANL/DIS-10-6

Ex Post Power Economic Analysis of Record of Decision Operational Restrictions at Glen Canyon Dam

Decision and Information Sciences Division

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Ex Post Power Economic Analysis of Record of Decision Operational Restrictions at Glen Canyon Dam

by
T.D. Veselka,[1] L.A. Poch,[1] C.S. Palmer,[2] S. Loftin,[2] and B. Osiek[2]
[1] Center for Energy, Environmental, and Economic Systems Analysis
Decision and Information Sciences Division, Argonne National Laboratory
[2] Western Area Power Administration, Colorado River Storage Project
Management Center, Salt Lake City, Utah

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FOREWORD

This report was prepared by Argonne National Laboratory (Argonne) in support of an economic analysis of operational restrictions at the Glen Canyon Dam (GCD) conducted for the U.S. Department of Energy's Western Area Power Administration (Western). Western markets electricity produced at hydroelectric facilities operated by the Bureau of Reclamation. The facilities known collectively as the Salt Lake City Area Integrated Projects include dams equipped for power generation on the Colorado, Green, Gunnison, and Rio Grande rivers and on Plateau Creek in the states of Arizona, Colorado, New Mexico, Utah, and Wyoming.

This report presents detailed findings of studies conducted by Argonne related to an ex post economic analysis of Record of Decision operating criteria for GCD issued by the U.S. Department of the Interior on October 9, 1996. Staff members of Argonne's Decision and Information Sciences Division prepared this report with assistance from staff members of Western's Colorado River Storage Project Management Center.

CONTENTS

ACRONYMS AND ABBREVIATIONS ix

UNITS OF MEASURE x

ABSTRACT 1

1 INTRODUCTION 2

2 HISTORICAL BACKGROUND 4

2.1 GLEN CANYON DAM AND PHYSICAL POWERPLANT CHARACTERISTICS ... 4
2.2 POWERPLANT CAPACITY AND MAXIMUM POTENTIAL POWER OUTPUT 6
2.3 POWERPLANT GENERATION 9
2.4 POWERPLANT EFFICIENCY 12
2.5 GLEN CANYON DAM OPERATING CONSTRAINTS 13
2.6 BEACH/HABITAT-BUILDING FLOWS AND EXPERIMENTAL RELEASES 20
2.7 SALT LAKE CITY AREA INTEGRATED PROJECTS 22
2.8 MARKETING OF GLEN CANYON DAM POWER AND ENERGY 23
2.9 CRSP DISPATCH PRACTICES 27
2.10 EVOLUTION OF WECC POWER MARKETS 28

3 METHODS AND MODELS 33

3.1 SCENARIO ASSUMPTIONS 33
3.2 CONSTRUCTING SLCA/IP FIRM CONTRACTS 36
3.3 CUSTOMER SCHEDULING ALGORITHM 40
3.3.1 Schedules for Large and Small Customers 41
3.3.2 Customer Scheduling Algorithm Objectives and Constraints 41
3.3.3 Total SLCA/IP Hourly Firm Loads 44
3.4 WECC MARKET HUB PRICES 44
3.4.1 Daily Minimum and Maximum Prices 45
3.4.2 Shaping Hourly Prices with WECC Total Loads 46
3.5 SIMULATION OF SLCA/IP HOURLY DISPATCH AND MARKET TRANSACTIONS 49
3.5.1 GTMax Model Input Data for Power Plants and Reservoir 49
3.5.2 GTMax Model Input Data, Loads, and Market Prices 51
3.5.3 GTMax Topologies 53
3.5.4 Ancillary Services 58
3.6 CALCULATING ECONOMIC VALUE 60

4 ECONOMIC COST OF THE ROD 61

4.1 COST OF ROD IN WY 1997 63
4.2 COST OF ROD IN WY 1998 66
4.3 COST OF ROD IN WY 1999 68
4.4 COST OF ROD IN WY 2000 71
4.5 COST OF ROD IN WY 2001 75
4.6 COST OF ROD IN WY 2002 78
4.7 COST OF ROD IN WY 2003 81

CONTENTS (Cont.)

4.8 COST OF ROD IN WY 2004 85
4.9 COST OF ROD IN WY 2005 87
4.10 SUMMARY OF ROD COST IN STUDY PERIOD 91

5 REFERENCES 97

5.1 REPORTS 97
5.2 FORMS 98

TABLES

Table 2.1 Glen Canyon Powerplant Improvements during the Study Period................................ 6
Table 2.2 Summary of Hydropower Operational Scenarios... 14
Table 2.3 List of Historical Experimental Flow Periods from 1997 through 2005...................... 22
Table 2.4 SLCA/IP Divisional Allocations under the Post-1989 Marketing Criteria 25
Table 2.5 SLCA/IP Divisional Allocations under the Post-2004 Marketing Criteria 25
Table 3.1 Overview of Scenario Assumptions 35
Table 3.2 Aggregate Annual SLCA/IP Contract Terms Under the Without ROD and With ROD Scenarios 37
Table 3.3 Monthly Project Capacity Use, by Customer 52
Table 3.4 Monthly Project Energy Use, by Customer.. 52

FIGURES

Figure 2.1 Powerplant Capacity and Output Capability in the Study Period 8
Figure 2.2 Powerplant Average Daily Power Factor for January 16–29, 2004 8
Figure 2.3 Annual Generation from the Glen Canyon Powerplant
in Calendar Years 1980 through 2005 10
Figure 2.4 Monthly Energy Production during the Study Period 11
Figure 2.5 Average Monthly Energy Production during the Study Period.................................. 11
Figure 2.6 Powerplant Capacity and Output Capability in the Study Period 12
Figure 2.7 Powerplant Capacity and Output Capability in the Study Period 13
Figure 2.8 Glen Canyon Releases over a Single Day Prior
to More Stringent Operating Restrictions (July 20, 1989, is shown).......................... 15
Figure 2.9 Glen Canyon Releases over a Single Day under Interim Operating Restrictions 16
Figure 2.10 Glen Canyon Releases over a Single Day under ROD Restrictions 18
Figure 2.11 Glen Canyon Releases over a Single Day under ROD Restrictions 19
Figure 2.12 Glen Canyon 2004 BHBF Releases 21
Figure 2.13 Illustration of SHP and AHP Capacity Offers.. 26
Figure 2.14 Illustration of the Market-Price-Driven Dispatch Guideline
under Flexible Hydropower Operations 28
Figure 2.15 Projected Versus Actual Delivered Cost of Fuel to Electric Utility Power Plants.... 29
Figure 2.16 Daily Spot Market Prices at the Palo Verde Hub 31
Figure 2.17 Daily Spot Market Price Spreads at Palo Verde Hub... 32
Figure 3.1 Modeling Process Overview... 34
Figure 3.2 Illustration of SLCA/IP Dispatch when Maximizing Economic Value of Resources 36
Figure 3.3 Aggregate Monthly SLCA/IP Contract Offers in 1999
under the Without ROD Scenario 38
Figure 3.4 Aggregate Monthly SLCA/IP Contract Offers in 1999
under the With ROD Scenario 38
Figure 3.5 SLCA/IP Capacity and Minimum Schedule Requirements 39
Figure 3.6 Aggregate Monthly SLCA/IP Contract Offers in 2003
under the Without ROD Scenario 40
Figure 3.7 Aggregate Monthly SLCA/IP Contract Offers in 2003
under the With ROD Scenario 40
Figure 3.8 Conceptual Illustration of an SLCA/IP Customer Scheduling Energy 43
Figure 3.9 Customer Hourly Demands for Energy under SLCA/IP Firm Contracts.................... 44
Figure 3.10 Process for Estimating Hourly WECC Market Hub Prices...................................... 45
Figure 3.11 Process for Estimating Total Hourly Loads in the U.S. portion of WECC............... 47
Figure 3.12 Illustration of Load Duration Curve Shaping to Match a Target Load Factor.......... 48
Figure 3.13 Original and Shaped Chronological Load Curve 48
Figure 3.14 Sequence of Operations for Simulating SLCA/IP Marketing
and System Operations 54
Figure 3.15 Topology Used for Flaming Gorge Dispatch and Jensen Gauge Simulations 55
Figure 3.16 SLCA/IP Topology Used for Powerplant Dispatch Simulations 57
Figure 3.17 Operating Range Reduction When Providing Ancillary Services 58
Figure 4.1 Monthly Water Releases in WY 1997... 63
Figure 4.2 Energy Component of ROD Cost and Price Spread in WY 1997 64

FIGURES (Cont.)

Figure 4.3 Operating Range and Outage Factor at Glen Canyon Dam in WY 1997 64
Figure 4.4 Cost of Capacity and Energy Components in WY 1997 65
Figure 4.5 Monthly Water Releases in WY 1998 66
Figure 4.6 Energy Component of ROD Cost and Price Spread in WY 1998 67
Figure 4.7 Operating Range and Outage Factor at Glen Canyon Dam in WY 1998 67
Figure 4.8 Capacity Factors of Without ROD and With ROD Scenarios in WY 1998 67
Figure 4.9 Cost of Capacity and Energy Components in WY 1998 68
Figure 4.10 Monthly Water Releases in WY 1999 69
Figure 4.11 Energy Component of ROD Cost and Price Spread in WY 1999 70
Figure 4.12 Operating Range and Outage Factor at Glen Canyon Dam in WY 1999 70
Figure 4.13 Cost of Capacity and Energy Components in WY 1999 70
Figure 4.14 Water Release Pattern During Low Summer Steady Flow in WY 2000 71
Figure 4.15 Monthly Water Release in WY 2000 72
Figure 4.16 Energy Component of ROD Cost and Price Spread in WY 2000 72
Figure 4.17 Operating Range and Outage Factor at Glen Canyon Dam in WY 2000 73
Figure 4.18 Comparison of Lake Powell Elevations and Power Conversion Factor
in WY 2000 74
Figure 4.19 Cost of Capacity and Energy Components in WY 2000 75
Figure 4.20 Monthly Water Releases in WY 2001 76
Figure 4.21 Energy Component of ROD Cost and Price Spread in WY 2001 76
Figure 4.22 Operating Range and Outage Factor at Glen Canyon Dam in WY 2001 77
Figure 4.23 Cost of Capacity and Energy Components in WY 2001 78
Figure 4.24 Monthly Water Releases in WY 2002 79
Figure 4.25 Energy Component of ROD Cost and Price Spread in WY 2002 79
Figure 4.26 Operating Range and Outage Factor at Glen Canyon Dam in WY 2002 80
Figure 4.27 Cost of Capacity and Energy Components in WY 2002 81
Figure 4.28 Monthly Water Releases in WY 2003 82
Figure 4.29 Energy Component of ROD Cost and Price Spread in WY 2003 82
Figure 4.30 Cost of Capacity and Energy Components in WY 2003 84
Figure 4.31 Operating Range and Outage Factor at Glen Canyon Dam in WY 2003 84
Figure 4.32 Monthly Water Releases in WY 2004 85
Figure 4.33 Energy Component of ROD Cost and Price Spread in WY 2004 86
Figure 4.34 Cost of Capacity and Energy Components in WY 2004 87
Figure 4.35 Operating Range and Outage Factor at Glen Canyon Dam in WY 2004 87
Figure 4.36 Monthly Water Releases in WY 2005 88
Figure 4.37 Energy Component of ROD Cost and Price Spread in WY 2005 89
Figure 4.38 Operating Range and Outage Factor at Glen Canyon Dam in WY 2005 90
Figure 4.39 Cost of Capacity and Energy Components in WY 2005 90
Figure 4.40 Annual Water Releases during the Study Period 91
Figure 4.41 Energy Component of ROD Cost and Price Spread during the Study Period 92
Figure 4.42 Operating Range and Outage Factor at Glen Canyon Dam
during the Study Period 93
Figure 4.43 Cost of Capacity and Energy Components in Study Period 93
Figure 4.44 Comparison of Lake Powell Elevations and Power Conversion Factor
during the Study Period 94

FIGURES (Cont.)

Figure 4.45 Comparison of Actual Monthly Electricity Prices/Price Spreads during California Energy Crisis to Those Values with California Energy Crisis Removed.................. 95
Figure 4.46 Energy Component of ROD Cost and Price Spread during the Study Period........... 95
Figure 4.47 Cost of Capacity and Energy Components in Study Period...................................... 96

ACRONYMS AND ABBREVIATIONS

The following is a list of the acronyms and abbreviations (including units of measure) used in this document.

AEO	Annual Energy Outlook
AHP	Available Hydropower
Argonne	Argonne National Laboratory
APSF	Aerial Photography Steady Flow
AZNM	Arizona, New Mexico, and Southern Nevada Power Area
BHBF	Beach/Habitat-Building Flows
CalISO	California Independent System Operator
CalPX	California Power Exchange
CAMX	California and Mexico Power Area
CDP	Customer Displacement Power
CROD	Contract Rate of Delivery
CRSP	Colorado River Storage Project
CSU	Colorado Springs Utilities
Deseret	Deseret Generation & Transmission Cooperative
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EOM	End of Month
EPM-EIS	Electric Power Marketing Environmental Impact Statement
FERC	Federal Energy Regulatory Commission
FGEIS	Flaming Gorge Environmental Impact Statement
F.R.	Federal Register
GCD	Glen Canyon Dam
GCDAMP	Glen Canyon Dam Adaptive Management Program
GCDEIS	Glen Canyon Dam Environmental Impact Statement
GCES	Glen Canyon Environmental Studies
GPA	Glen Canyon Protection Act
GTMax	Generation and Transmission Maximization
HF	High Flow
HMF	Habitat Maintenance Flow
ICE	Intercontinental Exchange
LDC	Load Duration Curve
LF	Low Flow
LP	Linear Programming
LSSF	Low Summer Steady Flow
LTF	Long-Term Firm
MC	Management Center (of the CRSP)
MLFF	Modified Low Fluctuating Flow
MSR	Minimum Schedule Requirement
NAPI	Navajo Agricultural Products Industry
NERC	North American Electric Reliability Corporation

NNFSF	Non-Native Fish Suppression Flow
NPV	Net Present Value
NTUA	Navajo Tribal Utility Authority
NWPP	Northwest Power Pool
PO&M-59	Power Operations and Maintenance, Form 59
PRPA	Platte River Power Authority
QP	Quadratic Programming
Reclamation	Bureau of Reclamation
RMPA	Rocky Mountain Power Area
ROD	Record of Decision
RRP	Replacement Resources Process
Secretary	Secretary of the Interior
SCADA	Supervisory Control and Data Acquisition
SHP	Sustainable Hydropower
SLCA/IP	Salt Lake City Area Integrated Projects
SRP	Salt River Project
SSARR	Streamflow Synthesis and Reservoir Regulation
Tri-State	Tri-State Generation & Transmission Association/Plains Electric Generation & Transmission Cooperative
UAMPS	Utah Associated Municipal Power Systems
UMPA	Utah Municipal Power Agency
USGS	U.S. Geological Survey
WECC	Western Electricity Coordinating Council
Western	Western Area Power Administration
WRP	Western Replacement Power
WTTD	Water Time Travel Distribution
WY	Water Year

UNITS OF MEASURE

AF	acre-feet
cfs	cubic feet per second
ft	feet
GWh	gigawatt-hour(s)
hr	hour(s)
kW	kilowatt
MAF	million acre-feet
MMBtu	millions of British thermal units
MVA	million volt-amperes
MW	megawatts
MWh	megawatt-hour(s)
pf	power factor
TAF	thousand acre-feet
yr	year

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T.D. Veselka, L.A. Poch, C.S. Palmer,* S. Loftin,* and B. Osiek*

ABSTRACT

On October 9, 1996, Bruce Babbitt, then-Secretary of the U.S. Department of the Interior signed the Record of Decision (ROD) on operating criteria for the Glen Canyon Dam (GCD). Criteria selected were based on the Modified Low Fluctuating Flow (MLFF) Alternative as described in the *Operation of Glen Canyon Dam, Colorado River Storage Project, Arizona, Final Environmental Impact Statement* (EIS) (Reclamation 1995). These restrictions reduced the operating flexibility of the hydroelectric power plant and therefore its economic value. The EIS provided impact information to support the ROD, including an analysis of operating criteria alternatives on power system economics. This ex post study reevaluates ROD power economic impacts and compares these results to the economic analysis performed prior (ex ante) to the ROD for the MLFF Alternative. On the basis of the methodology used in the ex ante analysis, anticipated annual economic impacts of the ROD were estimated to range from approximately $15.1 million to $44.2 million in terms of 1991 dollars ($1991). This ex post analysis incorporates historical events that took place between 1997 and 2005, including the evolution of power markets in the Western Electricity Coordinating Council as reflected in market prices for capacity and energy. Prompted by ROD operational restrictions, this analysis also incorporates a decision made by the Western Area Power Administration to modify commitments that it made to its customers. Simulated operations of GCD were based on the premise that hourly production patterns would maximize the economic value of the hydropower resource. In 2000 and 2001, electricity market prices experienced large price spikes and swings. Because of this event, many people felt market prices during that time period were not good surrogates for determining economic value of energy. To study the effect large electricity market price swings had on the economic value of the ROD, two case studies were performed. The base case used actual market prices during the entire study period. A sensitivity case adjusted prices in 2000 and 2001 using a methodology to smooth the market price swings. The base case estimated that economic impacts were on average $33.9 million in $1991, or $50 million in $2009. The sensitivity case estimated that economic impacts were on average $26 million in $1991, or $38 million in $2009.

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* Palmer, Loftin, and Osiek are employed by Western Area Power Administration, Colorado River Storage Project Management Center, Salt Lake City, Utah.

1 INTRODUCTION

Constructed between 1957 and 1964, Glen Canyon Dam (GCD) is a concrete arch structure located on the Colorado River 15 miles upstream from Lees Ferry. Currently, there are eight generating units at Glen Canyon Powerplant (or the Powerplant) with a total sustained operating capacity of approximately 1,320 megawatts (MW) and an instantaneous maximum output of about 1,356 MW (Veselka et. al 1995). The first two Glen Canyon units began generating power in September 1964, and the eighth and final unit came on-line in February 1966 (Form PO&M-59). The reservoir formed by the dam, Lake Powell, has a total water storage capacity of 27 million acre-feet (MAF) when full. Lake Powell was filled for the first time in 1980 when it reached a maximum reservoir water elevation of 3,710.6 feet (ft). When water is released from the reservoir through power plant turbines, the energy generated serves the electricity demands of consumers in several western states that are located in the Western Electricity Coordinating Council (WECC) region of the North American Electric Reliability Corporation (NERC).

Except for a minimum water release requirement at GCD, the daily and hourly operations of the dam initially were restricted only by the physical limitations of dam structures, Lake Powell, and the Powerplant. However, the Bureau of Reclamation (Reclamation) and other interested parties became increasingly concerned about the effects of GCD operations on the downstream riverine environment, including the impact on several endangered species. In response to these concerns, Reclamation began to restrict operations on June 1, 1990, when it conducted research discharges as part of Glen Canyon Environmental Studies (GCES). Numerous test flows were made during a 14-month period. The duration of an individual test flow ranged from four days to several weeks. As a result of information and analysis conducted over the research discharge period, Reclamation imposed interim flow operational constraints at GCD on August 1, 1991. Interim flow restrictions were imposed until February 1997, when new operational rules and project management goals were adopted to comply with the Glen Canyon Dam Environmental Impact Statement (GCDEIS) Record of Decision (ROD) (Reclamation 1996). Restrictions mandated in the ROD operating criteria limit both the operational range of water releases and the rate that water releases are permitted to change over time.

Operating criteria reduced the flexibility of operations, diminished dispatchers' ability to respond to market price signals, and decreased the economic power benefits of the GCD. Studies conducted by a team of analysts lead by Reclamation in support of the GCDEIS estimated the economic costs of the ROD operating constraints under two different marketing arrangements: hydrology and contract rate of delivery (CROD). The hydrology approach assumed that Western Area Power Administration (Western) would sell only the capacity and energy generated by Salt Lake City Area Integrated Projects (SLCA/IP) resources resulting from the available hydrology each year. Customers would have to purchase firm capacity and energy elsewhere on an annual basis to meet any additional needs. Annual economic costs using hydrology assumptions were estimated at $15.1 million expressed in terms of 1991 nominal dollars ($1991). The net present value (NPV) of costs over the study period was estimated at $174.6 million.

The CROD approach assumed that capacity and energy would be marketed according to the post-1989 criteria. That is, Western would contract to provide its customers with long-term firm capacity and energy based on the projected generating capability of SLCA/IP resources with some acceptable level of risk. Under this arrangement, Western would purchase capacity and energy to meet customer contracts in years when SLCA/IP generation was not sufficient because of poor hydrology. In both the hydrology and CROD marketing approaches, it was the customer's responsibility to replace capacity and energy lost as a result of constrained GCD operations. Annual economic costs assuming the CROD approach were $44.2 million in 1991 nominal dollars and an NPV of $511.2 million over the study period (Reclamation 1995).

In addition to revised operating criteria, the ROD created the Glen Canyon Dam Adaptive Management Program (GCDAMP) to conduct scientific experiments and studies. Under the GCDAMP, special releases are conducted to monitor and assess the effects of dam operations on downstream resources. The special releases are exempt from the ROD operating criteria. Some of the special releases include Beach/Habitat-Building Flows (BHBFs), Habitat Maintenance Flows (HMFs), and steady flows to conduct aerial photography.

This ex post study reevaluates the economic impacts of the ROD on the power system based on historical events that took place between 1997 and 2005. Data were primarily acquired through public data sources. A comparison of this ex post analysis with the economic analysis conducted prior (ex ante) to the ROD shows that the ex ante analysis produced a fairly accurate projection of ROD economic impacts.

2 HISTORICAL BACKGROUND

This section provides a brief historical overview of GCD and its associated power plant. It also describes the bundling of the Glen Canyon power resource with other hydropower plants in the region and Western's marketing of both power and energy to its preferred customers in the Western United States. Finally, specific restrictions on the GCD operating criteria and their effects on power production are presented, as well as Western's marketing programs.

2.1 GLEN CANYON DAM AND PHYSICAL POWERPLANT CHARACTERISTICS

Glen Canyon Dam was built by Reclamation between 1956 and 1964. It is a 710-foot–high concrete arch structure with a crest length of 1,560 ft containing 4,901,000 cubic yards of concrete. The thickness of the dam at the crest is 25 ft, and its maximum base thickness is 300 ft. The total capacity of its reservoir, Lake Powell, is 27.0 MAF, with an active capacity of approximately 20.9 MAF. Under normal water surface elevation levels, the reservoir has a length of 186 miles and a surface area of 161,390 acres.

GCD is part of the Colorado River Storage Project (CRSP) that was authorized by a special Congressional Act on April 11, 1956, to develop the water resources of the Upper Colorado River Basin and control a drainage basin of approximately 108,335 square miles. Besides GCD, CRSP consists of three other projects: namely, Flaming Gorge Dam on the Green River in Utah near the Wyoming border; Navajo Dam on the San Juan River in New Mexico near the Colorado border; and Wayne N. Aspinall Dams (formerly Curecanti) on the Gunnison River in west central Colorado. The power plants associated with Aspinall are Blue Mesa, Morrow Point, and Crystal. GCD accounts for about three-fourths of the CRSP total nameplate capacity.

The project regulates the flow of the Colorado River such that water-use developments in the Upper Colorado River Basin can take place while maintaining minimum water deliveries to the Lower Basin as mandated by the Colorado River Compact. The benefits of the CRSP include controlling floods, providing irrigation and recreation, supplying municipal and industrial water, and enhancing fish and wildlife conservation. The power plant benefits of GCD consist of both power (capacity) and energy (electricity generation) benefits (Western undated *a*).

Pondage hydro power plants such as the one at GCD have several unique physical attributes. The Glen Canyon Powerplant can ramp-up or down very quickly in response to rapid load changes. It can also quickly fill generation voids that result from abrupt unit forced outages. In addition, pondage hydro power plants are also well suited to providing regulation and spinning reserve services. Relative to other technologies, GCD has had low outage rates. Since it began operation, individual units at GCD have an average availability factor of approximately 91.7%. In comparison, the average availability factor for a large coal generating unit in the United States is approximately 83.1% (NERC 2009). This high level of dependability is an important factor that increases the value of its capacity, since less reserve capacity is needed to achieve an equivalent level of system reliability.

The first two generating units at GCD, each with a nameplate capacity of 112.5 MW, began to produce power in September 1964. Approximately a year and a half later, the eighth and final unit began generating in February 1966, bringing the total Powerplant nameplate capacity to 900 MW. Subsequent to unit installations, several rewinds were performed and, as of November 1985, the nameplate capacity of the Powerplant increased to approximately 1,356 MW. Further Powerplant improvements increased the nameplate capacity to about 1,373 MW by the end of the study period.

Major components of bulk power transmission at the Glen Canyon Powerplant include hydraulic turbines, an isolated phase bus, power circuit breakers, disconnect switches, and step-up transformers. When the Powerplant was commissioned, the ratings of these components were as follows:

- Hydraulic turbines: 171.70 MW,
- Isolated phase bus: 168.27 million volt-amperes (MVA) (7,150 Amperes),
- Generator unit breakers: 167.32 MVA (7,000 Amperes),
- Generator disconnect switches: 167.32 MVA (7,000 Amperes), and
- Step-up transformers: 300.00 MVA (one for each pair of generators).

Initially, components' rated output capacities exceeded the rated capacities of generating units. However, over the lifetime of the Powerplant, unit rewinds were carried out, and unit re-rates and up-rates were completed to the point where the electrical capacities of some components were less than the nameplate capacity of the generating units.

After rewinds were completed between 1984 and 1986, four units had a nameplate capacity of 173.68 MVA with a 0.95 power factor (pf), which exceeded the rated capacity of the unit circuit breakers and disconnect switches at 167.32 MVA, and the rated capacity of the isolated phase bus at 168.27 MVA. However, each generator was constrained by a mechanical limit of 165 MW, which is below the breaker and disconnect-switch limits.

Table 2.1 shows a timeline of the Powerplant capacity improvements during the 1997-though-2005 study period. A few months after ROD operating criteria were put into practice, the armature of unit 8 was rewound in October 1997. A few years later, in August 2003, an armature for unit 2 was also rewound. As a result of these improvements, both units increased the electrical rating to 173.68 MVA at a power factor of 0.95. However, the mechanical rating of the generator remained unchanged at 165 MW.

In 2000, the unit switchgear — including the unit circuit breakers and disconnect switches for all eight generators — was replaced. This upgrade raised the capacity of the breakers and switches from 167.32 MVA to 191.22 MVA. In addition, a portion of the isolated phase bus (between the generators and the switchgear, and from the switchgear to the plant lower roof) was replaced. The new bus sections have a 191.22 MVA rating. However, sections of the original bus were not upgraded; therefore, the rating of the bus remains at its original level of 168.27 MVA.

The plant is arranged such that two generators share one step-up transformer. The combined MVA output of generator pairs (330 MVA) exceeds the nameplate rating (300 MVA) of the shared step-up transformer. Although the nameplate rating of the step-up transformers is lower than the rating for two generators, industry standards allow operation of transformers above nameplate rating if temperature limits are maintained. Operational experience has demonstrated that the step-up transformers can be operated continuously with both connected generators at full output without exceeding temperature limits.

Table 2.1 Glen Canyon Powerplant Improvements during the Study Period

Month, Year	Event	Total Plant Output Capacity (MW @ 1.0 pf)	Total Plant Output Capacity (MW @ 0.99 pf)
Feb. 1997	ROD operating criteria began	1,320.00	1,314.63
Oct. 1997	Unit 8 rewind	1,320.00	1,315.97
2000	New unit switchgear	1,320.00	1,315.97
Aug. 2003	Unit 2 rewind	1,320.00	1,317.31

Source: Reclamation (2004).

Environmental restrictions on GCD water releases that began in August 1991 reduced power plant operations significantly below the transformer limits under all but the highest hydropower conditions. The impact of environmentally driven operational criteria on the maximum power plant production levels will be discussed in detail in Section 4.

The capacity in Table 2.1 differs somewhat from the economic analysis conducted for the GCDEIS that assumed a winter Powerplant capacity of 1,407 MW and a summer capacity of 1,315 MW under the No Action Alternative (Reclamation 1995).

2.2 POWERPLANT CAPACITY AND MAXIMUM POTENTIAL POWER OUTPUT

Some equipment capacity limitations at the Glen Canyon Powerplant are hard constraints; that is, there is a maximum level of operation governed by the laws of physics. One such constraint is the maximum penstock flow rate that is primarily limited by the reservoir water elevation. Other limitations are soft constraints in that the maximum rated level of operation can be exceeded for various periods of time with little or no damage to the equipment. As discussed in the previous section, Glen Canyon transformers can be operated routinely at 300 MVA. In some cases, however, operating the machines above the maximum rated capacity for an extended period of time may result in equipment degradation, shortened equipment lifetime, and higher failure rates.

In 1997, at the beginning of the study period, the nameplate capacity of the Glen Canyon Powerplant was about 1,356 MW. After the armature rewinding of unit 2 was completed, the nameplate capacity increased to about 1,373 MW. However, these levels of power output cannot be sustained continuously for long periods of time. The maximum possible output (continuous capacity) from the Glen Canyon Powerplant is significantly lower than the nameplate capacity. In addition, the maximum possible power output from the Powerplant varies as a function of several factors that include: plant power factor, Lake Powell forebay elevation, maximum penstock water flow rate, unit water-to-power conversion efficiencies, tailrace elevation, unit availability, and transformer and circuit breaker limitations.

The constraints that limit the maximum power output at the Glen Canyon Powerplant differ depending on the situation. At higher forebay elevation levels, the mechanical rating of the eight units at 165 MW apiece (for a total of 1,320 MW) is the limiting factor. When the reservoir water elevation is relatively low, the maximum penstock flow rate and the efficiency of the turbine to convert water flow into electric power reduces the maximum power output to a lower level.

Figure 2.1 shows Lake Powell elevation (primary y-axis) along with nameplate capacity, continuous capacity at a power factor of 0.99, and maximum output capability (secondary y-axis) during the study period. Lake Powell elevation data were obtained from Form PO&M 59 data. Maximum output capabilities were computed monthly based on a Glen Canyon Powerplant turbine flow rate equation that relates the maximum turbine flow rate to reservoir elevation. The computed turbine flow rate is multiplied by a power conversion factor to obtain the maximum output level. Its upper limit is constrained by the continuous capacity level. It is important to note that when the Lake Powell water elevation rises above 3,677 ft, the maximum output capability is set equal to the continuous capacity level. A more detailed explanation of the power conversion factor is provided in the next section.

The continuous capacity level is based on a power factor of 0.99, which Glen Canyon Powerplant operators have indicated is a typical operating level. This assumption is also supported by historical operations shown in Figure 2.2.

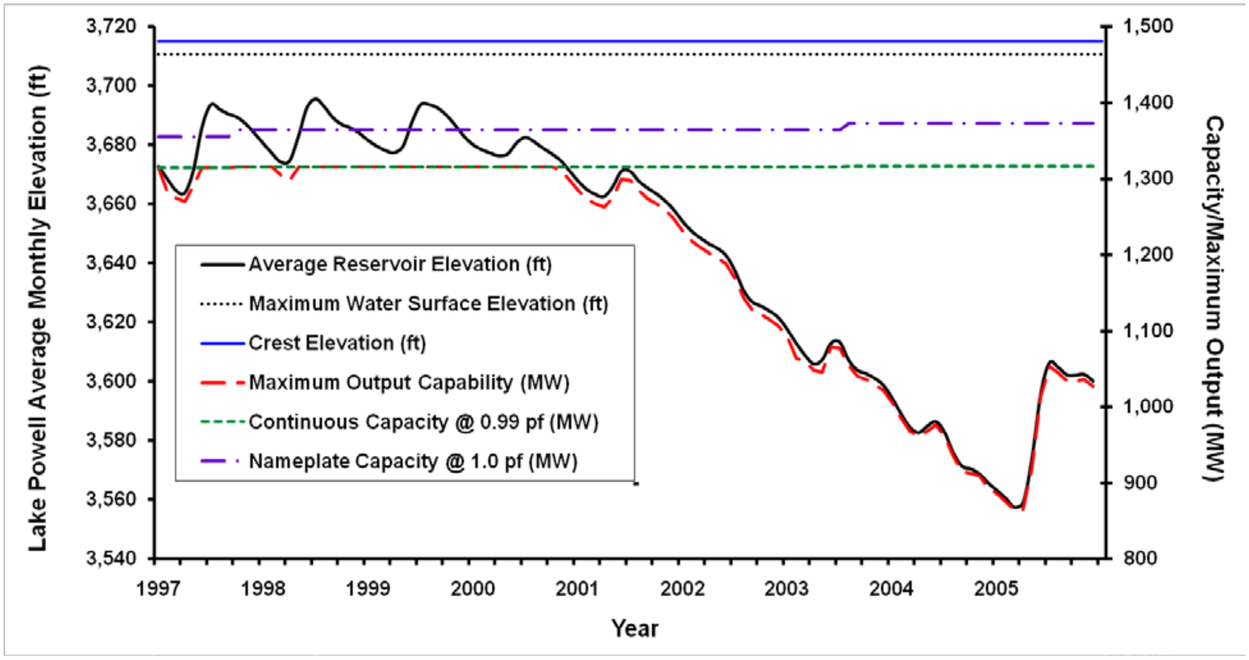

Figure 2.1 Powerplant Capacity and Output Capability in the Study Period

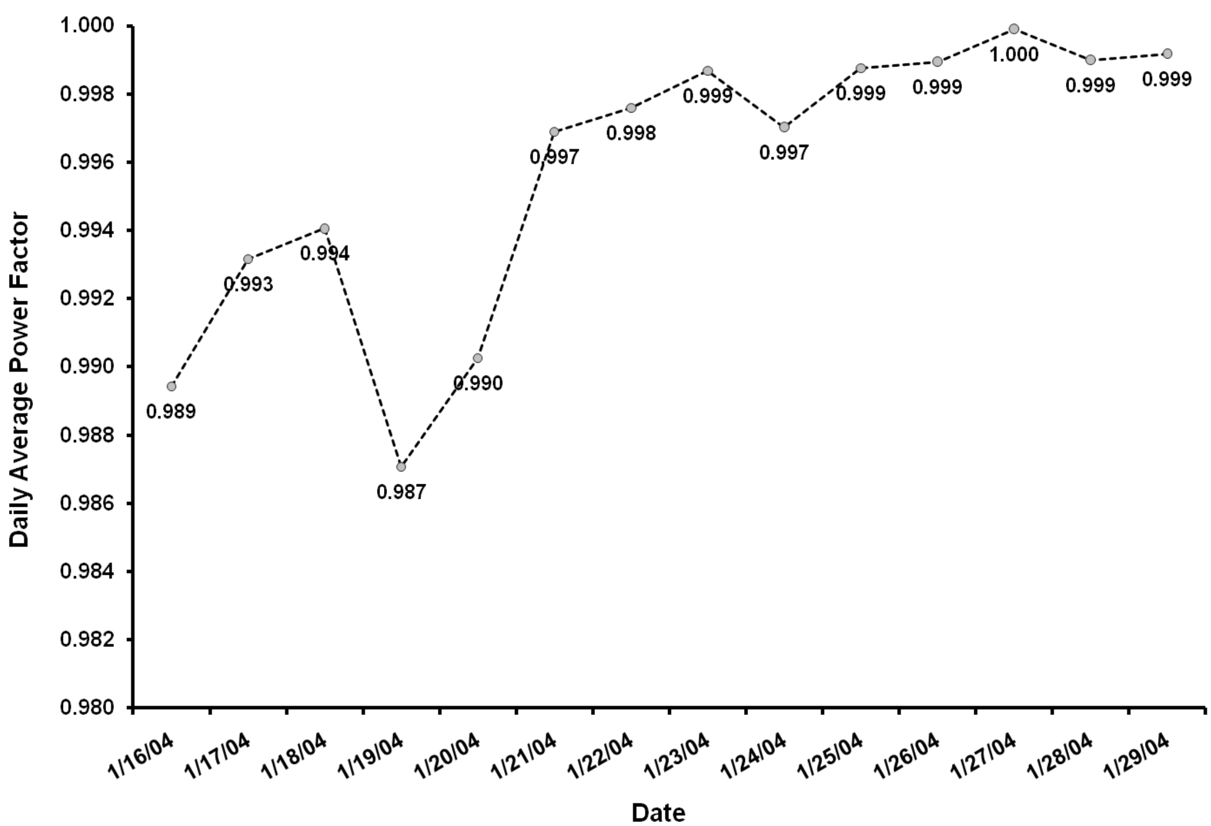

Figure 2.2 Powerplant Average Daily Power Factor for January 16–29, 2004

2.3 POWERPLANT GENERATION

Electricity generated from the Glen Canyon Powerplant has served consumer load in several western states since September 1964. From the time it was first brought on-line through the start of the ROD constraints in February 1997, the gross electricity generation from the Glen Canyon Powerplant was more than 141,662 gigawatt-hours (GWh). This energy displaces generation from other power sources that mainly burn depletable resources such as coal, oil, and natural gas.

During the first several years of operation through the end of 1979, the amount of water that was released for power purposes was relatively small, since some of the inflows into Lake Powell were used by Reclamation to fill the reservoir. Lake Powell was completely filled in 1980, or about 16 years after the Powerplant began to operate. From 1965, the first full year of Powerplant operations, through the end of 1979, the amount of water released per calendar year for power generation ranged from between 6.3 MAF and 9.5 MAF. These release amounts were in accordance with Lake Powell filling criteria established in July 1962 (GPO 1962). From 1980 through 2005, annual generation has varied by more than a factor of 2.6. Figure 2.3 shows that annual generation after 1980 was as low as 3,299 GWh in 2005 and as high as 8,703 GWh in 1984. The minimum annual allowable release of 8.23 MAF, which includes both turbine and non-turbine water during a water year (WY), was reached in several drought years. However, if drought conditions continue for an extended period of time, the minimum annual release may not be attainable in the future. The high level of generation variability of the Glen Canyon Powerplant since 1980 is mainly attributable to annual variations in precipitation levels in the Upper Colorado River Basin. Generation variability reduces the value of the resource because it adds to the overall uncertainty of the power system and increases the risk of not serving system load.

The annual generation amounts shown in Figure 2.4 display a continuous decline in production through the study period. The fifth-highest generation year occurred in 1997, the first study year, while the last four years, 2002 through 2005 inclusive, were the lowest on record. The average annual generation during the study period is more than 400 GWh lower than that of the overall 26-year historical period, that is, about 8% lower than the long-term average. Annual generation during the study period also displayed a wide range of hydropower conditions, from a low of 3,299.4 GWh in 2005 to a high of 7,435.3 GWh in 1997.

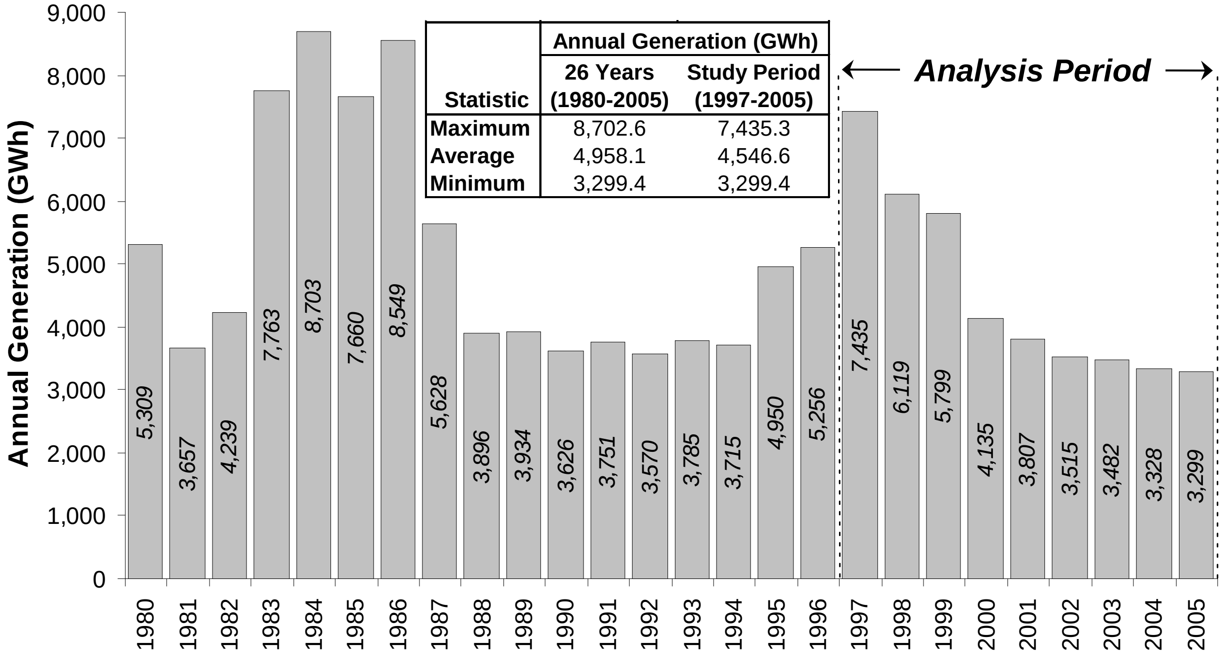

Figure 2.3 Annual Generation from the Glen Canyon Powerplant in Calendar Years 1980 through 2005

Monthly generation levels during the study period (shown in Figure 2.4) display a decreasing power production trend over time. Also evident in the monthly bar chart is a cyclical trend that is repeated annually. Figure 2.5 shows monthly generation averages during the study period. Generation tends to be highest during January, July, and August, while September and October have the lowest generation levels. In general, this monthly pattern of electricity generation from the Glen Canyon Powerplant has been beneficial from a power systems viewpoint, since relatively large amounts of energy are generated when it has the greatest value. The months with the highest generation levels coincide with peak demand periods that occur during the summer. Electricity produced during the summer has a high economic value since it displaces generation from sources that have the highest production costs. These sources tend to be units that are relatively inefficient and burn more expensive fuels, such as fuel oil and natural gas. Historically, relatively high levels of generation have also occurred during December and January, corresponding with the peak winter demand period. Low-generation months are March and April in the spring and October in the fall. These months have relatively lower electricity demands, and energy is typically less valuable.

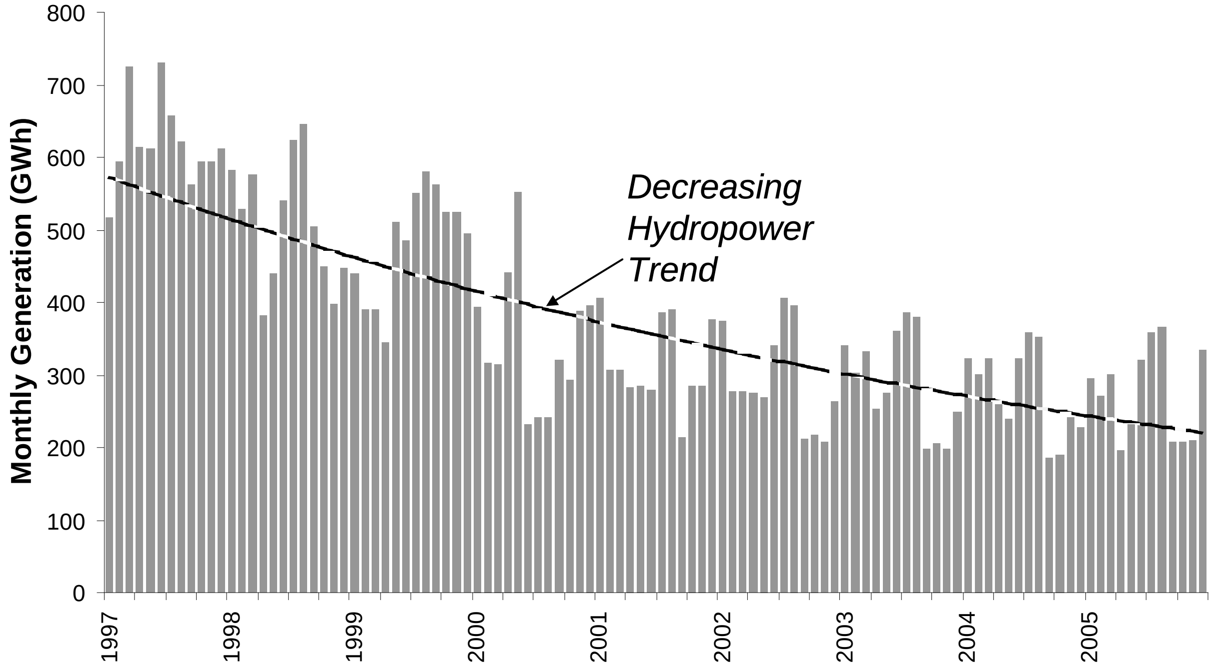

Figure 2.4 Monthly Energy Production during the Study Period

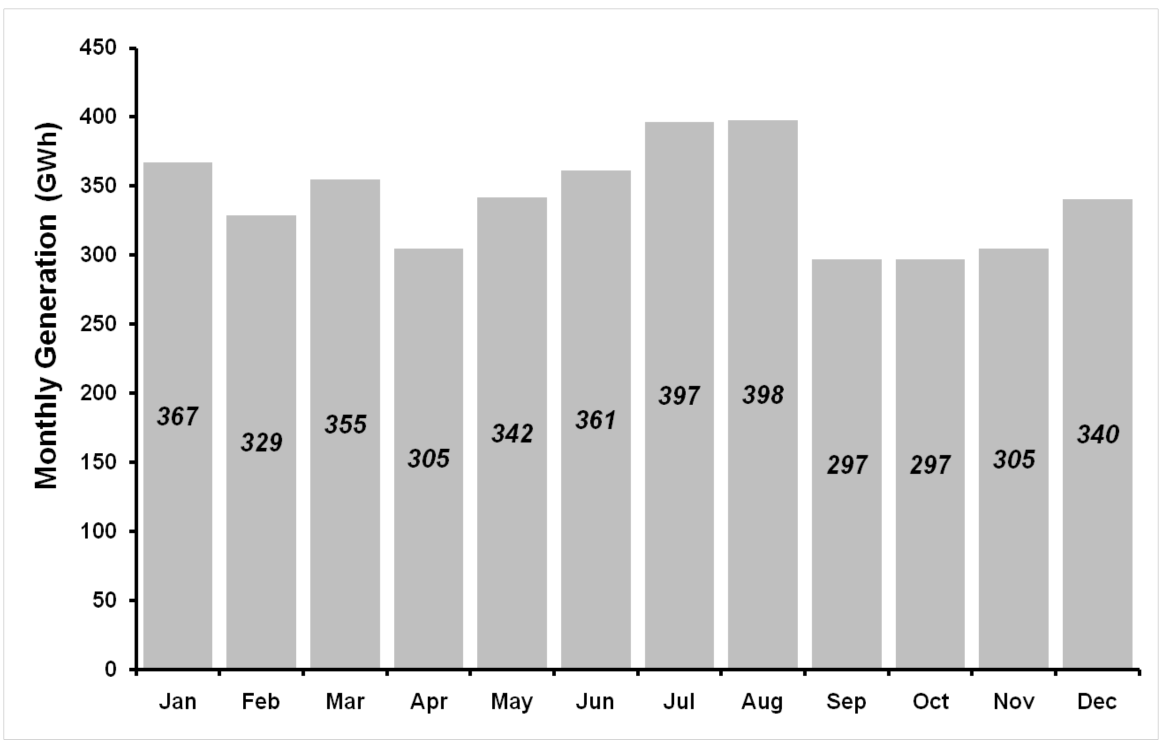

Figure 2.5 Average Monthly Energy Production during the Study Period

2.4 POWERPLANT EFFICIENCY

The efficiency at the Glen Canyon Powerplant is primarily a function of the water elevation level in Lake Powell and the flow rate of water through the turbines. For this analysis, historic power conversion factors were based on data contained in Form PO&M-59 and shown in Figure 2.6. The power conversion factor is the ratio of the monthly gross generation at the plant in megawatt-hours (MWh) to the monthly water power release in acre-feet (AF). As shown in the figure, the computed power conversion factor (secondary y-axis) is highly dependent on the water elevation in Lake Powell (primary y-axis). This high level of dependency is also shown in Figure 2.7. As the reservoir water level increases, the change in height between the forebay and tailwater elevations (i.e., head) rises, thereby increasing the potential energy of the falling water. Other factors — such as power plant unit commitment schedules and dispatch, individual turbine efficiency curves, water turbine flow rates, and the temperature of the water (i.e., density) — all influence the power conversion factor, resulting in a slight difference between the observations in Figure 2.7 (individual point) and the trend line.

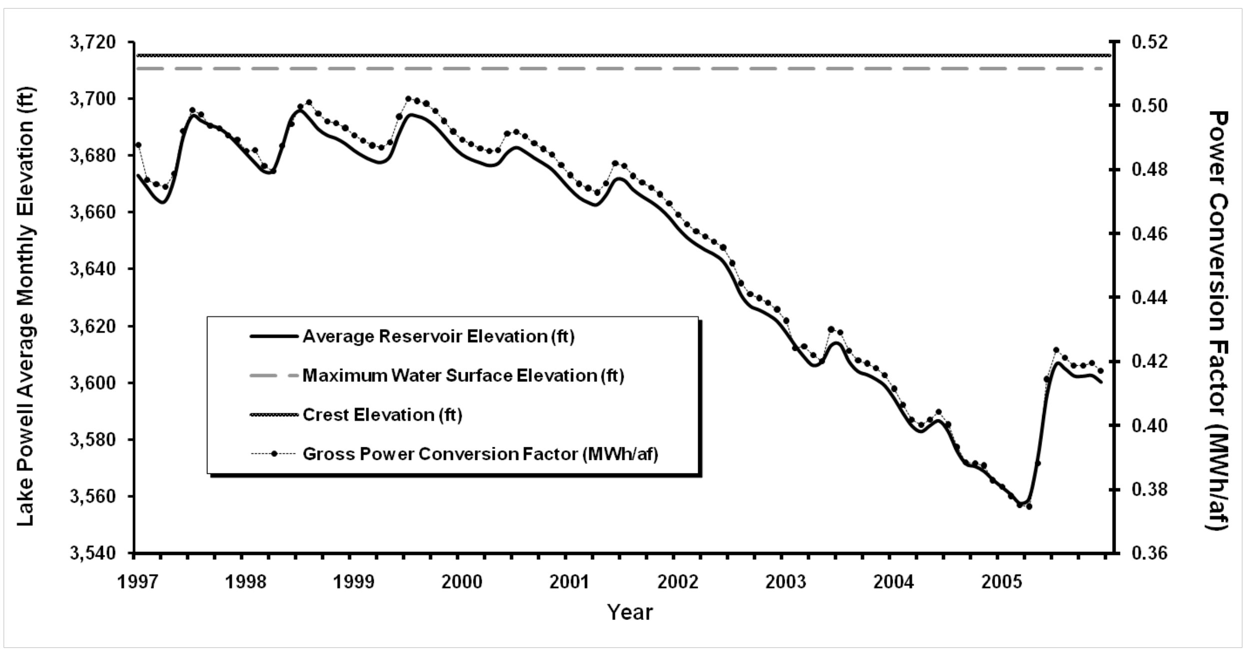

Figure 2.6 Powerplant Capacity and Output Capability in the Study Period

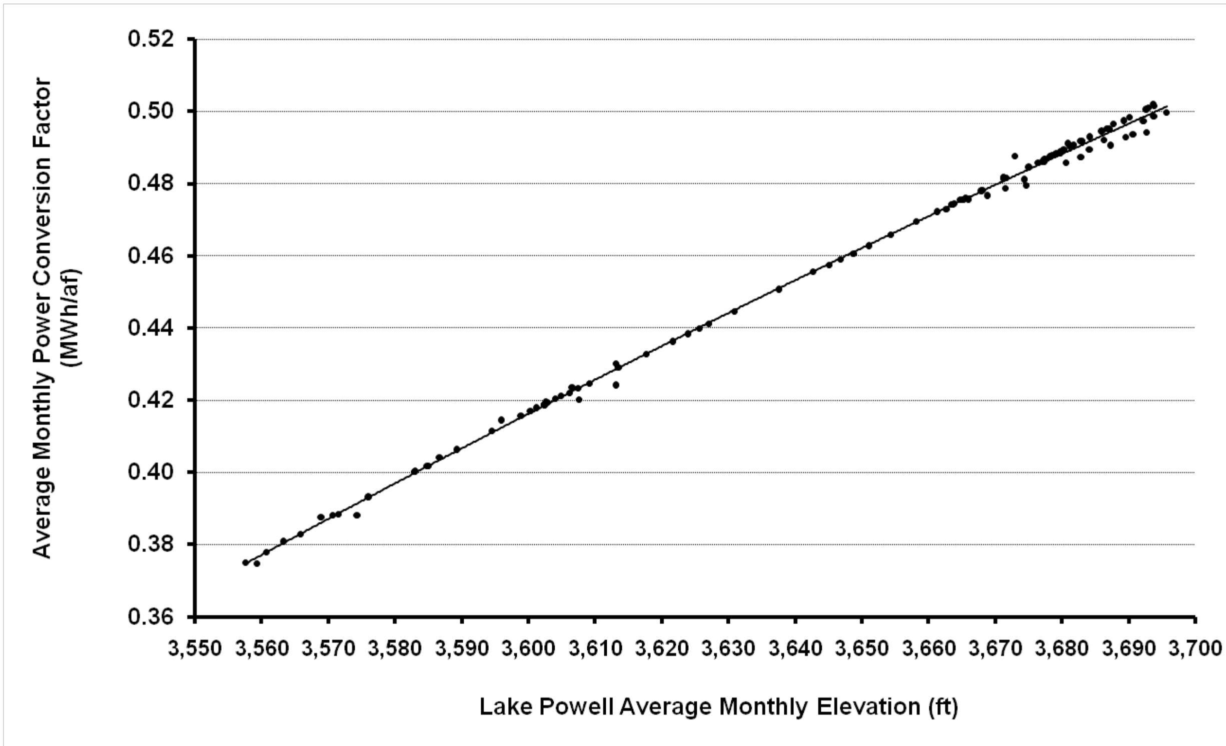

Figure 2.7 Powerplant Capacity and Output Capability in the Study Period

2.5 GLEN CANYON DAM OPERATING CONSTRAINTS

Operational limitations at GCD were minimal from 1964 through May 1990. As shown in Table 2.2, minimum releases from Lake Powell were 1,000 cubic feet of water per second (cfs) from Labor Day to Easter and 3,000 cfs during the rest of the year. These minimums are only a small fraction, approximately 3% to 9%, of the physical maximum turbine flow rate of 33,000 cfs at full reservoir.

Table 2.2 Summary of Hydropower Operational Scenarios

Scenario/ Power Plant	Minimum Release Rate (cfs)	Maximum Release Rate (cfs)	Maximum Daily Fluctuation (cfs/day)	Up-Ramp Rate (cfs/hr)	Down-Ramp Rate (cfs/hr)
Prior to Environmental Constraints					
Glen Canyon	1,000[a] or 3,000[c]	31,500	NR[b]	NR	NR
Interim Flow Restrictions (August 1991 through the end of January 1997)					
Glen Canyon	8,000 or 5,000[d]	20,000[e]	5,000, 6,000, or 8,000[f]	2,500	1,500
Post-ROD (after January 1997)					
Glen Canyon	8,000 or 5,000[d]	25,000[e]	5,000, 6,000, or 8,000[f]	4,000	1,500

[a] Labor Day to Easter.

[b] NR denotes no restriction.

[c] Easter to Labor Day.

[d] 8,000 (7:00 a.m.–7:00 p.m.); 5,000 (all other hours).

[e] During wet years, the maximum flow rate may be exceeded; however, flows during this time must be steady at or above 25,000 cfs.

[f] Limited to 5,000 cfs/day for months with water releases of less than 600 thousand acre-feet (TAF); 6,000 cfs/day for months with water releases of 600 TAF to 800 TAF; and 8,000 cfs/day for months with water releases greater than 800 TAF.

The maximum release rate for power generation was limited only by the generating capability of the plant and the forebay elevation, that is, the maximum physical water release through power plant turbines. There were no institutional limitations on either hourly or daily ramp rates. The relatively slow minimum release rate requirement, combined with limits that were only constrained by the physical power plant and dam characteristics, allowed for very flexible hydropower operations.

Figure 2.8 shows GCD water releases on July 20, 1989, before more stringent restrictions were imposed on dam operations. Water release was 3,471 cfs at 5:00 a.m. and increased dramatically to 28,985 at 3:00 p.m.; representing a daily change in release of 25,514 cfs (Patno 2008). In addition, during a one-hour period, water releases decreased by more than 11,263 cfs between 11:00 p.m. and midnight. The largest hourly ramping up of releases was 5,993 cfs/hr. Although this particular day had greater-than-usual changes in release levels, this example illustrates the large degree of latitude that dispatchers were allowed to exercise in the past to follow customer firm load and to respond to market prices.

The practice of large fluctuations in water releases began to change when Reclamation and other interested parties became increasingly concerned about the effects of GCD operations on the downstream riverine environment, including the impact on several endangered species. Reclamation began to restrict operations on June 1, 1990, when it conducted research discharges as part of the GCES. Numerous test flows were conducted during a 14-month period that concluded at the end of July 1991. The purpose of these research discharges was to collect and analyze data at different flow levels in order to investigate the effects of discharge patterns on the riverine environment downstream of the GCD. Only limited conclusions could be drawn from the information that was available before this research began. The National Academy of Sciences recommended that the GCES effort focus on studying specific flow levels. In October 1989, negotiations with the GCES office, Reclamation, and Western over the types, extent, and duration of the research discharges were initiated.

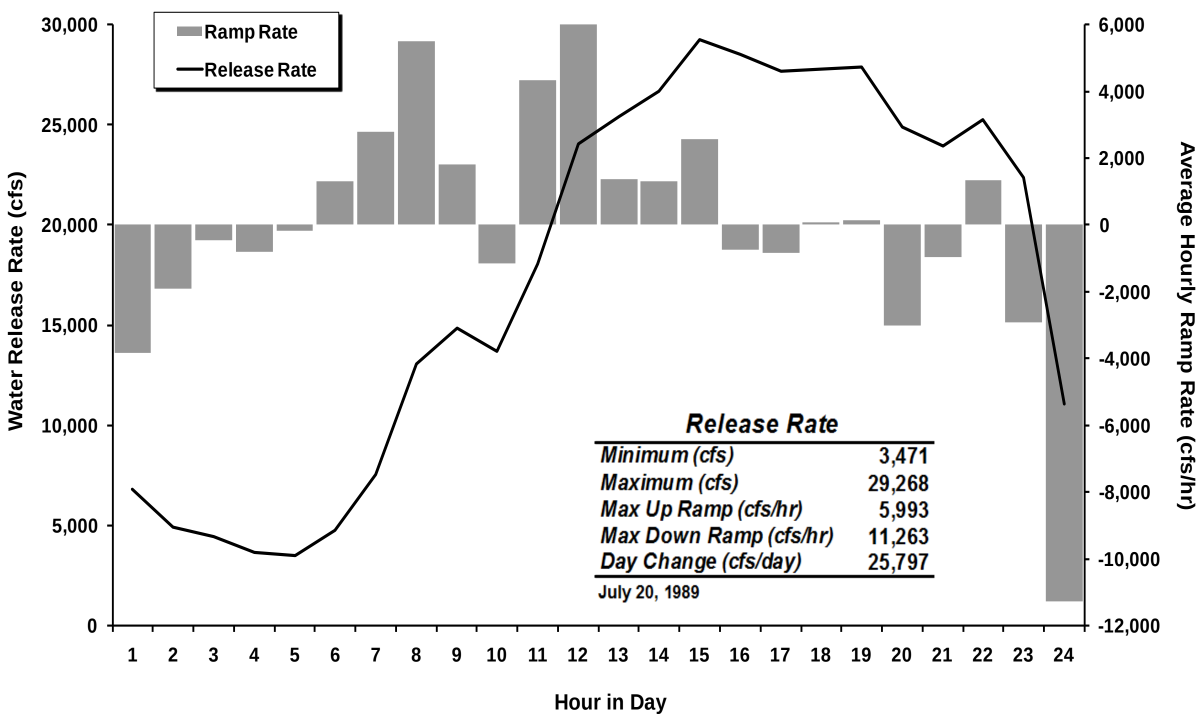

Figure 2.8 Glen Canyon Releases over a Single Day Prior to More Stringent Operating Restrictions (July 20, 1989, is shown)

Interim flow restrictions were imposed from August 1991 until February 1997, when new operational rules and project management goals were adopted to comply with the GCDEIS ROD. Relative to the period of minimal operational restrictions, interim flow limitations raise the minimum release rate, reduce the maximum release rate, and restrict both hourly and daily fluctuations in releases. As shown in Table 2.2, the minimum release through GCD was required to be at least 8,000 cfs between the peak hours of 7:00 a.m. to 7:00 p.m., and 5,000 cfs or more at night. The maximum allowable release from GCD was limited to 20,000 cfs. The interim operating criteria also limited the allowable release fluctuations in any 24-hour period. The amounts vary depending on the amount of water released in a month. The allowable daily fluctuation was 5,000 cfs/24 hours for months in which scheduled water releases through the dam were less than or equal to 600,000 AF (or 600 thousand acre-feet [TAF]) during the month. Daily fluctuations were restricted to 6,000 cfs/24 hours for months in which scheduled releases were more than 600 TAF to less than 800 TAF, and at 8,000 cfs/24 hours for months with releases greater than or equal to 800 TAF/month. Finally, the interim operating criteria also limited the rate at which the generators may ramp up or down. The maximum power plant ramp rate was 2,500 cfs/hr when increasing and 1,500 cfs/hr when decreasing.

Interim flow restrictions diminished the economic benefit of the Glen Canyon Powerplant, since the hydropower energy could not be used to its fullest extent to displace generation from more expensive peaking units. Figure 2.9 shows that the hourly generation pattern for July 14, 1994, was significantly different from the pattern on July 20, 1989, as shown in Figure 2.8. The daily fluctuation in release levels was between 10,010 cfs and 18,040 cfs. The largest up-ramp rate was 1,940 cfs/hr, while the largest down-ramp rate was 1,470 cfs/hr.

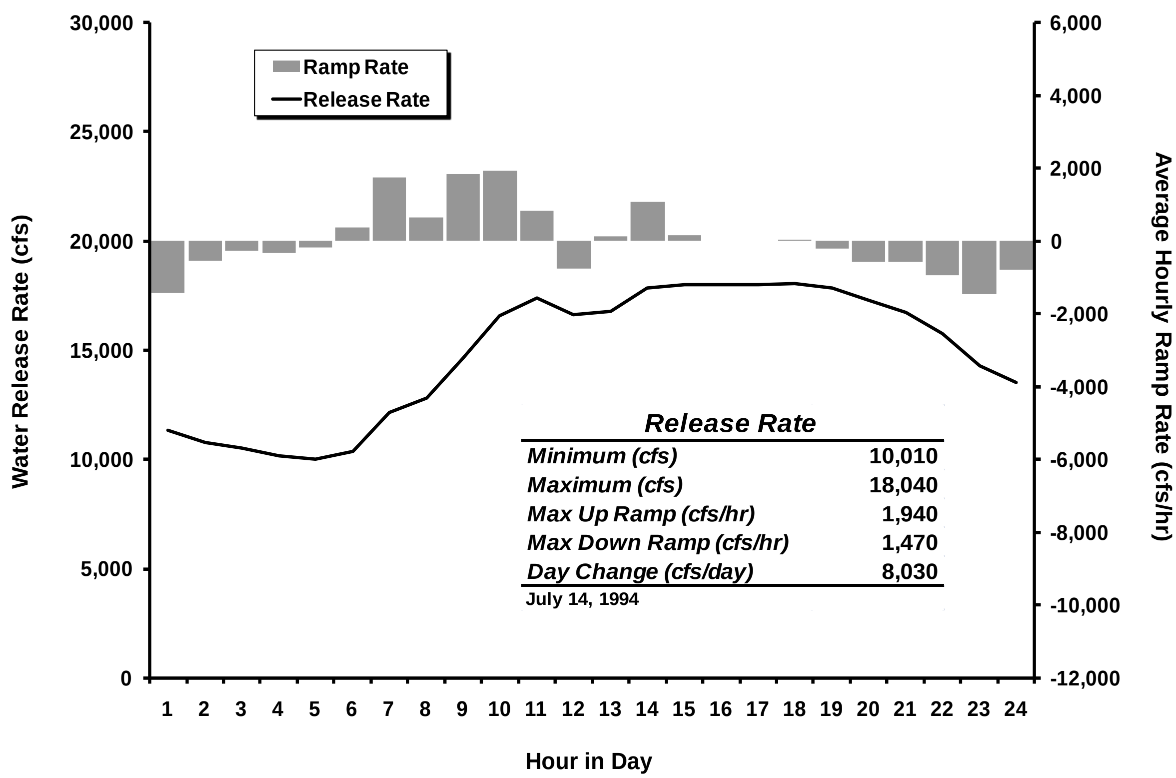

Figure 2.9 Glen Canyon Releases over a Single Day under Interim Operating Restrictions (July 14, 1994, is shown)

The GCDEIS process was completed when the ROD was signed by then-Secretary of the Interior Bruce Babbitt on October 9, 1996. The ROD affirmed the selection of the preferred alternative, Modified Low Fluctuating Flow (MLFF), for operating GCD. Reclamation issued *Operating Criteria for Glen Canyon Dam* in early 1997 (GPO 1997). The 1997 Operating Criteria expanded the operational criteria contained in the GCDEIS and ROD and provided Western and Reclamation operations staffs with the dam operation guidance. The 1997 Operating Criteria were first implemented in February 1997 and are, in many respects, similar to those of the interim flow. However, the hourly up-ramp rate constraint was relaxed from 2,500 cfs/hr to 4,000 cfs/hr. In addition, the maximum flow rate limit is 5,000 cfs higher than the interim flow restrictions, that is, 20,000 cfs under interim flows versus 25,000 cfs under the 1997 Operating Criteria. There are maximum flow rate exceptions to accommodate different types of flows that are conducted under the GCDAMP (see Section 2.6 for details). One such release is the Beach/Habitat-Building Flow (BHBF), which initially occurred in March 1996. Maximum release rate exceptions are also allowed to avoid spills or flood flow release during high runoff years. Under very wet hydrological conditions in which an average release rate of more than 25,000 cfs is required to release the target monthly volume, no hourly or daily ramping is permitted (flat flow releases).

Figure 2.10 shows the hourly generation pattern for July 19, 1999, when hydropower conditions were at near-normal levels. Under ROD constraints, the range of flows and hourly ramping rates are relatively small compared to those in Figure 2.8, when operating criteria were less restrictive but somewhat larger than operations under interim flow criteria. When hydropower conditions are significantly above normal, releases must be a constant. This ROD requirement was applicable in July 1997. Figure 2.11 shows that on July 2, 1997, releases were nearly constant at about 26,500 cfs. This operation is compliant with the ROD, which requires a constant release rate when the 25,000 cfs flow rate is exceeded to accommodate monthly release targets. Because the release rate was nearly constant, the ramp rates throughout the day were very small.

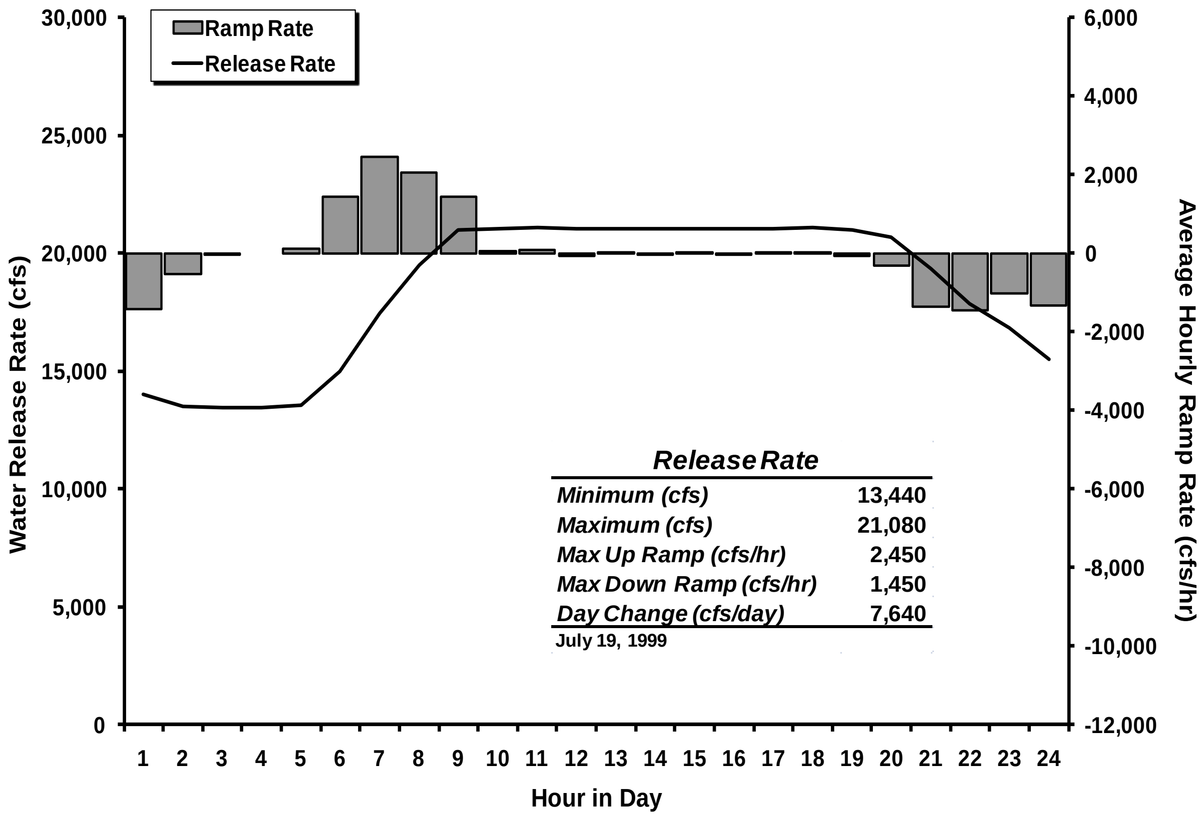

Figure 2.10 Glen Canyon Releases over a Single Day under ROD Restrictions (Normal Condition) (July 19, 1999, is shown)

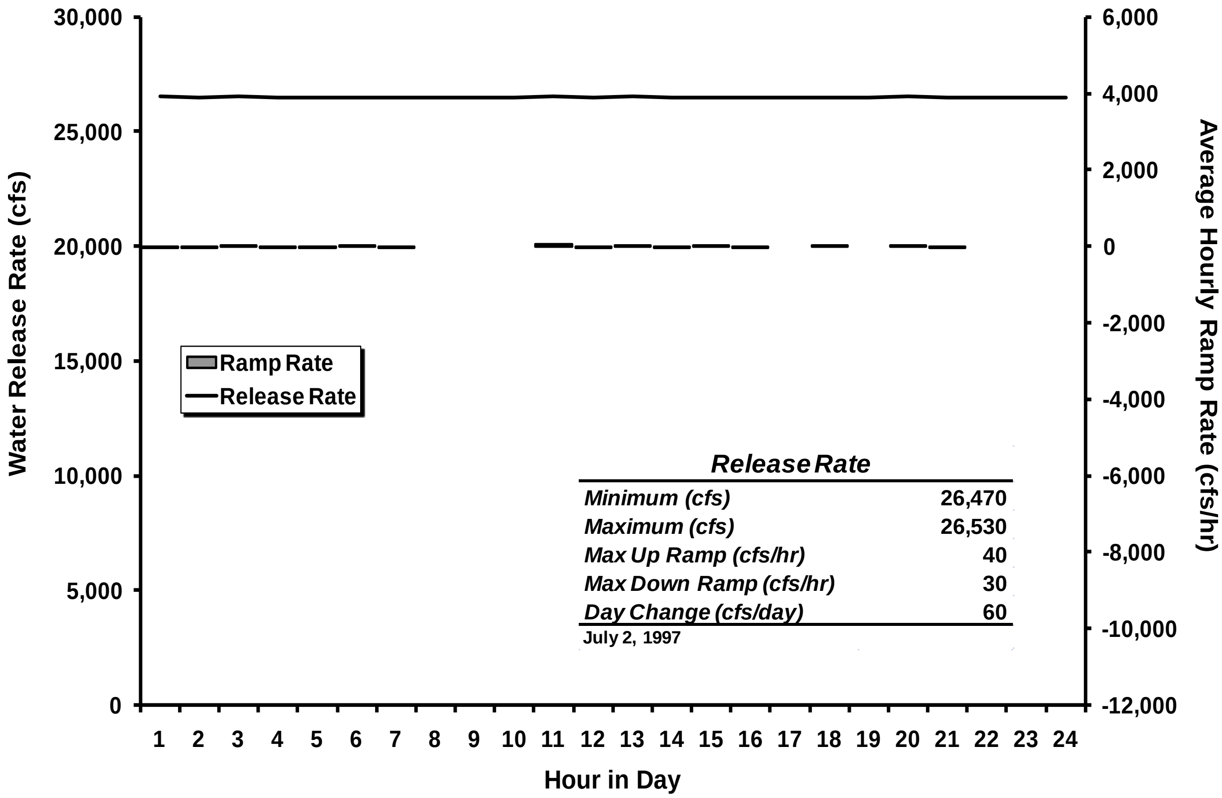

Figure 2.11 Glen Canyon Releases over a Single Day under ROD Restrictions (Wet Condition) (July 2, 1997, is shown)

The operational restrictions affect the economic benefits of the hydropower resource in two ways. First, the loss of operable capability must eventually be replaced. Second, the hydropower energy cannot be used to its fullest extent to reduce the need for generation from expensive peaking units. Maximum flow restrictions reduce Glen Canyon's operating capacity by approximately 36%, and ramp rate limitations decrease Western's ability to follow firm loads. Depending on reservoir conditions, the up-ramp rate constraint limits hourly increases in power to about 90 to 105 MW, and the down-ramp rate constraint limits hourly power decreases to 54 to 65 MW. Depending on Reclamation's monthly release levels and reservoir conditions, maximum daily fluctuations are limited to approximately 185 to 340 MW. Under dry hydropower conditions, ramp rate constraints will not permit Western to reach the 25,000-cfs maximum flow constraint on a daily basis and further reduce the Glen Canyon Powerplant's operating capacity. When flexibility at Glen Canyon is reduced, operations at other SLCA/IP hydropower plants may, at times, fluctuate more frequently and more rapidly.

2.6 BEACH/HABITAT-BUILDING FLOWS AND EXPERIMENTAL RELEASES

Before the Glen Canyon Dam was constructed, Colorado River flow rates through the Grand Canyon were relatively high in the spring of most years because of snowmelt in the Rocky Mountains. The snowmelt produced flooding events, which transported time large quantities of sediment into the Grand Canyon, creating and maintaining sandbars. Sandbars supply camping beaches for the river's runners and hikers, provide the sediment needed to protect archaeological resources from weathering and erosion, and create habitats used by native fish and other wildlife. For example, sandbars create areas of stagnant or low-velocity flow that are used as rearing areas by humpback chub and other native fishes.

The ROD created the GCDAMP to monitor and assess the effects of dam operations on downstream resources. An activity of the GCDAMP is to conduct special and experimental releases, which are exempt from the ROD operating criteria for the duration of the release. One special flow mimics natural flood events by releasing large volumes of water from GCD. These flows are known as Beach/Habitat-Building Flows (BHBFs). Based on a predefined set of triggers, Reclamation mimics spring flooding by releasing large volumes of water from Lake Powell during controlled floods to build beaches and habitats along the banks of the Colorado River downstream of the GCD. Some of the water discharged during the "spike" release does not generate electricity, since reservoir release rates exceed the turbine flow rate limits. Thus far, three BHBFs have been conducted by Reclamation.

A few months before the ROD was implemented, the first BHBF was conducted for research purposes during a 17-day period in late March and early April 1996. Steady releases at 8,000 cfs were maintained for a 4-day period from March 22 through March 25. On March 26 at approximately 2:00 a.m., releases were ramped up at a rate of 4,000 cfs/hr until a maximum flow of 45,000 cfs was attained at 12:00 noon. A 45,000-cfs release rate was sustained for seven days.

Water releases were then ramped down to 8,000 cfs by using three different ramp rates, depending on the flow rate. From 45,000 cfs to 35,000 cfs, the ramp-down rate was 1,500 cfs/hr; from 35,000 cfs to 20,000 cfs, the ramp-down rate was 1,000 cfs/hr; and below 20,000 cfs, the ramp-down rate was 500 cfs/hr. A flow rate of 8,000 cfs was maintained for approximately four days, namely, from 8:00 a.m. on April 4 until 2:00 a.m. on April 8, 1996. Reclamation estimated that during March and April, water releases during the spike flow were 409 TAF higher than the amount that would have been released without the spike flow. Of that amount, approximately 217 TAF of water bypassed the Powerplant (Harpman 1997).

A second BHBF event took place from November 20 to December 1, 2004. As shown in Figure 2.12, the event lasted 11 days, or six days shorter than the 1996 BHBF. On Sunday, November 21, releases were ramped up during a 13-hour period to achieve a release rate of just under 40,000 cfs. This rate was maintained for 60 hours, during which time water was routed through bypass tubes at a rate of 15,000 cfs. Releases were then ramped down over a 10-hour period to reach 8,000 cfs and were maintained at that level for about five days.

In addition to the high release experiments associated with BHBFs, the GCDAMP conducts several other special and experimental releases. In many of these releases, periods of strictly steady releases are observed, while in other releases, the rates fluctuate. A list of all experimental flows from 1997 through 2005 is provided in Table 2.3. Because special and experimental releases are authorized in the ROD, they are included in the ROD scenario.

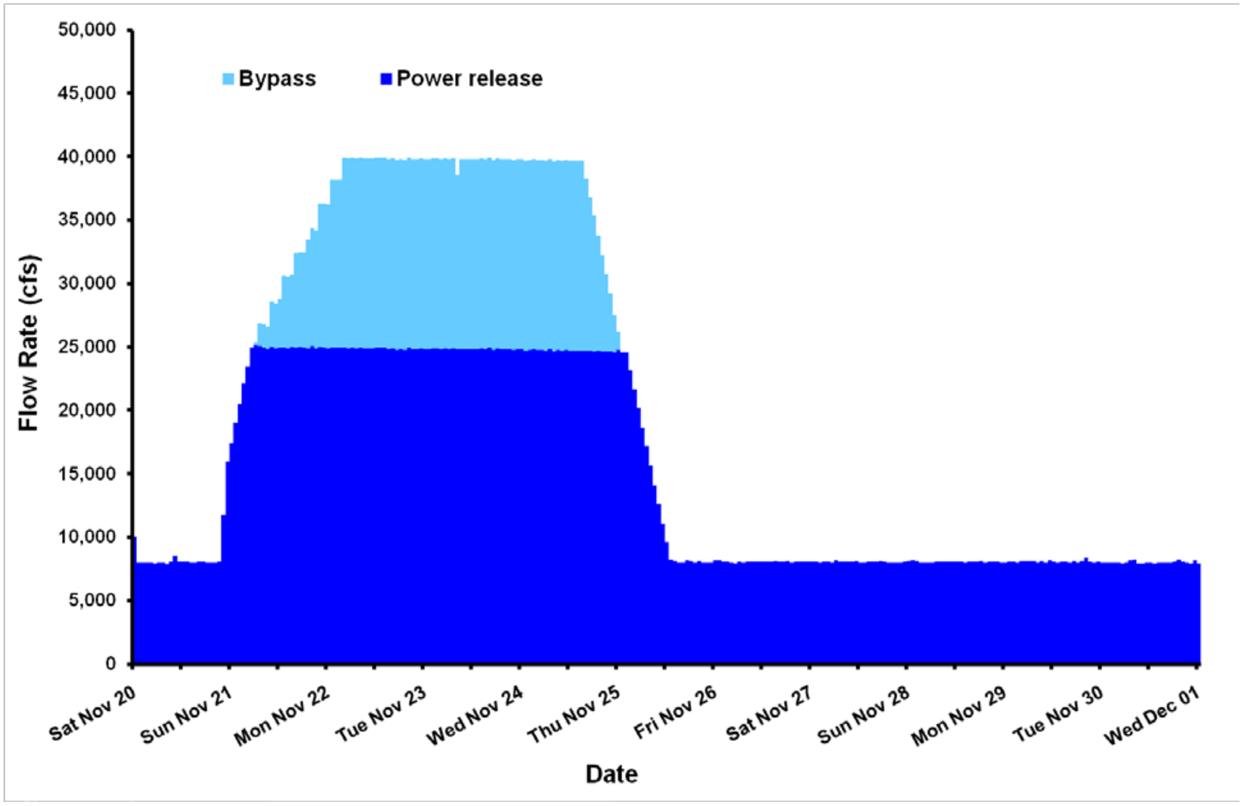

Figure 2.12 Glen Canyon 2004 BHBF Releases

Table 2.3 List of Historical Experimental Flow Periods from 1997 through 2005

Experimental Flow	Period	Description
Aerial Photography Steady Flow (APSF)	8/30/1997 to 9/2/1997	Steady 8,000 cfs release
Habitat Maintenance Flow (HMF)	11/3/1997 to 11/5/1997	48 hours of high releases at maximum turbine flow (~30,700 cfs)
APSF	9/4/1998 to 9/8/1998	Steady 15,000 cfs release
APSF	9/3/1999 to 9/7/1999	Steady 15,000 cfs release
Low Summer Steady Flows (LSSF)	3/25/2000 to 9/30/2000	Alternating periods of low (LF) and high (HF) steady flows: LF @ 8,000 cfs: 3/25–4/6, 6/1–9/4, 9/9–9/30 HF @ 13,000 to 30,000 cfs: 4/6–5/31, 9/4–9/9
APSF	6/28/2001 to 7/2/2001	Steady 8,000 cfs release
APSF	5/24/2002 to 5/31/2002	Steady 8,000 cfs release
Non-native Fish Suppression Flows (NNFSF)	1/1/2003 to 3/31/2003	Prescribed hourly release pattern ranging from about 5,000 cfs to 20,000 cfs each day
APSF	5/23/2003 to 5/27/2003	Steady 8,000 cfs release
NNFSF	1/1/2004 to 3/31/2004	Prescribed hourly release pattern ranging from about 5,000 cfs to 20,000 cfs each day
APSF	5/28/2004 to 5/31/2004	Steady 8,000 cfs release
APSF	11/17/2004 to 11/20/2004	Steady 8,000 cfs release
BHBF	11/21/2004 to 11/25/2004	11-day BHBF with maximum flow of ~40,000 cfs for 60 hours. Bypass releases reached 15,000 cfs
APSF	11/26/2004 to 11/30/2004	Steady 8,000 cfs release
APSF	12/3/2004 to 12/5/2004	Steady 8,000 cfs release
NNFSF	1/1/2005 to 3/31/2005	Prescribed hourly release pattern ranging from about 5,000 cfs to 20,000 cfs each day

2.7 SALT LAKE CITY AREA INTEGRATED PROJECTS

Glen Canyon does not operate and is not marketed as an isolated entity. Instead it is one component of a larger hydropower system, and it is packaged along with other power plants for marketing purposes. Capacity and energy from the CRSP, including from Glen Canyon, the

Seedskadee Project, the Collbran Project, and the Rio Grande Project, are bundled and marketed by Western as the Salt Lake City Area Integrated Projects (SLCA/IP) to preferred customers in Arizona, Utah, Colorado, New Mexico, Nevada, Wyoming, and Texas. The combined installed capacity of the 11 SLCA/IP power plants is 1,819 MW, and they serve cities and towns, rural electric cooperatives, agricultural irrigation districts, and Federal and state agencies. Capacity and energy are sold on the wholesale market under long-term firm (LTF) contracts. When energy exceeds LTF contractual obligations or when operational regulations result in generation levels above load, energy is sold on the spot market in order to maximize the value of the hydropower resource. The benefits of the Glen Canyon Powerplant also include serving the energy requirements of special project uses, such as irrigation, and fulfilling utility system requirements for spinning reserves and regulation services.

The Seedskadee Project, a participating project of the SLCA/IP, is in the Upper Green River Basin in southwestern Wyoming. It provides storage and regulation of the flows of the Green River for power generation, municipal and industrial use, fish and wildlife, and recreation. The Fontenelle Dam is the only power plant associated with the Seedskadee Project.

The Collbran Project, located in west central Colorado about 35 miles northeast of Grand Junction, was authorized by Congress in July 1952. It developed a major part of the water in Plateau Creek and its principal tributaries. Major project works include Vega Dam and Reservoir, two power plants, two major diversion dams, about 37 miles of canal, and about 18 miles of pipeline and penstock. East Fork Diversion Dam and Feeder Canal, along with the Bonham-Cottonwood Collection System, carry water to Bonham Reservoir, which supplies water to operate the Molina power plants.

The Rio Grande Project, which is 125 miles north of El Paso, Texas, began operation in 1916 after the Rio Grande Reclamation Project congressional act in 1905 established a much-needed irrigation project on the Rio Grande River in south central New Mexico and west Texas. The only dam with a power plant at the Rio Grande Project is Elephant Butte Dam.

The Dolores Project is located in the San Juan and Dolores River basins of the Upper Colorado River Basin in southwestern Colorado. It extends through portions of Montezuma and Dolores counties and uses water from the Dolores River for irrigation, municipal and industrial use, recreation, fish and wildlife, and production of hydroelectric power. There are hydroelectric power plants at the McPhee Dam and the Towaoc Canal.

2.8 MARKETING OF GLEN CANYON DAM POWER AND ENERGY

After GCD was built and connected to the grid, Reclamation was responsible for marketing and selling power generated by the Glen Canyon Powerplant. This responsibility was transferred in 1977 to Western, a newly formed Federal power marketing administration, created within the U.S. Department of Energy (DOE). Western also assumed Reclamation's responsibility for marketing other hydropower plants within and outside of the Colorado River Basin and for transmitting electricity. The marketing of SLCA/IP, including the Glen Canyon component, is currently under the auspices of Western's CRSP Management Center (MC) headquartered in Salt Lake City, Utah. Western's principal marketing program is the sale of LTF capacity and energy at LTF rates. Reclamation retained responsibilities for the construction, operation, and maintenance of dams and power plants and for water sales (Western undated *b*).

Western considers many factors when establishing LTF capacity and energy commitment levels, such as hydroelectric generator capability, transmission limitations, annual rainfall quantities, environmental constraints, and reservoir levels. When the ROD operating criteria were first implemented in 1997, Western sold LTF capacity and energy under its post-1989 marketing criteria. The post-1989 level was selected by Western as the SLCA/IP preferred alternative, following an extensive public process and preparation of an Electric Power Marketing-Environmental Impact Statement (EPM-EIS) (DOE 1996). Table 2.4 shows Western's seasonal allocations by division. The contract rate of delivery (CROD) is the maximum amount of capacity that can be scheduled by the SLCA/IP customer each season through the contract period. (In Table 2.4, the terms CROD and capacity are synonymous.)

Although the post-1989 marketing criteria contracts expired in 2004, they were revised and reissued to customers in 2004. A summary of post-2004 contracts, which were valid through the end of 2008, are shown in Table 2.5. Although the total amounts of capacity sold under both marketing criteria are similar, less energy has been sold under the post-2004 criteria because of persistent drought conditions. In addition, the post-2004 criteria increased the amounts of both capacity and energy available to the Southern Division at the expense of the Northern Division. More detailed information about capacity and energy allocations to individual customers is provided in Section 3.

Except for BHBF events, the amount of energy generated by the Glen Canyon Powerplant is only marginally affected by operational criteria. However, the maximum allowable output is restricted below continuous capacity levels by the maximum flow and the daily change restrictions. In accordance with the Glen Canyon Protection Act (GPA) of 1992, Western established a "Replacement Resources Process" (RRP) to compensate for reductions in the maximum power production levels that could be achieved and sustained on a daily basis (referred to in this report as operational capacity) at the Glen Canyon Powerplant. The GPA requires identification of economically and technologically feasible methods for replacing power resources made unavailable as a result of changes in long-term operating criteria of hydroelectric generating facilities at GCD.

The RRP is dependent on and interrelated with Western's power purchasing practices. Western's firm commitments are non-interruptible. Therefore, Western must acquire power from others when SLCA/IP resources cannot fully supply contractually guaranteed quantities. Since Western has an extensive transmission network across several Western states, purchases or exchanges can be made with a large number of utilities and generating resources. Western acquires power on the spot market on a short-term basis not only in response to shortfalls in hydroelectric generation, but for various other reasons, including the relief of operational constraints such as transmission limitations (Western 1998).

Table 2.4 SLCA/IP Divisional Allocations under the Post-1989 Marketing Criteria

Division	Winter Season		Summer Season	
	Capacity (MW)	Energy (MWh)	Capacity (MW)	Energy (MWh)
Southern				
Desert Southwest	119.0	264,842	210.0	463,854
Southern Division Total	*119.0*	*264,842*	*210.0*	*463,854*
Northern				
Rocky Mountain	535.2	1,240,563	493.1	1,117,187
CRSP MC	752.4	1,598,617	611.1	1,322,547
Northern Division Total	*1,287.6*	*2,839,180*	*1104.1*	*2,439,734*
Total of All Areas	***1,406.6***	***3,104,022***	***1314.1***	***2,903,588***

Table 2.5 SLCA/IP Divisional Allocations under the Post-2004 Marketing Criteria

Division	Winter Season		Summer Season	
	Capacity (MW)	Energy (MWh)	Capacity (MW)	Energy (MWh)
Southern				
Desert Southwest	157.1	291,681	246.5	447,013
Southern Division Total	*157.1*	*291,681*	*246.5*	*447,013*
Northern				
Rocky Mountain	499.9	954,706	460.6	859,744
CRSP MC	746.7	1,311,777	610.6	1,086,865
Northern Division Total	*1,246.7*	*2,266,483*	*1071.2*	*1,946,609*
Total of All Areas	***1,403.8***	***2,558,164***	***1317.8***	***2,393,622***

In response to the implication of GCD operating criteria on power plant operating capability, Western amended its firm contracts, with input from its customers. The amended contract closes the gap between the CROD and the capacity and energy that can be supplied by the SLCA/IP resources. The amendments established a long-term commitment level of sustainable hydropower (SHP), which sets the minimum commitment level of both capacity and energy that will be provided by Western to all SLCA/IP customers through a LTF contract period. The cost of purchases or exchanges by Western to fulfill the SHP commitment during any future period will be included as part of SLCA/IP wholesale firm-power rates. A long-term SHP for each season is based on a 10% risk level and the anticipated hydrological conditions through the long-term contract period.

When anticipated hydropower conditions less project use commitments (such as providing power for irrigation) exceed the SHP level, additional capacity or energy or both are offered to customers for an upcoming month as available hydropower (AHP). As shown in Figure 2.13, an AHP capacity offer varies between SHP, which is the contractual minimum, and CROD, which is the contractual ceiling. The amount of energy offered also varies by month, depending on the aggregate SLCA/IP hydropower condition consistent with AHP capacity offers.

The minimum amount of energy that customers must schedule in an hour is set by Western's minimum schedule requirement (MSR). Under prior power marketing criteria, this level was set to 35% of the CROD. However, beginning in early 2001 and because of persistent drought conditions, downward adjustments to this requirement were made on a monthly basis to provide customers with a reasonable amount of energy to schedule SLCA/IP peaking capacity. The 35% CROD level acts as a ceiling for the MSR.

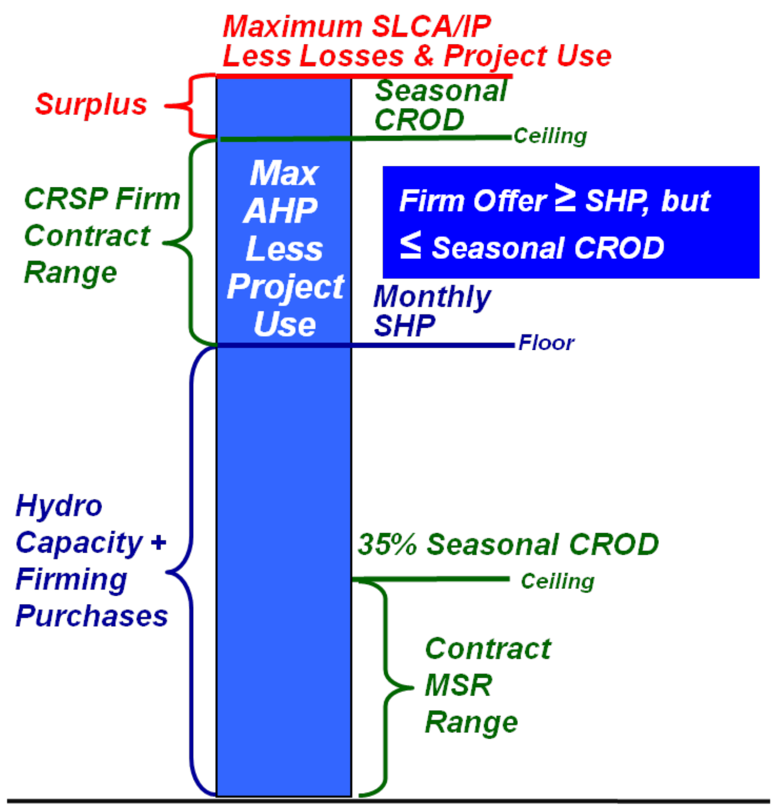

Figure 2.13 Illustration of SHP and AHP Capacity Offers

The amended contracts also address replacement of power, either by Western through Western Replacement Power (WRP), or by individual customers through Customer Displacement Power (CDP). Based on the price of WRP, customers can authorize Western to make the purchase, or they can decline the offer. Customers that do not contract for WRP may procure CDP up to their CROD. Customer displacement power can either be provided from a customer's internal resources or, if acquired from an entity directly or indirectly interconnected with Western, transmitted by Western to the customer's system subject to available transmission capacity. Acquisition costs for WRP at the request of a customer and for CDP are passed through to individual customers and are not included as part of the SLCA/IP wholesale firm-power rates.

2.9 CRSP DISPATCH PRACTICES

The GCD restrictions shown in Table 2.2 describe operational boundaries; however, within these limitations are innumerable hourly release patterns and dispatch drivers that comply with a given set of operating limits. Although the operational range was significantly wider prior to the ROD than afterward, a wide range of ROD-compliant operational regimes still exists. In addition to operational constraints at the GCD, other SLCA/IPs must also comply with operational limitations. For example, Flaming Gorge releases are patterned such that downstream flow rates comply with Jensen Gauge flow restrictions. Aspinall releases also cannot result in reservoir elevations that are outside of specified elevation limits, which include both upper and lower elevation bounds and limits on changes in reservoir elevations over one- and three-day periods.

Prior to 1990, SLCA/IP power plant dispatch was primarily driven by market price signals. This dispatch philosophy, coupled with a high level of operating flexibility at SLCA/IPs, allowed Western to produce energy at levels that were often distinctly different from its firm loads. As illustrated in Figure 2.14, Western routinely purchased energy during off-peak periods to meet firm loads, storing the water for power generation during on-peak periods when prices were higher and energy was more expensive. Using price as the main driver for SLCA/IP power plant operations, Western was able to maximize the economic value of electricity sales from Glen Canyon. Although total daily SLCA/IP energy is short of total load in the example shown in Figure 2.14, the net purchase cost is minimized because purchases are concentrated in hours when prices are relatively inexpensive, while sales are made when prices are highest.

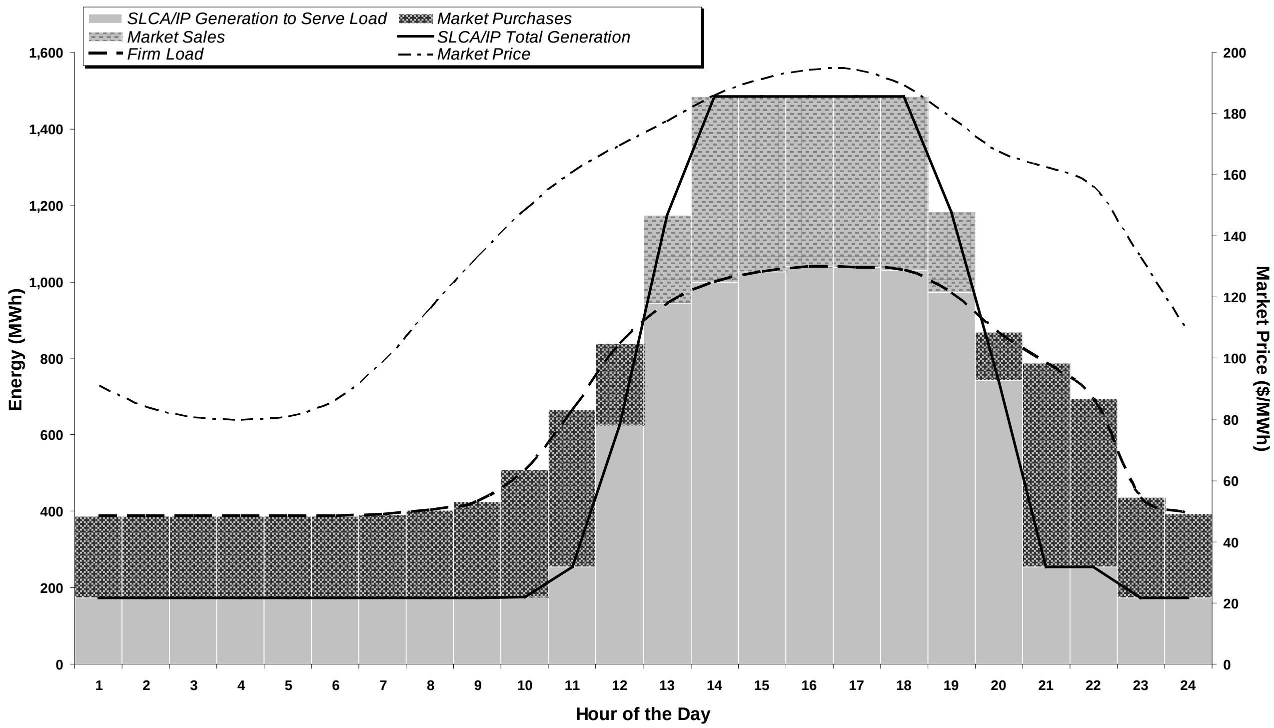

Figure 2.14 Illustration of the Market-Price-Driven Dispatch Guideline under Flexible Hydropower Operations

2.10 EVOLUTION OF WECC POWER MARKETS

The electric power industry in WECC has changed dramatically since the mid 1990s when Reclamation completed its economic analyses for the GCDEIS. In California, the industry transformed from a vertically integrated system to an open market in which generation, transmission, and distribution components are treated institutionally as separate entities. Market design and structural changes in California had a profound impact on prices throughout WECC, resulting in more competition among utilities. In addition to restructuring, other events took place that directly affected the industry. When the GCEIS economic analyses were conducted, many of these events could not be foreseen or anticipated, and several critical projections did not occur. Two significant events that were not projected were (1) the steep rise in fuel prices for petroleum and natural gas, and (2) the 2000 California energy crisis.

Figure 2.15 shows that, about the time that the GCDEIS economic analyses were being conducted, prices for natural gas delivered to electric utility power plants were relatively low compared to the prices that actually prevailed during much of the study period. From 1990 through 1995, natural gas prices remained fairly constant; in several years, a slight price decline was experienced when measured in terms of constant 1991 cents per million British thermal units (MMBtu). Projections of natural gas prices made by the Energy Information Administration (EIA) in its *Annual Energy Outlook 1994* (AEO94) (EIA 1994) anticipated a steady but modest increase in natural gas prices, as shown by the thin dashed line in Figure 2.15. Natural gas prices are critical components of the analyses, because bids from power plants that burn this fuel often set the market price for electricity in periods of high demand. Furthermore, fuel costs generally account for 90% or more of a generating unit's incremental production cost.

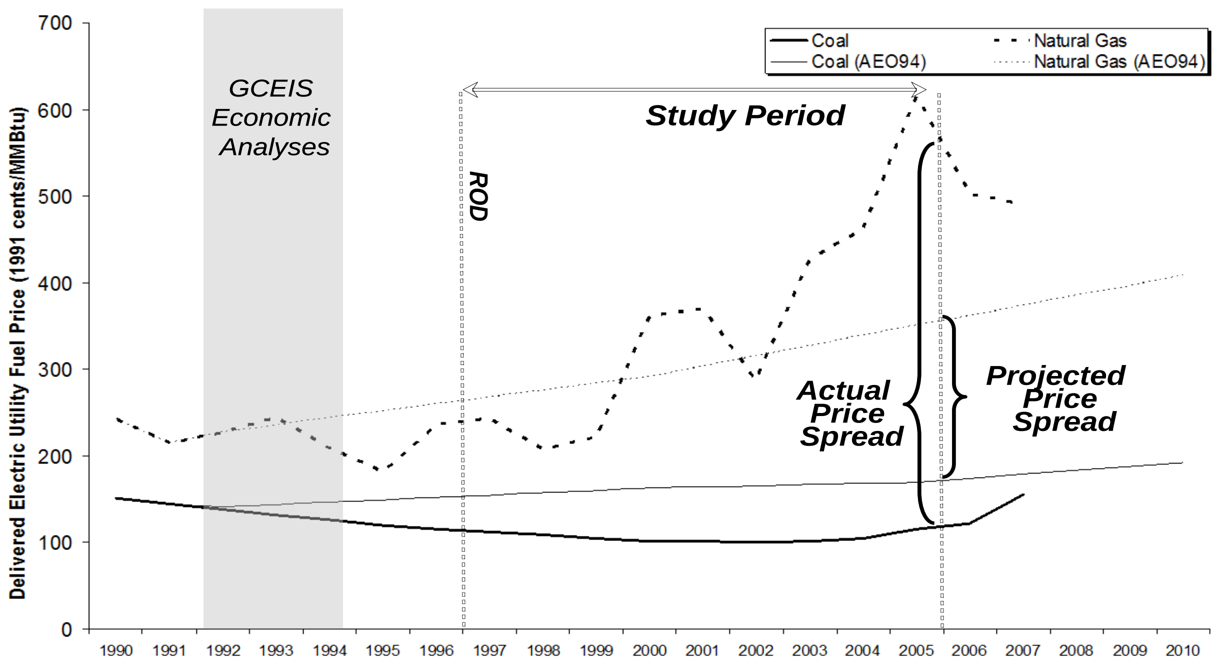

Figure 2.15 Projected Versus Actual Delivered Cost of Fuel to Electric Utility Power Plants

While coal prices in the early 1990s were declining over time, a very slow price increase was projected in the AEO94 forecast. As shown by the thick solid line in Figure 2.15, delivered prices for coal actually continued to decline through about 2003 and then began to increase slowly thereafter. WECC bids from power plants that burn coal often set market prices during periods of low demand.

The price spread between natural gas and coal is a key factor in the estimation of economic costs of ROD operating criteria at GCD. Except for the BHBF spills, which lowered the Lake Powell reservoir forebay elevation, the ROD has a relatively small effect on the amount of electricity generated by the Glen Canyon Powerplant over the course of a year. The ROD, however, tends to shift water releases and power generation from times of the day when electricity prices are high (and energy expensive) because of the cost of natural gas to times of the day when electricity has a lower value because of the cost of coal. The greater the difference between on-peak and off-peak prices, the higher the economic cost of the ROD criteria. The absolute price tends to be of little or no importance. For example, if the price of electricity is constant at $1,000 MWh during a month, the ROD criteria do not incur an economic cost since the criteria merely affect the hourly timing of releases, not the total amount of water released during the month.

Note that coal prices in the AEO94 forecast were projected to increase instead of decline and, at the same time, natural gas prices were projected to increase at a slower rate than what actually occurred. Therefore, the fuel price spread forecast by the AEO94 significantly underestimated what actually occurred.

In addition to much higher-than-anticipated fuel price spreads, various entities did not anticipate how the WECC power market would evolve. Federal Energy Regulatory Commission (FERC) Orders 888 and 889 were put in place in 1996, which paved the way for creating an open power market in California. The FERC orders allowed for wholesale trading of electricity. California fostered competition with the passage of *The Electric Utility Industry Restructuring Act* (Assembly Bill 1890) on September 23, 1996. Prior to restructuring, a single utility provided each customer with generation, transmission, and distribution of electricity and metering and billing services. As of March 31, 1998, the new structure allowed customers in most electric utility service areas to select a power supplier. Because generation companies outside of the state can sell into the California market, the clearing prices in California strongly influenced wholesale prices throughout WECC. All power suppliers in WECC are connected via the transmission system; therefore, the price in California sets the opportunity cost for selling and consuming energy. Consequently, the California market had a significant effect on the value of Glen Canyon.

Although transmission facilities in California were owned by individual companies, the California Independent System Operator (CalISO) was established as the power grid operator to provide fair and equitable access to all market participants. The CalISO is also responsible for assuring the reliability of the high-voltage transmission system. Initially, the market structure established the California Power Exchange (CalPX), which solicited bids from electricity buyers and generators and chose the lowest generation services bidders to meet power requests. However, in 2001, the CalPX filed for Chapter 11 bankruptcy protection and ceased operation.

Market prices in California's wholesale power market were relatively inexpensive for about a year and a half after the market began operation. However, the price of wholesale electricity sold through the CalPX started escalating in June 2000, and by December 2000, wholesale clearing prices on the CalPX were many times more expensive than the average price the previous December. California also experienced a significant increase in emergency conditions that, in some instances, necessitated involuntary power cuts. Subsequent actions taken by California and Federal Government authorities helped resolve problems in California's market. As a result of these actions, market prices eventually decreased (see http://www.eia.doe.gov/cneaf/electricity/california/california.html [EIA undated]).

Figure 2.16 shows estimated maximum and minimum daily prices at the Palo Verde market hub from the beginning of 1997 through the end of 2005. It is of note that the large price spikes beginning in the spring of 2000 though the middle of 2001 occurred during the height of the California energy crisis. During the crisis, prices exceeded levels that cannot be explained by production costs (fuel plus other operating expenses) alone. Once market difficulties were alleviated, electricity prices once again began to reflect marginal production costs. Note that electricity prices trended upward as the cost of fuel increased in 2005.

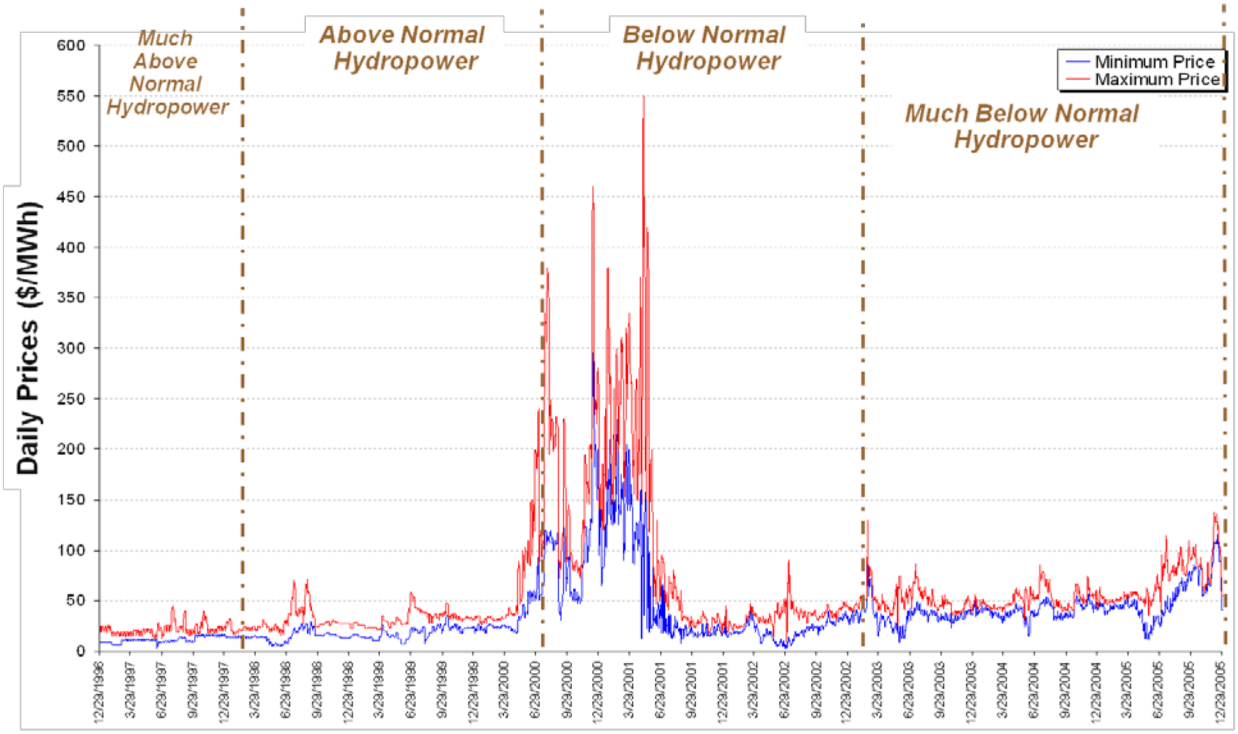

Figure 2.16 Daily Spot Market Prices at the Palo Verde Hub

As explained earlier, the price spread is of critical importance when estimating the economic cost of ROD criteria. Figure 2.17 shows historical price spreads at the Palo Verde market hub. Except for the year 2001 when the California market was in crisis, a seasonal cycle of price spreads is evident, with relatively high spreads occurring during the summer months.

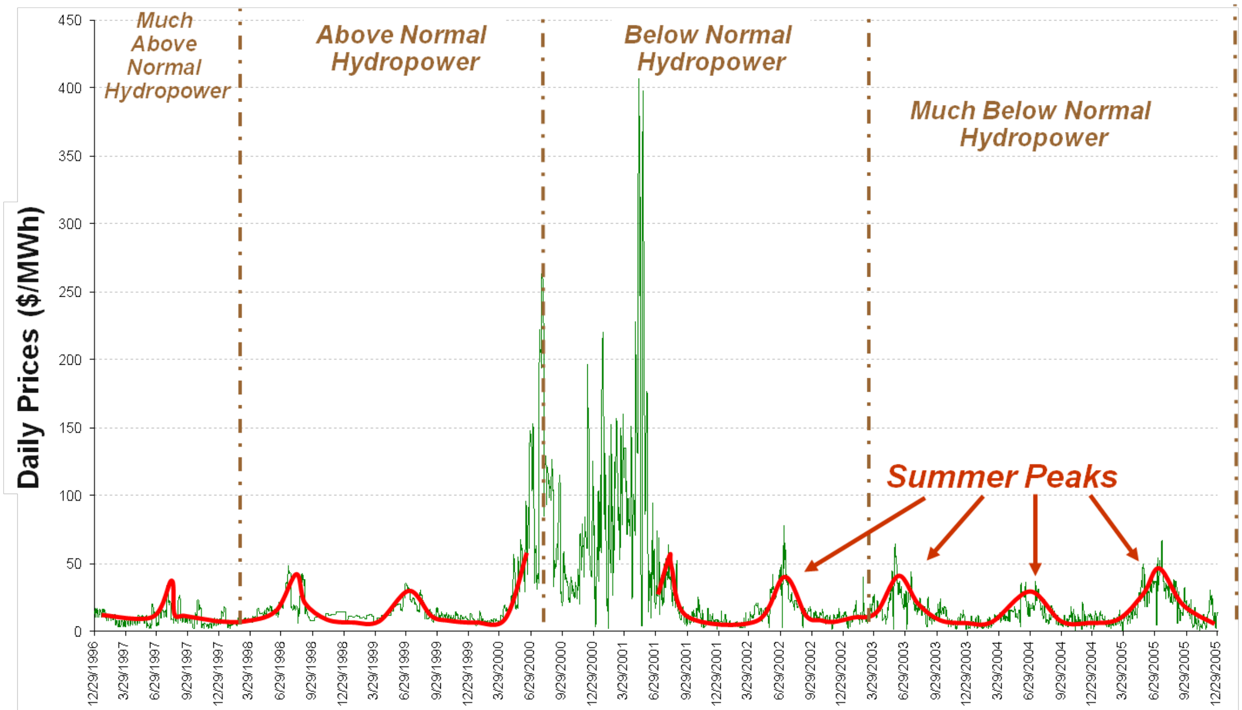

Figure 2.17 Daily Spot Market Price Spreads at Palo Verde Hub (On-Peak minus Off-Peak Price)

Actual market prices can often be used as a surrogate for the economic value of energy when prices are in line with the marginal cost of electricity production. However, when market prices deviate from production costs, such as during the California crisis, price is a poor yardstick for measuring the economic value of hydropower resources. If marginal production costs are $20/MWh, economic costs are identical whether electricity is sold for $1/MWh or $500/MWh. At a price of $500/MWh, there is a transfer of wealth from the energy consumer to the energy producer, which enhances the financial condition of the producer.

3 METHODS AND MODELS

This section discusses the methods, models, and data used to estimate economic costs attributed to implementing GCD ROD operating criteria. It also describes the modeling process that computes the economic value of energy and capacity, reflecting not only ROD constraints but also changes to firm contracts sold by Western and the revision of SLCA/IP dispatch guidelines that were implemented as a direct response to ROD constraints. The modeling process uses an integrated set of tools that share historical data, simulation results, and other information. Some modeling components were constructed specifically for this study, while others were based on existing tools with modifications to meet the specific requirements of this study. As will be discussed in greater detail, operating criteria costs are computed as the difference between the economic benefits of the SLCA/IP hydropower system when operating the GCD with ROD operating constraints compared to the economic benefits of operating the dam under less restrictive operating rules.

An overview of the modeling framework is shown on Figure 3.1. The first step in the process is to construct Western's LTF contracts in terms of the capacity and energy based on hydropower resources at GCD and other SLCA/IP facilities. Contracts are influenced by operational constraints along with dispatch goals and objectives. The contracts are then input into an algorithm that simulates customer hourly requests for SLCA/IP energy deliveries. Requests are within the terms of the firm contract and are a function of a customer's hourly load profile and WECC market prices. Using SLCA/IP historical hydropower information and aggregate customer hourly energy requests, the hourly operation of the SLCA/IP hydropower system is then simulated by using the Generation and Transmission Maximization (GTMax) model. The power plant dispatch is based, in part, on Glen Canyon operating criteria, operational limitations at all other SLCA/IP supply resources, and dispatch goals and objectives. The final step of the process computes the economic value of the GCD hydropower resource. The differences in benefits between the two scenarios measure the economic cost of implementing ROD operating criteria, including experimental flows.

3.1 SCENARIO ASSUMPTIONS

Net costs for energy and capacity incurred by both SLCA/IP customers and Western are computed under two scenarios: namely, "With ROD" and "Without ROD." As implied by its name, the With ROD scenario assumes that operational restrictions specified in the GCD ROD issued by the U.S. Department of the Interior (DOI) on October 9, 1996, are put into practice beginning in February 1997. Operating criteria under the Without ROD scenario are assumed to be identical to the ones practiced prior to 1991 when constraints were less stringent. Because research flow events, such as BHBFs, that took place during the study period occurred as a result of implementing the ROD, they are included in the With ROD scenario but not in the Without ROD scenario. This inclusion allows determination of the economic costs of implementing the ROD. A detailed description of operating criteria in terms of limitations on minimum and maximum release rates, daily changes in flow rates, and hourly ramp rates were discussed in Section 2.5 and summarized in Table 2.2.

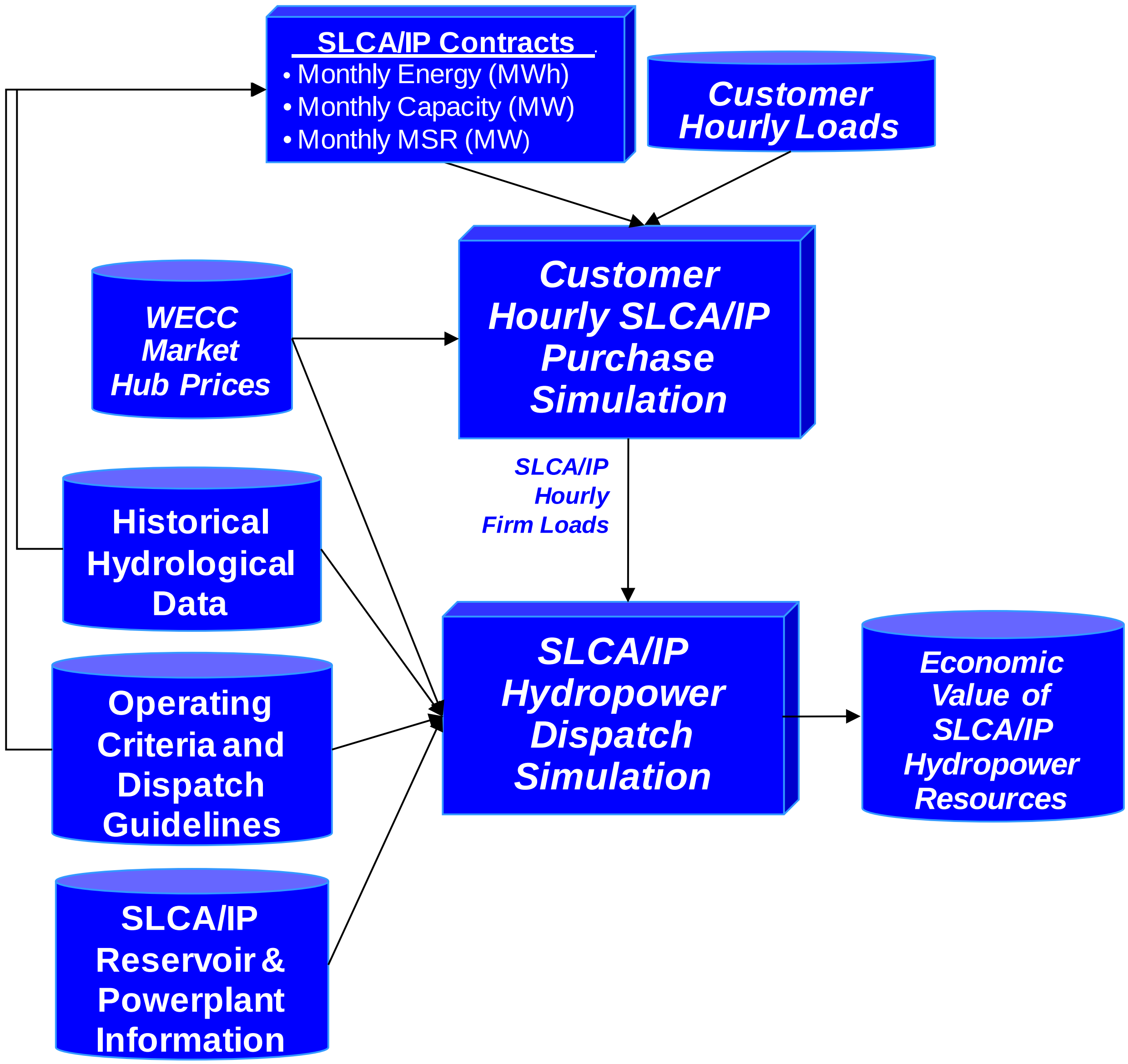

Figure 3.1 Modeling Process Overview

In addition to the operating criteria, specific SLCA/IP firm contract terms and guidelines for SLCA/IP hydropower dispatch are unique to each scenario. Assumptions made for the two scenarios are summarized in Table 3.1. Operating criteria not only affected GCD operations, they also influenced the terms under which Western was able to sell its firm energy and capacity. Under the Without ROD scenario, it is assumed that Western typically would have sold higher levels of firm capacity with total monthly energy sales and minimum schedule requirements that are identical to the With ROD scenario. As documented in the March 1998 report entitled “Replacement Resource Process Final Methods Report” (Loftin et al. 1998), firm contract modifications were needed to reflect the impact of operating criteria on the maximum production level from the Glen Canyon Powerplant. Contract modifications began in April 1998, that is, about 14 months after the ROD operating criteria were implemented.

Although Western adopted operating guidelines following the ROD for dispatching SLCA/IP hydropower plants, these guidelines were not required by the ROD. Because the purpose of this study is to determine the economic costs of implementing ROD requirements, those guidelines were not used in simulating system operation in either scenario. Therefore, both scenarios use the guidelines of maximizing economic value of the SLCA/IP resources. Figure 3.2 shows the typical daily dispatch of SLCA/IP resources using these guidelines.

Table 3.1 Overview of Scenario Assumptions

Scenario Element	Without ROD	With ROD
Operating Criteria	Prior to stringent environmental constraints defined in Table 2.2	Post-ROD operating criteria defined in Table 2.2
SLCA/IP Contract Terms	Based on post-1978 marketing approach	Effective April 1998, post-1989 marketing with replacement resource process modifications
Dispatch Objectives & Goals	• Maximize economic value of SLCA/IP resources with market purchases of low-priced energy for increased sales during high-priced hours • No restriction on daily release levels during weekends	Same as Without ROD, as long as ROD criteria are satisfied.
Experimental Flows	Do not occur	Specified in ROD and occur as historically recorded
AHP Values	Same as With ROD scenario	Historical Values
Minimum Schedule Requirement	Same as With ROD scenario	Historical Values

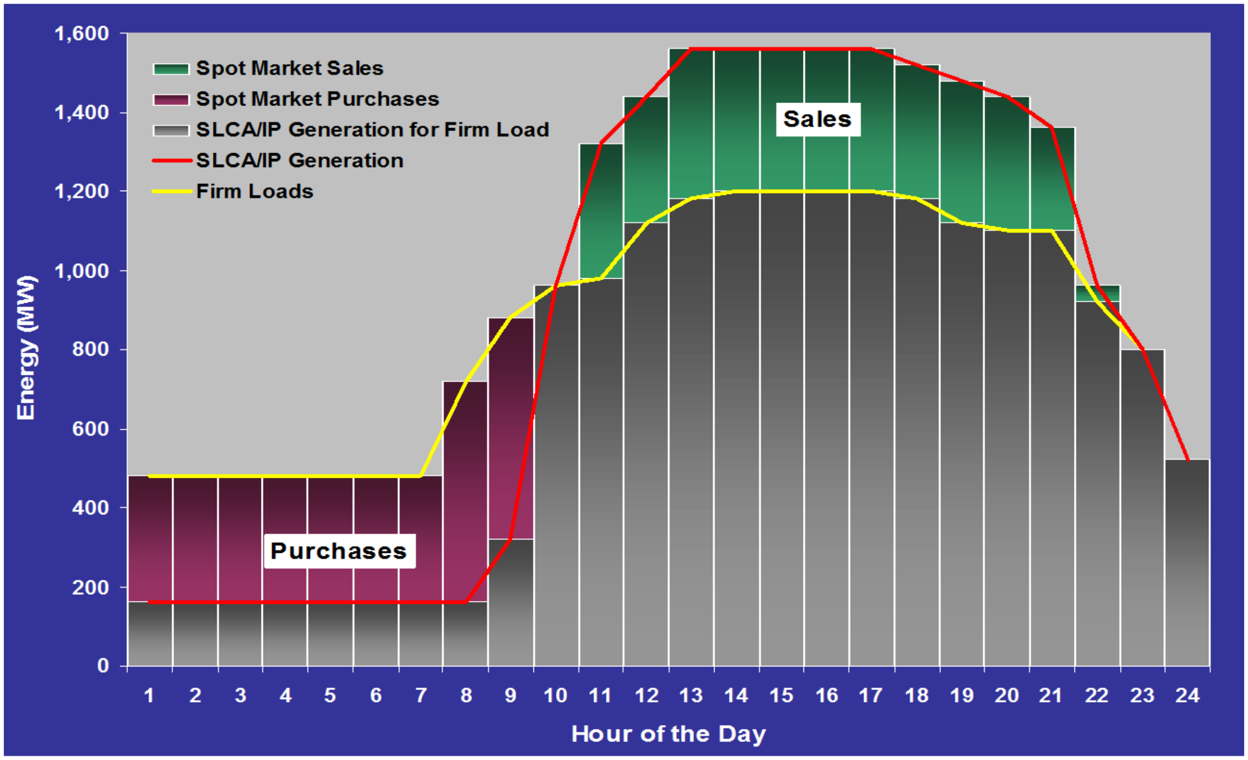

Figure 3.2 Illustration of SLCA/IP Dispatch when Maximizing Economic Value of Resources

3.2 CONSTRUCTING SLCA/IP FIRM CONTRACTS

Simulating hourly operation of the SLCA/IP hydropower system is initiated by constructing the firm contracts that Western has with its customers. To simplify this analysis, Western's LTF customers were categorized as either large or small depending on their existing CRSP firm power allocation. In contrast, smaller systems have limited or no generating resources and principally rely on purchases to meet load requirements. Collectively, small customers account for about 25% of total contract sales.

Because the majority of Glen Canyon Powerplant's contract capacity is made use of by a few customers and because energy contracts were determined individually for the large customer group, a single aggregate contract was formulated to represent all small customers. For each scenario, Western staff estimated monthly values for key contract specifications including capacity, energy, and minimum schedule requirements. Table 3.2 shows contract terms for aggregate customer offers under both scenarios. Of note is that beginning in 1998, the average monthly capacity offered to customers under the With ROD scenario is lower than that offered under the Without ROD scenario. This change reflects modifications to Western's contracts that were implemented in April 1998 as described in the replacement resource process. Lower capacity offers are consistent with the reduced maximum output capability at the Glen Canyon Powerplant resulting from the ROD operational criteria. The daily change requirement, in conjunction with the monthly water release limitation, accounts for the majority of loss in the maximum power output.

Under the post-1989 marketing criteria, each customer's MSR was 35% of its seasonal CROD. Initially, this rule was retained by Western after instituting the ROD constraints and after amending contracts by the RRP. However, as hydropower conditions deteriorated, very little discretionary energy above the MSR was available for the customers to schedule. Therefore, starting in April 2001, Western relaxed the MSR to levels that were more consistent with the sum of all SLCA/IP minimum generation levels. This adjustment is also shown in Table 3.2, where the MSR remains constant at 476 MW until 2001, when it begins to fluctuate annually. Both scenarios use the same MSR values in this study because changes in the MSR resulted from hydrological conditions and were not attributable to implementing the ROD.

Table 3.2 Aggregate Annual SLCA/IP Contract Terms Under the Without ROD and With ROD Scenarios

		Average Monthly Capacity (MW)			Minimum Schedule Requirement (MW)		Capacity Factor (%)	
Calendar Year	Annual Energy (GWh)	w/o ROD	with ROD	Change	w/o ROD	with ROD	w/o ROD	with ROD
1997	5,833	1,263	1,263	0	476	476	52.7	52.7
1998	6,514	1,263	1,041	221	476	476	58.9	71.4
1999	7,002	1,283	1,065	219	476	476	62.3	75.1
2000	6,077	1,263	855	408	476	476	54.9	81.2
2001	4,558	1,263	694	569	336	336	41.2	75.0
2002	4,716	1,263	724	538	342	342	42.6	74.3
2003	5,536	1,263	748	515	347	347	50.0	84.5
2004	4,487	1,263	744	518	263	263	40.6	68.8
2005	4,404	1,263	744	518	265	265	39.8	67.5

The total energy offers to customers are identical under both scenarios because ROD operating criteria primarily affect the timing of turbine water releases from the GCD but not the total annual volume of turbine water releases. One exception is that ROD criteria will occasionally trigger BHBF events, in which case large amounts of water are released though the dam bypass tubes. The highest BHBF release rate needed to simulate a flood event exceeds the maximum turbine flow rate, and bypass tubes are therefore opened sequentially over a specified time period. The non-power releases associated with a BHBF ultimately reduce the amount of water that flows through the power plant turbine and therefore annual generation levels. A BHBF event also lowers Lake Powell water levels, reducing the Glen Canyon Powerplant's power conversion factor. As stated earlier, BHBFs and other experimental flows were accounted for in the With ROD scenario but do not occur in the Without ROD scenario.

Monthly SLCA/IP aggregate offers constructed by Western staff for the year 1999 are shown in Figures 3.3 and 3.4 under the Without ROD and With ROD scenarios, respectively. Although more pronounced in the Without ROD scenario, capacity and energy offers tend to follow the general monthly load pattern in which loads are higher in the winter and summer months relative to the spring and autumn. The MSR for both scenarios varies in six-month blocks, representing winter (October through March) and summer (April through September) for which different CRODs are specified. Monthly capacity offers were patterned after customer loads and capped at the CROD level.

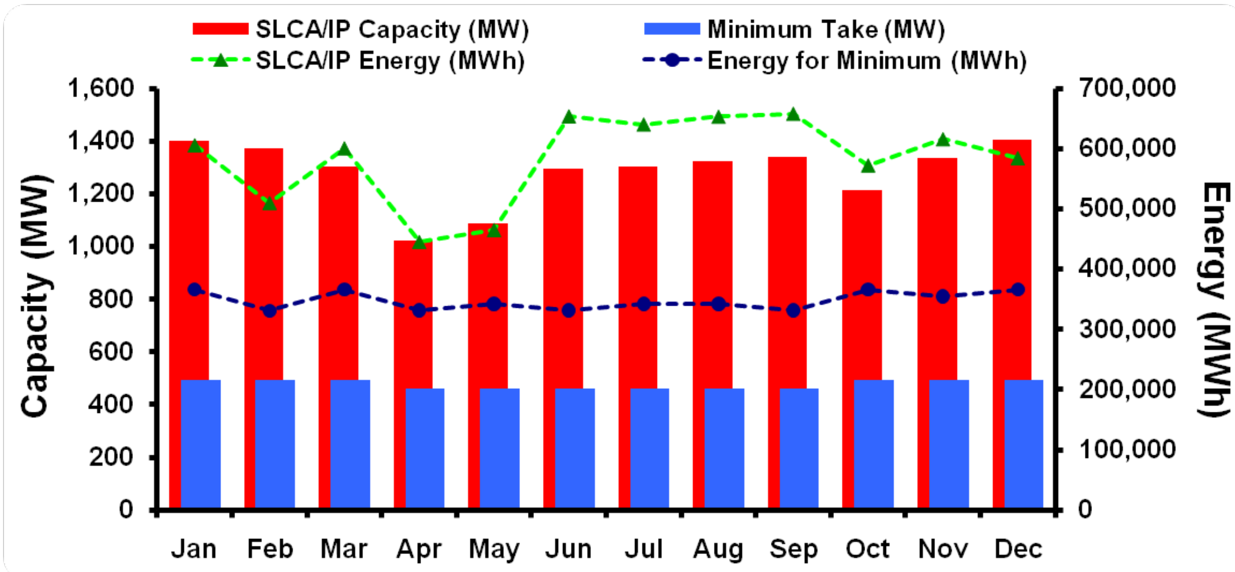

Figure 3.3 Aggregate Monthly SLCA/IP Contract Offers in 1999 under the Without ROD Scenario

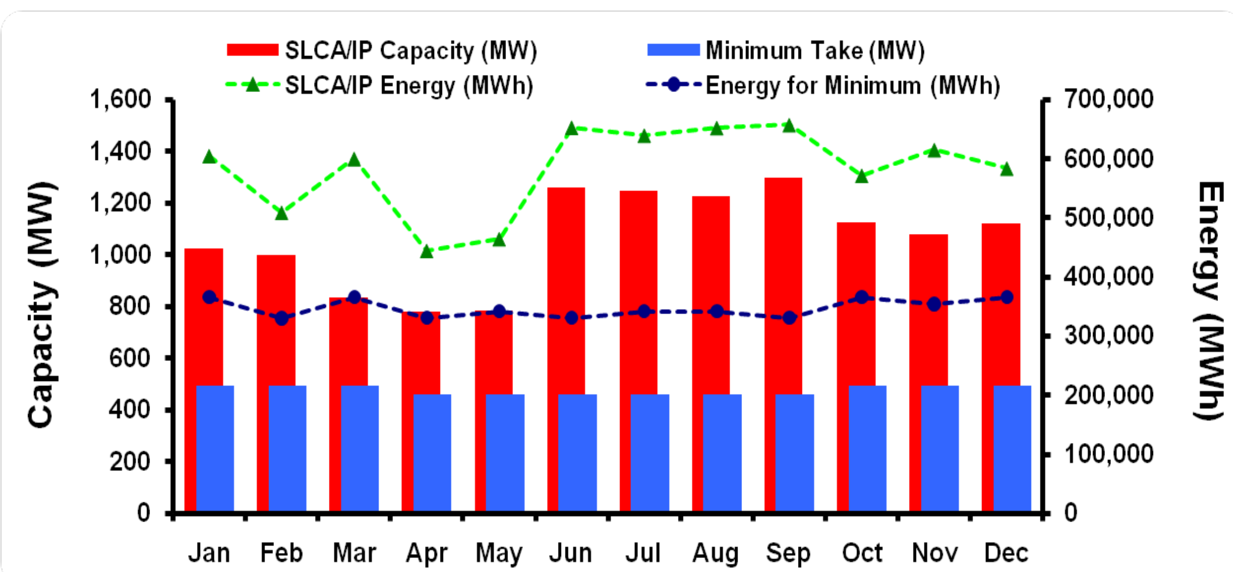

Figure 3.4 Aggregate Monthly SLCA/IP Contract Offers in 1999 under the With ROD Scenario

Figure 3.5 shows the monthly capacity, energy, MSR, and SHP offered under both scenarios during the study period. It is evident that the capacity offered under the With ROD scenario starts dropping below that offered under the Without ROD scenario in April 1998 when the contract modifications began. Then, from April 2001 to April 2002, the capacity offered by Western drops below the SHP. This change resulted from a combination of low hydrological conditions and sharp electricity market price spikes during the California energy crisis. Spot market prices began spiking in mid 2000 and continued into 2001. Because of low hydrological conditions, Western purchased power to meet SHP levels. This approach quickly drained Western's monetary resources such that by April 2001, it could no longer purchase the power it needed to meet SHP levels unless the contract price was raised substantially. Customers received power from Western on a run-of-river basis, namely, whatever Western could supply from its hydro resources. Customers had to purchase any power that Western was unable to supply through existing contracts with their other suppliers. By April 2002, electricity prices stabilized, and AHP levels again equaled or exceeded SHP levels. Figure 3.5 also shows that beginning in April 1998, the average CROD-based capacity offered under the With ROD scenario is about 455 MW less than that offered under the Without ROD scenario.

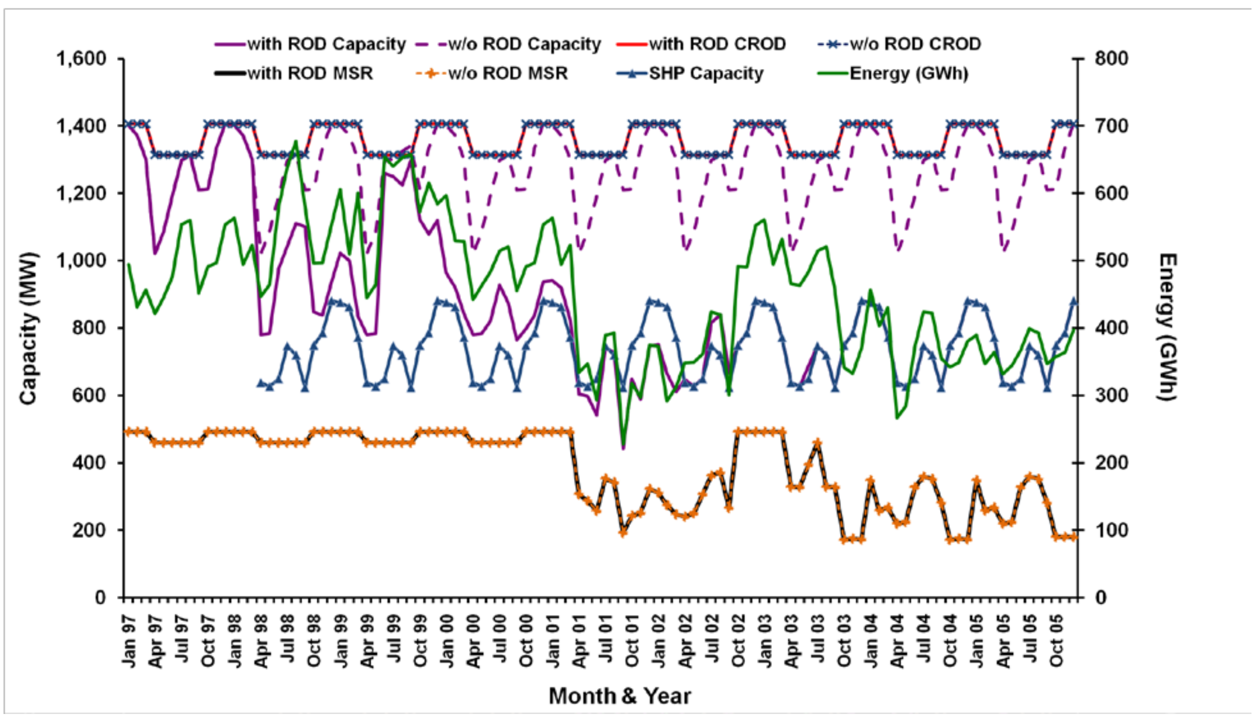

Figure 3.5 SLCA/IP Capacity and Minimum Schedule Requirements (note: SHP offering began in April 1998)

Monthly SLCA/IP aggregate offers for 2003 are shown in Figures 3.6 and 3.7 under the Without ROD and With ROD scenarios, respectively, for comparison with Figures 3.3 and 3.4, which depict the situation before the MSR reduction. The monthly MSR and monthly energy vary considerably compared to the way Western offered MSR before 2001.

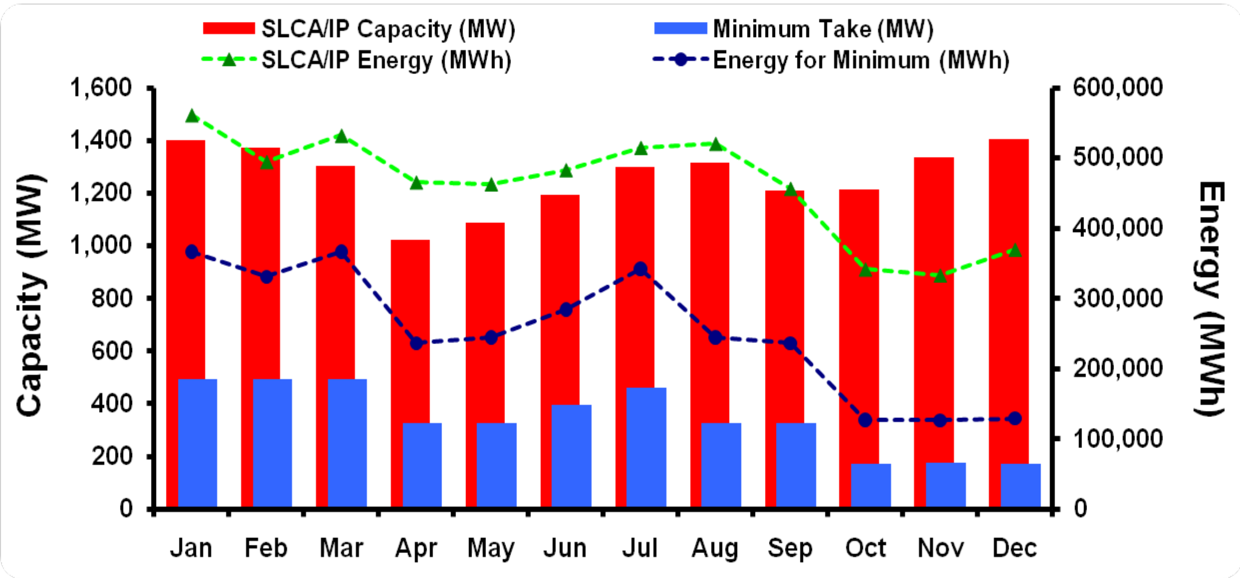

Figure 3.6 Aggregate Monthly SLCA/IP Contract Offers in 2003 under the Without ROD Scenario

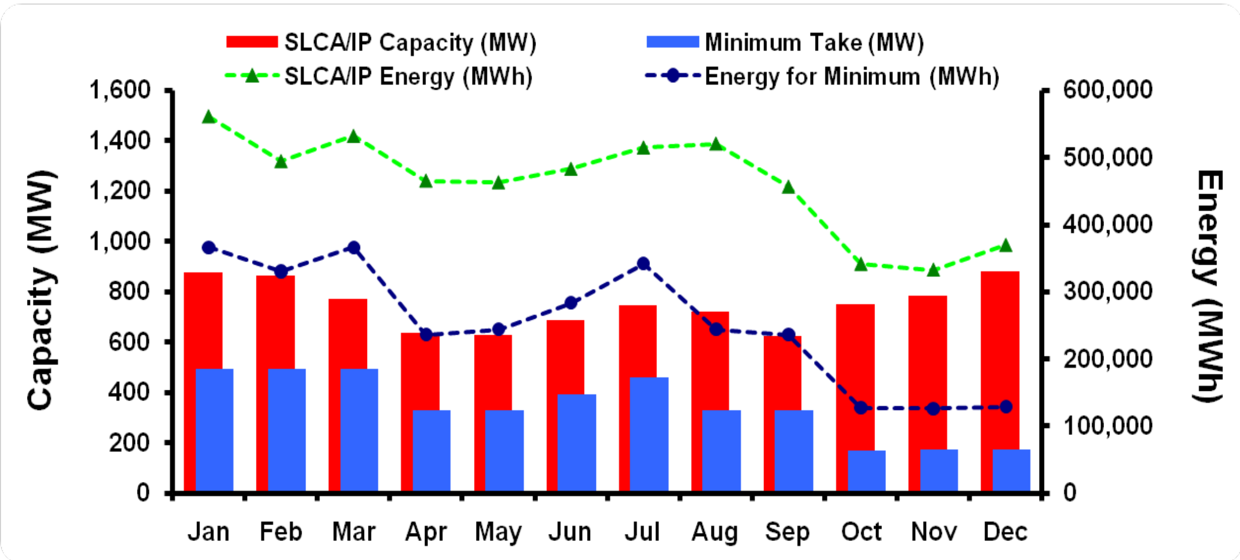

Figure 3.7 Aggregate Monthly SLCA/IP Contract Offers in 2003 under the With ROD Scenario

3.3 CUSTOMER SCHEDULING ALGORITHM

Western sells LTF contracts to about 132 wholesale power customers in six Western states. Within the terms of the contracts described in the previous section, customers request hourly energy deliveries throughout the year. These requests are simulated by the Customer Scheduling algorithm.

3.3.1 Schedules for Large and Small Customers

To simplify the modeling of energy requests under LTF contracts, Western's LTF customers are categorized as either large or small depending on their firm power allocation. Eight customers are placed into the large category. In general, these utilities own and operate generating resources and have extensive electric transmission and distribution capabilities. In contrast, smaller systems have limited or no generating resources and principally rely on purchases to meet load requirements. A small customer has a firm allocation of less than 2.5% of total Western LTF capacity and energy sales. Collectively, small customers account for about 25% of total contract sales.

Scheduling simulations are performed for each of the following eight large LTF customers:

- Colorado Springs Utilities (CSU)
- Deseret Generation & Transmission Cooperative (Deseret)
- Navajo Tribal Utility Authority (NTUA)
- Platte River Power Authority (PRPA)
- Salt River Project (SRP)
- Tri-State Generation & Transmission Association/Plains Electric Generation & Transmission Cooperative (Tri-State)
- Utah Municipal Power Agency (UMPA)
- Utah Associated Municipal Power Systems (UAMPS)

A ninth simulation is performed for a small customer aggregate schedule that represents the combined energy request of the remaining 124 Western customers.

In July 2001, Tri-State acquired Plains Electric Generation & Transmission Cooperative's loads, generation resources, and firm power allocations from Western. From that point forward, Plains no longer existed as an electric utility system. This study modeled Plains as a separate entity until the end of 2000.

3.3.2 Customer Scheduling Algorithm Objectives and Constraints

The Customer Scheduling algorithm estimates hourly energy requests from a customer using a quadratic programming (QP) optimization technique. The algorithm contains an objective function that has the following two components:

(1) Maximize the total value of SLCA/IP deliveries, and
(2) Minimize the peak load that must be served by other supply resources.

Because these two objective components at times may be in conflict, weights are therefore placed on each component. When all of the weight is placed on the component that minimizes the peak load, prices have no influence on the schedule produced by the algorithm. Similarly, if all of the weight is placed on the component that maximizes market value, customer loads are not relevant. For this analysis, all of the weight is placed on the objective to maximize the price benefit.

The simulation process uses a customer's load profile and a set of market prices to guide SLCA/IP hourly energy schedules. Customer hourly loads for the years 1997 through 2005, inclusive, were obtained from Form FERC-714. The compilation and derivation of customer-specific hourly prices are described in the next section.

The Customer Scheduling algorithm constrains a customer's energy schedule to be within both the monthly capacity offer and the MSR. In addition, the total energy scheduled by a customer is constrained by the monthly contract amount – either SHP energy or AHP energy. An illustration of the methodology used to simulate hourly SLCA/IP energy schedules over a one-day period is shown in Figure 3.8. The illustration depicts a contractual capacity limit totaling 150 MW and a weekly energy amount of 1,910 MWh. Contractually, the amount of energy that a customer schedules is limited on a monthly basis; however, as a simplification, the illustration depicts only a single day of scheduled energy.

The simulation algorithm divides contract capacity into two blocks: a 50-MW base block that is set to be equal to the MSR, and a 100-MW peak block. The entire 50-MW base block is always scheduled, accounting for 1,200 MWh of daily energy scheduled. The entire peak block or some portion of it is scheduled hourly at the discretion of the customer. Total daily peaking energy equals 710 MW. That amount equals the daily total energy limit of 1,910 MWh minus the 1,200 MWh of energy used to satisfy the MSR. The algorithm schedules this peaking energy when demand and prices are the highest. As shown in the illustration in Figure 3.8, the 100-MW peaking block limit is applicable all hours of the day, but it is only binding from hours 12 through 16 inclusive.

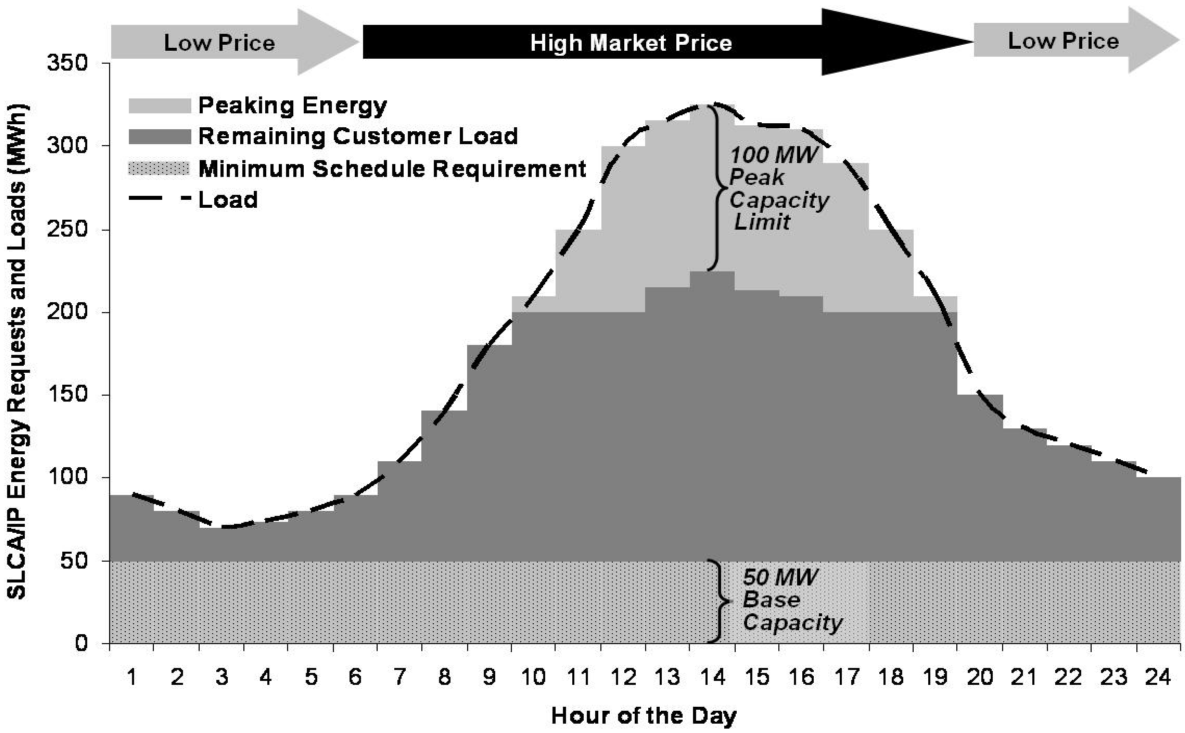

Figure 3.8 Conceptual Illustration of an SLCA/IP Customer Scheduling Energy

The dotted light-gray area at the bottom of the chart combined with the solid light-gray area at the top of the curve represents the total SLCA/IP energy offering of 1,910 MWh that a customer schedules during the day. Any customer load that remains after hourly SLCA/IP deliveries is shown as the dark gray area in the figure. It is assumed that this load will be served at least cost via an economic dispatch of the customer's own supply resources and through other power purchase agreements.

The objective to minimize the remaining peak load is typically restricted by the SLCA/IP capacity limitation. As shown in Figure 3.8, the peak remaining load that occurs in hour 14 is about 170 MW (i.e., 320 MW−150 MW). If more SLCA/IP peak capacity was contracted, then energy schedules from other hours of the day, such as hours 6 though 12 and 17 through 19, would be shifted to hours 13 though 16 to further reduce the peak remaining customer load (i.e., tallest dark-gray bar).

The objective to maximize the market value of energy deliveries over the day produces SLCA/IP energy schedules that are the largest during the highest price hours. Without an SLCA/IP capacity constraint, all of the contracted energy not used to serve the MSR would be scheduled during the highest price hour. Since a capacity limit is specified in SLCA/IP contracts, energy up to the contract limit is scheduled in the highest-priced hour. If any energy remains, it is then scheduled, up to the capacity limit, in the second-highest-priced hour. This process of scheduling energy in the next-highest-priced hour continues up to the point where all of the contracted energy is scheduled.

3.3.3 Total SLCA/IP Hourly Firm Loads

The Customer Scheduling algorithm is run individually for the eight large customers and for the small customer aggregate. As noted earlier, customer hourly loads for the years 1997 through 2005 inclusive, were obtained from Form FERC-714. Figure 3.9 shows that all of the hourly load profiles are added together to produce a multiyear profile of total customer loads to be served by Western. The derivation of hourly market hub prices is discussed in the next section.

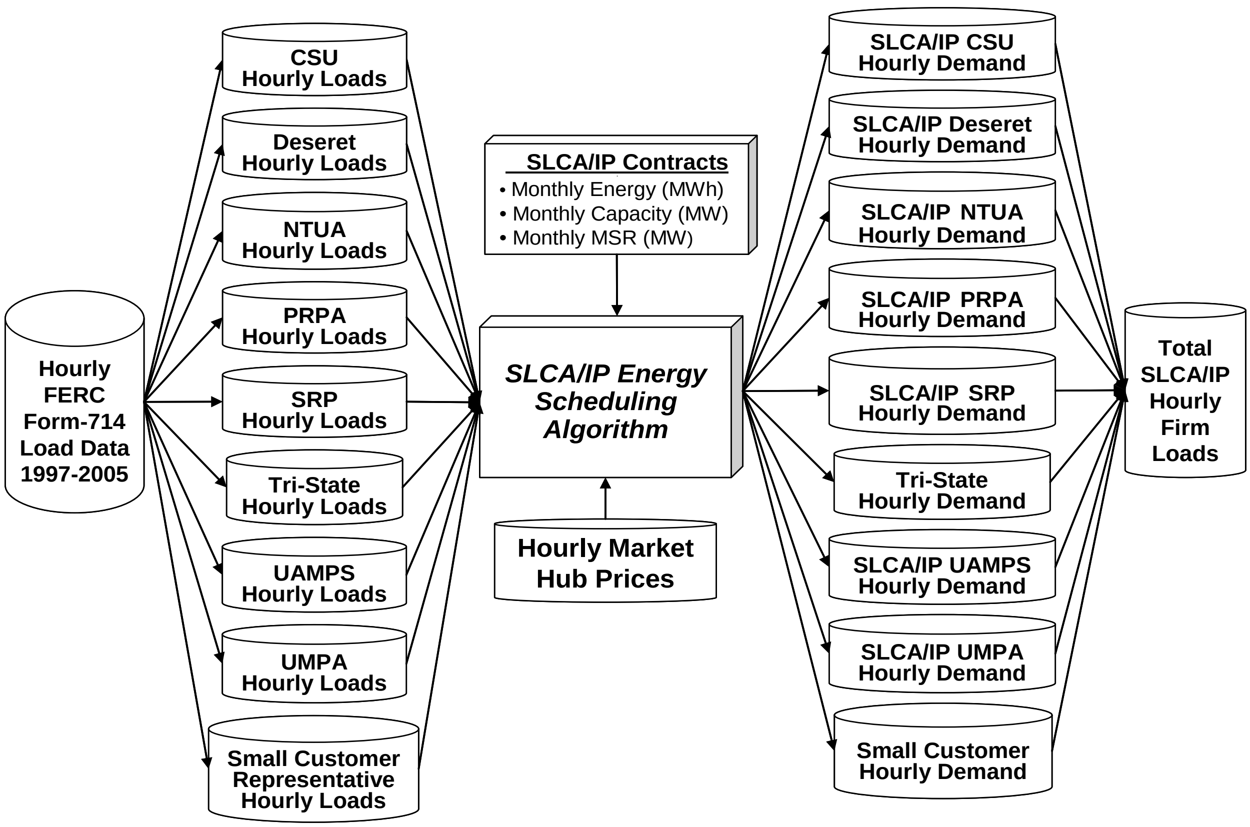

Figure 3.9 Customer Hourly Demands for Energy under SLCA/IP Firm Contracts

3.4 WECC MARKET HUB PRICES

The market prices in the WECC are one of the main driving forces for utility decision making including both short-term operations and long-term investments. As described in the previous section, prices guide customer schedules. Prices are also one of the key inputs into the GTMax model for dispatching SLCA/IP resources. Hourly market hub prices for the 1997-through-2005 time period are based on historical data and a routine that patterns prices to hourly WECC loads.

3.4.1 Daily Minimum and Maximum Prices

Hourly electricity prices were estimated using a multistep process — the first of which is to collect and process daily minimum and maximum prices. As shown in Figure 3.10, this process uses market prices posted by two independent entities, namely, the Intercontinental Exchange (ICE) and the CRSP Management Center in Salt Lake City, Utah. Data from ICE contains daily minimum and maximum prices, along with an average daily price for several WECC market hubs. The CRSP Management Center data are reported as weekly on-peak and off-peak price ranges for Four Corners, Central Rockies, and the Southwest. Monthly on-peak and off-peak price data were also collected for actual purchases made by the Energy Management and Marketing Office in Montrose, Colorado. These data were only used for comparative purposes and did not factor into the hourly price estimates used for economic evaluations.

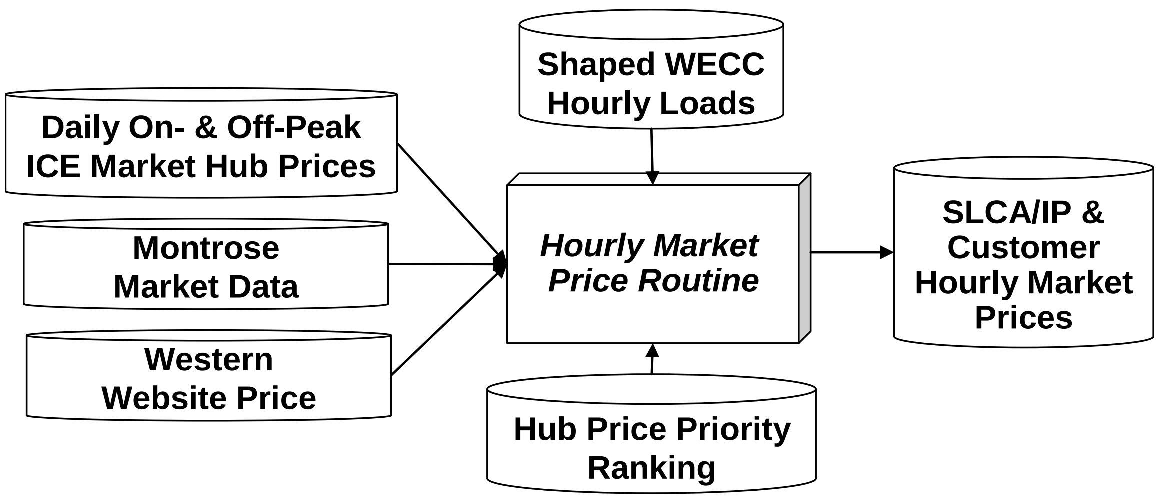

Figure 3.10 Process for Estimating Hourly WECC Market Hub Prices

The ICE data serve as the primary data source for daily minimum and maximum prices. A plot of these data for the Palo Verde hub was shown in Figure 2.16. When ICE data are not available for a specific day, the process uses CRSP prices as a surrogate. Prices are tailored for each customer by pairing a utility with market hubs. For example, prices used by the Salt River Project are based on Pinnacle Peak and Palo Verde data. When ICE data are not available, weekly CRSP data for the Southwest are used to estimate daily prices.

The large price spike that began in the spring of 2000 though the middle of 2001 coincides with the California energy crisis. During the crisis, prices exceeded levels that cannot be explained by production costs (i.e., by fuel plus other operating expenses) alone. Many attributed these price spikes to a market design problem in which some market participants influenced prices for financial gain. Once market difficulties were alleviated, electricity prices once again began to reflect marginal production costs. Electricity prices trended upward as a result of higher fuel prices in 2005.

In this study, the actual electricity market prices were used for calculating the economic value of the Glen Canyon ROD. However, it has been argued that the price swings during the California energy crisis were not indicative of the true electricity production costs at that time and that electricity prices in those years should not be used in an economic analysis. In order to determine how much a dysfunctional electricity market may have affected economic values a sensitivity analysis was performed. An attempt was made to remove the electricity price swings. This objective was accomplished by using a linear interpolation method for the months where prices spiked. The prices in those months were based upon prices that occurred in the year before and the year after the crisis. This technique smoothed the prices during the crisis period. The simulation model was run using these interpolated prices and the results compared to the simulation results using the actual prices in 2000 and 2001. The actual economic value would likely lie somewhere between the results from the base case, which used actual electricity market prices, and the sensitivity case.

3.4.2 Shaping Hourly Prices with WECC Total Loads

The Market Price spreadsheet uses the daily minimum and maximum market prices along with WECC total loads to estimate hourly prices. The market hubs assigned to each utility are likewise assigned to a WECC subregion for hourly price calculation. The hour of the day that has the lowest WECC load is assigned the minimum daily price, while the hour that has the highest load is assigned the maximum daily price. The remaining 22 hours of the day are assigned prices that fall between these two extremes. A nonlinear interpolation method assigns market prices such that a higher load hour is assigned a relatively expensive energy price, while a lower load hour is less expensive. The nonlinear interpolation method assumes that prices rise faster the closer a given load is to the maximum load.

Hourly loads for WECC subregions to support this hourly price-shaping routine are estimated from historical data collected by FERC (in Form-714) and WECC statistics. As shown in Figure 3.11, the process uses hourly loads collected for all control areas in WECC that are located the United States. Consistency checks are performed on the data and adjustments made when errors are found and data are missing. Control area loads are then grouped and aggregated into the following four WECC subregions: (1) Northwest Power Pool (NWPP), (2) Rocky Mountain Power Area (RMPA), (3) Arizona, New Mexico, and Southern Nevada Power Area (AZNM), and (4) California and Mexico Power Area (CAMX). Next, a Load Shaping Algorithm adjusts aggregated hourly load profiles to exactly match monthly peak and total load values that are reported for each WECC subregion.

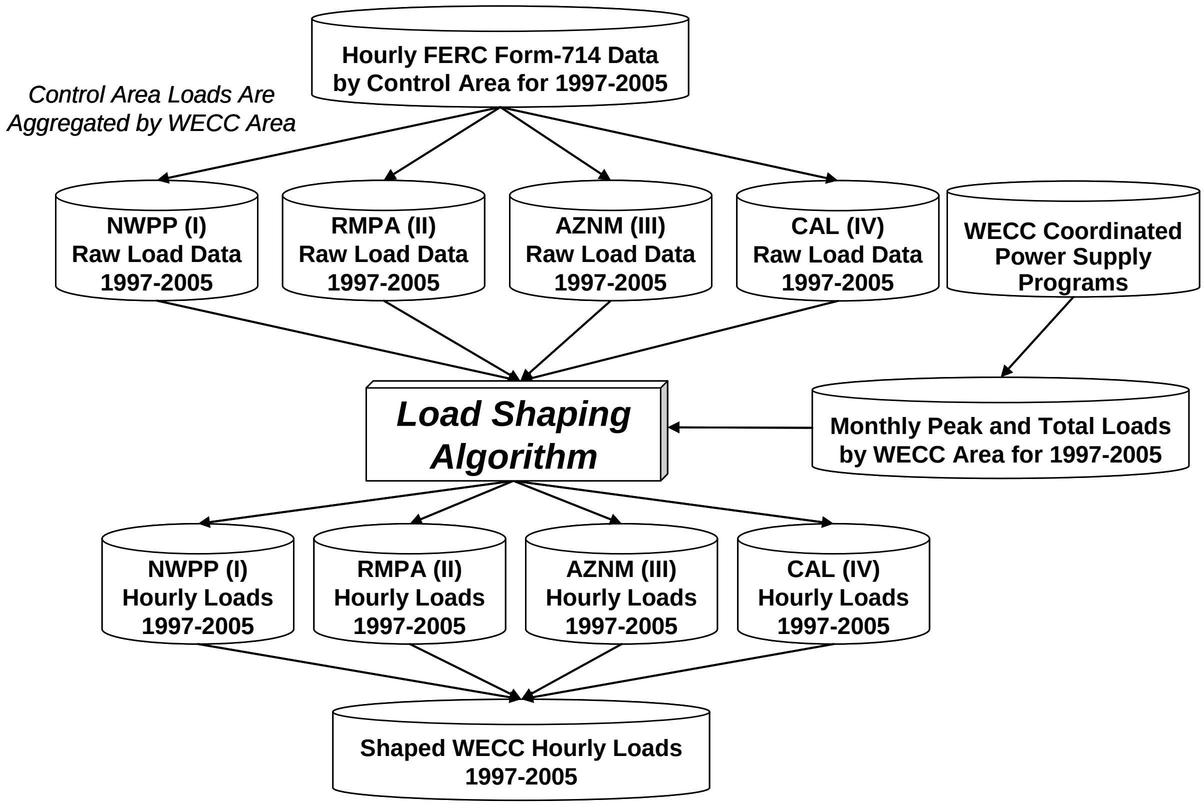

Figure 3.11 Process for Estimating Total Hourly Loads in the U.S. portion of WECC

The Loads Shaping Algorithm uses a QP technique that minimizes differences between a normalized Load Duration Curve (LDC) constructed from historical data and a reshaped LDC generated by the model. Figure 3.12 shows the original LDC, constructed from control area historical loads for August 2005 in the AZNM sub-region and the reshaped LDC. The reshaped curve is consistent with a monthly load factor computed from the peak and total load values reported by WECC. Upper and lower load constraints are specified by the user to bind the model's solution. For each point in the LDC, a scaling factor is then computed as the ratio of the reshaped load to the original load. Finally, the algorithm constructs a scaled chronological hourly profile based on the load scaling factors and an associated original hourly load. The end product, as shown in Figure 3.13, is a chronological load profile that exactly matches WECC monthly statistics.

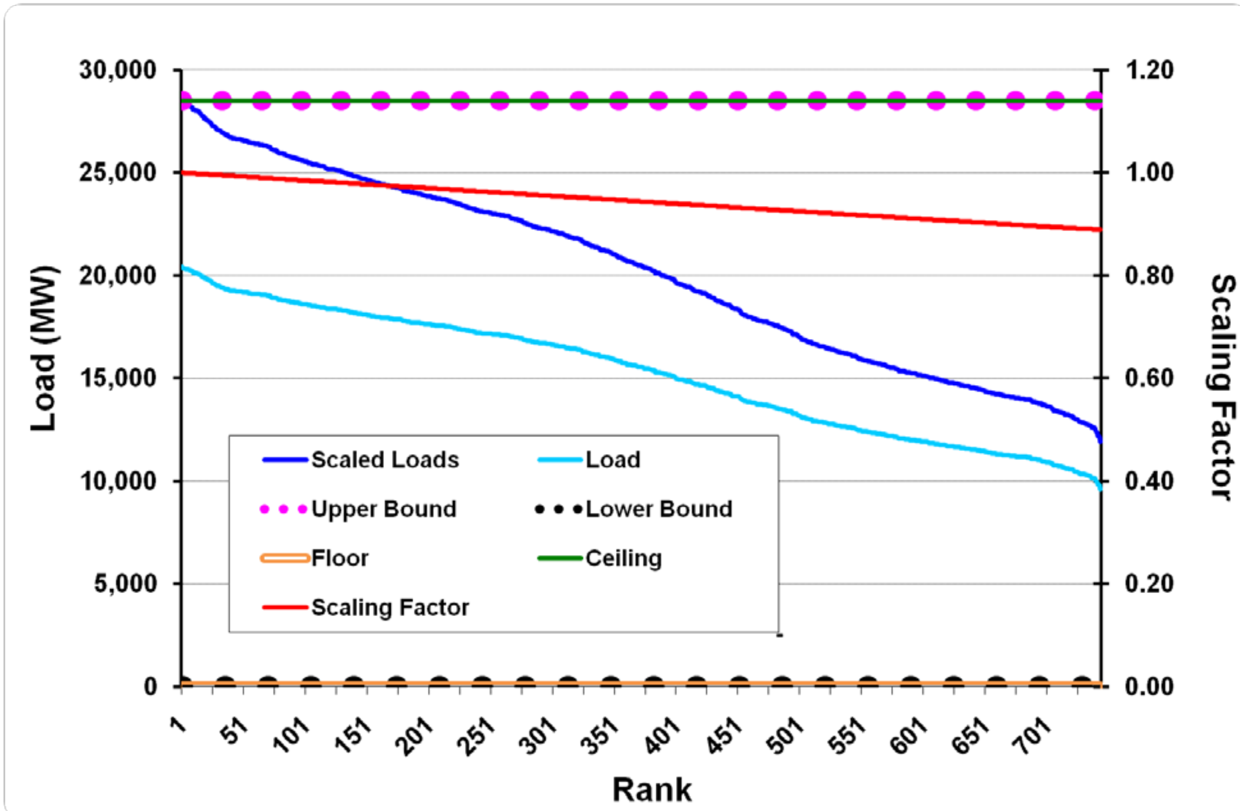

Figure 3.12 Illustration of Load Duration Curve Shaping to Match a Target Load Factor

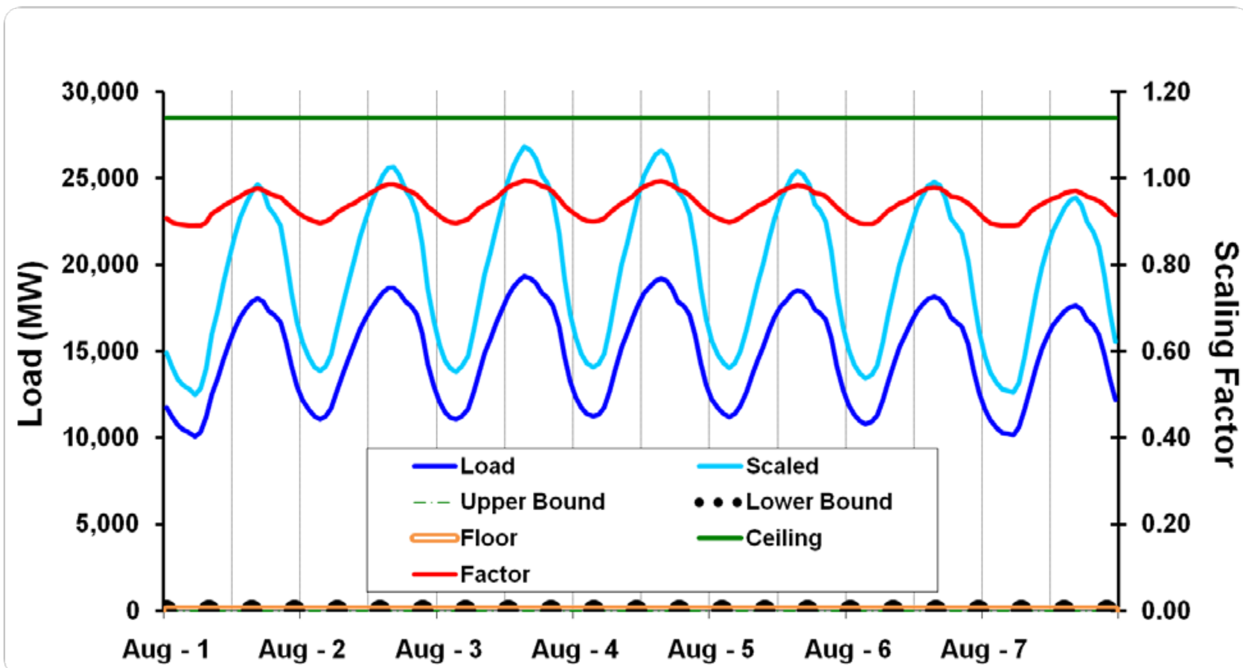

Figure 3.13 Original and Shaped Chronological Load Curve

3.5 SIMULATION OF SLCA/IP HOURLY DISPATCH AND MARKET TRANSACTIONS

For this study, the main function of the GTMax model is to simulate the operations of SLCA/IP power plants, including GCD. As noted earlier this dam is not operated or marketed as an isolated entity; but is operated as part of a system of bundled resources and marketed by Western as part of the SLCA/IP. Therefore, the modeling process used for this study simulates the entire SLCA/IP system.

The GTMax model is well suited for this application since it uses a systemic modeling approach to represent all system components while recognizing interactions among supply, demand, and water resources over time. GTMax represents Glen Canyon Dam as one component of a larger hydropower system that is packaged along with other power plants for marketing purposes. It simulates the system on an hourly time step as a large set of mathematical equations that are solved using linear programming (LP) software. All operations are within component limitations and system dispatch goals that are formulated as a set of linear constraints and bounds.

The model formulation contains a single objective function that maximizes the economic value of the entire SLCA/IP system over a one-week time period. All hours are solved simultaneously, allowing the model to recognize that the dispatch of supply resources in any one hour affects the dispatch during all other times in a simulated week. GTMax also accounts for the spatial dependencies among power plants that are at cascaded reservoirs, such as those in the Wayne N. Aspinall Unit on the Gunnison River.

The model and topologies developed for this study consider customer loads, historical power plant and reservoir information, environmental constraints, WECC market prices, and the maximum economic dispatch objective. GTMax topology nodes represent hydropower plants, aggregate customer load, power market energy transactions, and river gauges. Each node contains information about the specific attributes of the entity that it represents. For example, hydropower plants in the topology contain information about reservoir water releases, operating constraints, and the power plant specified at weekly, daily, and hourly time scales. The flow of energy between connected grid points and water channel flows are represented in the model by links that connect node objects together. Water links along with gauge nodes are used to estimate flows at specific points on river channels for environmental monitoring and compliance.

For each scenario, the GTMax model is run for one typical week per month for all months during the study period. Weekly simulations are scaled up such that each run represents a one-month time period. These results, along with actual operations that occurred during experimental periods, are used to evaluate the economic impact of the ROD.

3.5.1 GTMax Model Input Data for Power Plants and Reservoir

Data for reservoirs and power plants input into GTMax are based on historical monthly statistics contained in Form PO&M-59. This information includes water releases, forebay elevation, and power conversion factors. Because reservoir water release data are monthly and GTMax runs simulate a single week, releases are equally apportioned to each week of a simulated month. For example, February's typical weekly water release is set to 25% of the monthly value (i.e., 7/28). The PO&M form also reports end-of-month (EOM) reservoir elevations. Because it is assumed that the GTMax simulated week occurs approximately in the middle of the month, reservoir elevations input into the model for the Aspinall cascade reservoirs are interpolated from previous and current monthly forebay elevations.

When simulated monthly water release volumes from GCD in the Without ROD scenario differ from historical volumes, reservoir elevation levels and power conversion factors must be adjusted accordingly. A higher-than-historic monthly water release results in a lower-than-historic forebay elevation, while a lower-than-historic monthly water release results in a higher elevation. Equation 3.1 is used to estimate the reservoir water storage (*S*) volume, in acre-feet for GCD (*GC*) under the With ROD scenario (*w*) based on historical monthly forebay elevations (*E*) listed in Form PO&M-59. The water storage in the Without ROD scenario (*wo*) resulting from monthly water releases (*R*) that differ from the With ROD scenario is computed by Equation 3.2. It is based on the sum of releases in each scenario from the first simulation month through the current month (*m*). Whenever the storage volume under the Without ROD Scenario differs from the With ROD scenario, the forebay elevation under the Without ROD scenario must be computed using Equation 3.3. The equation relates reservoir elevation to storage volume.

$$S_{GC,m,w} = -14{,}708{,}784 + 13{,}033.4x\, E_{GC,m,w} - 3.8597\, xE_{GC,m,w}^{2} + 3.8199^{-4} xE_{GC,m,w}^{3} \qquad \textit{EQ 3.1}$$

$$S_{GC,m,wo} = S_{GC,m,w} + \sum_{j=1}^{m} R_{GC,j,wo} - \sum_{j=1}^{m} R_{GC,j,w} \qquad \textit{EQ 3.2}$$

$$\begin{aligned} E_{GC,m,wo} = {} & 3{,}413 + 0.02255xS_{GC,m,wo} - 6.7874^{-7}xS_{GC,m,wo}^{2} \\ & + 9.78155^{-12}xS_{GC,m,wo}^{3} \end{aligned} \qquad \textit{EQ 3.3}$$

The factor that relates the conversion of water releases to power production is a function of the forebay elevation. Therefore, a different reservoir elevation means that the power conversion factor must also be computed. The power conversion factor under the With ROD scenario is based on a historical value as recorded in Form PO&M-59. This value is used as a benchmark from which the Without ROD conversion factor is estimated. It is assumed that a change in reservoir elevation under the Without ROD scenario will either increase or decrease the total power production during the month. The power conversion factor (*PCF*) used in the Without ROD scenario is computed using Equation 3.4. Polynomial coefficients were derived by Western using historical Glen Canyon forebay levels and power conversion factors.

$$\begin{aligned} PCF_{GC,m,wo} = {} & PCF_{GC,m,w} + \left(-7.8633 + 3.6679x\, E_{GC,m,wo}^{-3} - 3.7993^{-7}xE_{GC,m,wo}^{2}\right) \\ & - \left(-7.8633 + 3.6679x\, E_{GC,m,w}^{-3} - 3.7993^{-7}xE_{GC,m,w}^{2}\right) \end{aligned} \qquad \textit{EQ 3.4}$$

The maximum output capability (*Output*) at GCD is computed monthly. It is the minimum of (1) the physical capacity of the power plant turbines as shown in Table 2.1 and (2) the maximum production level based on the forebay elevation as computed by Equation 3.5. This equation computes the maximum turbine flow rate and multiplies it by the power conversion factor to obtain the maximum output level.

$$Output^{max}_{GC,m,k} = PCF_{GC,m,k} x(-731.298 + 0.0379784x\ E_{GC,m,k} - 4.676345^{-5} x E^2_{GC,m,k}), for\ each\ scenario\ where\ k = w, wo \quad EQ\ 3.5$$

Further adjustments are made to the maximum generation level at the Glen Canyon Powerplant to account for unit outages. These adjustments include all types of outages, both scheduled and random, that take units off-line because of unforeseen problems at the plant. Historic outage levels provided by Reclamation were used to compute monthly outage factors. These factors were used to derate that maximum output of the plant as computed by the process described above. For example, if one and only one turbine was out of service for a month, the maximum output was reduced by approximately 12.5% (i.e., 1/8). As will be described in greater detail in Section 4, capacities and outages are important factors in determining the economic cost of the ROD.

3.5.2 GTMax Model Input Data, Loads, and Market Prices

There are two types of load data input into GTMax that include firm customer loads and project use loads. Hourly firm customer loads during the study period are estimated by the methodology described in Section 3.3. These data are not used directly. GTMax firm loads are instead based on customer energy schedules that represent a typical week. This week is constructed from the Customer Scheduling algorithm results that produce estimates of hourly customer schedules for an entire month. Simulated hourly schedules are processed to create typical shapes for three types of days, including a weekday, Saturday, and Sunday. Holidays are assigned to the Sunday load profile. Typical profiles for each type of day are average values for a specific hour. For example, the typical load at 1:00 a.m. on a weekday in January is the average of all 1:00 a.m. loads during weekdays in that month.

Project use loads are based on contract levels obtained from Montrose. Monthly values for capacity and energy are provided in Tables 3.3 and 3.4, respectively. Compared to firm customer loads, these values are small. Although some of these individual schedules can vary somewhat from one hour to the next, others are scheduled at a constant rate. As a simplification for modeling purposes, it was assumed that all project use loads are scheduled flat; that is, each hour has a schedule that equals the monthly level divided by the number of hours in the week. As will be described later in this section, additional modifications to these loads are made to account for generation, represented as negative load, from smaller SLCA/IP hydroelectric power plants.

Table 3.3 Monthly Project Capacity Use, by Customer

	Capacity (MW)										
	Dolores	**Heber**	**NAPI[1]**	**NAPI/ NTUA**	**Silt**	**Uintah**	**Ute Moun-tain**	**Wasatch**	**Dutch**	**Camp**	**Total**
Jan	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Feb	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Mar	0.50	0.60	0.50	12.00	0.00	0.02	0.00	3.00	0.19	0.64	17.45
Apr	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
May	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Jun	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Jul	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Aug	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Sep	8.30	0.60	22.50	12.00	0.37	0.12	0.00	3.00	0.20	0.98	48.06
Oct	0.50	0.60	0.50	12.00	0.00	0.02	0.00	3.00	0.19	0.64	17.45
Nov	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Dec	0.50	0.60	0.00	0.00	0.00	0.02	0.00	3.00	0.19	0.64	4.95
Annual Average	**4.40**	**0.60**	**11.33**	**8.00**	**0.18**	**0.07**	**0.00**	**3.00**	**0.19**	**0.81**	**28.59**

[1] NAPI = Navajo Agricultural Products Industry

Table 3.4 Monthly Project Energy Use, by Customer

	Energy (MWh)										
	Dolores	**Heber**	**NAPI[1]**	**NAPI/ NTUA**	**Silt**	**Uintah**	**Ute Moun-tain**	**Wasatch**	**Dutch**	**Camp**	**Total**
Jan	67	229	0	0	0	14	0	2,232	88	475	3,105
Feb	60	197	0	0	0	13	0	2,016	94	429	2,809
Mar	67	197	1,106	8,928	0	14	0	2,232	94	475	13,113
Apr	2,447	184	8,006	8,640	263	86	0	2,160	99	707	22,591
May	2,529	184	8,272	8,928	272	89	0	2,232	102	730	23,339
Jun	2,447	203	8,006	8,640	263	86	0	2,160	65	707	22,576
Jul	2,529	242	8,272	8,928	272	89	0	2,232	65	730	23,359
Aug	2,529	256	8,272	8,928	272	89	0	2,232	66	730	23,374
Sep	2,447	218	8,006	8,640	263	86	0	2,160	71	707	22,599
Oct	67	192	1,106	8,928	0	14	0	2,232	82	475	13,096
Nov	65	205	0	0	0	14	0	2,160	86	460	2,989
Dec	67	231	0	0	0	14	0	2,232	88	475	3,107
Annual Total	**15,321**	**2,537**	**51,046**	**70,560**	**1,606**	**607**	**0**	**26,280**	**1,000**	**7,100**	**176,058**

[1] NAPI = Navajo Agricultural Products Industry

Market prices input into GTMax are a key model driver, especially when the study objective is to maximize the economic value of hydropower resources. Consistent with the prices that are input into algorithms that simulate customers’ hourly requests for SLCA/IP energy, prices that are input into GTMax are based on WECC market hub prices as described in the previous section. For this study, prices input into the model are primarily based on the Palo Verde market hub. When data for this hub — identical to the prices used for SRP — are not available for a specific time, alternative information is used as a surrogate. This process of using surrogate data when no information is available for a specific hub is described in Section 3.4.1. Because prices are not known with certainty, and to be consistent with GTMax load profiles, average hourly price profiles for weekdays, Saturdays and Sundays are input into the model for each month.

3.5.3 GTMax Topologies

Two topologies are utilized in this study. Both were originally designed and are currently used to assess future Western purchase requirements for the CRSP Management and Marketing Office located in Montrose, Colorado. The topologies include one that has a highly specialized representation of the Flaming Gorge Dam and the downstream river system below the dam and another one that represents the entire SLCA/IP system.

Using these two topologies, the GTMax model is run three times to produce final results. Figure 3.14 is a flow chart that shows the sequence of operations and the flow of information for the GTMax simulations.

The first simulation estimates Flaming Gorge operations using the relatively simple Flaming Gorge topology, as shown in Figure 3.15. This run simulates Flaming Gorge operations on an hourly basis over a one-week time period. It also estimates down-stream water flows at the confluence of the Green and Yampa Rivers and at the Jensen Gauge. Hourly water releases at Flaming Gorge are constrained such that flows at the Jensen Gauge comply with environmental limits. Results from this simulation are input into the second GTMax run that simulates the Without ROD scenario.

The second run simulates SLCA/IP operations under the Without ROD scenario. It employs a more complex topology that contains all major SLCA/IP hydropower plants and market components as shown in Figure 3.16. GTMax inputs for Flaming Gorge operations in this second model run constrain the simulation such that it produces the exact same results for Flaming Gorge as the “Only Flaming Gorge” simulation. Therefore, model results for Flaming Gorge in these first two runs are identical. The second run also simulates operation for other major SLCA/IP hydropower plants and energy transactions (i.e., Western’s purchases and sales) with the market.

The third and final GTMax run simulates the With ROD Scenario. While this run uses the same topology as the second run, the attributes assigned to some of the nodes and links differ; most important among these are the operating restrictions at GCD. Also, except for Glen Canyon, operations at all other hydropower plants and reservoirs are constrained such that they produce identical results as in the Without ROD scenario. Using this approach isolates the effects of the ROD to operations at Glen Canyon only. Although the ROD only applies to Glen Canyon, operations at other SLCA/IP power plants may change operations in response to changes in production at Glen Canyon. By requiring identical operations under the two scenarios at all facilities except at Glen Canyon, the impacts are restricted to one facility.

In the final step of the process, the economic costs of the ROD are computed. As shown at the bottom of Figure 3.14, this process uses GTMax simulation results for the two scenarios and historical releases and power production from experimental flow periods.

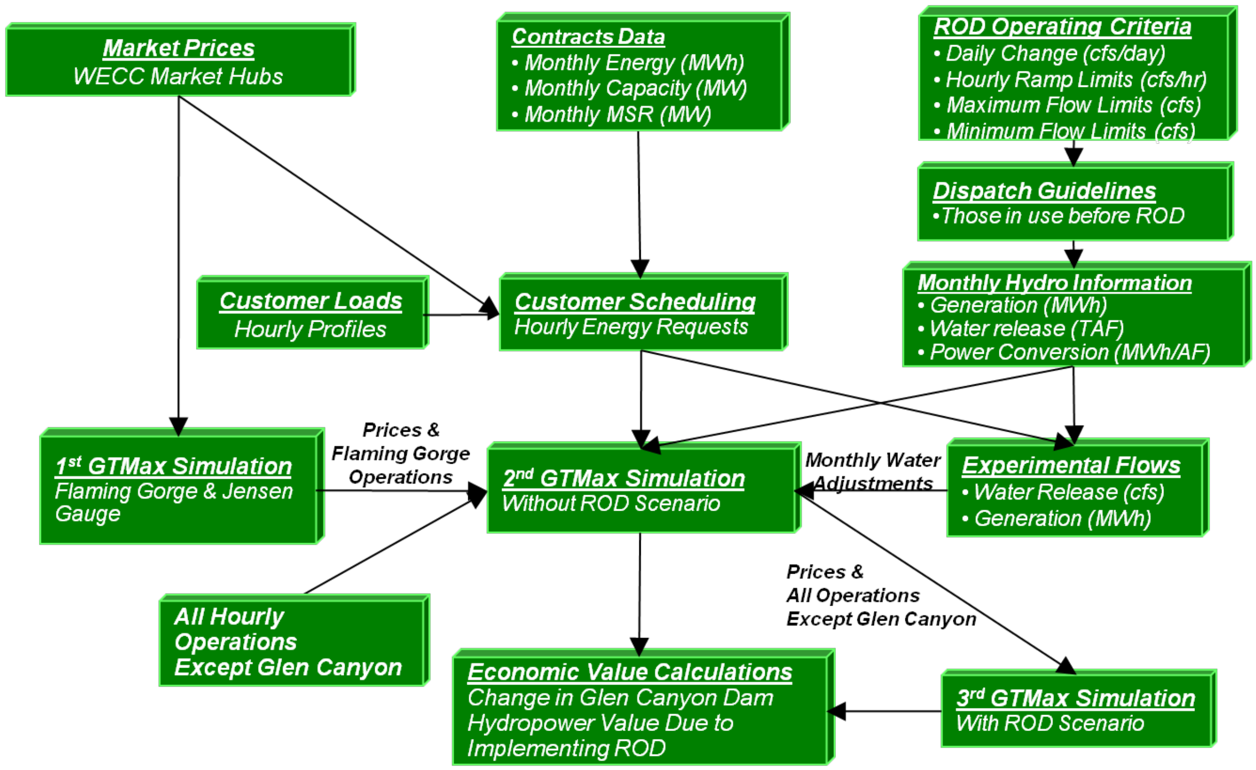

Figure 3.14 Sequence of Operations for Simulating SLCA/IP Marketing and System Operations

3.5.3.1 Flaming Gorge Topology

The first topology utilized in this study is shown in Figure 3.15. It simulates the operation of the Flaming Gorge Dam Reservoir and Powerplant such that water releases comply with downstream flow limitations at the Jensen Gauge while maximizing the value of the power resource. The gauge is located about 95 miles downstream of Flaming Gorge near Jensen, Utah. To protect endangered fish species, the stage change at the gauge is limited to 0.1 meters per day. Also, the amount of water that passes the gauge during a calendar day cannot vary by more than 3% from one day to the next.

The Flaming Gorge topology only represents the WECC power market (dark turquoise square in Figure 3.15), Flaming Gorge (dark blue square), the Green and Yampa river channels (dashed blue lines), the confluence of the two rivers, and the Jensen Gauge (blue water drop). Energy prices are conveyed to the Flaming Gorge node via the black line in the figure. To compute Jensen Gauge flows, GTMax uses a Water Time Travel Distribution (WTTD) function to represent a wave of water as it is released, moves, and attenuates downstream. This function is derived from model outputs produced by the Streamflow Synthesis and Reservoir Regulation (SSARR) model. Yampa River flows are based on historical U.S. Geological Survey (USGS) stream flow records.

The Flaming Gorge topology and associated model formulation were originally developed to support the Flaming Gorge Dam EIS (FGEIS). Using an iterative methodology developed for the FGEIS, the SSARR and GTMax models share information such that the value of power is maximized while downstream flows are within gauge limits. In addition to gauge constraints, Flaming Gorge Dam operations are also subject to a minimum release of 800 cfs, and both up-ramp and down-ramp rates are limited to 800 cfs/hr. The daily release patterns at Flaming Gorge are limited to single-cycle pattern during the summer and a double-cycle pattern during the winter, which are consistent with customer load patterns.

Market prices input into the GTMax market node are used as a measure of the economic value of energy. For this analysis, WECC prices at the Palo Verde hub were input in the model for both scenarios.

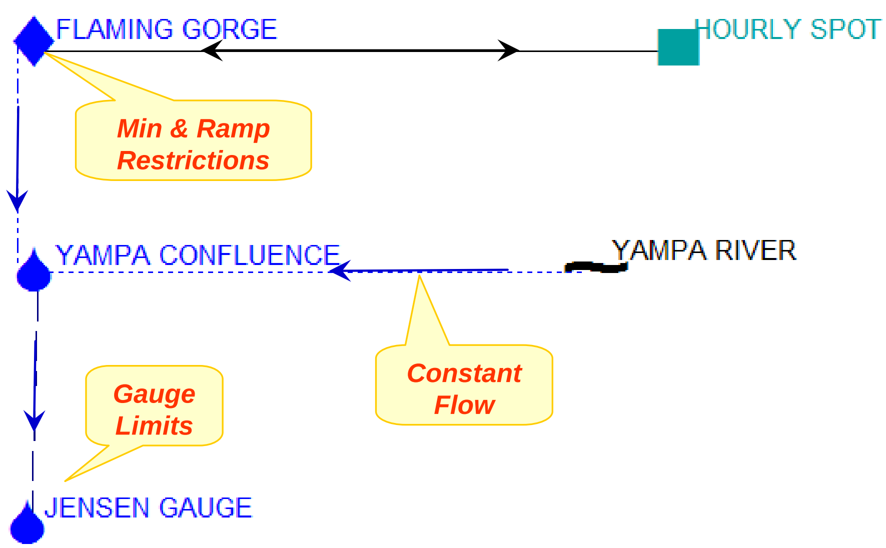

Figure 3.15 Topology Used for Flaming Gorge Dispatch and Jensen Gauge Simulations

3.5.3.2 SLCA/IP Topology

The second GTMax topology consists of all SLCA/IP system components, including power markets, Western LTF and project use loads and power resources in the CRSP, the Seedskadee Project, the Collbran Project, and the Rio Grande Project. This topology, which is shown in

Figure 3.16, also includes the Green, Yampa, and Gunnison Rivers along with side flows into the Aspinall group of dams.

The load or demand node (dark blue square in Figure 3.16) includes typical customer energy requests and net project use load. Energy consumed by the project is based on levels Western reserved for this purpose. Because some of this load is served by local generation produced by the Elephant Butte Dam, McPhee Dam, and Towaoc Canal power plants, the project use load is reduced by transmission losses. The net project use load calculation assumes that generation levels from all three small power plants are constant during the entire month. This method is similar to the one practiced in the Montrose Office when assessing future monthly energy purchase needs.

Using water channel links (i.e., the dotted blue lines in Figure 3.16), the SLCA/IP topology represents the Wayne N. Aspinall Unit on the Gunnison River as a tightly coupled cascade to account for the spatial dependencies among power plants. The Blue Mesa Dam and hydropower plant is at the top of the cascade (i.e., highest elevation level), followed by Morrow Point and then Crystal. This group of three dams is often referred to as the Aspinall Cascade. The Blue Mesa reservoir capacity is 940.8 TAF, which is the largest water storage capacity in the group. It is more than 8 times larger than the Morrow Point Reservoir and more than 36 times larger than the Crystal Reservoir.

Water channels connected to nodes represent both side flows from non-point water sources and reservoir evaporation. In the SLCA/IP topology, this node-channel configuration is used to represent the following aspects of the Aspinall Cascade: (1) Gunnison River flows into the Blue Mesa Reservoir, (2) side flows between the Blue Mesa and Morrow Point Reservoirs, and (3) side flows between the Morrow Point and Crystal Reservoirs. It is assumed that flows in these channels are constant throughout a simulated week. Monthly flows are based on water balance equations that use Form PO&M-59 water releases and forebay elevations along with reservoir-elevation curves. When applying the water balance equation, some errors were discovered in the PO&M-59 data. These issues were resolved by using data found on the Reclamation (undated) and Western (2010) Web sites.

The daily amount of water released from a reservoir in the Aspinall Cascade is identical each day of the week. One exception is the Blue Mesa Reservoir, where water typically is not released on Saturdays during the months of November through February. Each separate reservoir typically has a different daily release volume to accommodate side flows and to achieve historical EOM reservoir elevation levels.

Power production from Crystal is constant. However, as dictated by Reclamation, operations change occasionally to reflect evolving hydrological conditions and downstream water requirements. Other than the physical limitations of the reservoirs and release restrictions from the power plant, bypass tubes, and spillways, there are no operational limitations at Blue Mesa and Morrow Point. However, given flat releases from the Crystal Dam, Morrow Point releases are constrained such that the reservoir elevations at Crystal are within minimum and maximum levels and do not change more than specified levels over 1-day and 3-day calendar periods.

The Fontenelle Dam has the only power plant associated with the Seedskadee Project. Releases and associated power production levels are constant throughout a simulated week.

Collbran project daily generation produced by the Upper and Lower Molina power plants is scheduled at or near power plant maximum capability for continuous blocks of time, the length of which is determined by the amount of water that is available for release during a 24-hour period. Generation is first dispatched at capacity during hours with the highest market price. If more water is available, generation is then dispatched during low-price hours.

In addition to water channels, links in the SLCA/IP topology represent the flow of energy from generation resources and market purchases to serve SLCA/IP customer load and for sale to non-firm markets. It is assumed that 8.8% of the energy generated by the Glen Canyon Powerplant will be lost when it is transported to customer delivery points. A lower transmission loss rate of 5.5% is assumed for all other SLCA/IP hydropower plants, including those previously mentioned small plants that serve project use load.

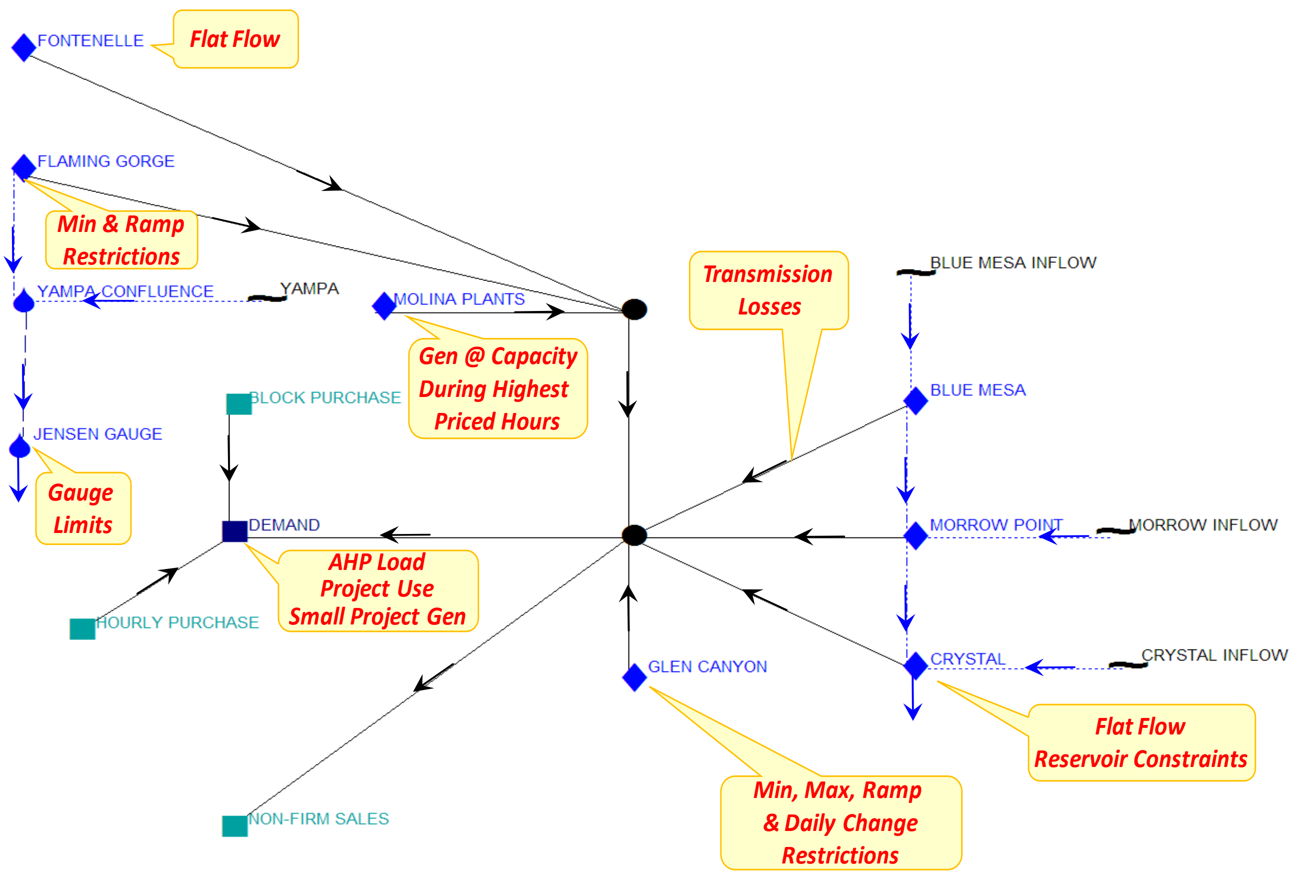

Figure 3.16 SLCA/IP Topology Used for Powerplant Dispatch Simulations

3.5.4 Ancillary Services

Ancillary services help maintain reliable system operations in accordance with good utility practice. Some of these services including spinning reserve, non-spinning reserve, replacement reserve, regulation/load following, black start, and voltage support. Quick start times, fast ramping capabilities, and the ability for rapid corrective responses to changes in grid conditions make hydropower plants an excellent resource for providing ancillary services.

Two ancillary services, spinning reserves and regulation, were included in GTMax simulations for this analysis. It was assumed that Glen Canyon would provide both services under the Without ROD and With ROD scenarios. The only exception is during experimental flows, for which it was assumed that these duties would be performed by Morrow Point. As depicted in Figure 3.17, ancillary services reduce the operating range of a power plant. Spinning reserves reduce maximum scheduled operations. On the other hand, regulation affects both maximum and minimum production levels. On the basis of information provided by Western, spinning reserves are assumed to be 80 MW, and regulation is assumed to be 40 MW. As will now be described in greater detail, the extent to which these services affect operations differs under the two scenarios.

Regulation is the amount of operating reserve capacity required by the control area to respond to automatic generation control to assure that the Area Control Error meets these two conditions: that it (1) equals zero at least one time in all 10-minute periods and (2) that it falls within specified limits to manage the inadvertent flow of energy between control areas.

It was assumed that Glen Canyon would provide regulation services by responding quickly to moment-by-moment up and down movements in control area electricity demand using automatic generation control. Glen Canyon is well suited for providing this service because at least one or more of its turbines are always on-line, and it operates at sufficiently high levels such that sudden decreases in load will not reduce generation below either its technical or regulatory minimums.

Glen Canyon provides regulation-down service without incurring any opportunity costs when it is not necessary to alter its hourly generation pattern to provide the service. The amount of regulation-down service that can be provided without incurring costs is as high as the power production level generated when the plant is operating at the mandated minimum release. Because the regulatory minimum release is on an hourly average basis, the service can be provided without costs because, during some moments, water releases may be less than the minimum flow rate as long as there are compensating releases greater than the minimum flow rate at other times within the hour.

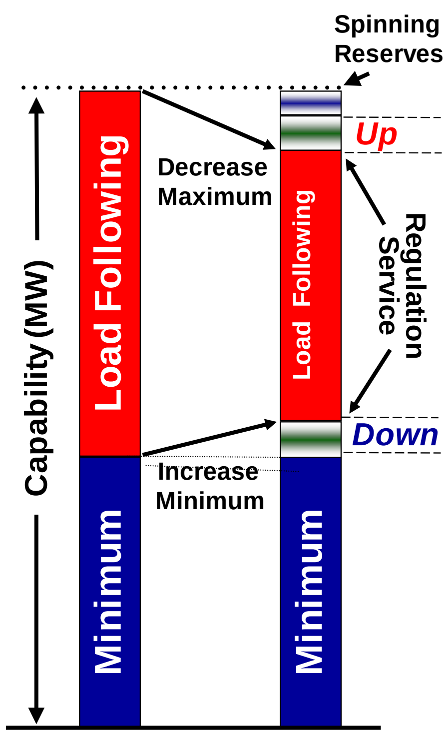

Figure 3.17 Operating Range Reduction When Providing Ancillary Services

This interpretation is consistent with regulation services in which the net power production level over a one-hour period sums to zero. Opportunity costs are only incurred when regulation-down service requires Glen Canyon to be operated at a higher level than required by the minimum release rate. At a 40-MW level of service, this situation never occurs under the With ROD scenario because the minimum flow requirement always produces significantly more than 40 MW. However, under the Without ROD scenario during the wintertime, the 1,000 cfs minimum release level produces insufficient output to provide this level of service when reservoir elevations are lower. Therefore, at times the minimum generation level at Glen Canyon must be increased during the nighttime to provide the assumed 40 MW of regulation service.

To provide regulation-up service, generation levels must be sufficiently low such that a power plant can respond to instantaneous decreases in grid loads without exceeding the output capability. Regulation-up services will incur an opportunity cost when maximum power plant sales during peak periods are required to be lower than the plant’s capability. The power plant’s average hourly production level must be at or below the plant’s capability minus the regulation-up service level. Under the With ROD scenario, regulation-up service does not incur any opportunity costs under all but very high hydropower conditions since the dam is operating below the maximum power plant capacity. It is of note that at many times, the regulatory flow rate is significantly below the physical plant limit. The ROD requires that the maximum average hourly release rate from Lake Powell be no more that 25,000 cfs under most hydrological conditions. This release rate is under the maximum turbine flow rate by 5,000 cfs to 6,000 cfs most of the time. Assuming a power conversion factor of 40 MW per 1,000 cfs, 200 MW or more of regulation-up reserves could be provided without incurring an opportunity cost. It should also be noted that providing regulation services will not affect either hourly ramping or daily changes at Glen Canyon. It is also assumed, on the basis of personal communication with Western staff at the Montrose Office, that both up- and down-regulation services will be provided by the Glen Canyon Powerplant at a 40-MW level. Under the Without ROD scenario, providing regulation-up service almost always incurs opportunity costs during some peak hours of the day, because a more open schedule of power sales is needed at times of high prices to accommodate this service.

Spinning reserves are defined as generating capacity that is running at a zero load, connected to an output bus, synchronized to the electric system, and ready to take immediate load. The portion of unloaded synchronized generating capacity, controlled by the power system operator, must be capable of being loaded in 10 minutes and capable of running for at least two hours. On the basis of personal communication with Western staff at the Montrose Office, it is assumed that 80 MW of spinning reserves will be provided by the Glen Canyon Powerplant.

When a generator supplies spinning reserve services, it will increase output in response to an outage situation. The increased output fills the generation void created by a generator in a balancing authority that suddenly ceases to produce power. Spinning reserves may also be called upon when an abrupt transmission line outage will no longer permit the reliable transport of power into a region. Generation levels in normal conditions must be sufficiently low such that when an outage occurs, it can increase output levels by its spinning reserve obligation without exceeding the maximum capability of the generator.

Spinning reserve services require that maximum production levels do not exceed the plant's capability minus the amount of spinning reserves required. Providing spinning reserves also requires that one or more turbines operate below capability or in a spinning state without producing power. The former condition may require the unit to operate in a sub-optimal state, while the latter releases water without power production to spin the turbines under no load. These additional requirements typically incur opportunity costs, because capacity must be reserved at the high end of operations to accommodate the spinning reserves. Unlike regulation-down services, spinning reserves do not affect minimum generation levels. Under the With ROD scenario, spinning services at GCD can be provided under most conditions because exception criteria allow for the maximum release constraint to be relaxed to support grid operations. The exception criteria also allow this service to be provided at little or no costs during most hydrological conditions. Similar to the situation with providing regulation-up service, there is ample room for increased production levels (200 MW or more) because ROD release regulations require that the Glen Canyon Powerplant is loaded significantly below its physical capability.

3.6 CALCULATING ECONOMIC VALUE

A spreadsheet is used to calculate the financial value of SLCA/IP resources under both the With ROD and Without ROD scenarios. In this spreadsheet, GTMax economic benefits are calculated by multiplying generation levels by the spot market price of electricity for each hour in a typical one-week simulation.

GTMax results for a typical week are scaled up to a month for all system components. A monthly estimate is obtained by multiplying simulated results for specific types of days by the number of occurrences of that type of day in the month. For example, the average weekday result from the GTMax simulated week is computed and then multiplied by the number of weekdays in the month. Results for all Sundays and Saturdays in the month are scaled by using a similar process. As mentioned previously, any holidays in the month are treated as a Sunday. However, when an experiment is conducted at GCD, the days of duration of the experiment are removed from the scaling process. Instead, actual historical generation data are used for these periods. The monthly scaling process applied to the Glen Canyon Powerplant accounts for the type of day on which the experiment was conducted, that is, the number of weekdays, Saturdays, Sundays, and holidays that occurred during the experiment.

The economics of power production during experimental flow periods are computed by multiplying the actual generation level at the plant, as recorded by supervisory control and data acquisition (SCADA), by the hourly value of energy. Consistent with computations made in the GTMax modeling process, an identical price set for an experimental period is used for this evaluation. The total economic value under the With ROD scenario is the sum of the value during experimental periods plus the value, as computed by GTMax, during non-experimental periods.

Results for a typical week are scaled up to a month for all systems. The economic cost of the ROD is computed as the difference between the two scenarios.

4 ECONOMIC COST OF THE ROD

This section presents the economic costs of implementing the ROD at GCD based on simulating the operations of the SLCA/IP by using GTMax. In the following sections, the results will be discussed in detail for each year of the study period. The costs are in $2009 and are displayed by water year (WY), which runs from October 1 to September 30.

The economic value of Glen Canyon power resources consists of both capacity and energy components. The ROD operating criteria reduce the economic value of both components by restricting Glen Canyon Powerplant's flexibility to respond to market price fluctuations and by lowering maximum output levels substantially below its physical capability.

Energy generated under the With ROD scenario is composed of energy generated from experimental releases and from normal releases that satisfy the operational constraints of the ROD. Energy generated under the Without ROD scenario is composed only of energy generated from normal releases that satisfy operational constraints that were in effect before the ROD. The value of energy is determined by multiplying the amount of energy generated in each hour by the hourly market hub price for GCD. Determination of hourly market hub prices was described in Section 3.4.

Actual electricity market prices and price spreads were used during the entire study period of this analysis, even during the California energy crisis in 2000 and 2001 when market design issues were revealed. As shown in Figures 2.16 and 2.17, large fluctuations in electricity prices and price spreads occurred during this period and many people felt these prices and price spreads were not indicative of the true electricity production costs at that time and should not be used in an economic analysis. Therefore, a sensitivity analysis, described in Section 4.10, was performed which attempted to smooth the prices during the crisis period. The results of modeling runs using market prices and smoothed prices were then compared to determine the magnitude of the effect of the market design crisis on the total economic costs of the ROD. The true economic cost of the ROD likely lies between the costs calculated from these two cases.

The second component of economic value at Glen Canyon is capacity. The available capacity in each scenario is determined by the GTMax simulations. The capacity value is based on the price of short-term capacity purchases; that value was derived from Reclamation's (2007) *Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead* (a.k.a. Shortage Criteria EIS) and was determined to be $82.8/kilowatt (kW) (in $2009). The value of capacity is the amount of capacity in each scenario multiplied by the short-term capacity price. The difference in the values of the capacity components of the two scenarios is the economic cost or benefit of the ROD.

There are several major factors that determine the economic costs of the ROD constraints, which include the following:

- **Price spreads:** In general, as the price difference between on-peak and off-peak periods increases, the cost of the ROD becomes more expensive.

- **Seasonal releases:** The total amount of water released from GCD is identical under both scenarios; however, the monthly distributions are important in that more releases during high-priced seasons, especially in the summer and (to a lesser degree) winter, will lead to a higher economic value.
- **Marginal water value:** The marginal value of water (i.e., additional dollars for an additional acre-foot of water) tends to be relatively high when monthly water releases are low, but lowers increasingly as more monthly water is released. Marginal values in the Without ROD scenario, especially at low water releases, are higher than marginal values under the With ROD scenario. Exceptions to this general rule occur at discontinuous points where the daily change transitions from a lower level (e.g., 6,000 cfs/day) to a higher level (e.g., 8,000 cfs/day).
- **Total monthly releases:** Although the marginal value of water tends to be higher under low hydropower conditions, the *total* cost of the ROD is somewhat smaller because a lower volume of water is shifted from on-peak periods to off-peak periods under the With ROD scenario. As more water is released, the *total* ROD cost initially increases; however, as hydropower conditions become higher than normal, ROD costs begin to decrease. At very high hydropower conditions, ROD costs diminish to zero as flat flows are required under both scenarios because of physical limitations to turbine flow.
- **Unit outage:** Under most conditions, unit outages have little or no impact on operations under the With ROD scenarios because typically there is excess capacity. However, under the Without ROD scenario, outages have a direct impact on the Glen Canyon Powerplant's value because any unit that is off-line reduces the amount of energy that can be sold during high-priced periods; therefore, as outages increase, the economic cost of the ROD decreases.
- **Summer and winter minimums:** *All other factors being equal,* the ROD costs are higher in the winter than in the summer, because the Without ROD scenario has seasonal minimum flow requirements, while the With ROD scenario has the same minimum requirements year round. The minimums are 1,000 cfs in winter and 3,000 cfs in the summer. Therefore, the Without ROD scenario can shift more water into winter peak hours to increase the water's value.
- **Ancillary services:** Although the level of ancillary services that GCD supplies are identical in both scenarios, these services reduce the economic value of GCD under the Without ROD scenario more than they do under the With ROD scenario under most conditions. The economic value of GCD under the With ROD scenario is reduced only during high hydropower conditions. This result occurs because the With ROD scenario has more uncommitted capacity and exception criteria that allow operations to go above normal operations when reserves are called upon. If ancillary services were assumed to be performed by other SLCA/IP hydropower resources, ROD costs would have been significantly higher in terms of both capacity and energy.
- **Capacity sales:** Differences in capacity sales between the two scenarios tend to decrease as the hydrological condition increases (or gets wetter). Under the Without ROD scenario, Glen Canyon Powerplant can quickly ramp-up generation and maintain a relatively high level of generation for several peak hours even under low monthly water releases. On the other hand, daily ramp restrictions under the With ROD scenario limit the peak flow that the GCD can achieve, especially under low hydrological conditions. When the hydropower condition increases and monthly water releases increase, the daily

change becomes less restrictive, and a higher baseload flow can be maintained such that the 25,000 cfs level can be attained more easily.

All of these factors can impact the ROD cost at different magnitudes, depending on the hydrological conditions and energy market prices. In addition, some factors have a larger impact on energy versus capacity values than others. The analysis performed in the study estimated economic costs during each month from 1997 through 2005 as hydropower conditions changed and energy markets evolved. The following sections describe annual (water year) economic costs and provide some insights into the major factors that resulted in estimated cost trends.

4.1 COST OF ROD IN WY 1997

This year is the first in which restrictions imposed by the ROD came into effect; they began in February 1997 (the fifth month of the WY). This year had one experimental flow, an Aerial Photography Steady Flow (APSF) that ran from August 30 to September 2 and consisted of a constant flow of about 8,000 cfs. This year also had a total flow of almost 14,000 TAF, making it the fifth-highest annual release in the dam’s history.

Figure 4.1 shows the monthly releases; the amount of water released in each scenario is identical. Although an APSF experiment was conducted, it lasted only a few days. Therefore, the water releases that were required to conduct this experiment were reallocated only within the months of August and September. This relatively short experiment did not require a change or reallocation of water to other months of the water year to accommodate the APSF experiment.

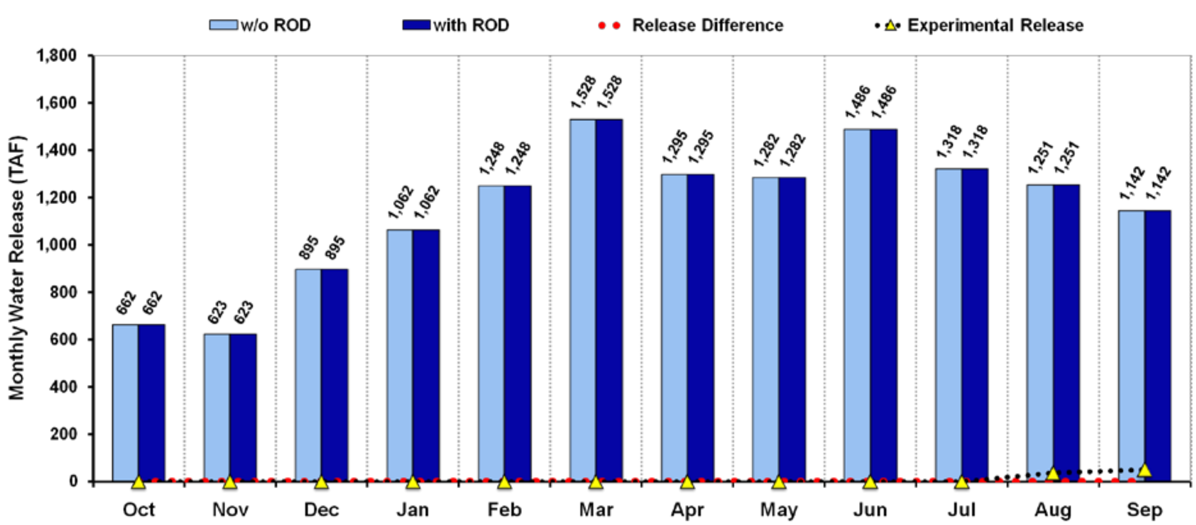

Figure 4.1 Monthly Water Releases in WY 1997

Figure 4.2 shows the ROD cost from energy differences combined with the difference or spread in the average monthly on-peak and off-peak electricity market prices. The energy component of the ROD costs from February, when the ROD went into effect, to May generally follow the price spread; namely, the cost increased as the price spread increased. However, the ROD cost was still relatively low because water releases in those months were high. Releases during off-peak and shoulder hours are relatively high under the Without ROD scenario, because capacity limits (along with ancillary service requirements [120 MW]) and outages limited on-peak production levels. The With ROD scenario shifted generation to the shoulder and off-peak periods to a limited extent only.

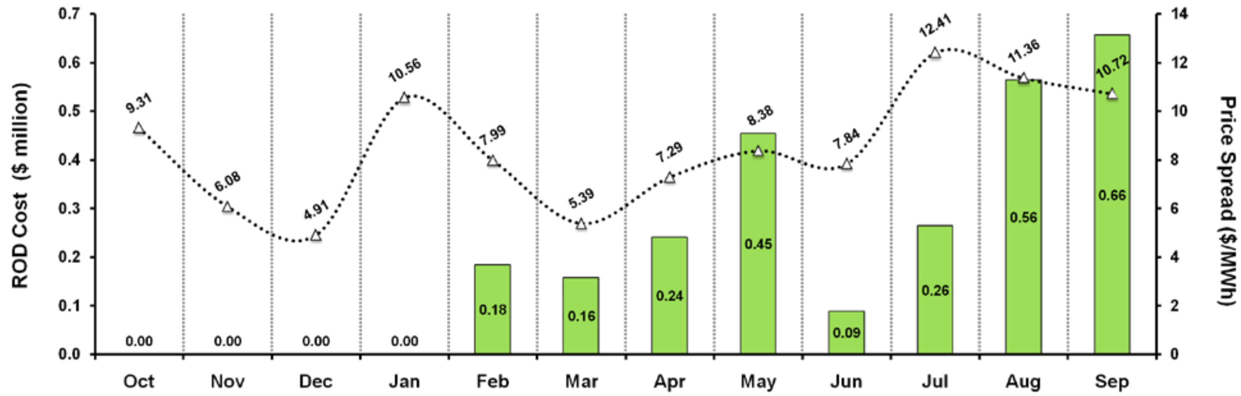

Figure 4.2 Energy Component of ROD Cost and Price Spread in WY 1997

In June, the ROD cost dropped to the lowest level of the year even though the price spread was only slightly less than in May. The low cost in this month could be attributed to a very high water release, resulting in a small operating range (i.e., the difference between the maximum and minimum outputs) as simulated by GTMax. The difference in monthly operating ranges provided in Figure 4.3 shows the operating range and the outage factor for the Glen Canyon Powerplant. June had a very narrow operating range because simulated dam releases during this period were nearly constant. Most of the time, production levels are equal to the output capability of the plant less the resources that were reserved for ancillary services.

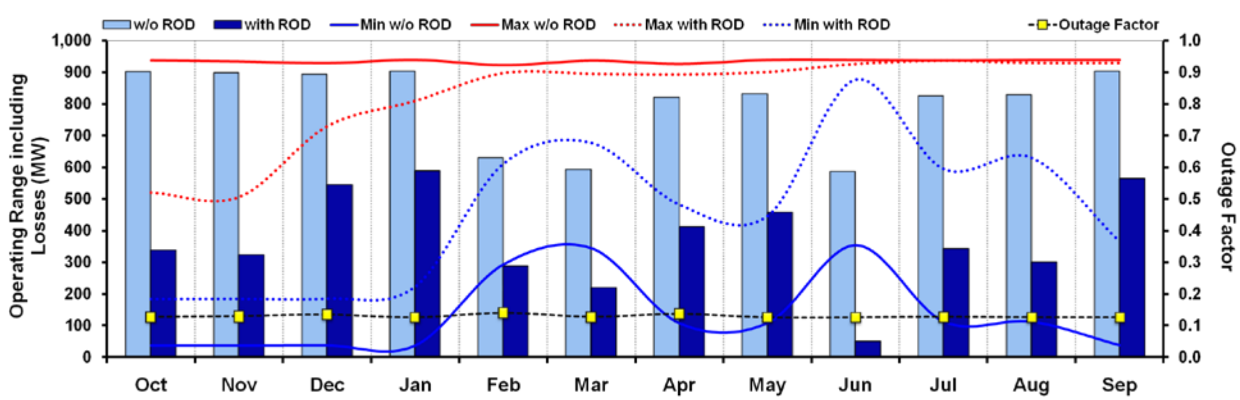

Figure 4.3 Operating Range and Outage Factor at Glen Canyon Dam in WY 1997

Figure 4.3 shows that the maximum capacity in the Without ROD scenario is nearly constant the entire year. However, that capacity is lower than the dam's maximum overall capacity for several reasons: namely, (1) the dam supplies ancillary services, such as spinning reserves and regulation services, which amount to 120 MW; (2) units are out of service; in this year, outage levels are at 12%, so capacity is reduced proportionally; and (3) the electric losses of the transmission system reduce net generation by another 8.8%. To help understand fluctuations in maximum capacity, these three factors should be kept in mind when viewing graphs of this type presented for subsequent years throughout this section.

Costs in July rose less than expected compared to June, even though the price spread increases sharply (Figure 4.2). This result is again attributable to nearly identical capacity factors in the two scenarios and continued high water releases in July, although lower than in June.

Costs in August and September continued to rise because water releases were falling, price spreads continued to be high, and operating ranges increased. An APSF occurred in these two months over the Labor Day weekend. The estimated costs of this experiment are minor, as releases were low during this period (i.e., the holiday) when electricity prices were inexpensive.

The combined ROD costs for both capacity and energy are shown for each month in Figure 4.4. The cost of the capacity component is the product of the difference in monthly maximum capacities between the two scenarios and the price to purchase that capacity, which is based upon the Shortage Criteria EIS (Reclamation 2007), where the capacity price is $83/kW (in $2009). Figure 4.3 shows that the difference in maximum capacity between the two scenarios is zero in July and very small (space between the dashed and solid red lines in the graph) in June and August, which is the reason why the capacity component of the ROD cost is much smaller in those months than in the other months of WY 1997. Finally, the figure shows that the ROD has a cost in every month of this year. The total ROD cost in 1997 is more than $3.8 million.

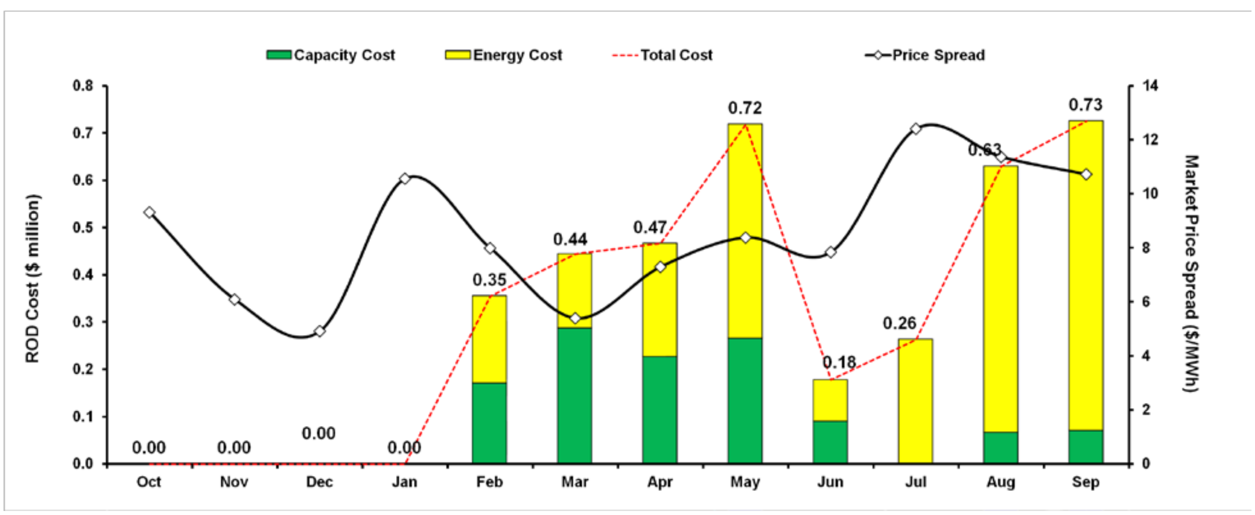

Figure 4.4 Cost of Capacity and Energy Components in WY 1997

4.2 COST OF ROD IN WY 1998

The total amount of water released in 1998 was only slightly lower than that released in 1997. Two experimental flows were conducted in this year: a Habitat Maintenance Flow (HMF) from November 3–5 and an APSF from September 4–8, which was also Labor Day weekend. Water releases were 30,000 cfs during most of the three-day HMF experiment and 15,000 cfs during the APSF.

Figure 4.5 shows the monthly releases; the amount of water released in each scenario is identical. Although HMF and APSF experiments were conducted in this year, the experiments lasted only a short time and required reallocation of the water only within the months of November and September, not to other months of the water year.

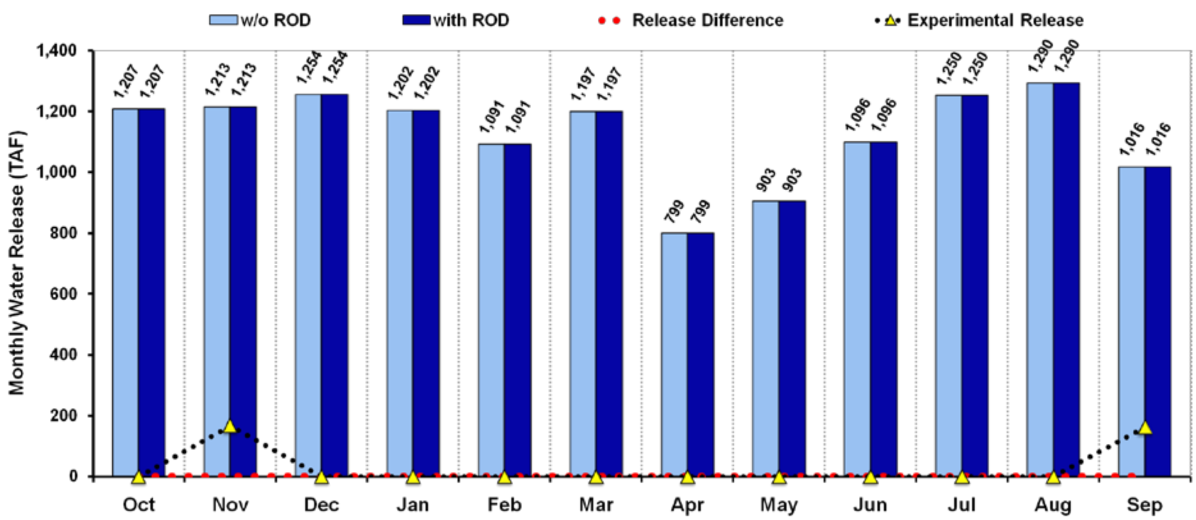

Figure 4.5 Monthly Water Releases in WY 1998

Figure 4.6 shows the ROD cost from energy differences combined with the monthly electricity price spread. The energy component of the ROD cost tracks the price spread closely in this year. However, the months of December and March do not follow that trend for several reasons. December and March had high water releases (see Figure 4.5) coupled with a high outage factor, as shown in Figure 4.7. These two factors resulted in little to no difference in maximum capacity between the two scenarios and, as shown in Figure 4.8, both scenarios have the same capacity factor. Because of this capacity factor, there was little opportunity to shift energy generation from off-peak to on-peak hours in the Without ROD scenario. In other months of the year, there is a greater difference in capacity factors between the two scenarios.

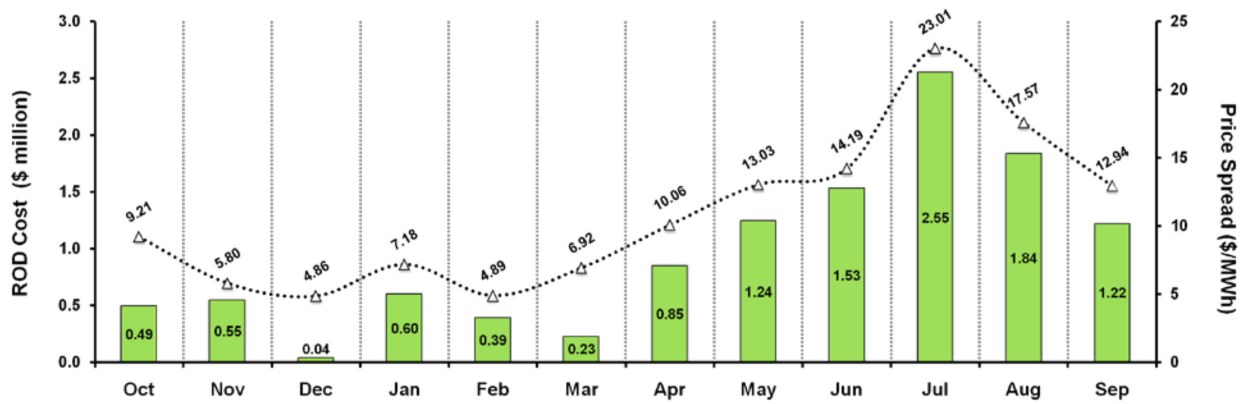

Figure 4.6 Energy Component of ROD Cost and Price Spread in WY 1998

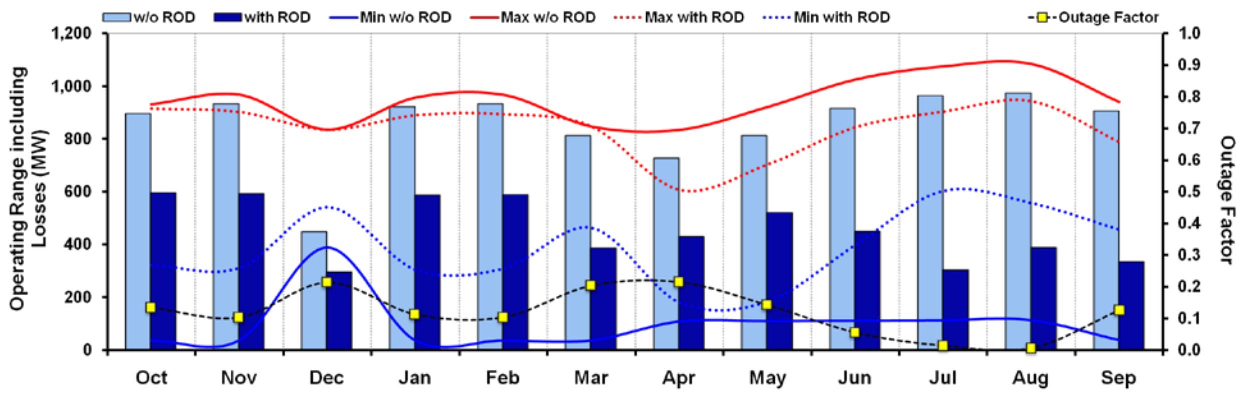

Figure 4.7 Operating Range and Outage Factor at Glen Canyon Dam in WY 1998

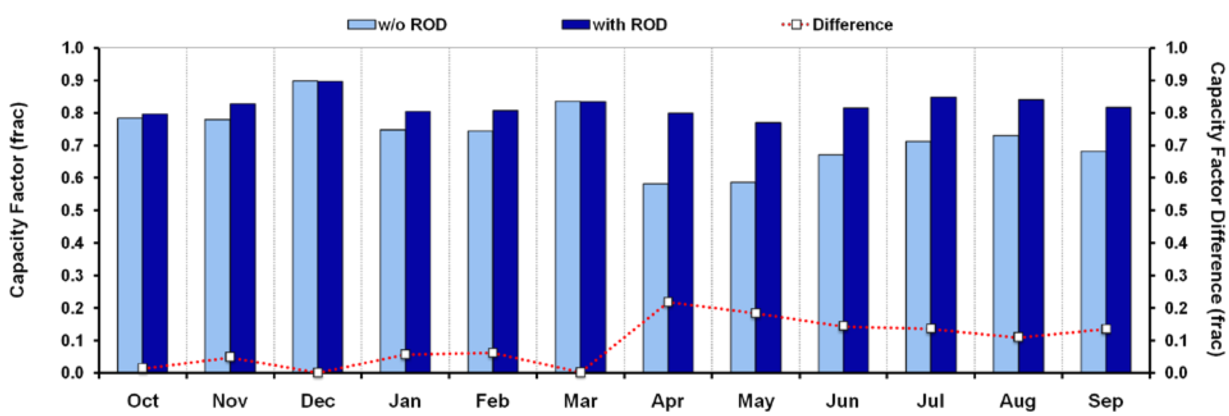

Figure 4.8 Capacity Factors of Without ROD and With ROD Scenarios in WY 1998

The ROD's energy cost did not drop in November as would be expected, given the sharp decrease in price spread, namely, from $9.21/MWh to $5.80/MWh. This result is at least partially attributable to the HMF, which had a large release in excess of 30,000 cfs for three days. Because large amounts of water were released in the low-price evening hours, there was less water available for the high-price peak hours during the month. Therefore, this experimental release was costly.

The combined ROD cost for both capacity and energy is shown in Figure 4.9. Figure 4.7 shows that the difference in maximum capacity between the two scenarios is zero in December and near zero in March, which is the reason why there is no ROD capacity cost in those months.

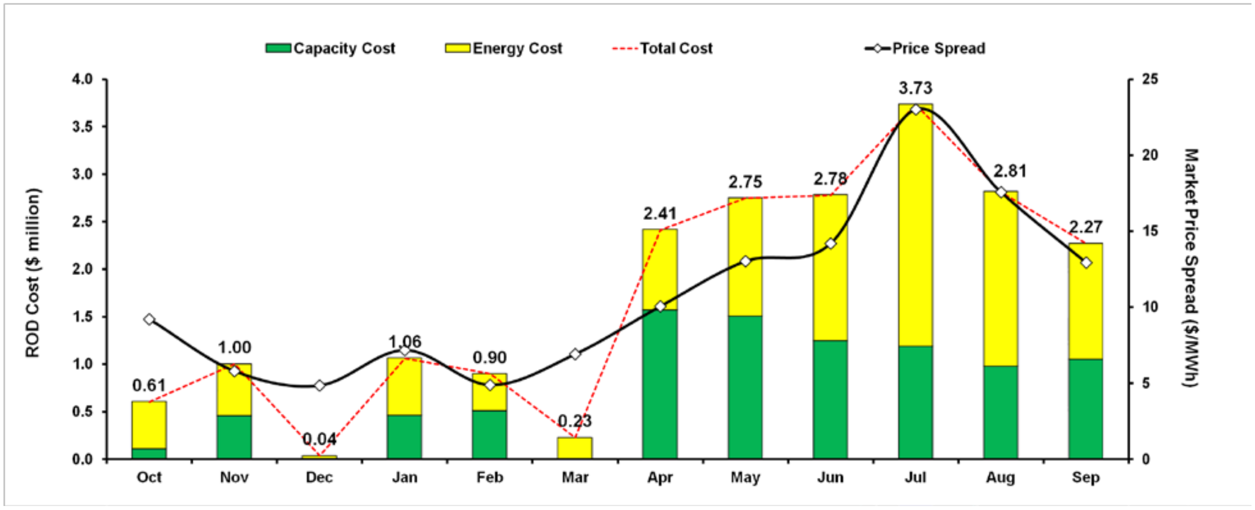

Figure 4.9 Cost of Capacity and Energy Components in WY 1998

Figure 4.9 also shows that energy differences contribute more to the total cost of the ROD in June through September, while capacity differences contribute more to the total cost of the ROD in April and May. Energy differences make up a larger portion of the total cost in June to September because of the large price spread, coupled with a smaller capacity difference in those months as compared to April and May. The April-May period has a larger capacity difference between the two scenarios coupled with a lower price spread. Finally, Figure 4.9 shows that the ROD has a cost in every month of this year. The total ROD cost in 1998 is almost $21 million. This amount is a significant increase over WY 1997 costs, which were estimated to be approximately $3.8 million.

4.3 COST OF ROD IN WY 1999

The total amount of water released in 1999 was lower by more than 1,300 TAF as compared to either 1997 or 1998. The only experimental release was an APSF, which ran from September 3 to 9, which was again a Labor Day weekend. The APSF had a constant water release of about 15,000 cfs.

Figure 4.10 shows the monthly releases. As in the case of the two previous water years, the monthly amount of water released in each scenario was identical, and water was reallocated only within the month to accommodate the APSF.

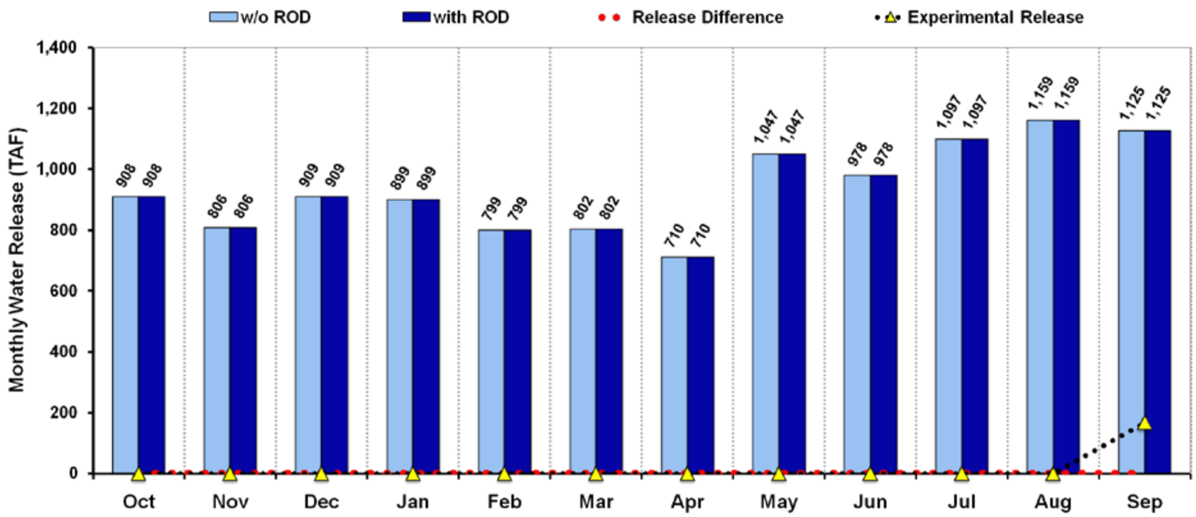

Figure 4.10 Monthly Water Releases in WY 1999

Figure 4.11 shows the ROD cost from energy differences combined with the monthly electricity price spread. The energy component of the ROD cost tracks the price spread closely in this year. However, the months of October, November, and April have a lower cost than might be expected. This result was attributable to a high outage factor of about 25%, as shown in Figure 4.12. With such a high outage factor, the GCD in the Without ROD scenario cannot utilize as much water in the peak hours as it could if its capacity were not out of service. The cost was even lower in April than in either October or November. The April monthly release was the lowest in the year. Therefore, the Without ROD scenario had relatively less water to shift into on-peak hours. It should also be noted that the minimum hourly release under the Without ROD scenario is 3,000 cfs in April, as opposed to only 1,000 cfs in both October and November. As discussed previously, this factor results in relatively lower ROD costs.

ROD costs related to the APSF in September were fairly small as it was scheduled during Labor Day weekend when prices are relatively low. However, because the experimental flow release rate was 15,000 cfs as compared to the 8,000 cfs release rate for the APSF in 1997, the costs in WY 1999 are somewhat more expensive, despite the fact that both price spreads and monthly water release volumes are similar.

The combined ROD costs for both the capacity and energy differences between the two scenarios are combined and shown in Figure 4.13. The cost resulting from capacity differences makes up a greater share of the total ROD cost in some months than it does in others. Figure 4.12 shows that the differences in maximum capacity between the two scenarios are the lowest in October, November, and September, which is the reason why the capacity component of the ROD cost is smaller in those months than in the other months of WY 1999. Finally, Figure 4.13 shows that the ROD has a cost in every month of this year. The total ROD cost in 1999 is almost $36.5 million.

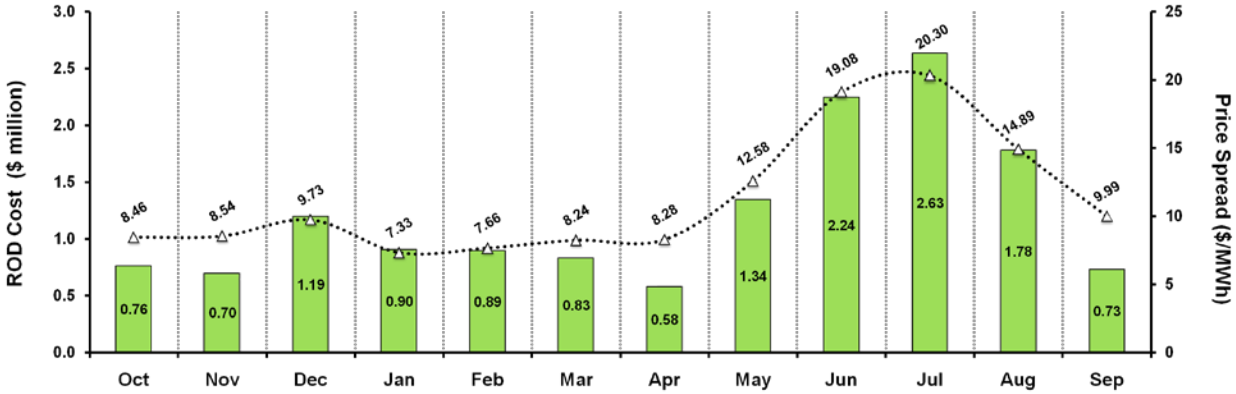

Figure 4.11 Energy Component of ROD Cost and Price Spread in WY 1999

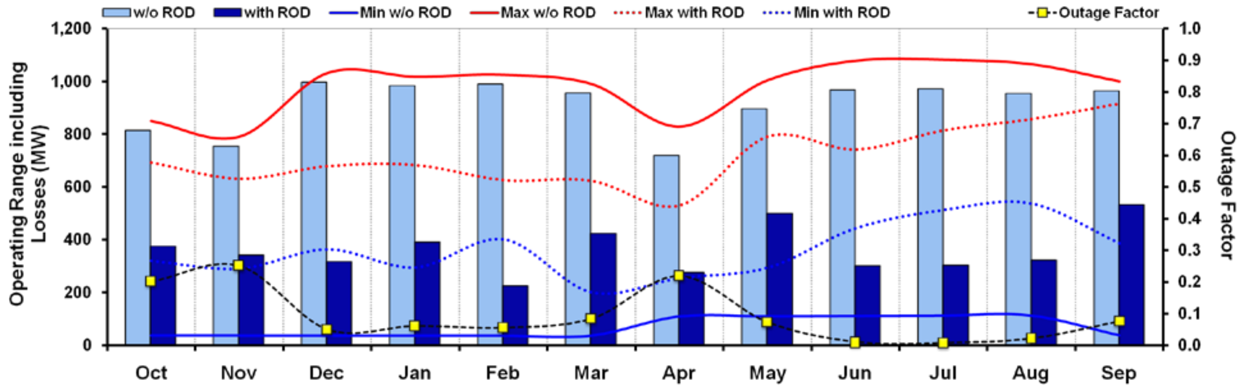

Figure 4.12 Operating Range and Outage Factor at Glen Canyon Dam in WY 1999

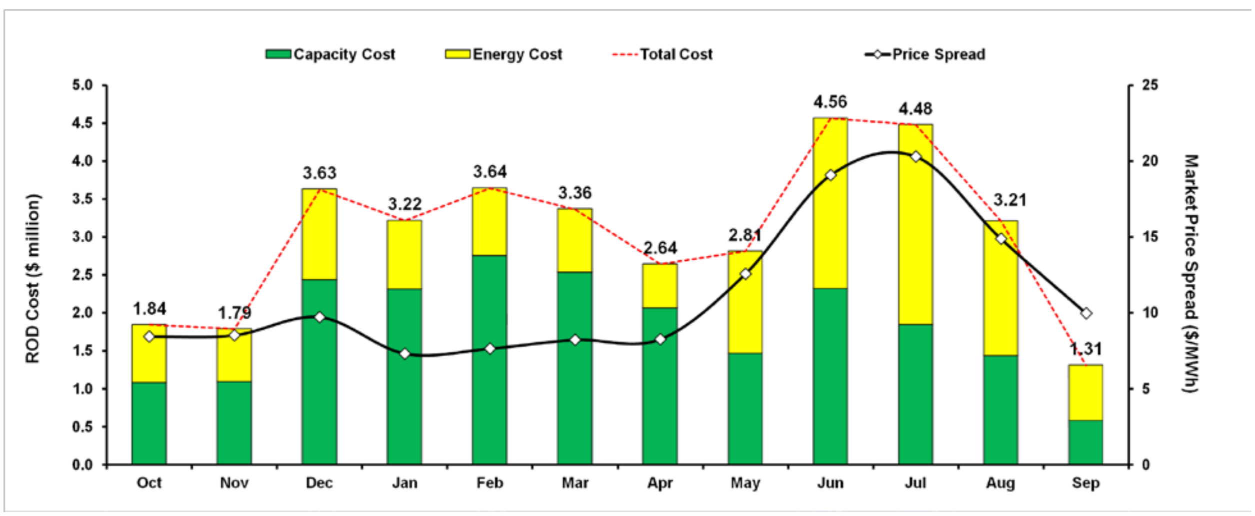

Figure 4.13 Cost of Capacity and Energy Components in WY 1999

4.4 COST OF ROD IN WY 2000

In 2000, the total amount of water released dropped by more than 2,000 TAF as compared to 1999. There was only one experimental release, a low summer steady flow (LSSF). Unlike in the case of the previous three years in which experiments lasted only a few days, this experiment ran for more than 6 months from March 25 to September 30. The Glen Canyon Powerplant's generation during this time period is shown in Figure 4.14. Note that after June 1, generation levels were very low for the remainder of the experiment, because the required release rate was 8,000 cfs for most of that period.

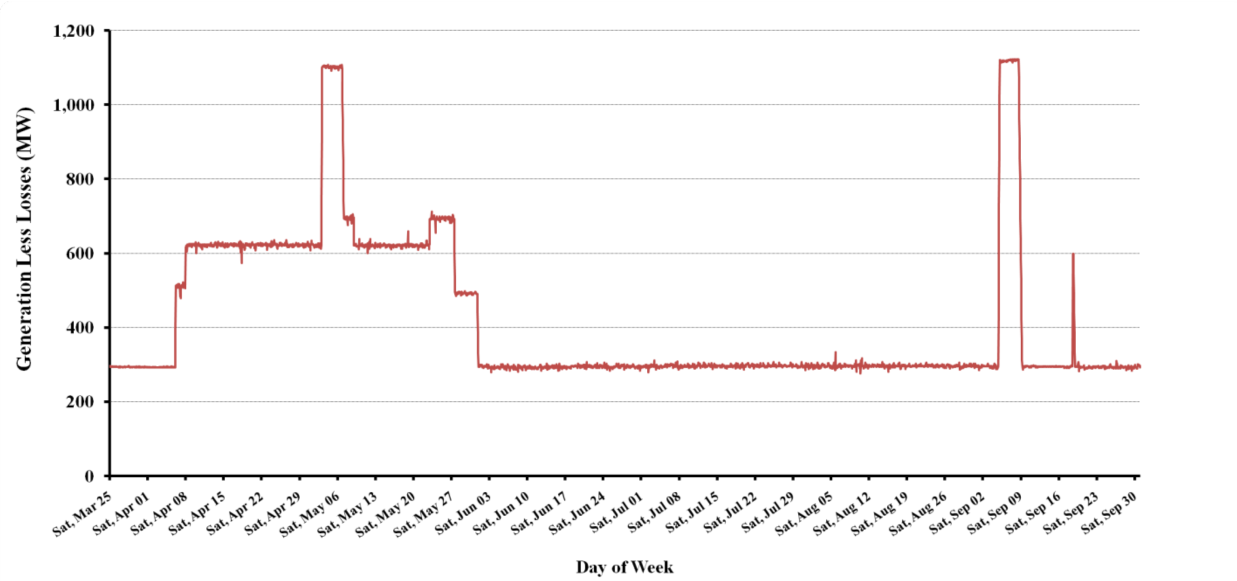

Figure 4.14 Water Release Pattern During Low Summer Steady Flow in WY 2000

Figure 4.15 shows the monthly water releases; the amounts of water released in each scenario differed in the months of April to September because of the reallocation of water to support the LSSF experiment. Releases during the LSSF were characterized by high flows from April to the end of May, followed by low flows in June, July, and August, and then two short high spikes in September. To accommodate the high flows in the early months of the release, water was reallocated from June, July, and August to other months. Because the Without Experiments scenario is a hypothetical case, its monthly releases are based on Riverware model simulations performed by Reclamation.

Of note in this year is the fact that the With ROD scenario releases 618 TAF more water than the Without ROD scenario. However, that water difference is made up in 2001, when the Without ROD scenario will release 618 TAF more water relative to the With ROD scenario. It should be noted that water releases during June through August, months which typically have the highest electricity prices, are lower under the With ROD scenario. This circumstance increases the cost of the ROD during those months.

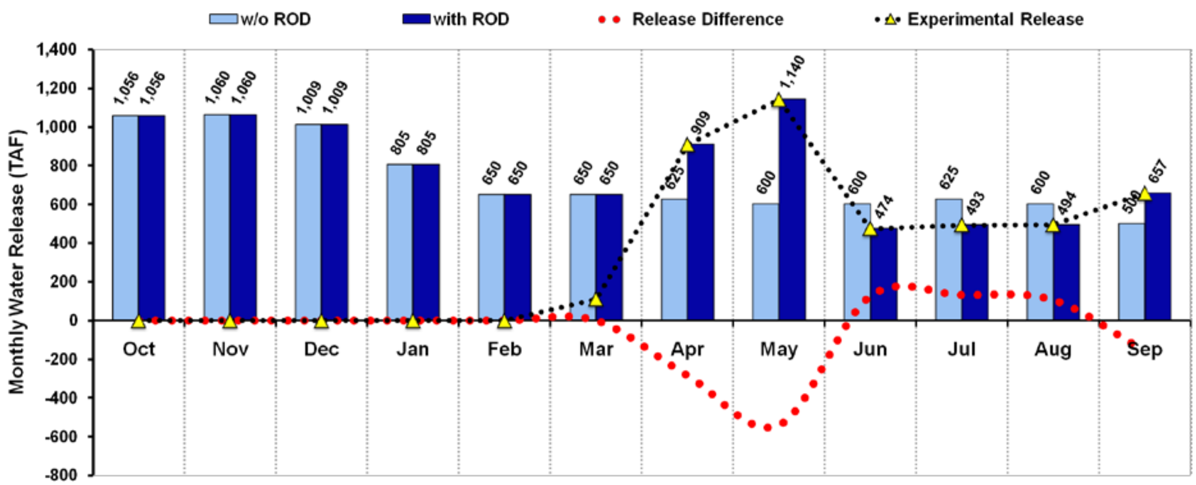

Figure 4.15 Monthly Water Release in WY 2000

The California energy crisis began in this year and, as stated earlier, actual electricity market prices and price spreads were used during the entire study period. Figure 4.16 shows the ROD cost from energy differences combined with the monthly electricity price spread. A number of observations can be made when examining the energy component of the ROD cost. In October through March, the ROD energy cost is low because of a relatively small price spread and very high outage factors during these months, that is, of between 13% to 24%, as shown in Figure 4.17. As explained in Section 4.3 about 1999 results, the high outage rate reduces the amount of water that can be released during on-peak hours in the Without ROD scenario, which can greatly lower the cost of the ROD. It is also noted that in the months of February and March, the water release is 650 TAF, which restricts the daily fluctuation in the With ROD scenario to 6,000 cfs. This fluctuation limit restricts the operational range, thereby increasing overall ROD costs.

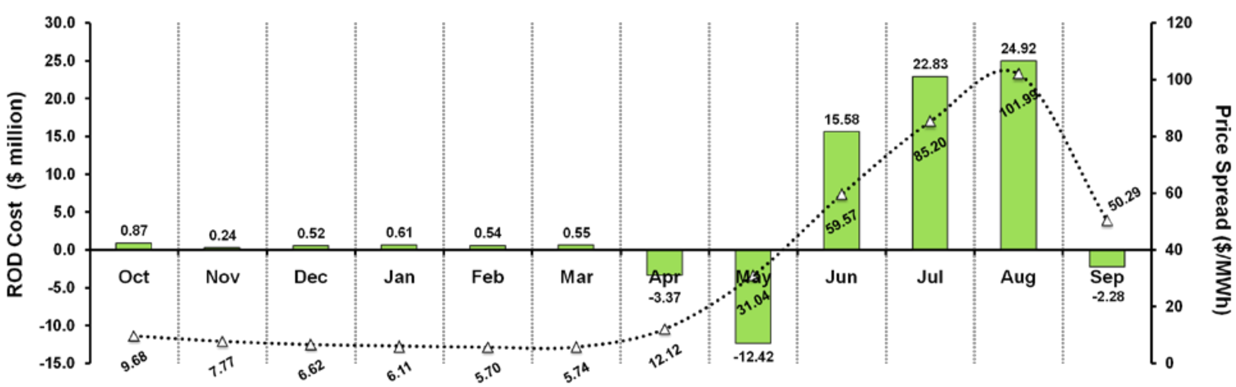

Figure 4.16 Energy Component of ROD Cost and Price Spread in WY 2000

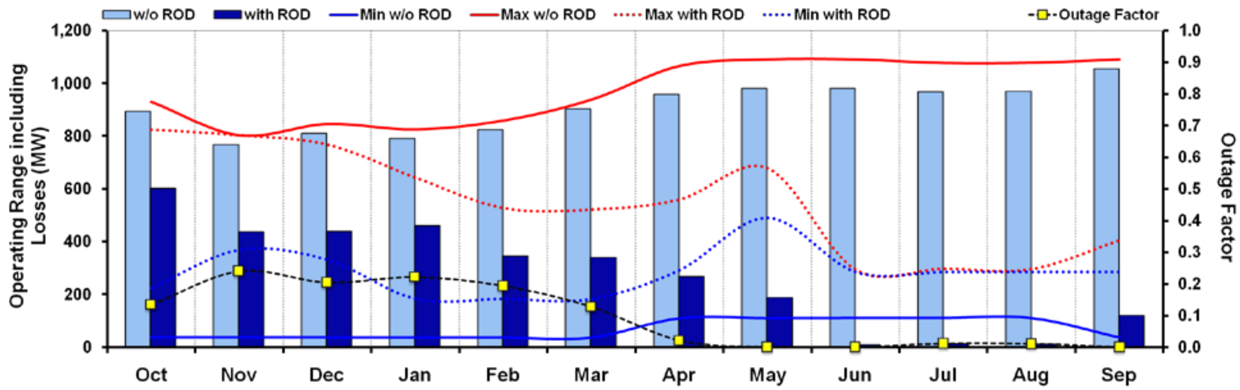

Figure 4.17 Operating Range and Outage Factor at Glen Canyon Dam in WY 2000

In April, May, and September, the energy component of the ROD yields a benefit (or a negative cost). This result occurs because more water is released in the With ROD scenario than in the Without ROD scenario because of reallocating water to accommodate the LSSF. Therefore, more water was released in both on- and off-peak hours. In June through August, the Without ROD scenario had higher releases, which resulted in high ROD costs. Another factor that significantly contributed to the high ROD costs during these peak summer months is that LSSF releases were flat during this period, eliminating any possibility to shape generation to market prices.

Another observation, as depicted graphically in Figure 4.18, is that during the months of April through September, Lake Powell's elevation is different in both scenarios. The high spring releases during the experimental period lowered Lake Powell's forebay elevation. If the LSSF had not been conducted, it is estimated that the reservoir level would not have dropped as dramatically in April and rebounded to higher levels in May. The lower level of Lake Powell reduced the power conversion under the With ROD scenario as compared to the Without ROD scenario. A reduced power conversion means that less electricity is produced per unit of water released. The lower reservoir level impacts generation not only during the spring but, as described in the next section, persists until the end of the following water year. Therefore, the economic cost of the ROD after March was slightly higher than it otherwise might have been.

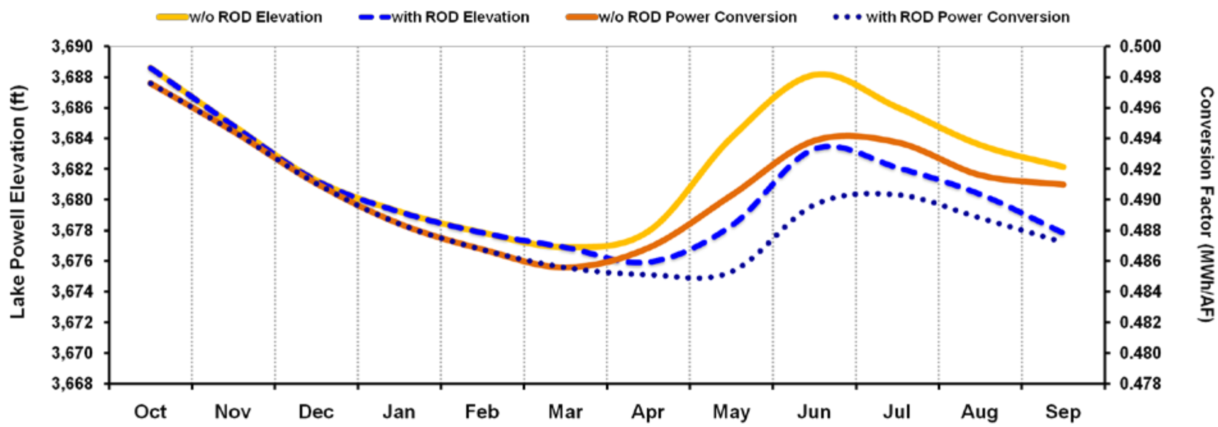

Figure 4.18 Comparison of Lake Powell Elevations and Power Conversion Factor in WY 2000

The combined ROD cost from both capacity and energy differences between the two scenarios is shown in Figure 4.19. Early in the year the capacity cost is low, which is largely attributable to a high outage factor that makes the capacity difference between the two scenarios small, as shown in Figure 4.17. However, later in the year, the capacity difference increases greatly, which accounts for the large capacity cost of the ROD. Capacity benefits during the long LSSF experiment were computed in a slightly different manner than are “normal” periods of operation. Capacity values are based on average monthly generation levels during the experiment, as opposed to the maximum output levels during periods of normal operation. These averages are shown in Figure 4.17 (dashed red line). It should also be noted that in May, the energy benefit of the ROD exceeds the capacity cost, resulting in an overall benefit from the ROD. Although the ROD also had an energy benefit in April and September, the capacity cost is larger and results in a net loss. However, the total cost of the ROD in April is much lower than it might have been given the price spread.

The total ROD cost in 2000 is over $86.6 million, exceeding the costs experienced in all previous years. ROD costs would have been even higher if the amounts of the total annual release had been equal in both scenarios. A higher annual release under the With ROD scenario significantly reduced the estimated ROD costs.

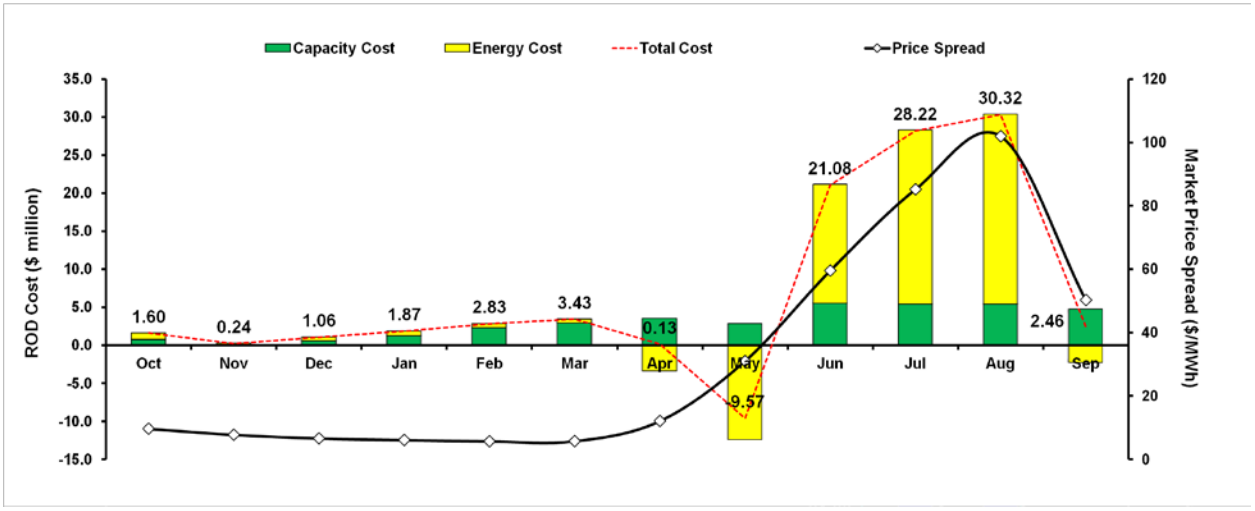

Figure 4.19 Cost of Capacity and Energy Components in WY 2000

4.5 COST OF ROD IN WY 2001

The amount of water released in 2001 was similar to the amount in 2000; however, the With ROD scenario released 618 TAF less water than the With ROD scenario because of the previous year's LSSF. In 2001, there was only a single experimental release, an APSF that occurred from June 28 to July 2. It had a steady release of 8,000 cfs; water was reallocated within the months in which the APSF occurred.

Figure 4.20 shows the monthly water releases; the amount of water released in each scenario was different in most months because of water reallocations from the previous year's LSSF. Monthly water releases under the Without ROD scenario were estimated by Argonne staff on the basis of the actual release pattern and the tendency to release higher water volumes during the summer and winter months to take advantage of higher market prices during these periods. Less water was released in the With ROD scenario during the months of January, February, June, July, August, and September as compared to the Without ROD scenario.

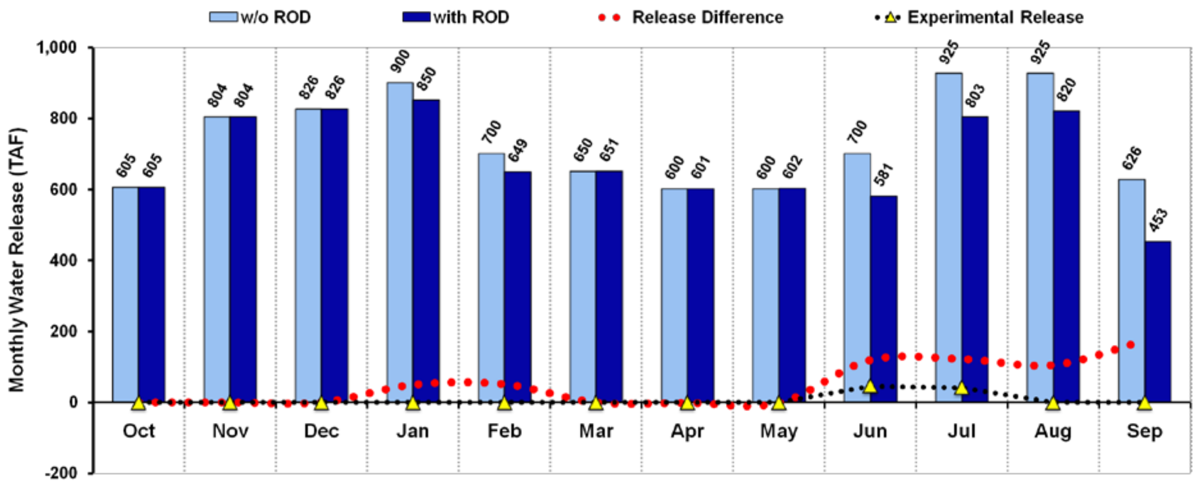

Figure 4.20 Monthly Water Releases in WY 2001

Figure 4.21 shows the ROD cost from energy differences combined with the monthly electricity price spread. A number of observations can be made after examining the energy component of the ROD cost. In keeping with the general trend, ROD energy costs rise from October to December as the price spread increases. The cost increase may have been larger in October and November than the price spread difference would dictate because of several factors. The water released in November was greater than the October release by about 200 TAF. The cost increase reflects the fact that at lower monthly water release volumes, the total monthly ROD costs tend to increase as more water is released. In December, there was a larger energy cost than November because the price spread increased sharply and the outage factor dropped significantly. As shown in Figure 4.22 the outage factor in December drops to near zero, down from almost 15% in November; thus, a decrease in the outage factor results in an increase in the ROD energy cost estimate.

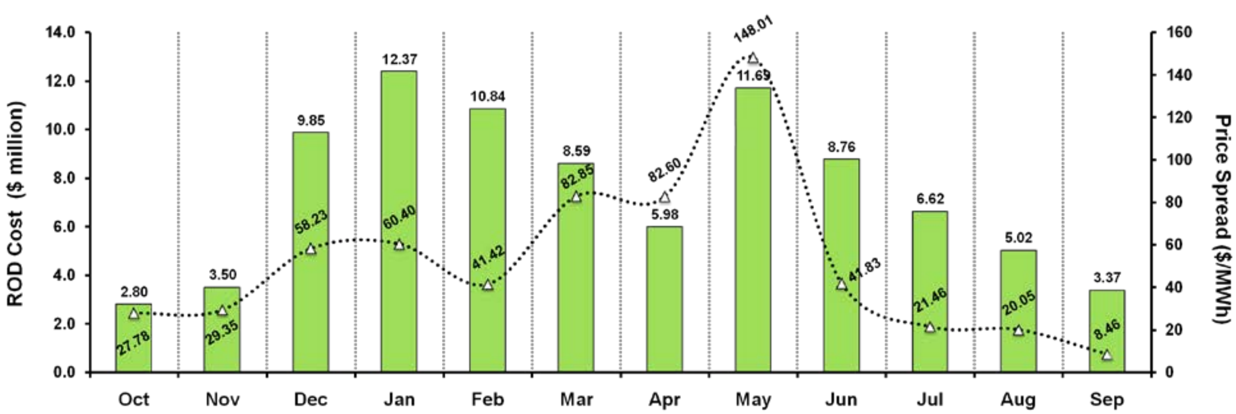

Figure 4.21 Energy Component of ROD Cost and Price Spread in WY 2001

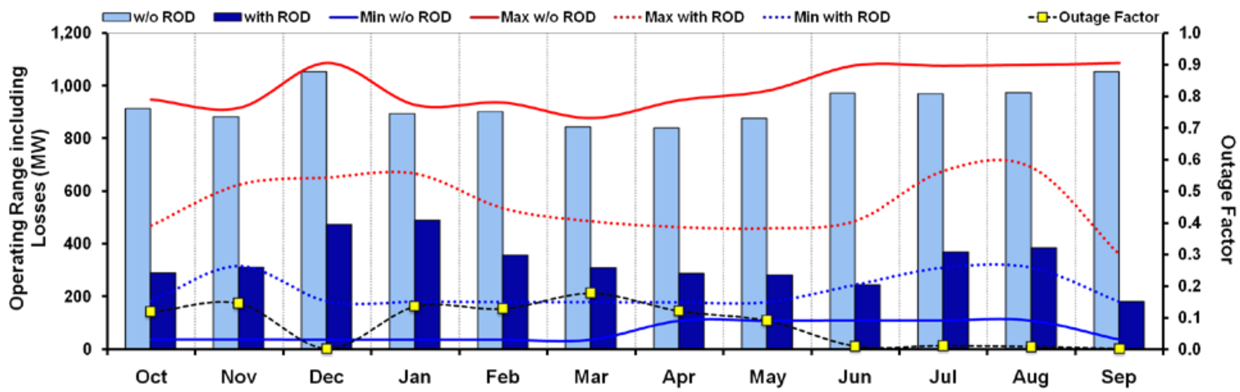

Figure 4.22 Operating Range and Outage Factor at Glen Canyon Dam in WY 2001

The energy cost of the ROD rose again in January because of both an increase in the electricity market price spread and a smaller water release in the With ROD scenario compared to the Without ROD scenario. In February, the With ROD scenario again had a lower water release compared to the Without ROD scenario; however, the price spread fell, and so the ROD cost in February is lower than the cost in January.

In March, although the price spread rose relative to February, the energy cost of the ROD fell. This result is attributable to a relatively high outage rate of nearly 18% in March (see Figure 4.22), which limited the transfer of water releases from off-peak to on-peak hours in the Without ROD scenario.

The price spread stayed nearly constant from March to April, but the ROD's energy cost fell. This is due to the Without ROD scenario transitioning from winter to summer minimum releases; namely, from 1,000 cfs in winter to 3,000 cfs in summer as shown in Figure 4.22. Therefore, beginning in April, the value of water decreases in the Without ROD scenario relative to the With ROD scenario because more water is used to generate in off-peak hours than on-peak hours. This effect is compounded because a smaller amount of water is released in April relative to March. Then in May, the price spread increased and the ROD's energy cost increased correspondingly.

In June through September, the ROD's energy cost decreased as the price spreads decreased, but not as much as expected. This result was because of a substantial difference in the amount of water released in the Without ROD scenario as compared to the With ROD scenario. The differences in the water releases were more than 105 TAF in any of those months, and the largest difference was 173 TAF in September.

The combined ROD cost for both capacity and energy differences between the two scenarios is shown in Figure 4.23. The capacity cost fluctuates depending on the differences in maximum capacity between the Without ROD and With ROD scenarios. The higher the difference, the larger the capacity cost. As shown in Figure 4.23, the months of September, June, and May have the greatest capacity differences and therefore have the greatest capacity costs.

Figure 4.23 shows that the ROD has a cost in every month of the year, totaling more than $126 million in 2001. This cost again exceeds the previous year despite the absence of a prolonged experimental flow. As discussed above, this result is largely attributed to a higher annual water release under the Without ROD scenario, a step that was required to achieve identical water releases under the two scenarios in 2000 and 2001 combined. It should also be noted that the Without ROD scenario has higher reservoir elevations and therefore a larger power conversion factor throughout 2001. Although relatively minor, the elevation difference also contributed to the ROD cost. At the end of WY 2001, both scenarios have identical elevation levels.

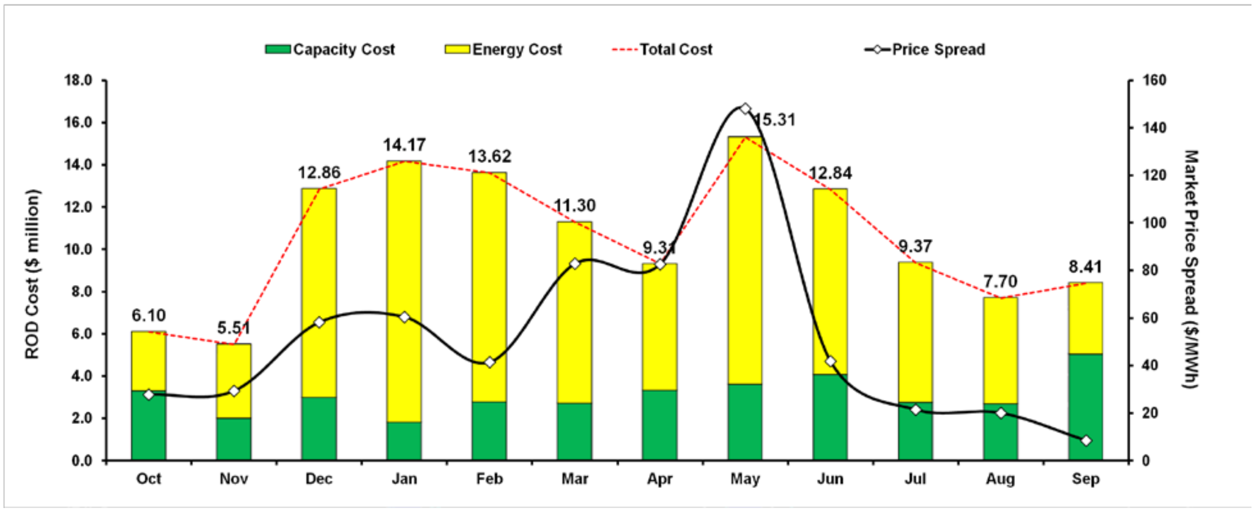

Figure 4.23 Cost of Capacity and Energy Components in WY 2001

4.6 COST OF ROD IN WY 2002

The amount of water released in 2002 was similar to the amount released in 2001. There was only a single experimental release, an APSF, which occurred from May 24 to May 31 and included the Memorial Day weekend. It had a steady release of 8,000 cfs.

Figure 4.24 shows the monthly water releases; the amount of water released in each scenario is identical. Water was reallocated only within the month of May to accommodate the APSF.

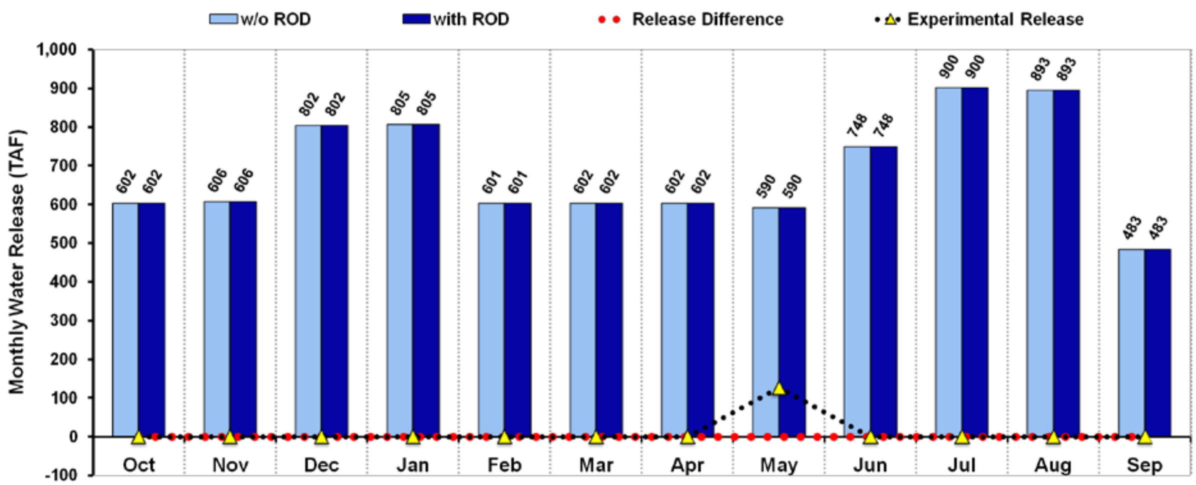

Figure 4.24 Monthly Water Releases in WY 2002

Figure 4.25 shows the ROD cost from energy differences combined with the monthly electricity price spread. The energy component of the ROD cost tracks the price spread closely in this year; it rises and falls with the price spread. Figure 4.26 shows that outages are very high in December through April; the March outage factor exceeds 15%, while the outage factors in other months exceed 25%. High outage factors tend to reduce the ROD's energy cost. The high outage factor in April kept the ROD energy cost lower than it might have been in spite of a price spread that was about double that which occurred in November and February.

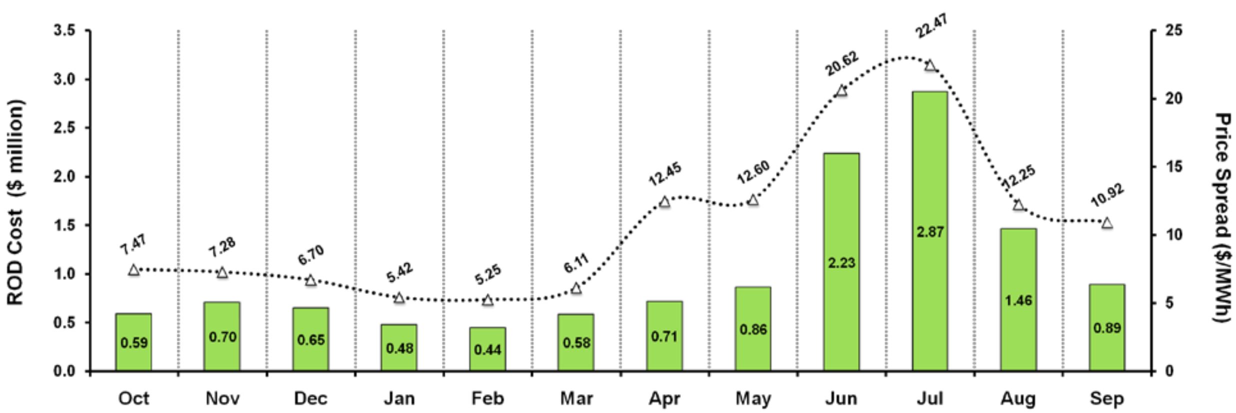

Figure 4.25 Energy Component of ROD Cost and Price Spread in WY 2002

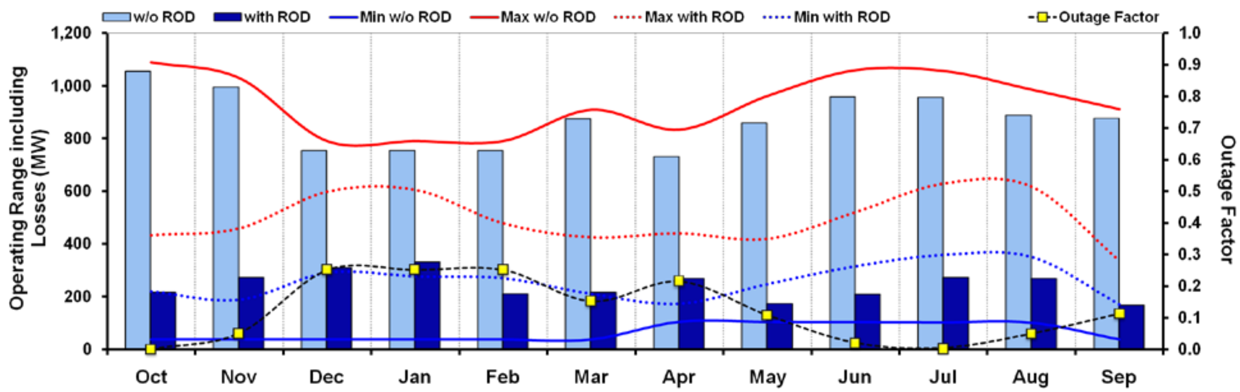

Figure 4.26 Operating Range and Outage Factor at Glen Canyon Dam in WY 2002

The total energy cost in May rose more than expected in spite of the small price spread increase from April and with very little difference in monthly water release. The higher cost was attributable to a low water release during the month of less than 600 cfs, which limited the daily fluctuation to 5,000 cfs. Furthermore, because the APSF experiment occurred for eight consecutive days in the month at a constant flow of 8,000 cfs, water could not be released at a higher rate even during on-peak hours when electricity prices were highest. Although water was reallocated within the month so that the same amount of water was released in the With ROD scenario as during the Without ROD scenario, the financial benefit gained by increased generation earlier in the month was offset by losses during the week of the experiment. Finally, outage rates dropped from April to May, allowing relatively more operational flexibility under the Without ROD scenario in May.

Outage factors were very low and price spreads high in the months of June, July, and August, which resulted in a high energy cost in those months.

The combined ROD costs for both capacity and energy are shown in Figure 4.27. The capacity cost fluctuates depending on the differences in maximum capacity between the Without ROD and With ROD scenarios. The higher the difference, the larger the capacity cost. As shown in Figure 4.26, the months of October, November, and September have the greatest capacity differences and therefore have the greatest capacity costs. Finally, the figure shows that the ROD has a cost in every month of the year; the total ROD cost in 2002 is above $48 million.

In addition, very dry hydrological conditions begin in WY 2002 and last through the end of the study period. This trend tends to increase the capital cost component of the ROD economic impact, because under the Without ROD scenario, Glen Canyon Powerplant can quickly ramp-up generation and maintain a relatively high level of generation for several peak hours. On the other hand, under the With ROD scenario, the low daily ramp rates imposed by the ROD become even more restrictive under low hydrological conditions and severely limit the peak flow that the GCD can achieve. In most low hydrological conditions, the 25,000 cfs level is unattainable.

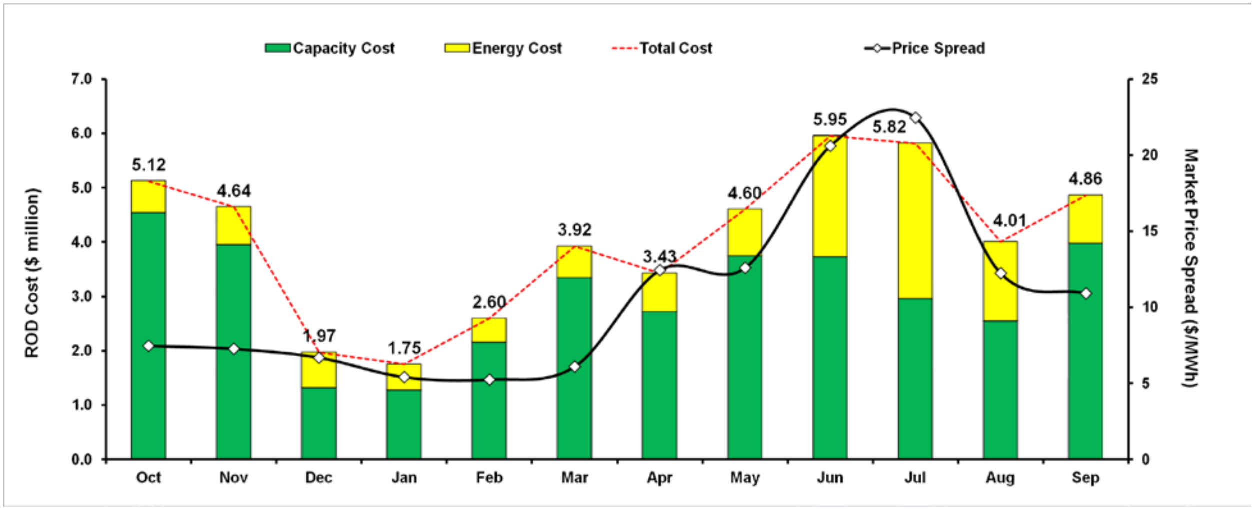

Figure 4.27 Cost of Capacity and Energy Components in WY 2002

4.7 COST OF ROD IN WY 2003

The amount of water released in 2003 was similar to the amount released in 2002. There were two experimental releases: namely, a non-native fish suppression flow (NNFSF) and an APSF. The NNFSF was a lengthy flow that ran from January 1 to March 31 and required water reallocation to other months of the water year. The APSF occurred from May 23 to May 27, which included the Memorial Day weekend, and had a steady release of 8,000 cfs.

Figure 4.28 shows the monthly water releases; there are differences between the two scenarios in the amount of water released in almost every month. This result is mostly attributable to the reallocation of water to accommodate the NNFSF. The NNFSF followed a prescribed hourly release, ranging from approximately 5,000 cfs to 20,000 cfs each day. Releases were highest during the day and reduced at night. The Without ROD monthly release pattern was based on a typical 8.23 MAF year, that is, the minimum allowable annual release. In general, for the With ROD scenario, more water was released in the months of February, March, May, June, and July, and less water was released in the months of October, November, December, January, and September.

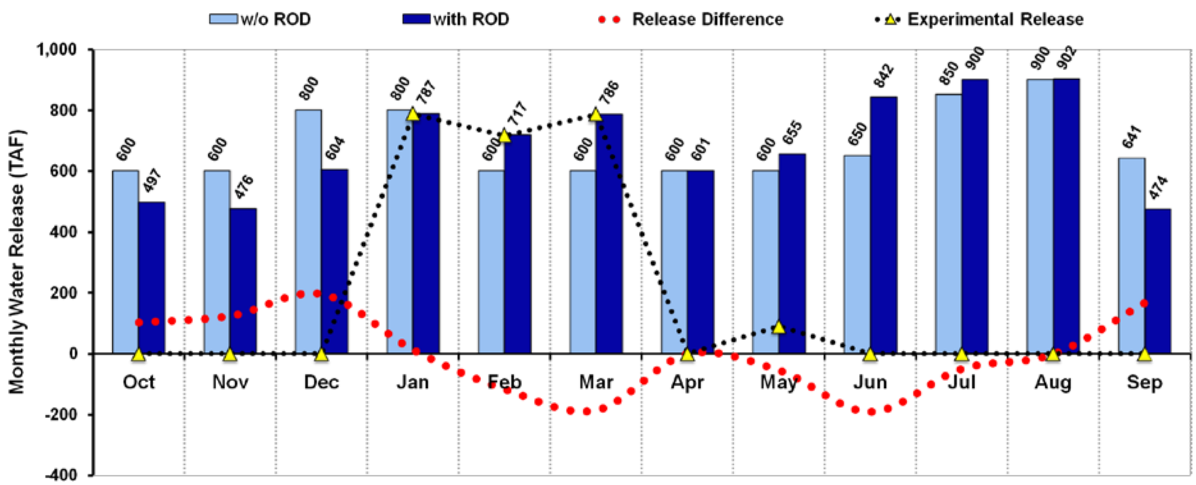

Figure 4.28 Monthly Water Releases in WY 2003

Figure 4.29 shows the ROD cost from energy differences combined with the monthly electricity price spread. The energy costs fluctuate between costs and benefits over the entire year. Energy costs are high from October to December, because more water is released in the Without ROD scenario than in the With ROD scenario, and ROD operating constraints are more strict. The cost is especially high in December because the difference in water release between the two scenarios is nearly 200 TAF.

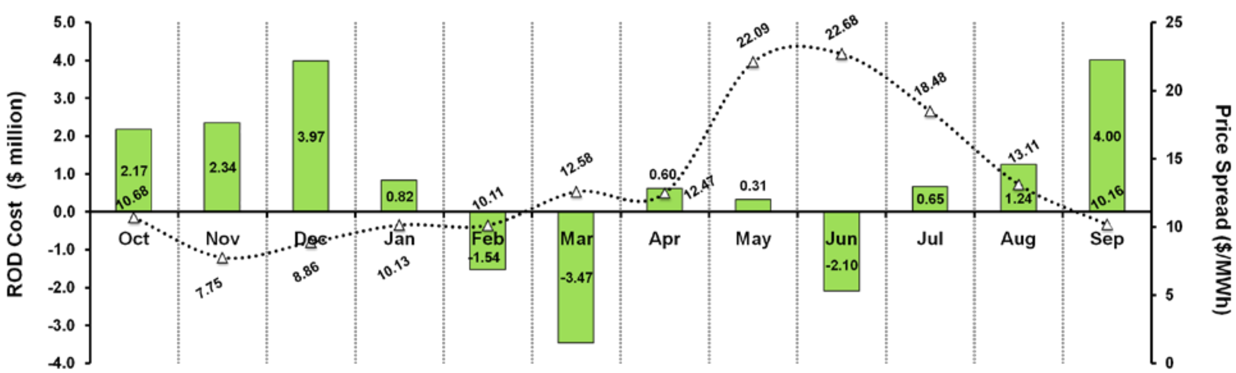

Figure 4.29 Energy Component of ROD Cost and Price Spread in WY 2003

The energy cost in January is much lower than in previous months in spite of an increase in the price spread because the NNFSF has a very favorable release pattern. Releases were higher in the day and lower at night, which allowed more energy to be generated in on-peak rather than off-peak hours than is allowed under normal ROD operating constraints. As noted earlier, experiments are exempt from ROD restrictions. Then, in February and March, the ROD yielded a benefit instead of a cost. This result occurred because more water was released in both months in the With ROD scenario than in the Without ROD scenario, and the NNFSF was conducted during these two months. In February, more than 115 TAF more water was released, and in March almost 200 TAF more water was released. The higher price spread between on- and off-peak prices also increases the benefit, because more energy is produced on-peak than off-peak in the With ROD scenario with high releases.

In April, the same amount of water was released in both scenarios, which resulted in an energy cost for the ROD. May also resulted in an energy cost even though more water was released in the With ROD scenario. The difference is only 55 TAF, which is not enough to outweigh the costs of lower operational flexibility mandated by the ROD coupled with the price spread almost doubling from April to May. The ROD resulted in a benefit in June, largely due to almost 200 TAF more water released in the With ROD than in the Without ROD scenario.

July resulted in an energy cost for the ROD, even though more water was released in the With ROD scenario. However, like May, the difference is only 50 TAF, which is not enough to outweigh the costs of lower operational flexibility mandated by the ROD. The cost rises again in August when the water releases for the two scenarios are nearly equal.

The water released in the Without ROD scenario is greater than in the With ROD scenario in September, resulting in a sharp cost spike. The price spread had declined from previous months; however, almost 170 TAF more water was released in the Without ROD scenario, which outweighed the benefits of a decreasing price spread.

The combined ROD costs for both capacity and energy are shown in Figure 4.30. The capacity cost fluctuates depending on the difference in maximum capacity between the Without and With ROD scenarios. The higher the difference, the larger the capacity cost. As shown in Figure 4.31, capacity differences during the three-month NNFSF are relatively low. During the NNFSF, the operational range and maximum generation levels were higher under the experiment than would have otherwise been allowed under ROD operating constraints. Figure 4.31 also shows that the months of October, November, December, and September have the greatest differences in capacity and therefore have the greatest capacity costs as shown in Figure 4.30.

Finally, Figure 4.30 shows that the ROD has a cost in every month except for a very small benefit in both February and June, and a larger one in March. The total ROD cost in 2003 is almost $35.6 million. This drop in cost from levels reached in previous years is due in part to low hydropower conditions, which led to lower energy cost differences, and the three-month experimental flow period during which a large range of daily operations were exhibited.

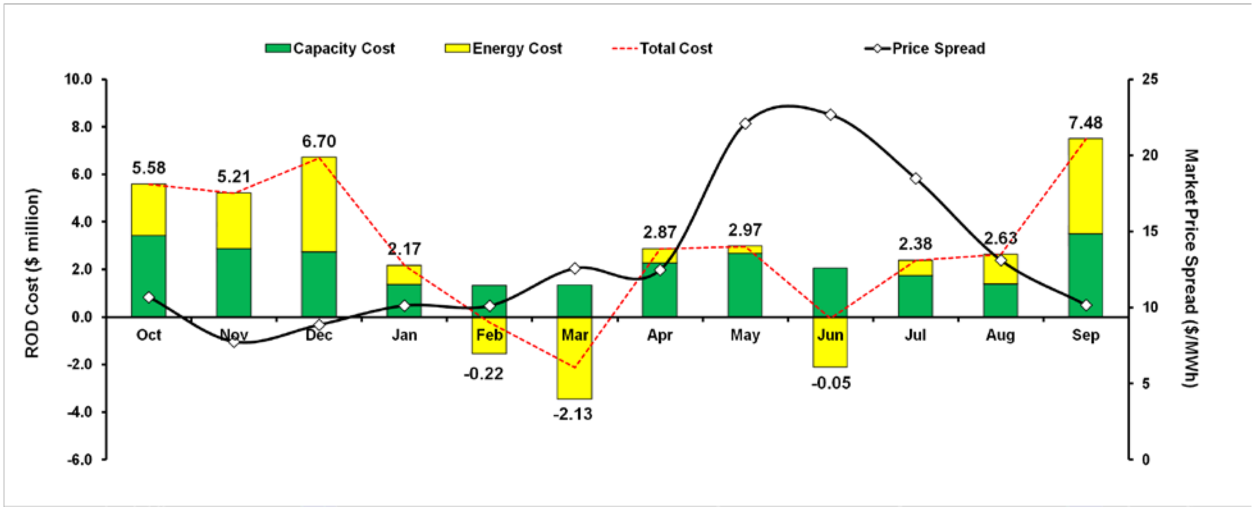

Figure 4.30 Cost of Capacity and Energy Components in WY 2003

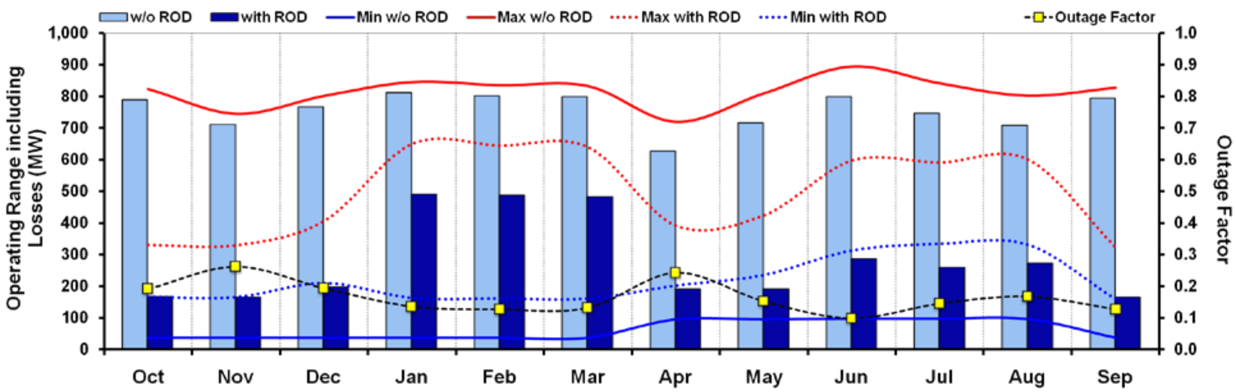

Figure 4.31 Operating Range and Outage Factor at Glen Canyon Dam in WY 2003

4.8 COST OF ROD IN WY 2004

The amount of water released in 2004 was similar to the amount released in 2003. There were two experimental releases: namely, an NNFSF and an APSF. The NNFSF was a lengthy flow that ran from January 1 to March 31 and required water reallocation to other months of the water year. The APSF occurred from May 28 to May 31, which included the Memorial Day weekend, and had a steady release of 8,000 cfs.

Figure 4.32 shows the monthly water releases; the amount of water released in each scenario was different in almost every month. This result is largely because of reallocating water to accommodate the NNFSF. The Without ROD monthly release pattern was based on a typical 8.23 MAF year. The NNFSF was a prescribed hourly release ranging from approximately 5,000 cfs to 20,000 cfs each day during the month of January. Releases were highest during the day and reduced at night. During February and March, the release pattern was even more favorable as water releases during Sundays were lower than during weekdays. On Sundays, releases ranged from about 5,000 cfs at night to approximately 8,000 cfs during the day. In general, for the With ROD scenario, more water was released in the months of February, March, April, June, and July, and less water was released in the months of October, November, December, January, and September.

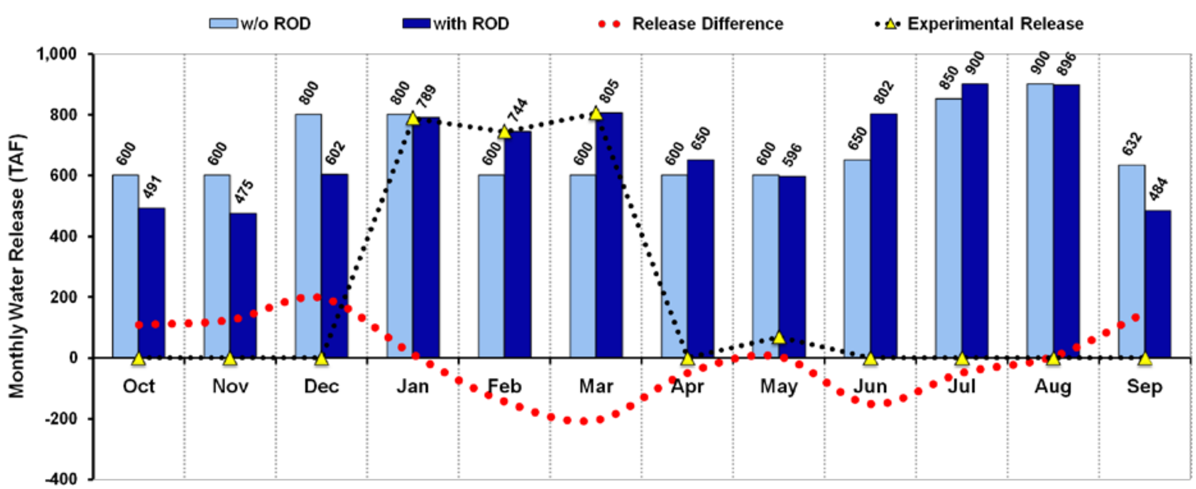

Figure 4.32 Monthly Water Releases in WY 2004

Figure 4.33 shows the ROD cost from energy differences combined with the monthly electricity price spread. The energy costs fluctuated between costs and benefits over the entire year. There were high energy costs from October to December, because more water was released in the Without ROD scenario compared to the With ROD scenario. The energy cost was especially high in December, because the difference in water releases between the two scenarios was nearly 200 TAF.

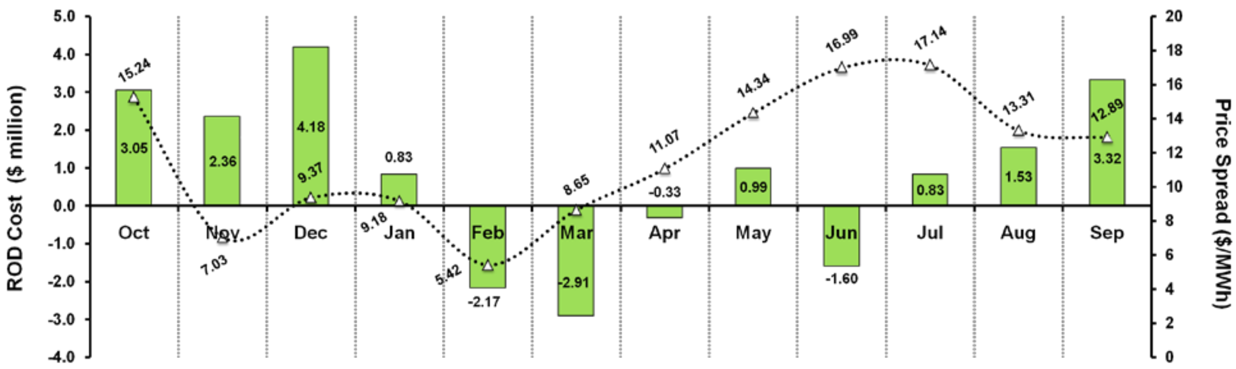

Figure 4.33 Energy Component of ROD Cost and Price Spread in WY 2004

The energy cost in January was much lower than in previous months in spite of a slight increase in the price spread, because the NNFSF had a very favorable release pattern as described in the previous section (i.e., for WY 2003). Then, in February, March, and April, the ROD yields a benefit instead of a cost. This result occurs because more water was released in those months in the With ROD scenario than in the Without ROD scenario. In February, 144 TAF more water was released; in March, more than 200 TAF more water was released; and in April, 50 TAF more water was released.

In May, the water released in the Without ROD scenario was marginally more than in the With ROD scenario, resulting in an energy cost for the ROD. In June, the ROD results in a benefit because more than 150 TAF more water was released in the With ROD scenario. July has an energy cost in spite of there being 50 TAF more water released in the With ROD than in the Without ROD scenario. As was the case in 2003, the higher water release cannot compensate for the high price spread of $17/MWh and the lower operational flexibility mandated by the ROD.

The ROD continues to have an energy cost in August, when the amount of water released in both scenarios was almost equal. There is an even higher energy cost in September, because the water release in the Without ROD scenario exceeds that of the With ROD scenario by almost 150 TAF. The price spread in September declined only slightly from August.

The combined ROD costs for both capacity and energy are shown in Figure 4.34. The capacity cost fluctuates depending on the difference in maximum capacity between the Without ROD and With ROD scenarios. The higher the difference, the larger the capacity cost. As shown in Figure 4.35, the months of October, November, December, April, May, and September have the greatest capacity difference and therefore have the greatest capacity cost. Finally, the Figure 4.34 shows that the ROD has a cost in every month except for February and March; the total ROD cost in 2004 is almost $40 million, which is slightly higher than in WY 2003.

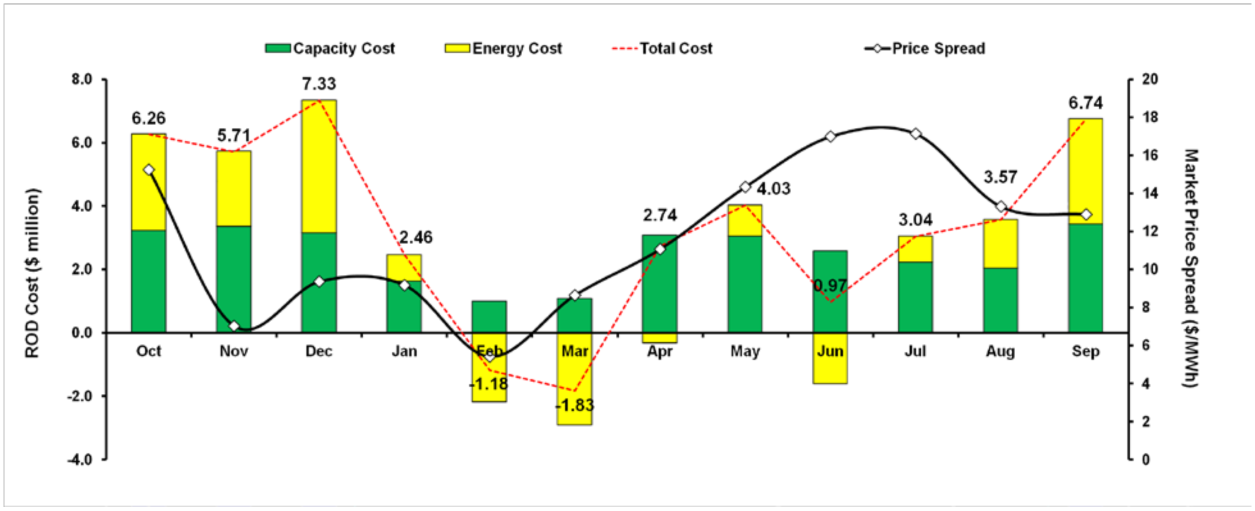

Figure 4.34 Cost of Capacity and Energy Components in WY 2004

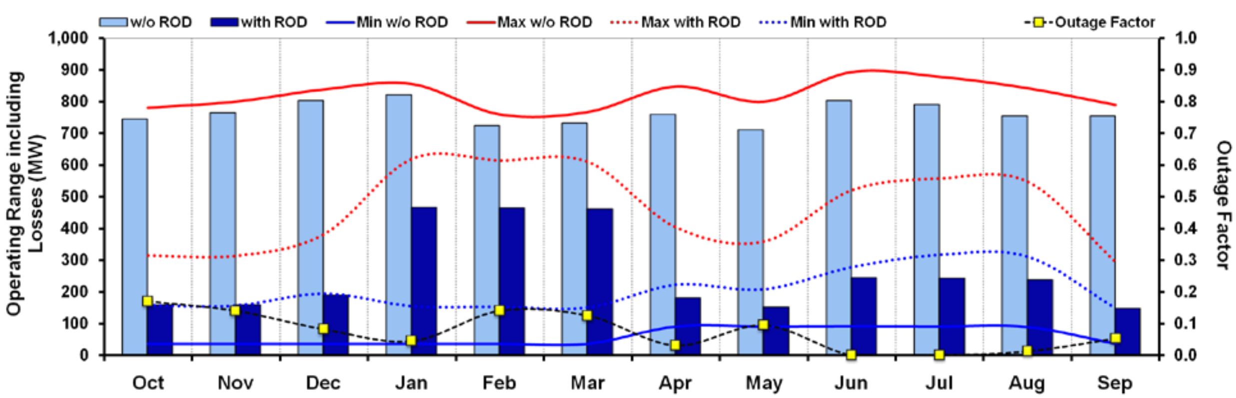

Figure 4.35 Operating Range and Outage Factor at Glen Canyon Dam in WY 2004

4.9 COST OF ROD IN WY 2005

The amount of water released in 2005 was similar to the amount released in 2004. There were five experimental releases in this year, as follows: an NNFSF, a BHBF, and three APSFs. The NNFSF was a lengthy flow, which ran from January 1 to March 31 and required water reallocation within the year. One APSF occurred from December 3 to December 5 and had a steady flow rate of 8,000 cfs. A BHBF occurred from November 21 to November 25, which was scheduled between an APSF occurring before the BHBF (from November 17 to November 20) and another following (from November 26 to November 30). The entire sequence of experimental flows lasted 14 days. The BHBF required water to be reallocated within the year. Because the BHBF ramped up to a flow of 40,000 cfs for 60 hours, the turbine capability was exceeded, and water was released over the spillway at 15,000 cfs. Total spills during the BHBF were about 93 TAF. The APSFs that occurred before and after the BHBF had flow rates of 8,000 cfs.

Figure 4.36 shows the monthly water releases; the amount of water released in each scenario was different in almost every month. This result was largely attributable to reallocation of water to accommodate the NNFSF. The NNFSF flow pattern followed a prescribed hourly release, ranging from approximately 5,000 cfs to 20,000 cfs each day from Monday through Saturday. Releases on Sunday ranged from about 5,000 cfs to 8,000 cfs. Releases were highest during the day and reduced at night. When reallocating water for the With ROD scenario, more water was released in the months of November, February, March, and June, and less water was released in the months of October, December, January, April, August, and September.

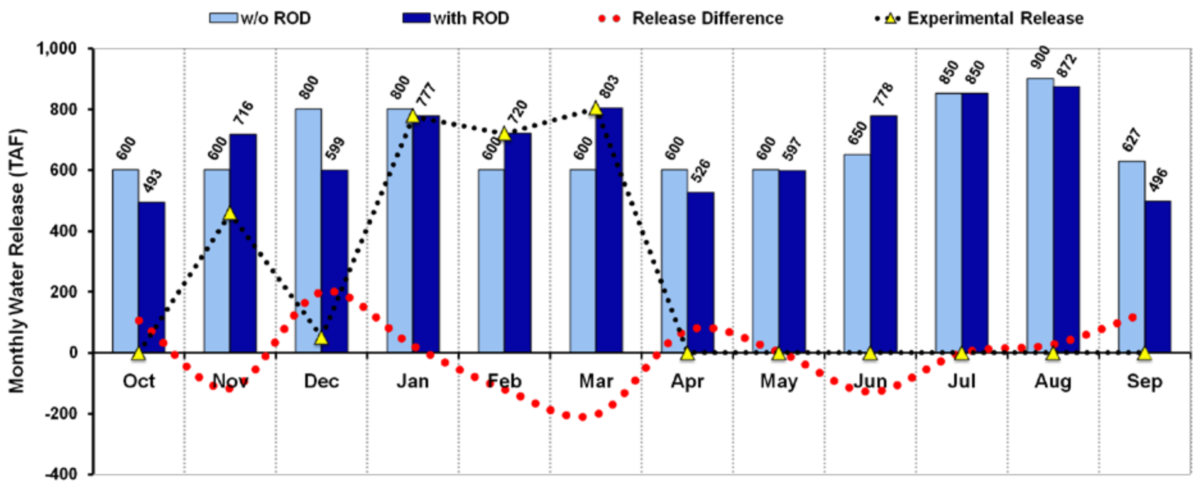

Figure 4.36 Monthly Water Releases in WY 2005

Figure 4.37 shows the ROD cost from energy differences combined with the monthly electricity price spread. The energy costs fluctuated between costs and benefits over the entire year. In general, the ROD had high energy costs in months in which the amount of water released in the Without ROD scenario was greater than in the With ROD scenario. There were lower energy costs — and even benefits — in months in which the amount of water released in the With ROD scenario was greater compared to that released in the With ROD scenario.

The ROD incurred an energy cost in October and December because the water released in the Without ROD scenario exceeded that released in the With ROD scenario. The cost was especially high in December, because the difference in water releases between the two scenarios was above 200 TAF.

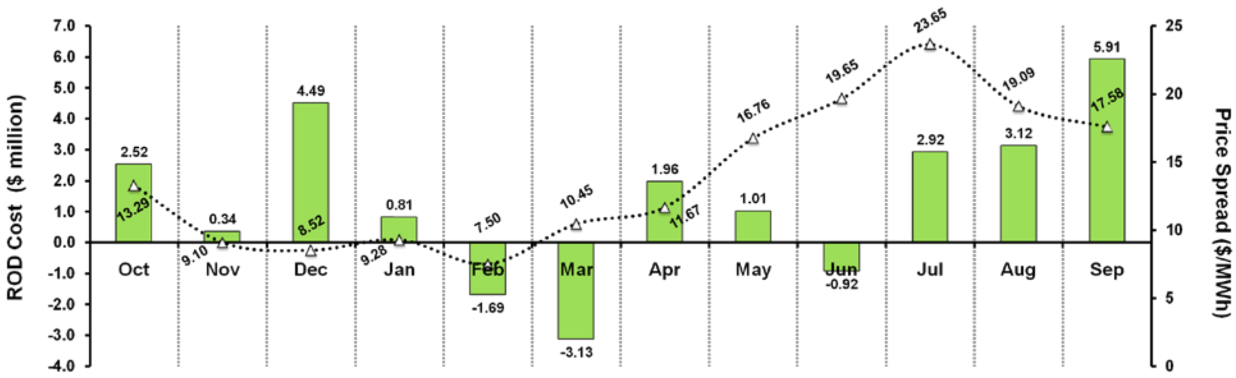

Figure 4.37 Energy Component of ROD Cost and Price Spread in WY 2005

In November, the monthly water release under the With ROD scenario exceeded the Without ROD scenario by 116 TAF. Despite this, the ROD incurred a modest energy cost because, out of the 116 TAF of water that was released, approximately 93 TAF was spilled, which generated no power, leaving only 23 TAF for power production. The generation produced by this small additional amount of water was insufficient to outweigh the cost of conducting the BHBF and the two APSFs that month. In addition, although ROD operational constraints were suspended during the experiments, they were in effect during the rest of the month, which limits water release and therefore electric generation flexibility.

Water releases in January were marginally higher in the Without ROD scenario compared to the With ROD scenario, resulting in a ROD energy cost. Although the price spread was slightly higher than in December, the cost was low because the power production pattern during the NNFSF was very favorable for energy economics during January. In both February and March, the water released in the With ROD scenario exceeded that in the Without ROD scenario, resulting in an energy benefit for the ROD. These benefits were enhanced by the NNFSF; that is, the benefits would have been lessened if ROD operational constraints had been in effect. The benefit was high in March because the With ROD scenario released 200 TAF more water than the Without ROD scenario.

In April and May, water releases in the Without ROD scenario again exceeded those in the With ROD scenario, resulting in a ROD energy cost. The energy cost in April was lower than expected, given the higher price spread and the difference in water releases. This result is attributable to a high outage factor of almost 23%, which reduced the generation flexibility in the Without ROD scenario. Figure 4.38 shows the operating range and outage factors of the GCD in 2005. The energy cost in May was relatively low because the difference in water released was only 3 TAF, and the outage factor was over 21%.

In June, water released in the With ROD scenario exceeded the Without ROD scenario by almost 130 TAF, resulting in an energy benefit for the ROD.

The ROD has higher energy costs in July, August, and September. There is an energy cost in July because of a higher price spread and equal amounts of water are released in both scenarios.

Energy costs are higher still in August because of both high price spreads and more water released in the Without ROD scenario as compared to the With ROD scenario. The ROD energy cost is highest in September because of a high price spread and more than 130 TAF of water is released in the Without ROD scenario as compared to the With ROD scenario.

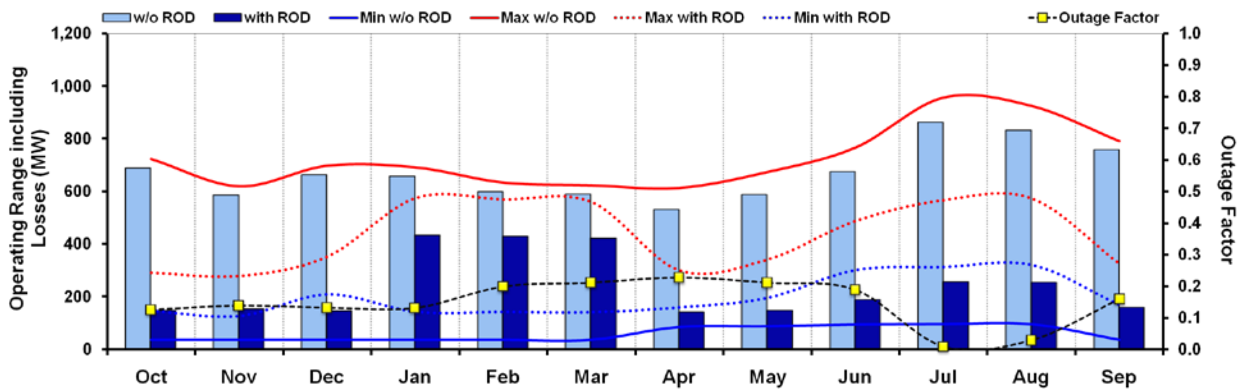

Figure 4.38 Operating Range and Outage Factor at Glen Canyon Dam in WY 2005

The total ROD costs from both capacity and energy differences between the two scenarios are combined and shown in Figure 4.39. The capacity cost fluctuates depending on the difference in maximum capacity between the Without ROD and With ROD scenarios. The higher the difference, the larger the capacity cost. As shown in Figure 4.38, only the months of January, February, and March have capacity differences of less than 120 MW; all other months have capacity differences of more than 260 MW and therefore incur the greater capacity costs. Finally, Figure 4.39 shows that the ROD has a cost in every month except for February and March; the total ROD cost in 2005 is more than $41.5 million, which is higher than costs in WY 2003 and WY 2004.

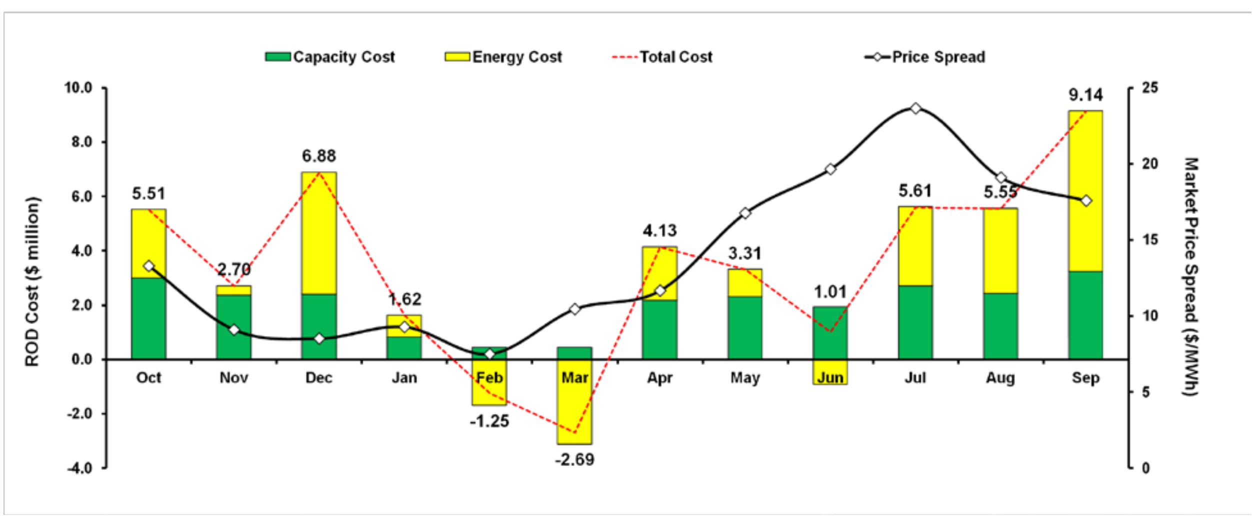

Figure 4.39 Cost of Capacity and Energy Components in WY 2005

4.10 SUMMARY OF ROD COST IN STUDY PERIOD

The study period of 1997 through 2005 was characterized by extremes in terms of hydrology, experimental flows, and market prices. When considered in this way, it is difficult to draw any broad sweeping generalizations about ROD costs, except that ROD costs are highly variable in terms of both energy and capacity and are subject to rapidly changing conditions. These rapidly evolving ROD costs over the study period are summarized below.

Annual water releases for each year in the study period are shown in Figure 4.40 Annual water releases were very high during 1997 and 1998 but diminished quickly. By 2002, water releases were reduced to about 8.23 MAF annually. This minimum release level was maintained through the end of the study period. The annual releases are identical in both scenarios except in 2000 and 2001, when an LSSF required water to be reallocated between water years 2000 and 2001; namely, while 618 TAF less water was released in 2000 for the With ROD scenario as compared to the Without ROD scenario, that same amount of 618 TAF more water was released in 2001 in the Without ROD scenario.

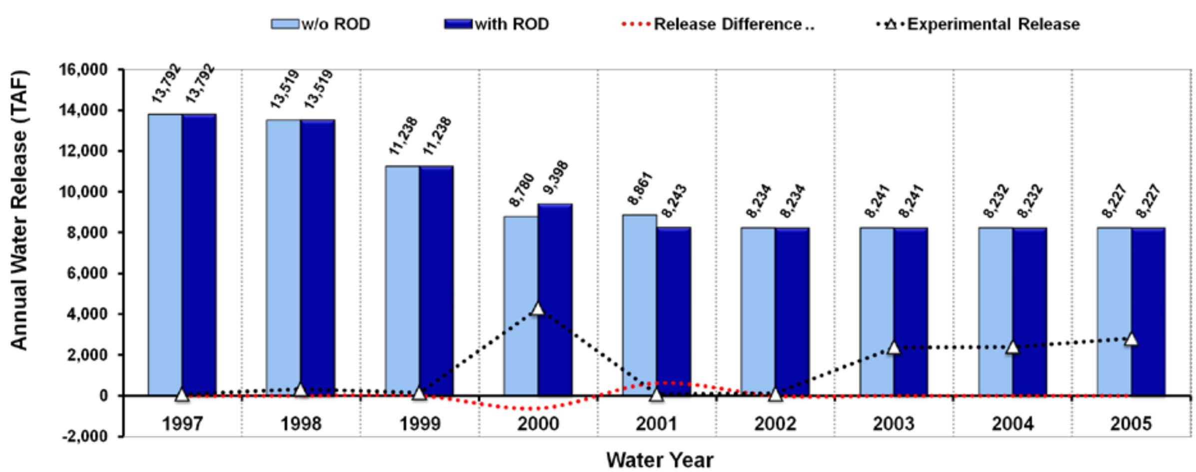

Figure 4.40 Annual Water Releases during the Study Period

The ROD costs resulting from energy differences and the monthly price spread are shown in Figure 4.41. It is of note that actual electricity market prices were used during the study period, including the large price spikes that occurred in 2000 and 2001 which were attributable to the electricity market problems during the California energy crisis. A sensitivity study, which is described later in this section, was performed to assess the impacts of the California energy crisis on the economic cost of the ROD. The highest ROD energy cost occurs in 2001 and the lowest in 1997. The relatively low cost in 1997 is because the ROD did not take effect until February 1997, the fifth month of the water year.

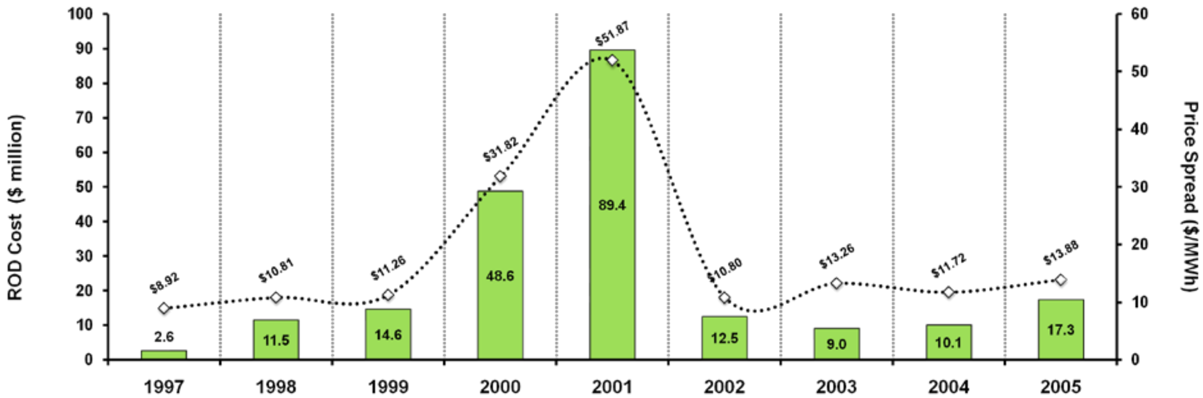

Figure 4.41 Energy Component of ROD Cost and Price Spread during the Study Period

The energy cost of the ROD increases through 2001 as it follows the price spread increase. The costs are highest in 2000 and 2001 when the price spreads were at least 3 to 5 times more than the price spread in any other year. The energy cost might have been larger in 2000 had there not been a larger water release in the With ROD scenario because of the LSSF. The cost was highest in 2001 because of the high price spread and less water being released in the With ROD scenario to compensate for the higher release of the previous year.

The energy cost drops sharply in 2002 because of a nearly five-fold drop in the price spread from 2001 to 2002. Although the price spread increased in 2003 compared to 2002, the energy cost of the ROD actually fell. This result is because of the NNFSF that occurred that year. Releases during the NNFSF can be as high as 20,000 cfs during the day and reduced substantially at night. This release pattern allows more energy production in peak hours, thereby lowering the ROD’s energy cost.

In 2004, the price spread decreased from 2003, but the energy cost increased slightly. This result is because the outage rate dropped by more than a factor of two from 2003 to 2004 as shown in Figure 4.42. Therefore, more energy could be sold during high-price peak hours in the Without ROD scenario. Finally in 2005, the energy cost increased for two reasons. First, the price spread increased from 2004 to 2005, and second, a costly BHBF occurred in 2005. This BHBF had a maximum flow of 40,000 cfs, which exceeded the turbine capacity; therefore, water was spilled without generating electricity.

The total ROD cost resulting from capacity and energy differences between the two scenarios are combined and shown in Figure 4.43. Both the lower- and upper-bound costs calculated in the GCDEIS are displayed for comparison. The capacity cost component is highest in 2000, 2001, and 2002. This result can be explained by the difference in maximum capacities between the two scenarios as shown in Figure 4.42. The capacity difference is largest in those three years before it begins to narrow in 2003, when the maximum capacity in the Without ROD scenario begins to decline. This capacity decline is linked to the decline in the Lake Powell elevation, which began in 2002 and continued to 2005. The elevation levels and power conversion factors are shown in Figure 4.44.

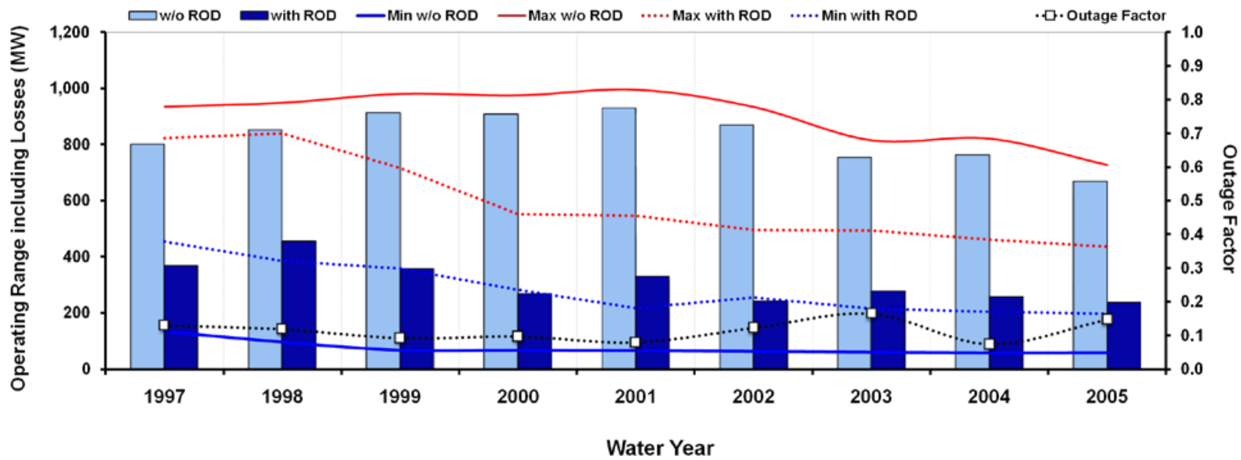

Figure 4.42 Operating Range and Outage Factor at Glen Canyon Dam during the Study Period

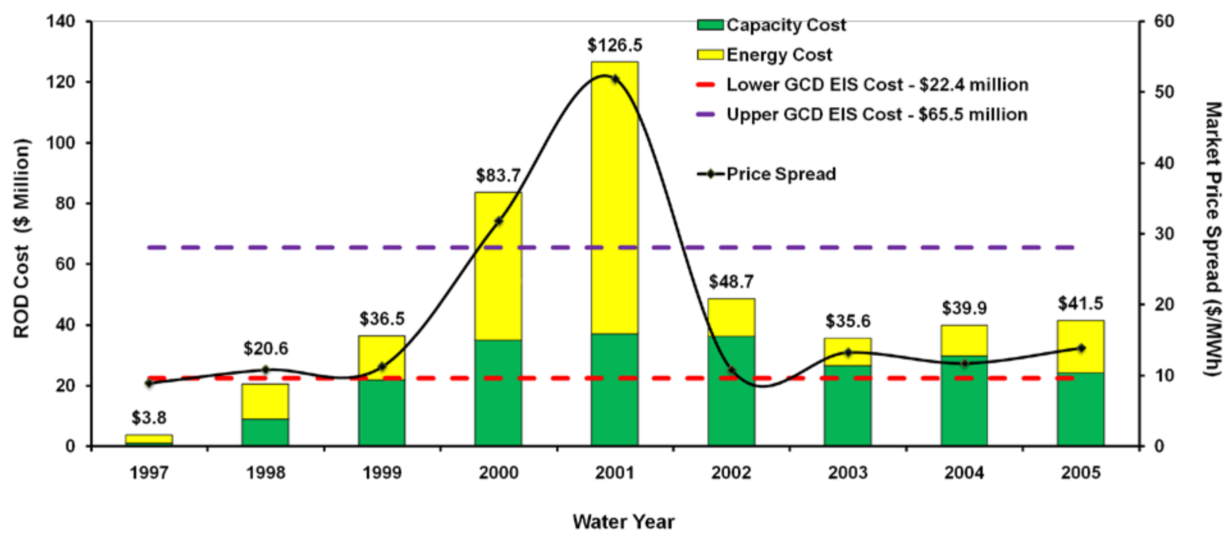

Figure 4.43 Cost of Capacity and Energy Components in Study Period

The energy cost component makes up the largest share of the total cost of the ROD during the California energy crisis in 2000 and 2001. It makes up almost 60% of the total ROD cost in 2000 and over 70% in 2001. The total ROD costs in these years are also about 2 to 3 times higher than the next-closest cost.

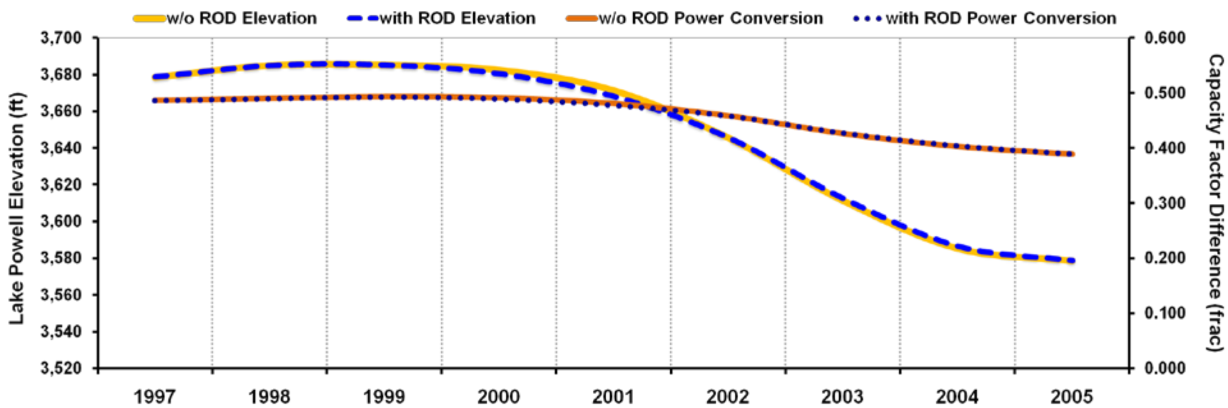

Figure 4.44 Comparison of Lake Powell Elevations and Power Conversion Factor during the Study Period

Figure 4.43 also compares the lower and upper annual economic ROD costs calculated in the GCDEIS against the costs calculated from this ex post study. The values from the GCDEIS were converted from $1991, the price index year for the EIS, to $2009. The lower bound cost was $15.1 million in $1991 or $22.4 million in $2009 and the upper bound cost was $44.2 million in $1991 or $65.5 million in $2009. The costs from this study are between the upper and lower GCDEIS costs except for 1997, 2000, and 2001. The ROD was not implemented until the fifth month of the 1997 water year and the California energy crisis occurred during 2000 and 2001. Over the nearly 9-year study period, the average annual economic cost of the ROD is $50 million ($2009) or $33.9 million ($1991) which is within the upper bound annual ROD cost from the GCDEIS. Note that the average was calculated using only 8 months of 1997 since the ROD was not implemented in the first 4 months of that year. However, the total ROD cost in 2000 is 30% higher than the upper GCDEIS cost and the total ROD cost in 2001 in more than double the upper GCDEIS cost.

To determine the effects of the California energy crisis in 2000 and 2001 on the total cost of the ROD, a sensitivity analysis was performed. It was determined that large swings in electricity market prices began in February 2000 and lasted through approximately August 2001. Therefore, the sensitivity study used an interpolation method described in Section 3.4.1 on electricity prices in this time period to remove the effects of the crisis period. Figure 4.45 compares actual prices and price spreads experienced by the market with the adjusted prices and price spreads. The figure shows that both prices and price spreads experienced large price fluctuations during the time period. The model was then run using the adjusted prices for 2000 and 2001 and the cost results were compared to those using actual market prices. Comparing the costs resulting from both cases would determine the range of total ROD economic costs. The true total economic cost of the ROD would be within this range.

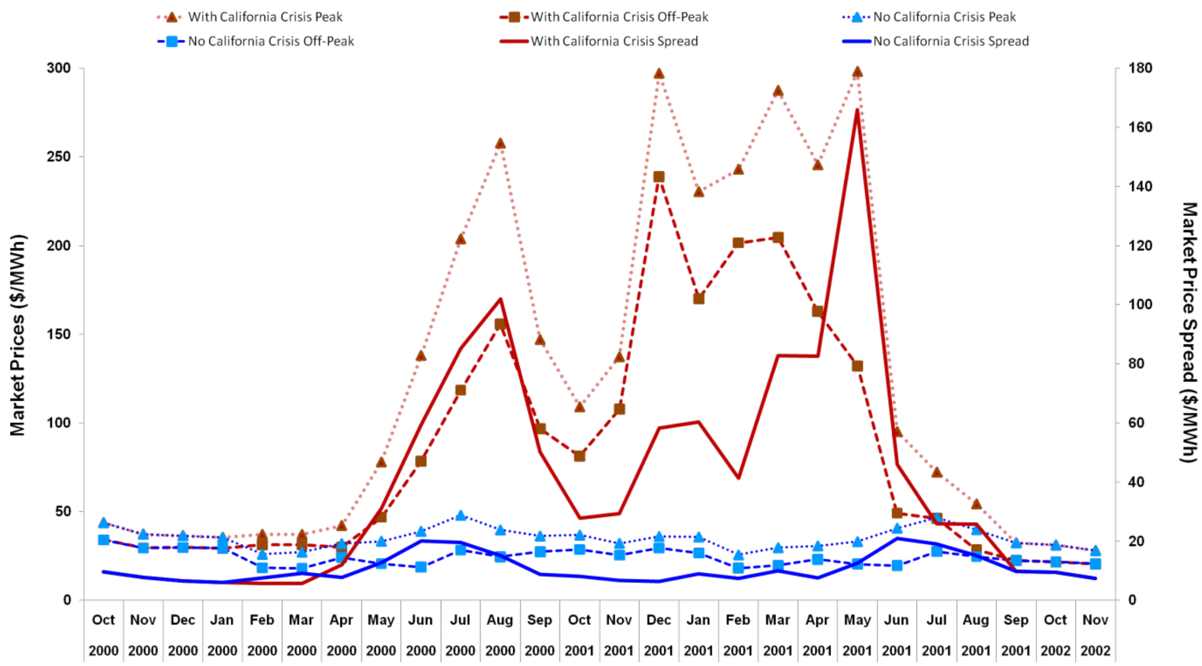

Figure 4.45 Comparison of Actual Monthly Electricity Prices/Price Spreads during California Energy Crisis to Those Values with California Energy Crisis Removed

The sensitivity case's ROD costs resulting from energy differences and the monthly price spread are shown in Figure 4.46. Costs and price spreads differ from Figure 4.41 only in 2000 and 2001. For the sensitivity case in 2000 the energy cost is about half the cost in 1999 in spite of a minimal drop in price spread. This result occurred because there was a larger water release in the With ROD scenario because of the LSSF. Then, in 2001, when less water was released in the With ROD scenario to compensate for the higher release of the previous year, the energy cost increased substantially, although the price spread in 2001 was nearly equal that in 2000.

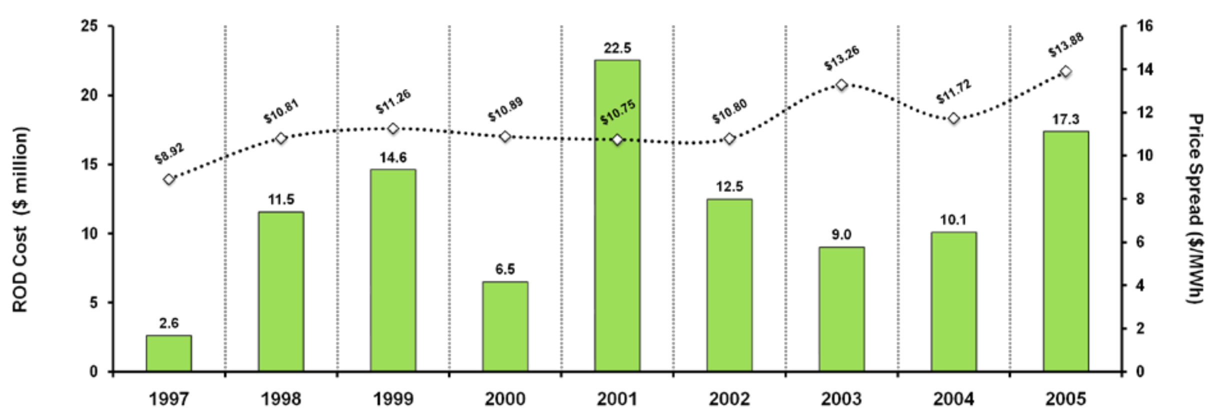

Figure 4.46 Energy Component of ROD Cost and Price Spread during the Study Period (based on adjusted electricity prices for the California energy crisis of 2000 and 2001)

The total cost of the ROD for the sensitivity case is shown in Figure 4.47. The costs from the sensitivity case are between the upper and lower GCDEIS costs except for 1997 and 1998. The ROD was not implemented until the fifth month of the water year in 1997, and in 1998 the cost is only 8% less than the lower GCDEIS cost.

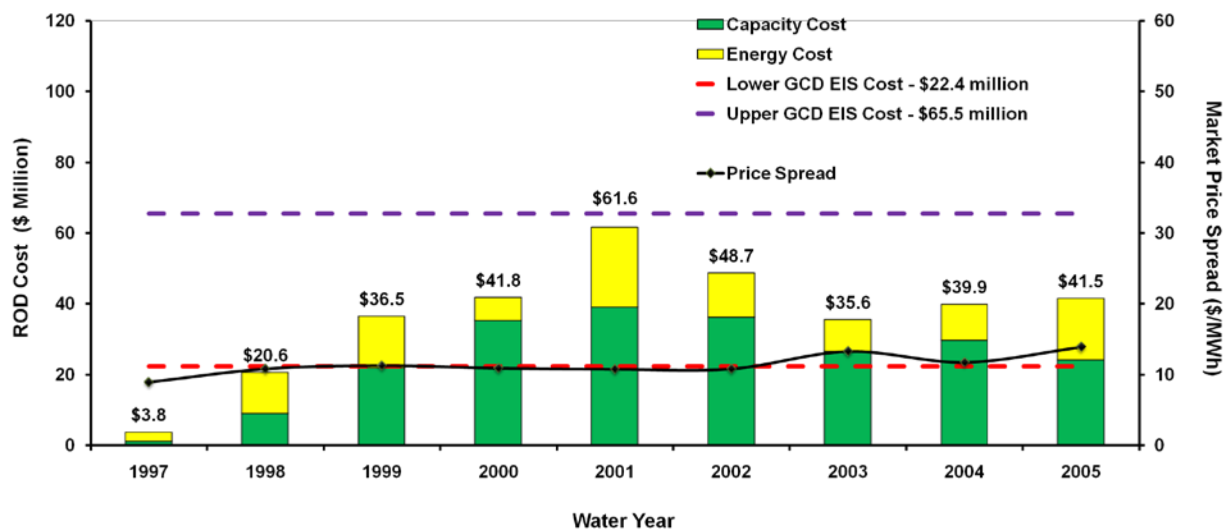

Figure 4.47 Cost of Capacity and Energy Components in Study Period (based on electricity prices adjusted to remove effects of the 2000/2001 California energy crisis)

The annual average economic cost over the nearly 9-year study period for the sensitivity case is $38 million ($2009) or $26 million ($1991) which is about 24% lower than the average annual economic ROD cost using actual market prices. The conclusion to be drawn by comparing the results of these two cases is that one must be careful when using market prices as surrogates for economic value of energy. When market prices differ significantly from underlying energy production costs, such as happened during the California energy crisis of 2000 and 2001, economic value of energy resources can be skewed and yield misleading results.

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Decision and Information Sciences Division
Argonne National Laboratory
9700 South Cass Avenue, Bldg. 221
Argonne, IL 60439-4844

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