Operation of Flaming Gorge Dam Draft Environmental Impact Statement

Power Modeling Technical Appendix

POWER SYSTEM ANALYSIS TECHNICAL APPENDIX

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NOTATION

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

ACRONYMS AND ABBREVIATIONS

Argonne	Argonne National Laboratory
BPA	Bonneville Power Administration
CRSP	Colorado River Storage Project
CRSS	Colorado River Simulation System
CSC	Customer Service Center
EIS	Environmental Impact Statement
EOM	end of month
FGEIS	Flaming Gorge Environmental Impact Statement
GenOpt	Generation Optimization
GTMax	Generation and Transmission Maximization
NPV	net present value
PO&M-59	Power Operations and Maintenance
Reclamation	Bureau of Reclamation
SLCA/IP	Salt Lake City Area Integrated Projects
SSARR	streamflow synthesis and reservoir regulation
USFWS	U.S. Fish and Wildlife Service
Western	Western Area Power Administration
WL	water lag
WLF	water lag factor
WSCC	Western Systems Coordinating Council

UNITS OF MEASURE

AF	acre-feet
cfs	cubic-feet per second
ft	foot (feet)
GWh	Giga-watt hour(s)
hr	hour(s)
HP	horsepower
lbs	pound(s)
MW	Mega-watt
MWh	Mega-watt hour(s)
TAF	thousand-acre-feet

Power System Analysis Technical Appendix

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ABSTRACT

This report describes the methods that were used to simulate the hourly operations of the Flaming Gorge Dam and powerplant that meet environmental flow constraints at a downstream gauge located near Jensen, Utah. Operations are simulated under two alternative sets of flow constraints that include current limitations and a new set of flow recommendations formulated by the Fish and Wildlife Service. The methodology is also used to estimate the total economic benefits of powerplant electricity generation. This report documents these economic benefits and compares the two alternatives. Economic benefits are also estimated for a Cumulative Impact Scenario in which there are no environmental restrictions imposed on powerplant operations. Simulated operations and economic estimates are in support of the Bureau of Reclamation's Flaming Gorge Environmental Impact Statement.

1. INTRODUCTION

The Bureau of Reclamation (Reclamation) has been studying the potential effects on endangered species in the Green River below Flaming Gorge Dam and reservoir. These studies are in response to their obligations under Section 7 of the Endangered Species Act and have included close coordination with the U.S. Fish and Wildlife Service (USFWS), as well as numerous other agencies and interested members of the public. The USFWS has formulated flow recommendations for endangered fish species downstream from Flaming Gorge Dam and Reclamation is addressing impacts to other resources in the Green River related to such flow recommendations in an Environmental Impact Statement (EIS).

This report describes various aspects of the Flaming Gorge Environmental Impact Statement (FGEIS) that will affect powerplant operations at the dam. It also provides a detailed description of the methodology that was used to simulate dam and powerplant operations under two FGEIS alternatives. The analyses conducted under this power systems study provide an estimate of the economic impacts of EIS alternatives over a 25-year period from 2002 though 2026, inclusive. Cumulative impacts of all operational restrictions at Flaming Gorge are estimated by comparing the economic benefits of power production at Flaming Gorge to a scenario that has no environmental restrictions. Economic estimates are based on the quantity of energy produced by Flaming Gorge and spot market prices. Benefit calculations are performed on an hourly basis. Restrictions specified by each of the alternatives have to some degree an affect on the economic value of the Flaming Gorge hydropower resource.

2. FLAMING GORGE DAM AND POWERPLANT OVERVIEW

The Flaming Gorge Dam is part of the Colorado River Storage Project (CRSP) that was authorized by a Congressional Act of April 11, 1956. It is located on the Green River in northeastern Utah about 32 miles downstream from the Utah/Wyoming border. The concrete thin-arch structure that was built by Reclamation has a maximum height of 502 feet and a crest length of 1,285 feet. Flaming Gorge Reservoir has a total capacity of 3,788,700 acre-feet (AF) at a reservoir water elevation of 6040 feet above sea level. The reservoir has an active capacity of 3,515,700 AF and a surface area of 42,020 acres. Construction of the Flaming Gorge Dam began in October 1956 and the reservoir was topped out in late 1962 ***(Flaming Gorge Flow Recommendations Document, Section 3.2, Page 56)***. To the extent possible the dam has been operated at near-full reservoir levels while attempting to avoid spills.

The powerplant began commercial operation in 1963 with three generating units. Each unit originally had a capacity of 36 Mega-watt (MW) for a plant total of 108 MW. Since that time, the three units were upgraded to approximately 50.65 MW thereby increasing the total installed capacity to 151.95 MW (***Form PO&M-59)***. However, due to turbine limitations the operable capability of the powerplant is approximately 141.0 MW. On average, the Flaming Gorge Dam powerplant generates about 528.9 Giga-watt-hours (GWh) of electricity annually.

The Western Area Power Administration's (Western) CRSP Management Center markets CRSP power resources, including Flaming Gorge, and hydroelectric powerplants of the Collbran and Rio Grande projects. Energy and capacity from these projects, collectively referred to as the Salt Lake City Area Integrated Projects (SLCA/IP), are marketed to more than 140 customers in six western states on both a long-term and short-term firm basis (***ANL/DIS/TM-10)***. Generation from the Flaming Gorge powerplant also serves the energy requirements of special project uses such as irrigation and can be used to fulfill utility system requirements for spinning reserves and area load control. Electricity is also sold on the spot market when available energy exceeds firm contractual obligations. Spot market activities also include purchasing energy at relatively low prices during off-peak hours and using the stored energy for sale when spot market prices are high. This hydro-shifting activity allows Western to maximize the economic value of hydropower resources.

The FGEIS power systems methodology focuses on the operations of the Flaming Gorge Dam subject to environmental flow constraints at a critical downstream reach on the Green River. Power generation from

Flaming Gorge is injected into the transmission grid. The economic value of this generation is based on the market price of electricity at the Four Corners delivery point.

3. EIS ALTERNATIVES

The FGEIS contains two alternatives. The first is referred to as the No Action Alternative. It assumes that Green River flow constraints established under the 1992 Biological Opinion will continue through the end of the study period. The dam is currently operated to meet flow limitations specified by this alternative. The second is referred to as the Action Alternative. It assumes that Flaming Gorge Dam operations will comply with a new set of USFWS flow recommendations. The Action Alternative requires monthly and hourly water release patterns from the Flaming Gorge Dam that differ from those established by the 1992 Biological Opinion.

The economic impacts of altering generation patterns to meet new flow requirements under the Action Alternative are estimated in this analysis. Most of the facets of the Action Alternative that affect the economic value of the power system are precisely documented. However, there is a set of rules that will be assumed under both alternatives that is not based on written documentation, but rather on verbal agreements and current operational practices. Essentially, these are temporary agreements made among various institutions that are assumed to continue throughout the study period. However, these unwritten rules may or may not continue in the future. Tables 3.1 and 3.2 show key operational elements and gauge flow constraints contained in the two alternatives that will affect the economic value of the Flaming Gorge power resource.

3.1 Green River Flow Constraints

The FGEIS defines three reaches shown on figure 3.1 Flaming Gorge Flow Recommendations Document, P. 2-2. For the power systems analysis conducted in this study, the only flow constraints considered are at reach 2 as measured at the Jensen Gauge. Reach 2 begins at the confluence of the Green and Yampa Rivers; that is, about 65.1 miles downstream from Flaming Gorge Dam. Reach 2 extends for about 98.8 miles downstream from the Yampa to the confluence of the White River. The Jensen Gauge is located nearly 28.6 miles downstream of the Yampa confluence. Therefore, a Flaming Gorge water release must travel about 93.7 miles (i.e., 65.1 + 28.6) before it registers at the Jensen Gauge.

Jensen Gauge flows are primarily a function of Flaming Gorge releases and Yampa inflows. Since Yampa inflows are not controlled, releases from Flaming Gorge must be regulated such that flows are in compliance with Jensen Gauge requirements. However, water releases from Flaming Gorge are not required by EIS alternatives to compensate for large and unpredictable changes in Yampa inflows. On the other hand, FGEIS alternatives require that the general pattern of Yampa inflows be accounted for when scheduling Flaming Gorge releases.

Green River flow constraints under the No Action Alternative are based on four time periods that includes a spring spike, a summer season, a winter season and a post-winter flow period. Each of these periods is listed in tables 3.1 and 3.2 for the No Action and Action Alternatives, respectively.

Except for the post-winter period, time period designations are identical for both alternatives. The post-winter period for the Action Alternative begins 1 month earlier than in the No Action Alternative.

The No Action Alternative requires that flows at the Jensen Gauge remain within 12.5 percent of the daily average flow during the summer and autumn seasons. This allows for a maximum daily fluctuation of

Table 3.1. Assumptions for the No Action Alternative (1992 Biological Opinion)

Spring Flows (Spike)	Summer	Winter	Post-Winter
Period of spike, inclusive	Day after end of spike to Oct 31, inclusive	Nov 1 to Apr 31, inclusive	May 1 until the start of spike, inclusive
No gauge constraints	Requires Jensen Gauge flows to remain within a 12.5% of the daily average		No gauge constraints
	Jensen Gauge flows limits are constant among all days of a month.		
Restrict daily water releases from Flaming Gorge			
	Daily average gauge flows range from 31 to 51 m^3/s	Daily average gauge flows range from 31 to 68 m^3/s	
		Ice cap issues not considered	
Assumed that Yampa flows are constant throughout a month			
Operational rules: 800 cfs minimum flows, 800 cfs maximum up-ramp rate, 800 cfs maximum down-ramp rate, single hump per day.			

Table 3.2. Assumptions for the Action Alternative (2000 Flow and Temperature Recommendations)

Spring Flows (Spike)	Summer	Winter	Post-Winter
Period of spike, inclusive	Day after end of spike to Oct 31, inclusive	Nov 1 to February 28 (29), inclusive	March 1 until the start of spike, inclusive
No gauge constraints	Jensen Gauge stage flows limited to an intra-day change of 0.1 meters		No gauge constraints
Restrict daily water releases			
	3% daily average gauge constraint does not apply		
	Consistent with the Green River model daily average gauge flows are between 26 to 85 m^3/s		
	Consistent with the Green River model will not utilize 40%/25% variation around year mean flows		
Assumed that Yampa flows are constant throughout a month			
Operational rules: 800 cfs minimum flows, 800 cfs maximum up-ramp rate, 800 cfs maximum down-ramp rate, single hump per day.			

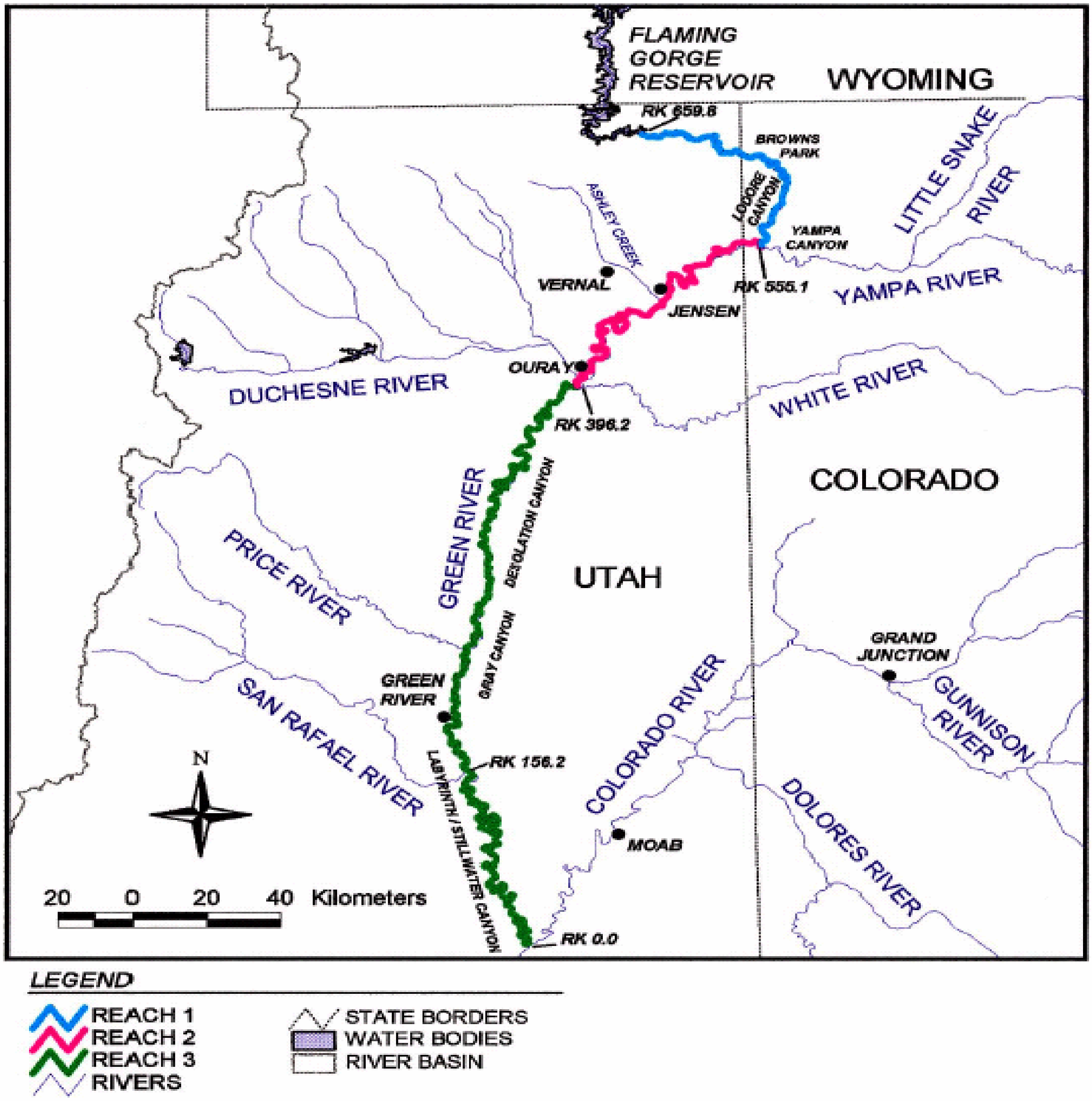

Figure 3.1. Critical Reaches Downstream From the Flaming Gorge Dam.
Source: 2000 Flow and Temperature Recommendations Report.

25 percent; that is, 12.5 percent higher than the average and 12.5 percent lower than the average. Although it is not specified by the No Action Alternative, for this study it is assumed that the 25-percent maximum daily fluctuation requirement will also constrain dam operations in the winter season. This is consistent with historic short-term verbal agreements and current operational practices. This agreement may or may not continue in the future and operations may change.

The Action Alternative specifies Jensen Gauge flow constraints in terms of Green River stage change. The intra-day stage change is limited to 0.1 meters (i.e., 0.328 feet) from the average stage. Figure 3.2 shows the relationship between the stage and flow rates at the Jensen Gauge Data Source: Email from Richard Clayton on 9/16/2002 with attached files jesu.q$15 & jesu.xls.

As shown in figure 3.3, when the 0.1-meter gauge constraint (i.e., Action Alternative) is expressed in terms of percent change, the Action Alternative is more stringent than the No Action Alternative over the entire range of the gauge flows. However, the difference is significantly smaller at lower gauge flows. Table 3.4 shows a comparison of the two alternatives at the lower flow rates. At 800 cubic feet per second (cfs), the Action Alternative has approximately a 23-percent flow range; that is, a range that is 2 percent less than the No Action Alternative. Unlike the No Action Alternative that has a 12.5-percent allowable flow range both above and below the daily average, these percentages are asymmetrical for the Action Alternative. At a stage of 3.1 ft a 9.9-percent flow decrease below the daily average is allowed for the Action Alternative while an 11.6-percent increase above the daily average sets the upper flow bound. This occurs since flow stages as shown in figure 3.2 are non-linear.

Although the Action Alternative is more restrictive, the lower flow rates are expected to occur more frequently than higher flow rates. Difference in the gauge flow flexibility between the two scenarios is usually from 2 percent to 4 percent. Figure 3.4 shows the flow rate exceedance curve for the Action Alternative for all days of the 25-year study period. The curve is based on Green River model projections of daily Flaming Gorge releases and inflows from the Yampa Data Source: Email from Andrew Gilmore with attached files RepresentativeTraceAction.xls. The figure shows that the range for the Action Alternative drops to 21.2 percent at 2,060-cfs flow rate. Daily average flows are less than 2,060 cfs about 50 percent of the time.

The No Action Alternative requires the daily average flow at the Jensen Gauge to remain constant over a period (e.g., season). While the range of allowable flows at the Jensen Gauge under the No Action Alternative remains constant, the window of allowable flows at the Jensen Gauge under the Action Alternative can change from one day to the next by up to 3 percent. The intent of this daily change allowance is to permit Reclamation to adjust water releases in response to unpredicted changes in the system hydrology. Therefore, for the purpose of modeling power system operations, water releases from Flaming Gorge are not permitted to change from one day to the next.

3.2 Flaming Gorge Operational Rules

The hourly average water release from the Flaming Gorge Dam must be at least 800 cfs as mandated in 1967 Flaming Gorge Flow Recommendations Document, P. 3-6. This directive was given in order to establish and maintain tailwater trout fisheries. Over a period of one week, the 800 cfs minimum release accounts for approximately 11.1 thousand acre-feet (TAF). Weekly water releases above this level can be used at the discretion of dispatchers within other dam operational and downstream flow constraints. Typically a dispatcher releases this water through the turbines when it has the highest economic value as indicated by spot market prices.

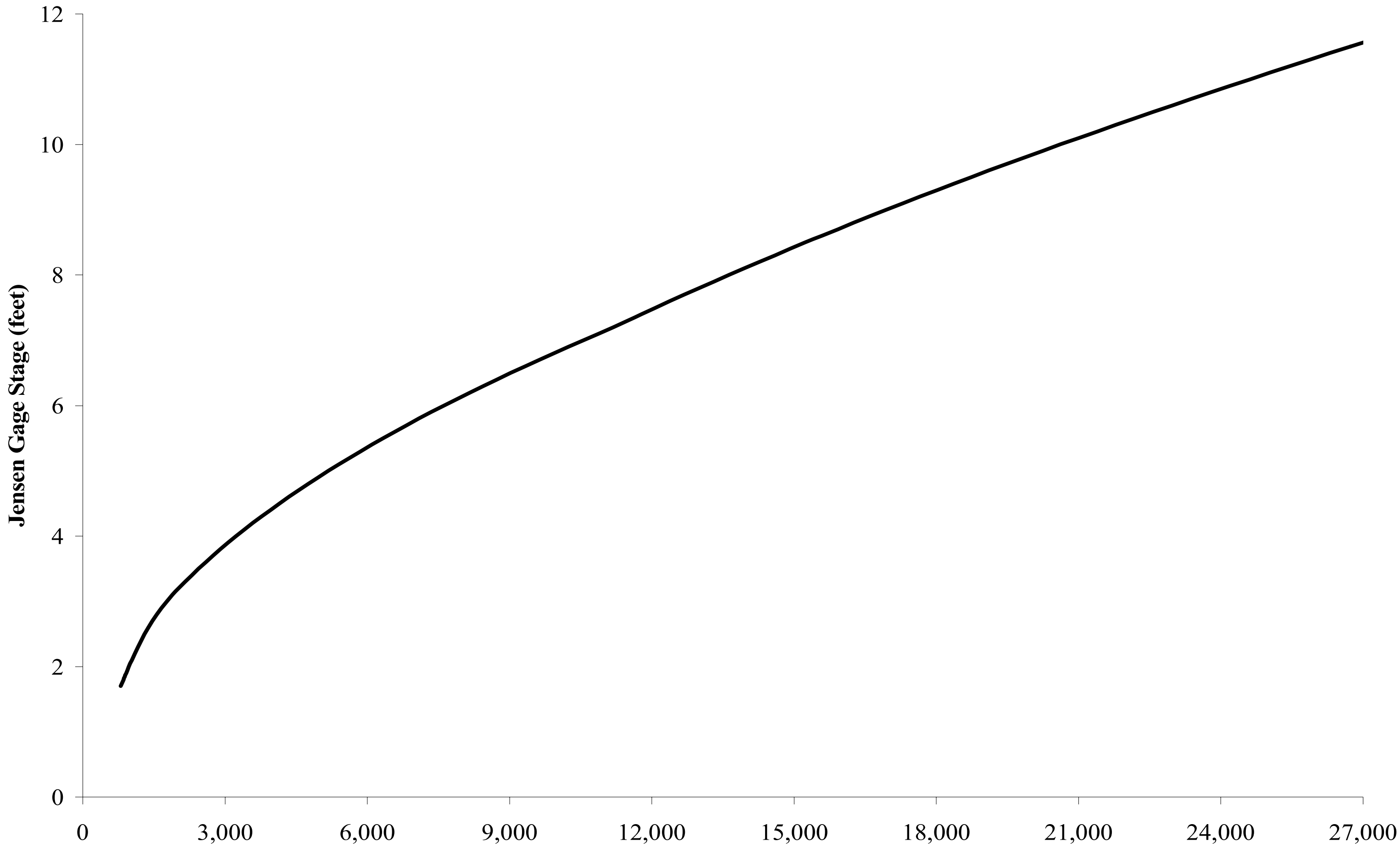

Figure 3.2. Green River Stage as a function of Flow Rate at the Jensen Gauge.

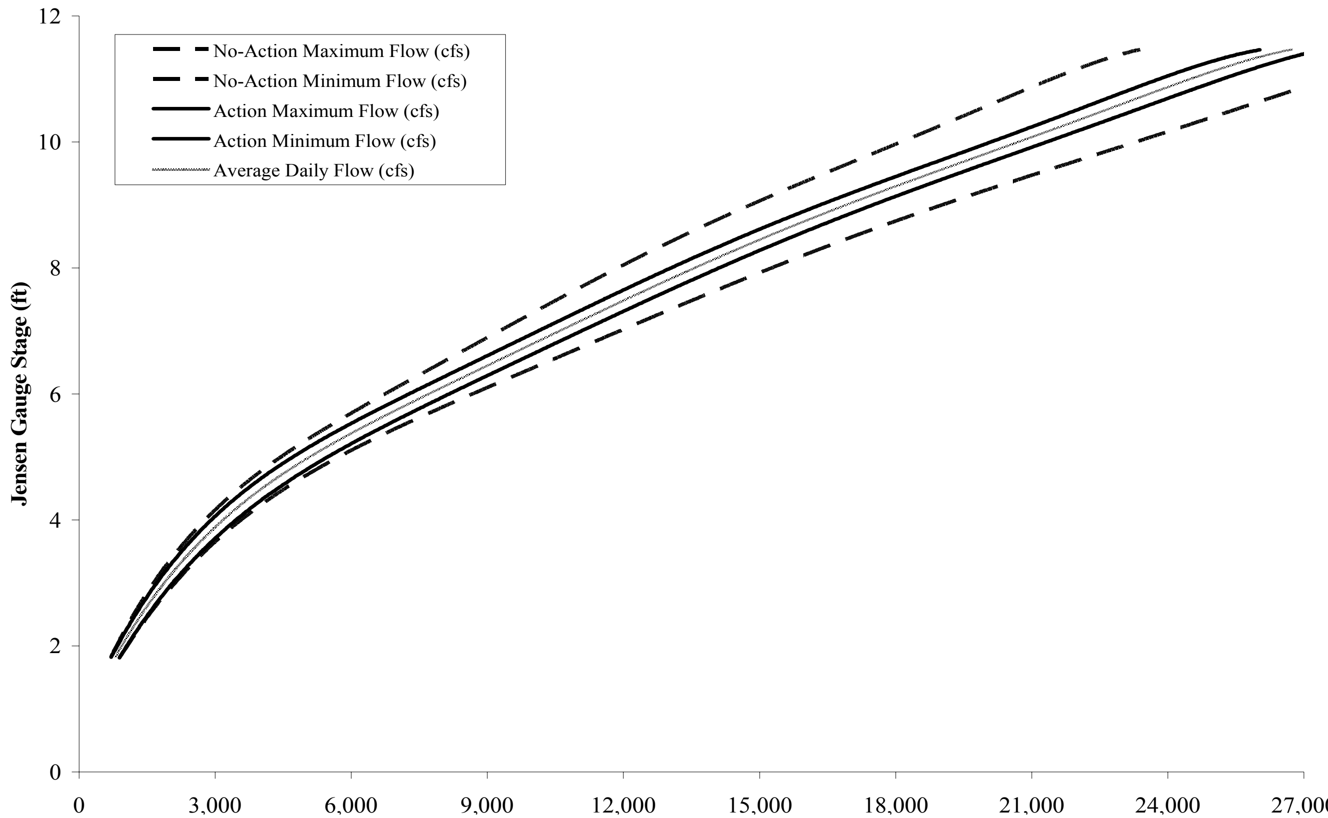

Figure 3.3. Allowable Flow Range for the No Action and Action Alternatives.

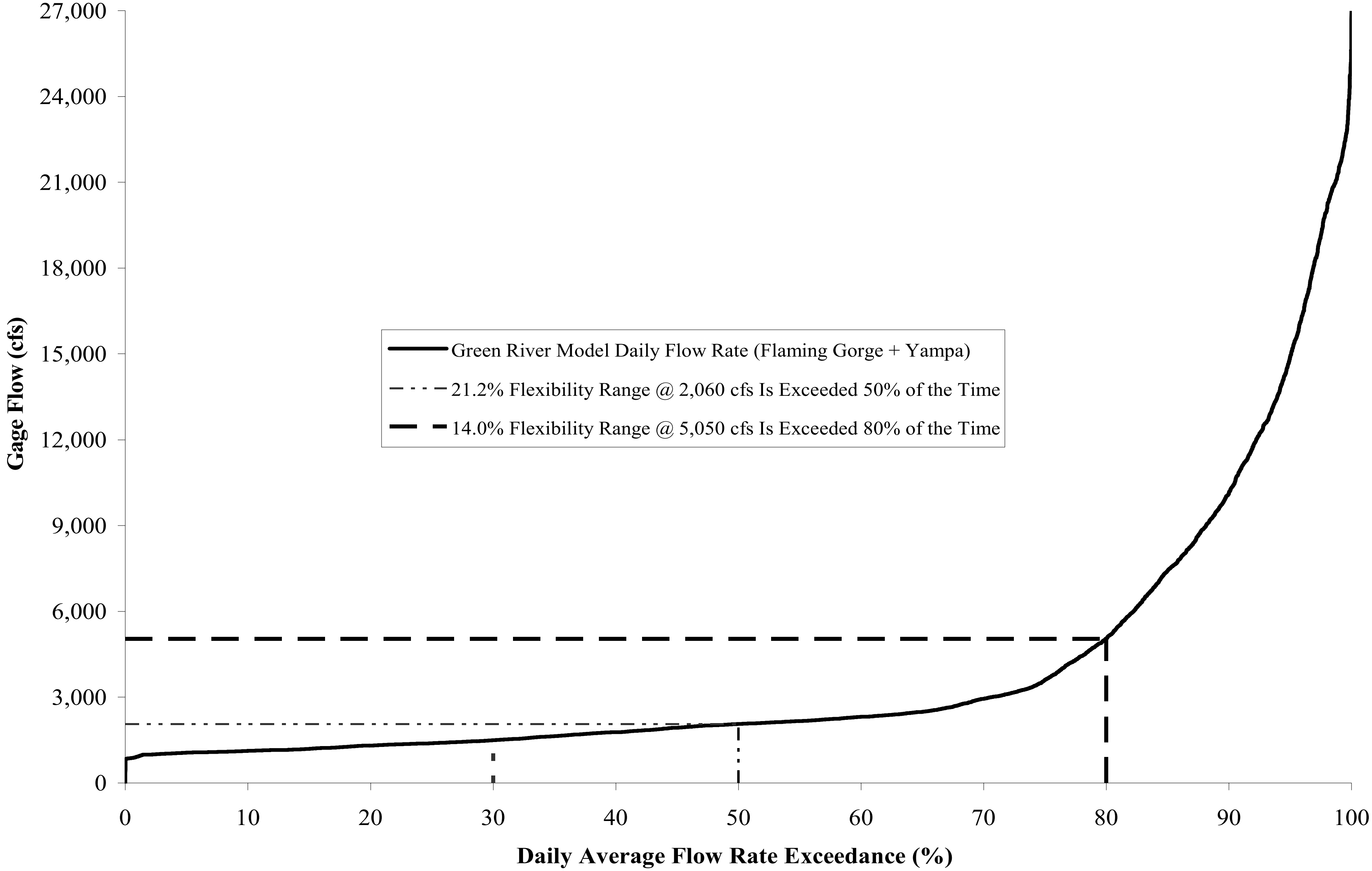

Figure 3.4. Projected Daily Average Flow Rate Exceedance Curve at the Jensen Gauge for the Action Alternative.

Table 3.3. Spike Period Dates and Duration

Year	No Action Alternative			Action Alternative		
	Start Date	End Date	Duration (days)	Start Date	End Date	Duration (days)
2002	24-May	22-Jun	30	30-May	09-Jul	41
2003	15-May	05-Jun	22	19-May	12-Jun	25
2004	08-May	31-May	24	13-May	10-Jun	29
2005	10-May	31-May	22	12-May	27-May	16
2006	15-May	09-Jun	26	22-May	05-Jun	15
2007	06-May	28-Jun	54	07-May	08-Jun	33
2008	09-May	31-May	23	10-May	25-May	16
2009	13-May	26-Jun	45	17-May	28-Jun	43
2010	01-May	29-Jun	60	12-May	18-Jun	38
2011	01-May	31-May	31	10-May	05-Jun	27
2012	15-May	26-Jun	43	24-May	18-Jul	56
2013	29-May	19-Jun	22	02-Jun	07-Jul	36
2014	11-May	11-Jun	32	04-May	27-Jun	55
2015	13-May	04-Jun	23	18-May	18-Jun	32
2016	08-May	04-Jul	58	28-May	23-Jun	27
2017	15-May	03-Jul	50	30-May	26-Jun	28
2018	15-May	05-Jun	22	16-May	25-Jun	41
2019	10-May	20-Jun	42	01-Apr	28-Jun	89
2020	28-May	03-Jul	37	02-Jun	25-Jul	54
2021	19-May	20-Jun	33	21-May	21-Jul	62
2022	27-May	20-Jun	25	02-Jun	16-Jun	15
2023	29-May	24-Jun	27	07-Jun	31-Jul	55
2024	18-May	08-Jun	22	22-May	16-Jun	26
2025	15-May	20-Jun	37	21-May	28-Jun	39
2026	18-May	09-Jun	23	22-May	09-Jun	19
Minimum			22			15
Average			33.3			36.7
Maximum			60			89

Table 3.4. Comparison of Alternative Gauge Constraints at Low Flow Rates

Stage (feet)	Average Flow (cfs)	No Action Alternative			Action Alternative		
		Minimum Flow (cfs)	Maximum Flow (cfs)	Range (%)	Minimum Flow (cfs)	Maximum Flow (cfs)	Range (%)
1.70	800	700	900	25.0	708	892	23.0
1.80	856	749	963	25.0	764	949	21.7
1.90	913	799	1,027	25.0	820	1,011	20.9
2.10	1,032	903	1,161	25.0	934	1,137	19.6
2.30	1,160	1,015	1,305	25.0	1,055	1,275	18.9
2.50	1,300	1,138	1,463	25.0	1,185	1,435	19.2

There are two other operational rules that are not written, but have been agreed upon by Reclamation and Western for near-term system operations. These include up- and down-ramp rate limits of 800 cfs per hour and a daily one-hump restriction.

The hourly ramp rate restriction limits the change in water release rates from one hour to the next. For example, if the water release from Flaming Gorge is 2,400 cfs at noon, then releases at 1 PM must remain within a band that ranges from 1,600 to 3,200 cfs. From the beginning of 1992 through April 8, 2001, the 800-cfs ramp rate restriction has been violated less than 1% of the time based on HourlyReleaseInspection.xls file. Figure 3.5 shows the ramp rate exceedance curve for 1996, a typical ramping year.

As agreed upon by the two institutions for near-term operations, releases are currently limited to a single "hump" per day. When restricted to a single daily hump, dam releases are permitted to change the ramp direction only twice per day—once in the up direction and once in the down direction. Flat flow periods in between the up and down ramp rate phases are allowed. This includes periods when flows are constant or continuously ramp either up or down throughout a day. Releases typically ramp up from a low rate at night to a higher one during the daytime and then back down to a lower release rate during the following night. After March of 1993 through the present, the single hump restriction has been part of the Flaming Gorge operational regime. However, there were situations in the past when very minor zigzag patterns of increasing and decreasing flows were embedded into a larger single-hump pattern. Figure 3.6 shows an example of 1 day when this zigzag pattern occurred. The one-hump restriction reduces the economic value of the hydropower resources and does not allow plant operators to send pulses of water down the Green River to meet gauge constraints.

4. POWER SYSTEM MODELING

One objective of this study is to simulate operations at the Flaming Gorge Dam such that it maximizes the value of the hydropower resource while complying with both operational limitations and flow constraints at the Jensen Gauge. Several models are used to perform these simulations. Some models simulate the hydrology of the Green River and others are used to optimize the hourly operations of the hydropower resource. The set of modeling tools that were selected to perform these tasks was integrated into a modeling system referred to as the Flaming Gorge Power Modeling Package. Model integration, as depicted in figure 4.1, enables data and information to be exchanged among package components.

4.1 Green River Model

The Green River model provides long-term simulations of the Flaming Gorge Dam. It was written by Reclamation to simulate reservoir operations on the Green River and the requirements specified under FGEIS alternatives. The model is based on the same philosophy and principles as the RiverWare modeling software and its predecessor, the Colorado River Simulation System (CRSS). RiverWare and CRSS have been used by Reclamation for numerous long-term policy studies including the Glen Canyon Dam EIS and the Power Marketing (***EIS Salt Lake City Area Integrated Projects Electric Power Marketing Final Environmental Impact Statement U.S. DOE Western Area Power Administration Jan 1996)***. The Green River model projects the operations of Flaming Gorge including monthly and daily water release volumes from the dam. It also predicts reservoir elevations and volumes on a monthly basis.

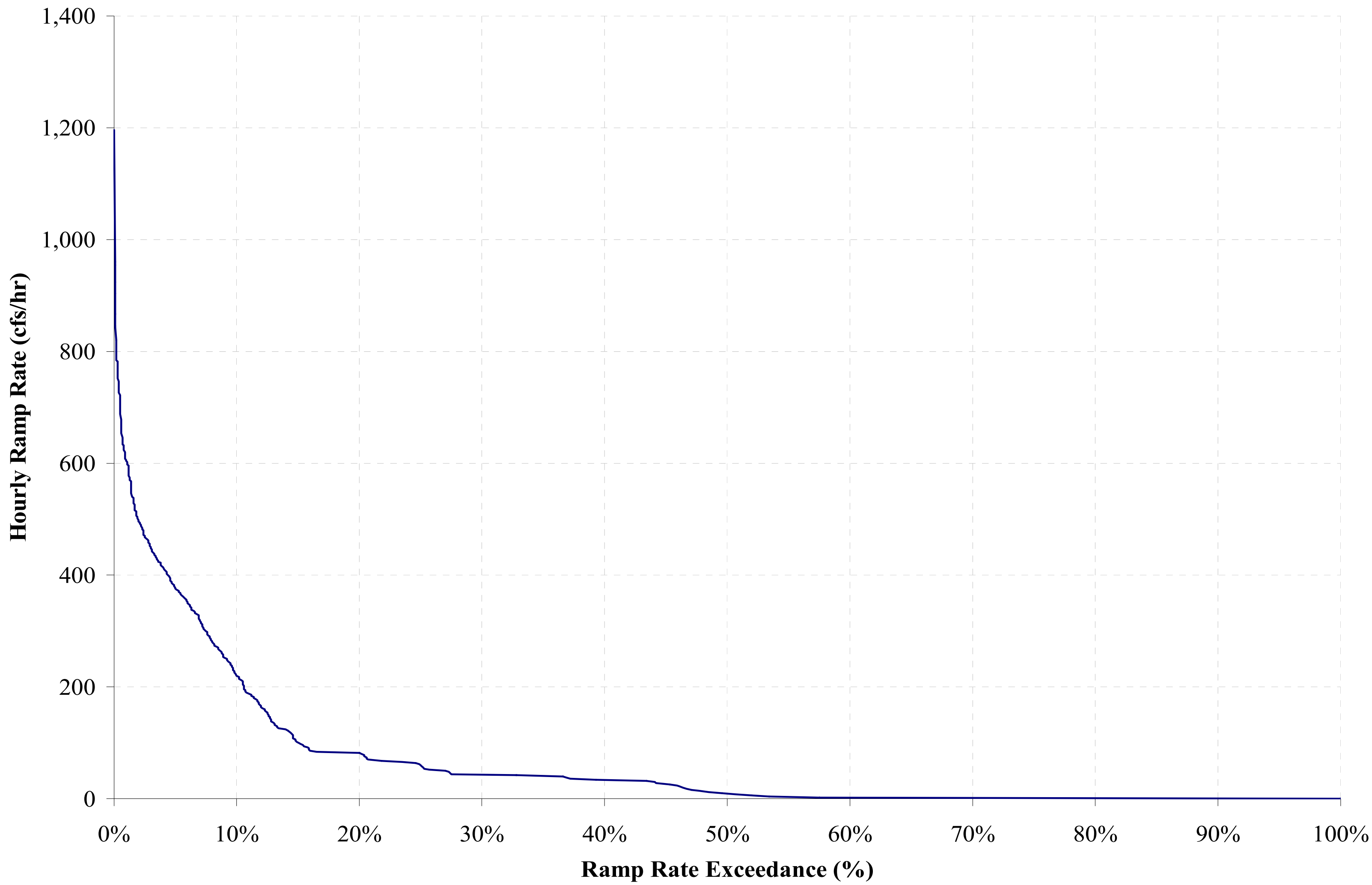

Figure 3.5. Ramp Rate Exceedance Curve for 1996.

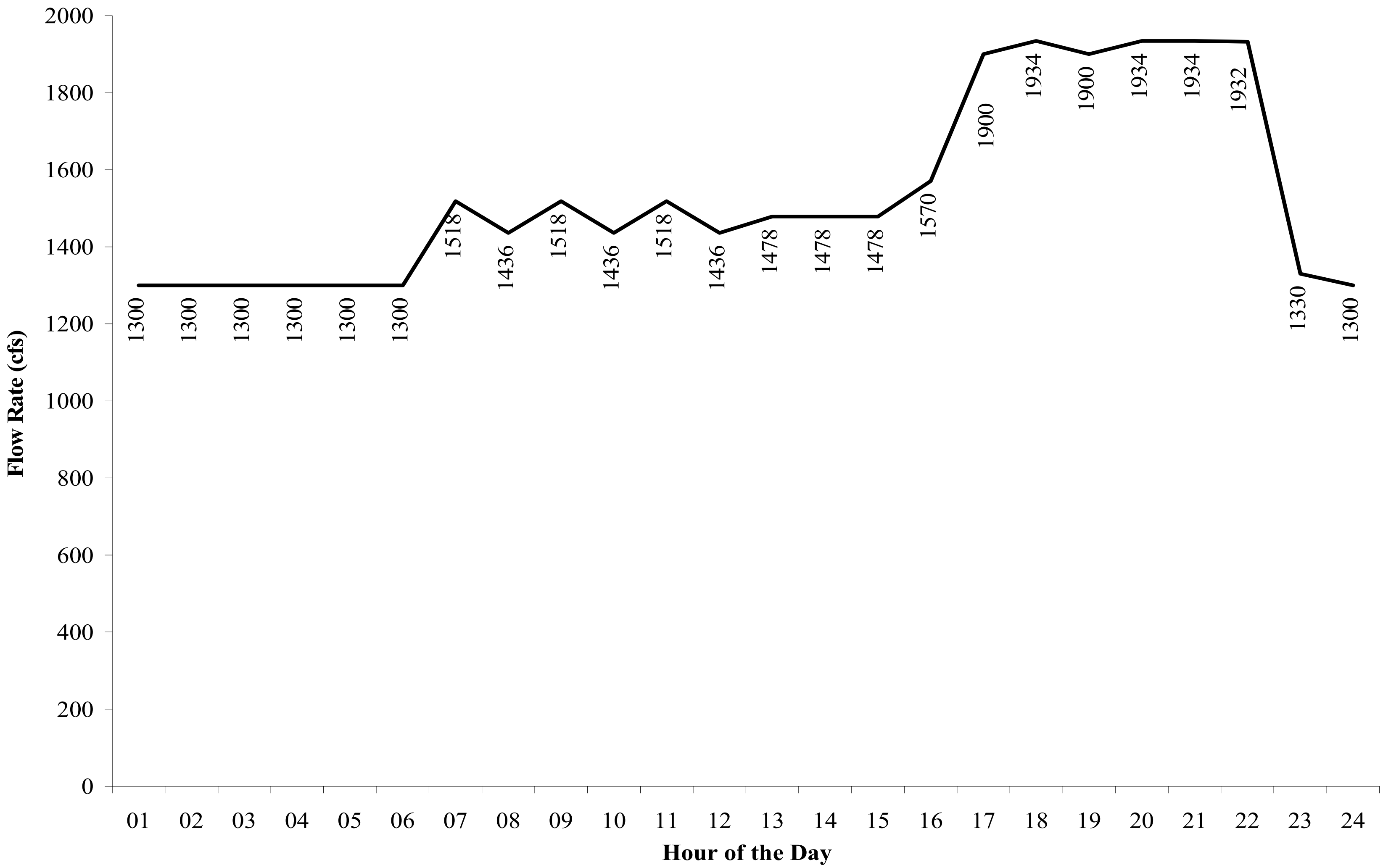

Figure 3.6. Minor Violation of Single Daily Hump Agreement on August 16, 1996.

The Green River model contains a database of historical inflows. Since future inflows beyond the near future (i.e., 2 to 6 months) are largely unpredictable, these historic inflows are used to predict numerous possible outcomes. The hydrologic inflows from 1921 through 1985 were adjusted for upstream regulation, projected consumptive uses, and losses at inflow points in the basin. The first year that Yampa data were collected is 1921, marking the beginning of the historical sequence, and 1985 is the last year that reliable and consistent data were compiled.

The Green River model simulated Flaming Gorge for the period from January 2002 through December 2040 using the state of the reservoir at the end of December 2001 as the initial condition. To assess future hydrologic uncertainty, the model was run in an "index sequential mode." In this mode, the model is run multiple times, where each run is based on a different hydrologic trace extracted from the historic record (***Labadie, et al., 1990)***. The first trace uses the adjusted historic sequence in which 1921 hydrology is assumed to occur in 2002 and hydrology for 1922 is used to represent 2003. These hydrology assignments continue sequentially through 2040 in which it is assumed that 1960 hydrology will be repeated. The second trace is similar to the first except that historic hydrology assignment begins with 1922 data instead of 1921. Therefore, 2002 is assigned 1922 hydrology data and 2003 is assigned 1923 data.

Using the index sequential method, a total of 65 possible monthly and daily futures were projected for each alternative. It is assumed that any one of these historical inflow sequences may be repeated in the future and that each trace has an identical probability of occurrence in the future.

Since the Green River model contains a database with known inflow traces (i.e., it contains a perfect forecast of the future), it would be unrealistic to use that information to simulate Flaming Gorge Dam operations. Therefore, forecast errors are computed and subtracted from the perfect inflow forecast to produce a more realistic simulation of the future. In the model, dam operators make decisions based on the imperfect forecast, but the unadjusted inflows (i.e., inflows with no errors) occur. Errors resulting from imperfect forecasts propagate to subsequent months since it is assumed that each month's forecast error is correlated to the previous month's error. Reclamation staff developed equation 4.1, a hydrology forecast error equation.

$$E_i = a_i x_i + b_i E_{(i-1)} + c_i + z_r d_I \qquad (4.1)$$

where

- E_i = the error in the forecast for the current month in million acre-feet;
- $E_{(i-1)}$ = the forecast error for the previous month;
- x_i = the natural inflow into the Flaming Gorge Reservoir for the current month through July;
- z_r = a randomly determined mean deviation taken from a normal distribution; and
- d_i = the standard error of the estimate for the regression equation.

The regression coefficients a_i, b_i, and c_i are based on a multiple linear regression analysis of actual inflows and forecasted values over the 1965 to 1999 time period.

The Green River model operates the system using the forecast trace and a set of system operator rule sets. The rules that are input into the model are consistent with the restrictions specified by a FGEIS alternative. Errors associated with the forecast incorporate uncertainty into the model and help to facilitate the simulation of operator decisions with inflow uncertainty. Based on the forecast, the Green

River model simulates operations at the Flaming Gorge Dam such that it will usually comply with alternative specifications. However, forecasted flows do not always come to fruition and the model will at times violate one or more FGEIS alternative flow requirements; that is, there is some probability that there will be a flow violation at the Jensen Gauge.

It is impractical from a computational standpoint to perform detailed economic analyses for all 65 possible hydrologic traces; therefore, Reclamation staff selected the 37th hydrological trace (i.e., run 36) as a representative sequence of future inflows. This trace was selected since inflow volumes for the first 20 years is the closest to the mean inflow volume of all 65 traces. The trace is used in this analysis to simulate powerplant operations and to estimate the economic benefits associated with the alternatives.

4.2 SSARR Model

The Streamflow Synthesis and Reservoir Regulation (SSARR) model is a numeric model of the hydrology of a river basin system SSARR User Manual. It was initially developed by the U.S. Army Corps of Engineers North Pacific Division to assist hydrological systems analysts for the planning, design, and operation of water control works. The SSARR model was further developed for operational river forecasting and river management activities in connection with the Cooperative Columbia River Forecasting unit, sponsored by the National Weather Service, U.S. Corps of Engineers, and the Bonneville Power Administration. Numerous river systems in the U.S. and abroad have been modeled with SSARR by various agencies, organizations, and universities.

SSARR is comprised of a generalized watershed model and a stream flow and reservoir regulation model. The watershed model simulates rainfall-runoff, snow accumulation, and snowmelt-runoff. Algorithms are included for modeling snow pack cold content, liquid water content, and seasonal conditioning for melt. Interception, evapotranspiration, soil moisture, base flow infiltration, and routing of runoff into system streams are accounted for. The river system and reservoir regulation model routes stream flows from upstream to downstream points through channel and lake storage, and reservoirs under free flow or controlled-flow modes of operation.

The basic routing method used in the watershed and river models is a “cascade of reservoirs” technique, wherein the lag and attenuation of the flood wave is simulated through successive increments of lake-type storage. A channel is represented as a series of small “lakes” that represent the natural delay of runoff from upstream to downstream points.

In this analysis, SSARR is used to forecast the hourly flows at the Jensen Gauge. SSARR is given both hourly Flaming Gorge water releases as determined by the Generation Optimization (GenOpt) model and Yampa inflow data from the Green River model. Upon completion of a SSARR simulation, the resulting gauge flows are examined to determine if Flaming Gorge water releases will result in a violation at the Jensen Gauge. If any violation is found, then the GenOpt model is run again with a revised set of input data. This process is repeated until an acceptable solution is found.

4.3 AURORA Model

Electricity generated from the Flaming Gorge powerplant is injected into the power grid to serve system loads. Since utility systems are connected via transmission lines, the value of this energy is a function of system dynamics and constraints over a large geographical area; that is, the Western Systems Coordinating Council (WSCC) region. The economic value of Flaming Gorge energy is set equal to the spot price of energy times the quantity of electricity injected into the grid.

Projections of future spot prices for this analysis are based on AURORA model simulations. This model has been used in the past to simulate the WSCC region for the Bonneville Power Administration (BPA). AURORA uses fundamentals of competitive markets to forecast hourly electric prices (***http://www.epis.com/products/AURORA/aurora.htm)***. The pricing structure used by AURORA satisfies the requirements of both supply and customer demand in a dynamically changing competitive energy market. In AURORA, the hourly pricing of energy is determined by the economic dispatch of regional resources to meet regional energy requirements. The model incorporates hourly information on demand, supply, fuel costs, transmission costs, and availability. The hourly dispatch of resources is based on the lowest cost resource available to meet customer demand. The energy price at any time is the cost of the last resource that is dispatched into each market area. Spot prices vary among market areas and energy delivery points to reflect regional production costs, transportation costs, and transmission line constraints. Price projections also reflect numerous assumptions concerning the future such as delivered utility fuel prices, electricity demand growth rates, changes in hourly electricity consumption patterns, and advancements in generation technologies.

Since AURORA model simulations span many years, additional capacity must be constructed in the future to meet the growing demand for electricity. The model projects a capacity expansion path based on an open utility market structure. Spot prices reflect these new capacity additions and their impact on the market.

Flaming Gorge energy injections into the grid are very small compared to total WSCC loads. Therefore, it is assumed that power injections into the grid for both alternatives will not change regional electricity prices.

4.4 GENOPT Model

The GenOpt model optimizes the economic value of electricity generated at Flaming Gorge while complying with all powerplant operational constraints. The model uses the same approach as the Generation and Transmission Maximization (GTMax) model that was used for a number of studies conducted by Western and Argonne to evaluate the economic value of power resources in the CRSP system. GenOpt was constructed to customize the mathematical formulation of the problem for the purposes of the FGEIS. Also, the customization streamlined the modeling process and significantly decreased simulation runtime.

The Flaming Gorge powerplant in GenOpt is modeled as a single generating entity. Under this representation, the three units at the plant turn on and off as many times as necessary during a simulated period in order to maximize the economic value of the hydropower resource. This may entail turning a turbine on and off several times in a single day.

The model's objective function, shown in equation 4.2, is to maximize the value of water releases from the Flaming Gorge Dam. The value of the plant power is maximized when the plant's limited water potential is used to generate energy when market prices are the highest.

$$\text{Max} \sum_{h} Gen_h \times SP_h, \tag{4.2}$$

where

Gen_h = Generation in Mega-watt hours (MWh) during hour h; and

SP_h = spot market price ($/MWh) during hour h.

The spot price of electricity, SP_h, in the above equation is a model input and for this study is based on AURORA model projections.

Water that is released through the turbines is converted to electricity and sold to the market. As shown in equation 4.3, the amount of water and associated generation is based on block-level conversion factors. These conversion factors are a function of both the reservoir elevation level and the designation of powerplant block.

$$TR_h = \sum_b BGEN_{b,h} / CF_{b,e}, \quad \text{where} \tag{4.3}$$

TR_h = turbine water release (cfs) during hour h, for power block b;

$BGEN_{b,h}$ = generation from powerplant block b during hour h; and

$CF_{b,e}$ = power conversion factor (MWh/cfs) for powerplant generating block b at reservoir elevation e.

Each generation block has a defined limit that is specified in equation 4.4. The block limits are a function of several factors such as reservoir elevation level, maximum turbine flow rates, and turbine efficiencies. These limits and associated power conversion factors are input into the model. The procedure used to determine values for these parameters is described in section 5.

$$BGEN_{b,h} \le BLOCKMAX_{b,e}, \tag{4.4}$$

where

$BLOCKMAX_{b,e}$ = maximum power output (MW) for block b.

Except for the second block, all other blocks in GenOpt must have a lower conversion factor than the one loaded before it; for example, block 3 must be more efficient than block 4. As discussed in section 5.1, this simplifying assumption may result in minor errors when estimating powerplant output levels; that is, errors are less than 3 MW.

Blocks and associated conversion factors are defined such that the first block is the amount of power that is generated at the minimum mandatory release rate. As specified in equation 4.5, the minimum average hourly release for all hours is 800 cfs. This minimum release rate applies to both alternatives.

$$800 = BGEN_{1,h} / CF_{1,e} \tag{4.5}$$

Electricity that is sold at spot market prices in equation 4.1 is computed by summing up the generation levels for all blocks as shown in equation 4.6.

$$GEN_h = \sum_b BGEN_{b,h}, \tag{4.6}$$

As formulated in equation 4.7, total dam water releases are a function of both turbine and non-turbine releases. Under certain wet hydrological conditions and spike flows it may be necessary to release some water through the dam's bypass tubes and spillways. Typically, the GenOpt model will only spill water when the powerplant is generating at its maximum capability during all hours of a simulated period or as required to simulate a spring spike. Note that non-power water releases are not associated with generation in equation 4.3 and therefore do not increase the objective function value given in equation 4.2.

$$DR_h = TR_h + NTR_h, \tag{4.7}$$

where

DR_h = water release (cfs) from the Flaming Gorge Dam in hour *h*; and

NTR_h = non-turbine water release (cfs) from Flaming Gorge through bypass tubes and spillways in hour *h*.

The average water release rate during a day is computed by equation 4.8. It equals the sum of all hourly releases in a day divided by 24 hours.

$$ADR_d = \sum_{h=1,24} DR_h / 24, \tag{4.8}$$

where

*ADR*d = average daily water release (cfs) from the Flaming Gorge powerplant during day *d*.

Maximizing the economic value of water releases is subject to powerplant operational constraints. One such constraining factor limits the amount of water that can be released during a specific time period. For the No Action and Action Alternatives during a spike release period, the average daily flow must equal the amount that is specified by the Green River model. This restriction also applies to both alternatives (refer to table 3.1). It is represented in the model by equation 4.9. To maximize the value of the hydropower resource, the GenOpt model releases as much water as possible through turbines when spot market prices are the highest. During low priced periods water releases are at a minimum.

$$ADR_d = GRDR_d, \tag{4.9}$$

where

$GRDR_d$ = average daily Flaming Gorge water release (cfs) from Green River model.

As shown in equation 4.10 water releases in GenOpt over a multiple-day period must equal the total amount that is specified by Green River model simulations. Typically this multi-day period equals one week.

$$\sum_d ADR_d = \sum_d GRDR_d \tag{4.10}$$

Equations 4.11 and 4.12 restrict the change in hourly water releases from the dam. Water releases from one hour to the next for both increasing levels and decreasing levels cannot differ by more than 800 cfs. The GenOpt model starts multi-hour ramping periods such that it can obtain maximum generation levels when prices are the highest and relatively low generation when electricity prices are inexpensive.

$$DR_h - DR_{h+1} \le 800 \tag{4.11}$$

$$DR_{h+1} - DR_h \le 800 \tag{4.12}$$

The single daily hump restriction is assured by equations 4.13 and 4.14. It is assumed that the lowest release rate (i.e., generation level) of the day will occur during hour, *h*, that has the lowest spot price; that is the minimum daily $SP_{h.}$ On the other hand, release rates are the fastest during the hour of the day with the highest spot prices.

$$DR_{h-1} - DR_h \geq 0 \tag{4.13}$$

for hours, *h*, of the day that are from midnight to the hour with the lowest daily spot price, SP_h, and also for hours of the day from the highest spot price until the last hour of the day.

$$DR_h - DR_{h-1} \geq 0 \tag{4.14}$$

for hours, *h*, of the day that are from the hour with the lowest daily spot price to the hour with the highest spot price.

GenOpt also includes equation 4.15 that relates Flaming Gorge releases and Yampa inflows to flows at the Jensen Gauge. These flows are calculated only when there are gauge constraints as specified in tables 3.1 and 3.2.

$$JF_h = AYF_m + \sum_{p=\min l, \max l} \mathrm{DR}_{h-p} \mathrm{WLF}_p, \tag{4.15}$$

where

JF_h	= GenOpt estimate of stream flow (cfs) at the Jensen Gauge in hour *h*;
AYF_h	= average inflows from the Yampa (cfs) during month *m*;
WLF_p	= fraction of Flaming Gorge water that reaches the Jensen Gauge *p* hours after it has been released from the dam;
minl	= the minimum time, in hours, that a Flaming Gorge water release takes to travel to the Jensen Gauge; and
maxl	= the maximum time, in hours, that a Flaming Gorge water release takes to travel to the Jensen Gauge.

The water lag factors, *WLF*, in equation 4.15 represent the relationship between water releases from the Flaming Gorge reservoir and water flows at the gauge. As a wave of water travels downstream from the Flaming Gorge Dam it attenuates or flattens out as it travels downstream. This attenuation becomes more pronounced the farther the wave travels downstream from the dam. Also, the farther downstream a given point (e.g., a gauge) is from the dam, the longer it takes for the wave of water to reach it. It usually takes a minimum of about 20 to 25 hours for a water release from Flaming Gorge to register at the Jensen Gauge.

Figure 4.2 shows a model run in which water releases are constant in all but the first hour of a SSARR simulated period. During the first hour a relatively high volume of water (i.e., wave of water) is released. The SSARR model projects that 24-hours (i.e., *minl*) after the pulse release from Flaming Gorge, water flows at the Jensen Gauge begin to increase above the base level. About 35 hours after the high volume release, the flow rate at the Jensen Gauge is at a peak and after 50 hours (*maxl*) water flow rates return to the base level.

A *WLF* relates the fractional amount of water from a Flaming Gorge release that will pass the Jensen Gauge in a one-hour time period and the time that it takes that portion of the water to travel to the gauge. As shown in figure 4.3, about 9.9 percent of the wave's water volume flows past the gauge during the 35th hour after the water was released from the dam. Hours both prior to and after the 35-hour lag time have smaller amounts of water that flow past the gauge.

The *WLF*s roughly form a bell-shaped distribution. Typically this distribution is skewed to the left toward shorter travel times. The sum of the water lag factors equals 1.0; that is, it is assumed that all of the water released from the Flaming Gorge Dam flows past the Jensen Gauge at some time in the future.

In addition to operational constraints at the dam, the GenOpt model also restricts Jensen Gauge flows. Equation 4.16 is used to compute the daily average flow at the gauge.

$$AJF_d = \sum_{h=1,24} JF_h / 24, \tag{4.16}$$

where

AJF_d = average daily flow rate (cfs) at the Jensen Gauge.

For the No Action Alternative all daily average flows at the gauge are constant from one day to the next over a multi-day period; that is, a month period or from the end of the spike period through the end of the month. Equation 4.17 ensures that daily average flows passing the gauge are identical.

$$AJF_d - AJF_{d+1} = 0 \tag{4.17}$$

Both the No Action and Action Alternatives also restrict gauge flows within a day. Equation 4.18 restricts the intra-day hourly flows.

$$AJF_d \times (1 - LGL_d) \leq JF_h \leq AJF_d \times (1 + UGL_d) \tag{4.18}$$

where

UGL_d = gauge upper flow limit (fraction) for day *d* (e.g., 0.125 for the No Action Alternative); and

LGL_d = gauge lower flow limit (fraction) for day *d* (e.g., 0.125 for the No Action Alternative).

As described in section 3.1, Jensen Gauge flows are limited to 12.5 percent of the daily average for the No Action Alternative. The lower and upper gauge limits for the Action Alternative are based on 0.1-meter stage change. The daily average flow rate along with the river stage plot shown in figure 3.3 are used to express the limits in terms of a fraction.

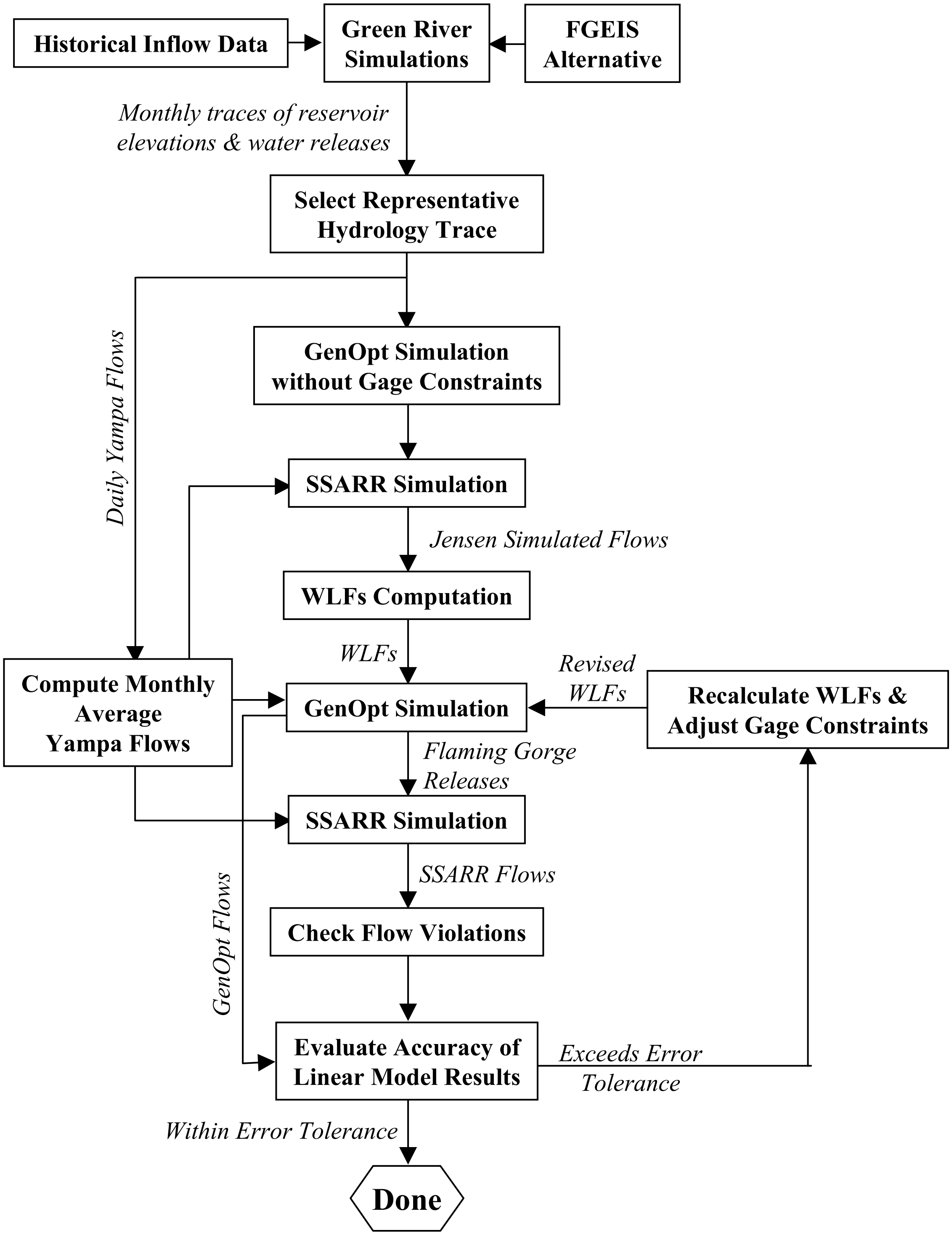

Figure 4.1. Overview of the Flaming Gorge Power Modeling Package.

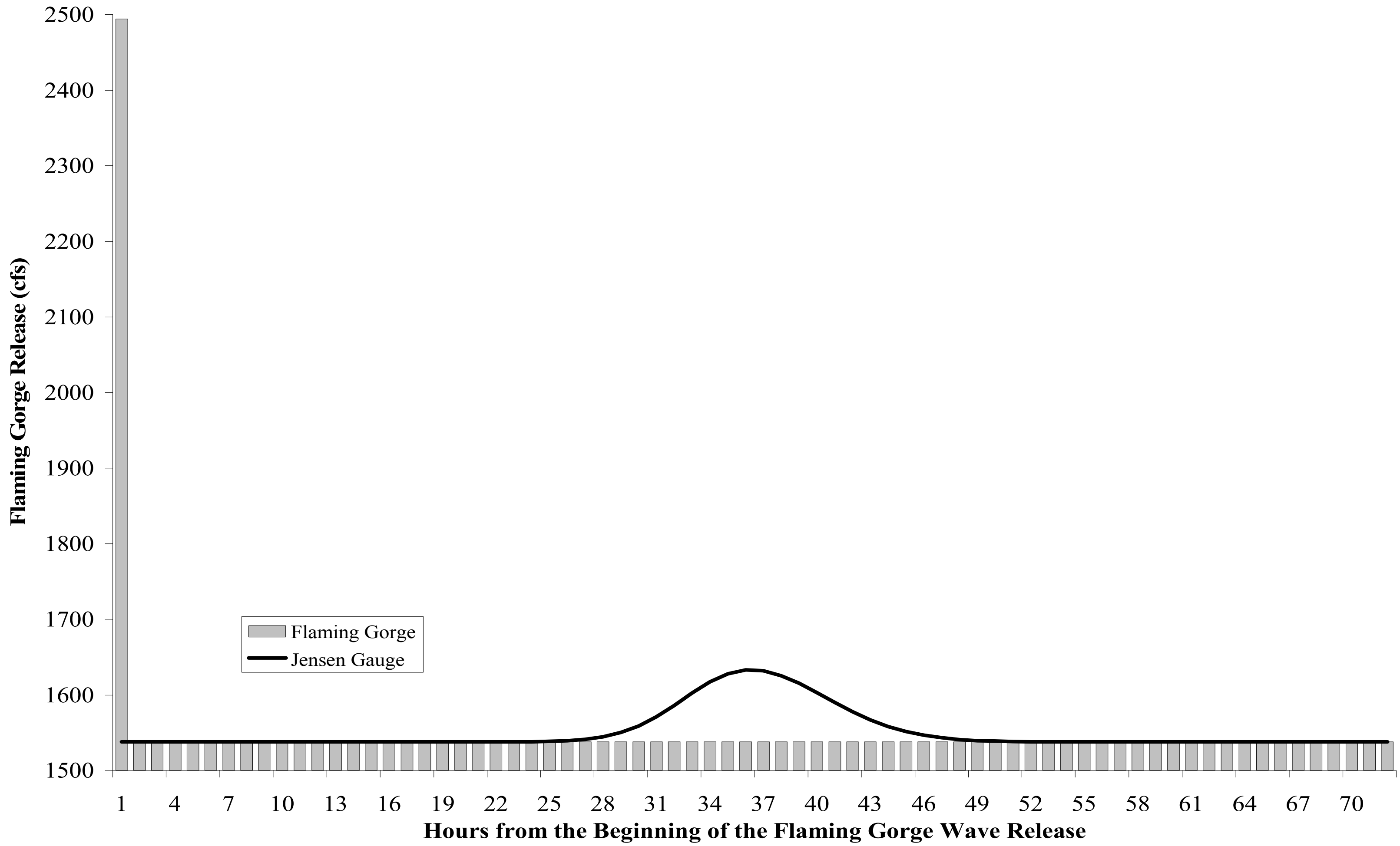

Figure 4.2. Travel Time for a Wave of Water Released From Flaming Gorge to the Jensen Gauge.

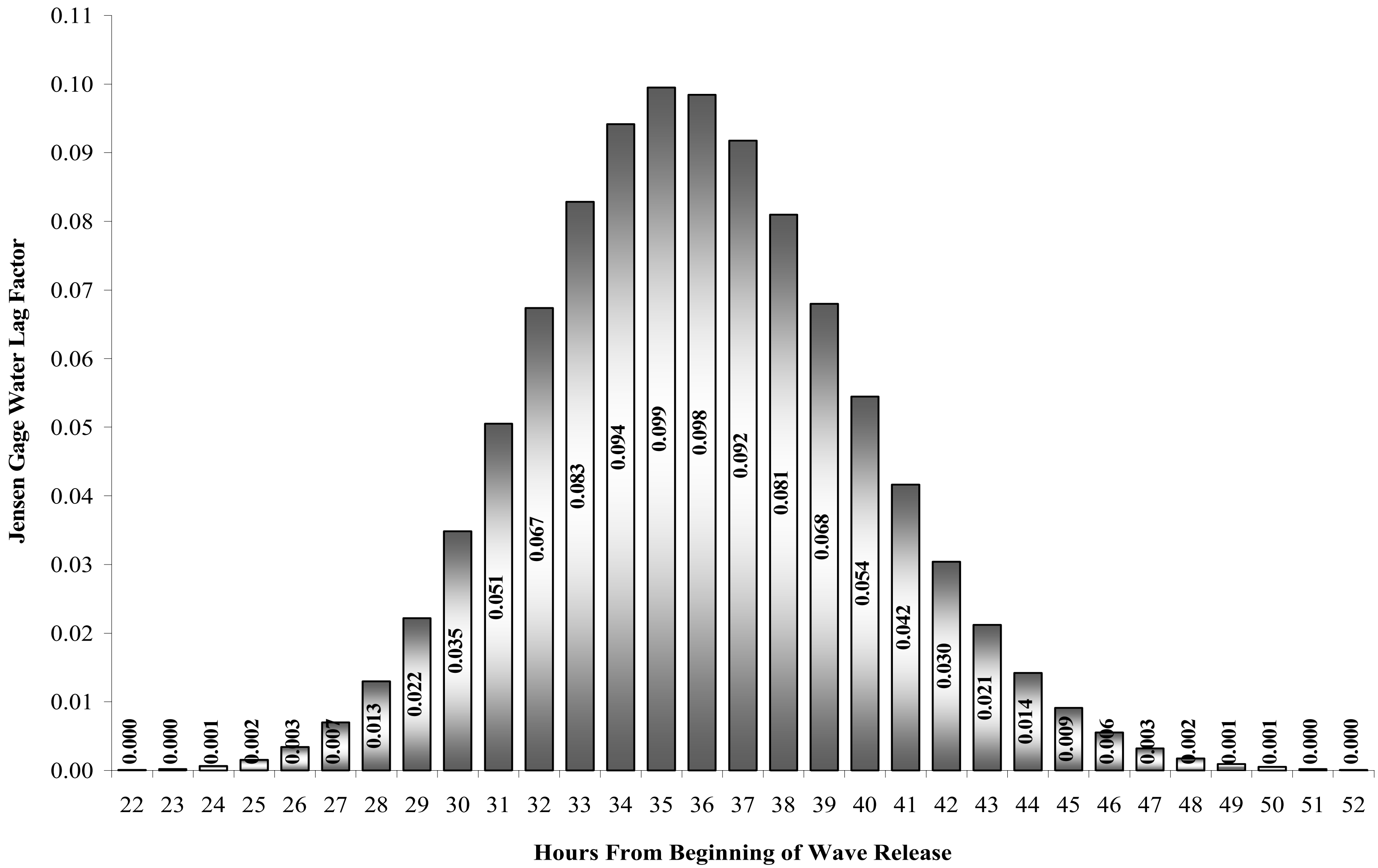

Figure 4.3. Water Release Lag Factors for Flaming Gorge Travel to the Jensen Gauge.

4.5 WL Algorithm

The Water Lag (WL) algorithm computes *WLF*s based on SSARR simulations of Green River flows at the Jensen Gauge. The objective of the model, shown in equation 4.19, is to compute a set of *WLF*s that minimizes gauge flow differences estimated by equation 4.15 and those estimated by SSARR.

$$\text{Min} \sum_h ABS(SJF_h - JF_h), \tag{4.19}$$

where

SJF_h = stream flow (cfs) at the Jensen Gauge estimated by SSARR.

The *WLF*s are based on a known set of water releases and Yampa inflows that are identical to the ones used as input into the SSARR model. The WL algorithm computes Jensen Gauge flows using equation 4.20. Both Yampa inflows and Flaming Gorge releases are known and the algorithm solves for *WLF*.

$$JF_h = AYF_M + \sum_{p=\min l, \max l} SDR_{h-p} WLF_p, \tag{4.20}$$

where

SDR_{h-p} = Flaming Gorge releases that are input into the SSARR model.

*WLF*s are subject to constraints provided in equations 4.21 and 4.22 that ensure that the shape of the *WLF*s follows a bell shaped curve as shown on figure 4.3. When the lag time, *p*, is less than the lag hour with the largest *WLF* (i.e., lag hour with the peak influence on the gauge), equation 4.21 requires that the *WLF* for the previous lag hour be less than the next lag hour. For example in figure 4.3, all *WLF*s for lags of 24 hours to 35 hours (i.e., hour with the largest value or 0.099) must be greater than or equal to the previous lag value.

$$WLF_{p+1} - WLF_p \geq 0 \tag{4.21}$$

For lag hours greater than the one with the largest *WLF*, equation 4.22 is used.

$$WLF_p - WLF_{p+1} \geq 0 \tag{4.22}$$

The lag time with the maximum *WLF* value is determined by running the SSARR model for numerous combinations of Flaming Gorge Dam releases and Yampa inflows. These runs were used to create the surface shown in figure 4.4. For example, when Yampa inflows are zero and 800 cfs is released from the Flaming Gorge Dam, the Jensen Gauge will have the highest *WLF* for lag hour 44.

As the release from Flaming Gorge increases from 800 cfs to approximately 3,500 cfs, the lag time to the maximum *WLF* (i.e., peak influence on the gauge) decreases from about 44 hours to about 28 hours. As

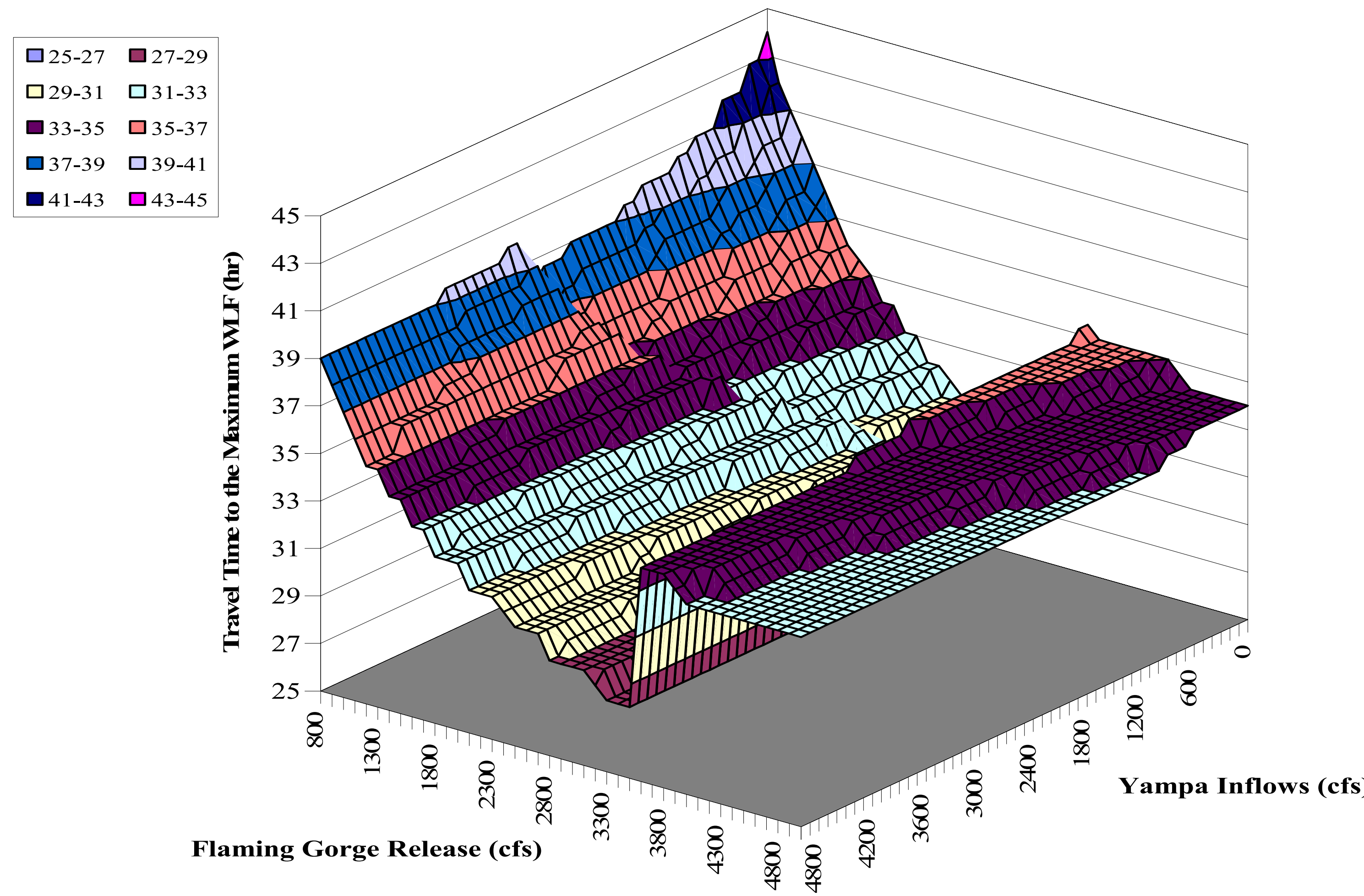

Figure 4.4. Travel Times for the Maximum WLF to Reach the Jensen Gauge as a Function of Flaming Gorge Releases and Yampa Inflows.

release rates increase beyond this level the lag time to the maximum *WLF* abruptly increases to about 35 hours. At higher release rates water spills out of the main river channel and the flow rate decreases. Flow rates above the 3,500 cfs level slowly shorten lag times.

Although less dramatic, a similar pattern is observed with Yampa inflows. Note in figure 4.4 for a Flaming Gorge release of 800 cfs that the lag time to the maximum *WLF* abruptly increases when Yampa inflows are greater than 2,500 cfs.

Based on Green River model results for Flaming Gorge daily releases and Yampa inflows, the lag time with the largest *WLF* value was approximated. This lag time and the ones surrounding it are separately run through the WL algorithm. The GenOpt model uses the set of *WLF*s that yields the smallest error.

4.6 Model Integration

The main advantages of using equation 4.15 in the GenOpt model are that the equation is based on SSARR simulations and that the mathematical problem can be quickly solved. Also, since the equation is linear it can be directly incorporated into the GenOpt model making it possible to simultaneously maximize the economic value of hourly reservoir operations while complying with downstream flow restrictions. However, the linear representation of Jensen Gauge flows is only an approximation of the complex behavior of Green River flows. Despite these shortcomings, the linear representation in GenOpt produces flow estimates that are very similar to the ones output from SSARR provided that *WLF*s are estimated for a specific hydrological condition.

The determination of *WLF*s in the WL algorithm poses a problem since it requires a set of known Flaming Gorge releases, Yampa inflows, and SSARR flow simulation results for the Jensen Gauge. The GenOpt model can approximate Flaming Gorge releases, but equation 4.15 requires an estimate of *WLF*s as input data. This is a classic "chicken-and-egg" problem. As shown in the flow chart on figure 4.1, an iterative method is used to solve it. First, an initial GenOpt model is run with the assumption that there are no gauge constraints. In this simulation, equation 4.15 and gauge constraint equations 4.16 through 4.18 are not considered.

Next, the SSARR model is run with GenOpt's initial estimates of Flaming Gorge releases. As shown in figure 4.5, this first SSARR simulation typically results in a gauge flow violation. Simulated flows for the No Action Alternative are about 200 cfs above the maximum limit and about 50 cfs below the minimum limit. Flaming Gorge water releases follow the spot market price trends with minimum releases at night when prices are the lowest and significantly higher releases during the day when prices peak. Daytime releases are almost 3.5 times higher than the minimum release rate.

Based on initial Flaming Gorge releases and SSARR results, the WL algorithm is then run to produce an initial set of *WLF*s. These *WLF*s are then input into GenOpt and the model optimizes Flaming Gorge releases such that both dam operational and Jensen Gauge constraints are not violated. The GenOpt model also estimates gauge flows. However, since the GenOpt gauge flow simulation is only a linear approximation, actual flows may violate gauge constraints based on the more detailed SSARR simulation. As shown in figure 4.6, gauge flows estimated by SSARR using the revised set of Flaming Gorge releases are about 30 to 40 cfs higher than the maximum limit during each day. Low flows, however, never violate the limit. Since the initial set of *WLF*s is based on Flaming Gorge releases without gauge constraints, the GenOpt model under- predicts peak gauge flows. However, compared to the initial simulation, gauge violations for the second GenOpt run are significantly smaller.

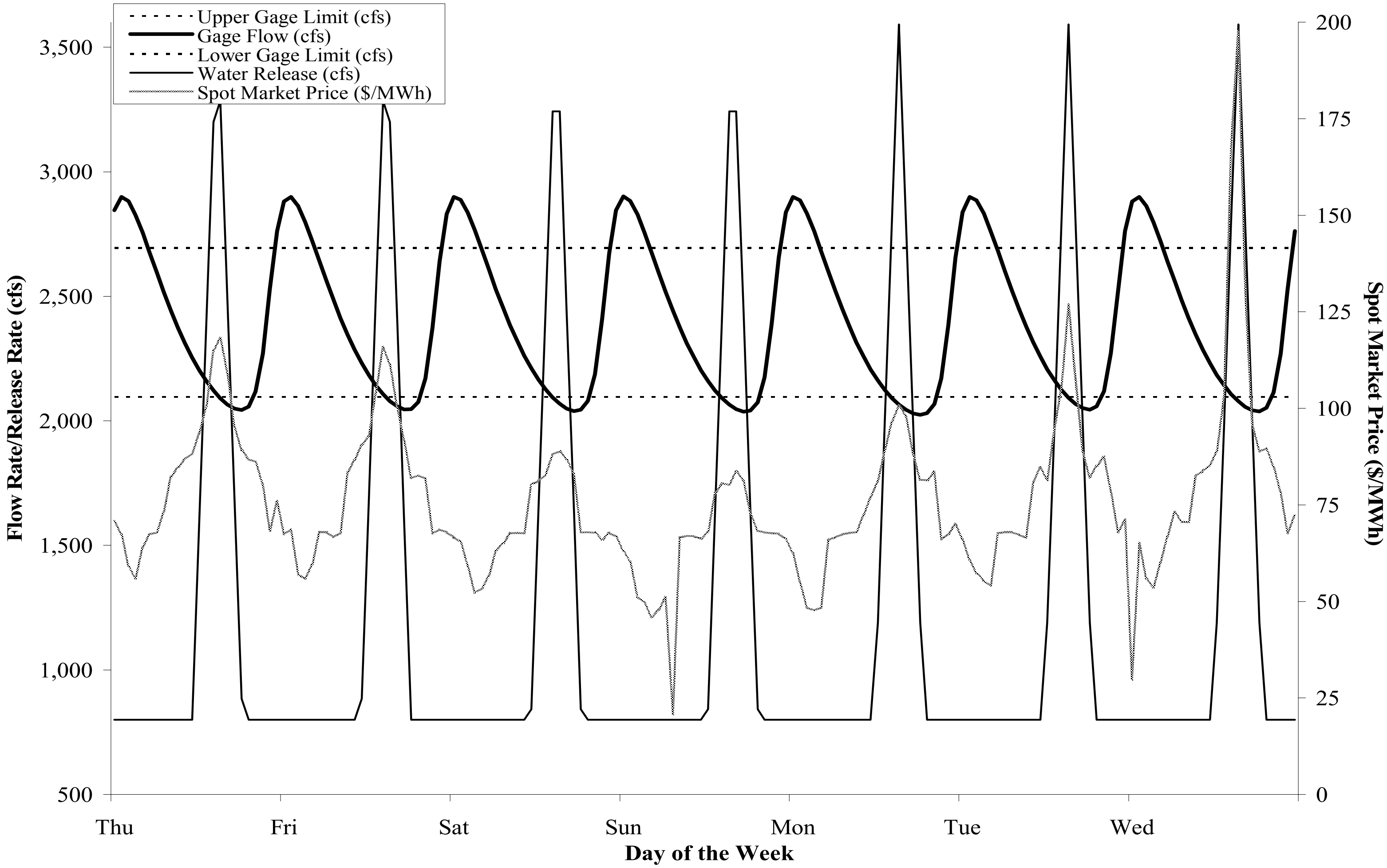

Figure 4.5. Flaming Gorge Releases and Simulated Jensen Gauge Flows Assuming No Gauge Constraints.

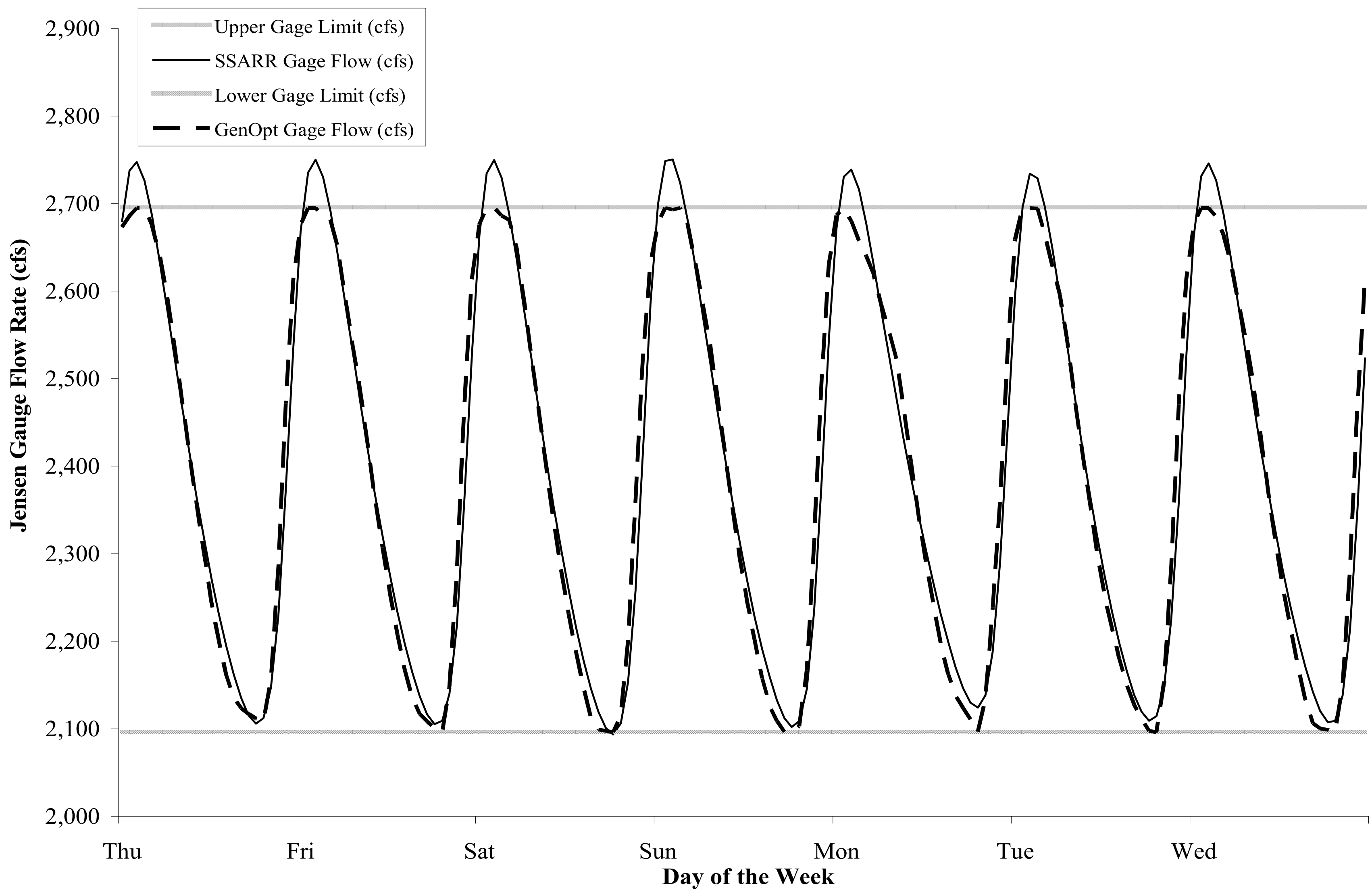

Figure 4.6. Comparison of Jensen Gauge Flow Estimated by the GenOpt and SSARR Models for the First Iteration.

Compared to the initial run without gauge constraints, peak releases from Flaming Gorge are lower; that is, from about 35,000 cfs to 29,000 cfs. As shown on figure 4.7, water releases during the peak hours were shifted to the less valuable shoulder hours. This shifting of water decreases peak Jensen Gauge flows and increases the lower flows.

The updated dam releases from GenOpt along with the new SSARR results are input into the WL algorithm to update estimates of *WLF*s. Since the *WLF*s are based on a set of Flaming Gorge releases that are closer to compliance than the initial set, the linear representation of Jensen Gauge flows improves.

The new *WLF*s are input into the GenOpt model and Flaming Gorge releases are recomputed. The SSARR model is also run again. Figure 4.8 shows that violations estimated by SSARR for the second iteration are very small; that is, about 5 to 25 cfs during peak flows. Also, compared to the first iteration, estimates of gauge flows by the GenOpt model are closer to SSARR simulations. As shown on figure 4.9, the lower violation level was the result of shifting more water from peak release periods to shoulder hours.

The process of sequentially running GenOpt, SSARR, and the WL algorithm continues in an iterative process until there are no gauge violations based on SSARR simulations. Figure 4.10 shows that results for the final iteration have no gauge violations as simulated by the SSARR model. Peak releases from Flaming Gorge are much lower than the initial run without gauge constraints and less water is released when it has the highest value.

Updating the *WLF*s via the iteration process may never achieve compliance in some situations since the linear representation produces results that do not always exactly match SSARR projections. In these situations a successive relaxation method is used to adjust the gauge limits input into GenOpt.

When compliance is not achieved after a user specified number of iterations, a gauge limit input into GenOpt is adjusted such that it is slightly more stringent than the one specified by an alternative. For example, if SSARR gauge flow simulations are over the limit by a maximum of 0.2 percent for the No Action Alternative, then the upper gauge flow limit input into GenOpt is lowered from 12.5 percent to 12.4 percent. That is, the gauge limit given to GenOpt is reduced by one-half of the violation level as expressed in equation 4.23 where the adjustment parameter, *UAP*, is set equal to 0.5.

$$AUGL_{i,d} = AUGL_{i-1,d} - (UAP_d \times UVL_d), \qquad (4.23)$$

where

$AUGL_d$ = adjusted gauge upper flow limit (fraction) for day d and iteration i, where $AUGL_{1,d}$ is set equal to UGL_d;

UAP_d = upper flow limit adjustment parameter (fraction) for day d and iteration i; and,

UVL_d = maximum violation above the upper flow limit in day d (fraction).

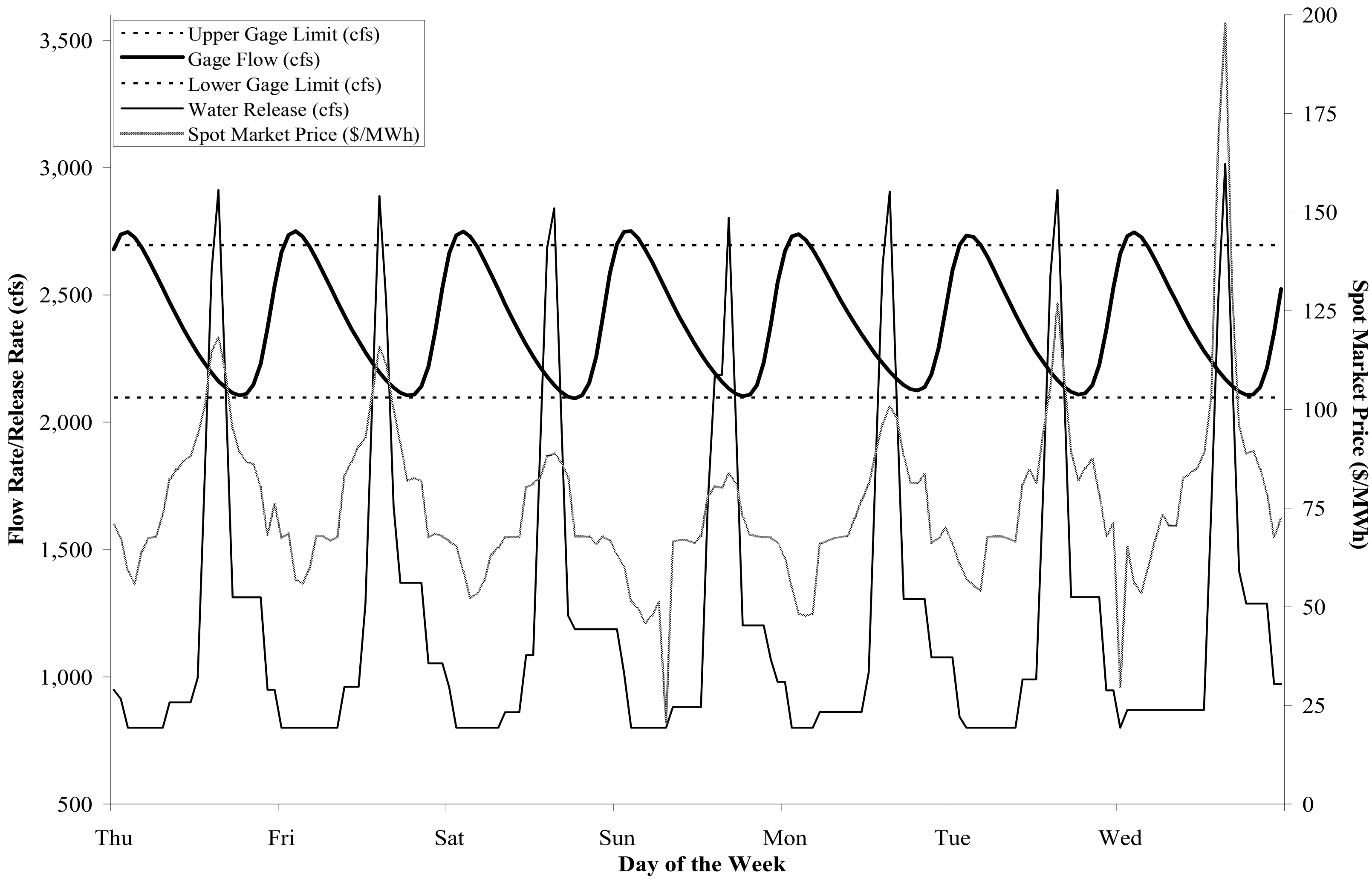

Figure 4.7. Flaming Gorge Releases and Simulated Jensen Gauge Flows for the First Iteration.

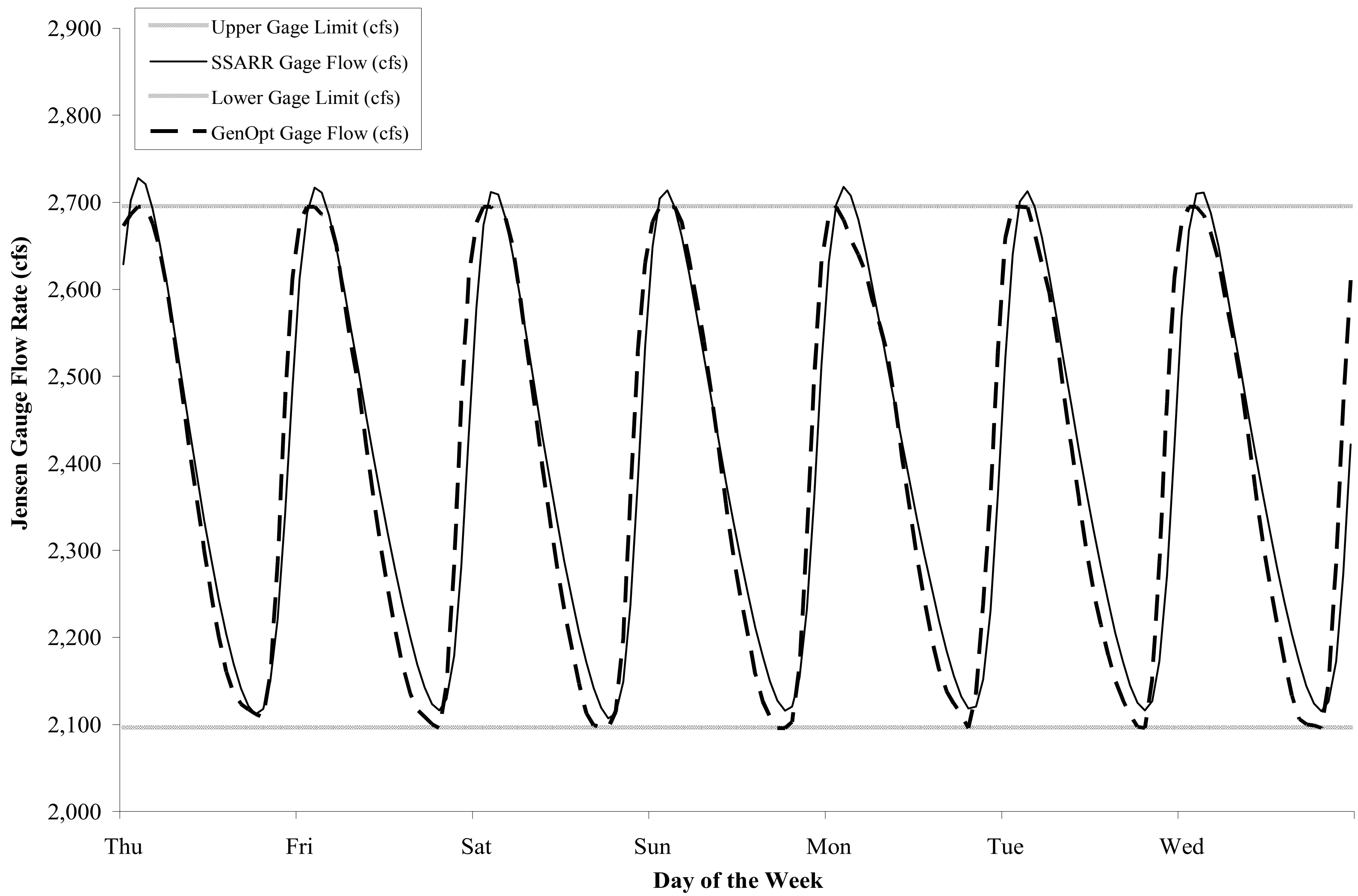

Figure 4.8. Comparison of Jensen Gauge Flow Estimated by the GenOpt and SSARR Models for the Second Iteration.

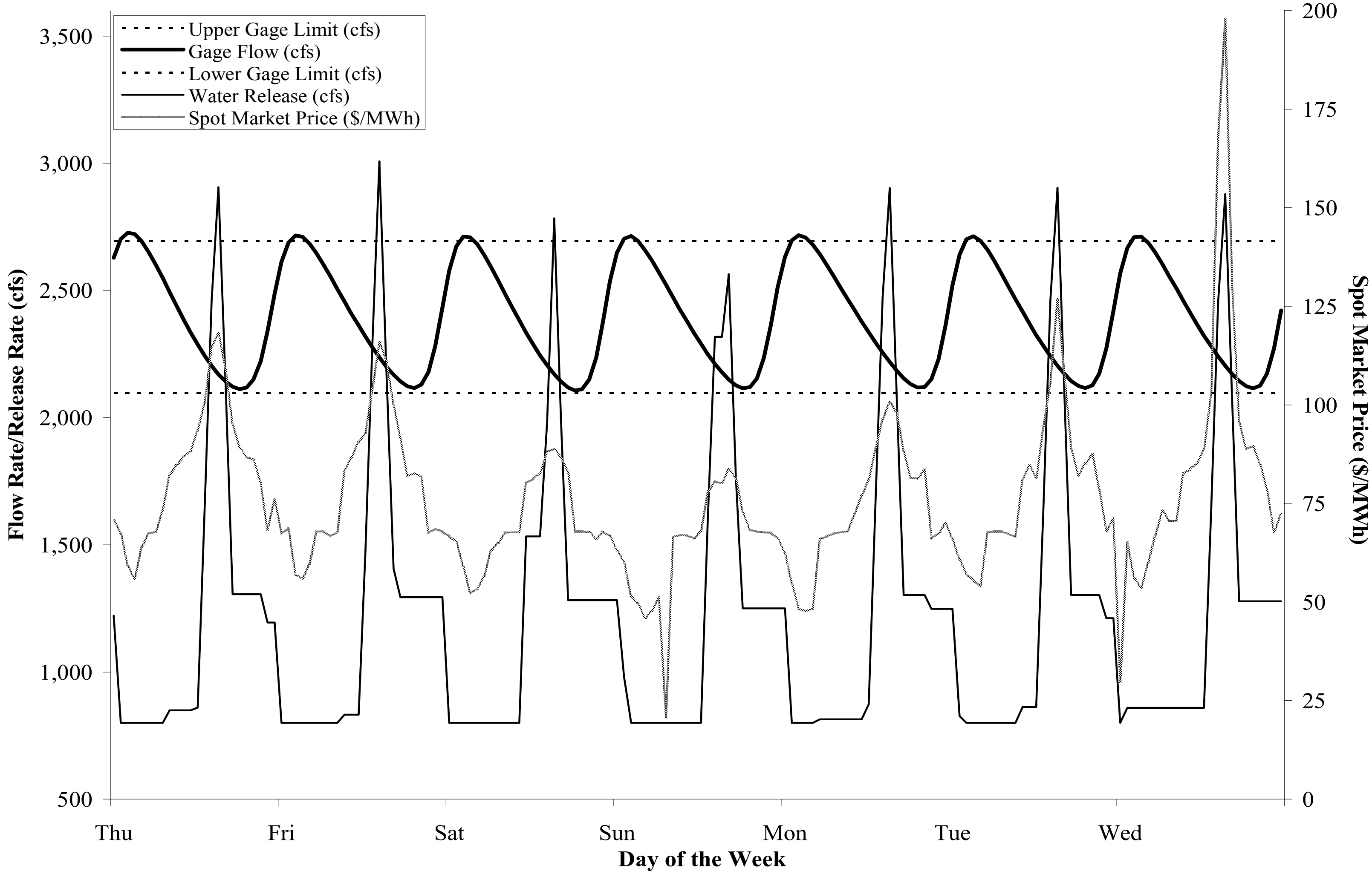

Figure 4.9. Flaming Gorge Releases and Simulated Jensen Gauge Flows for the Second Iteration.

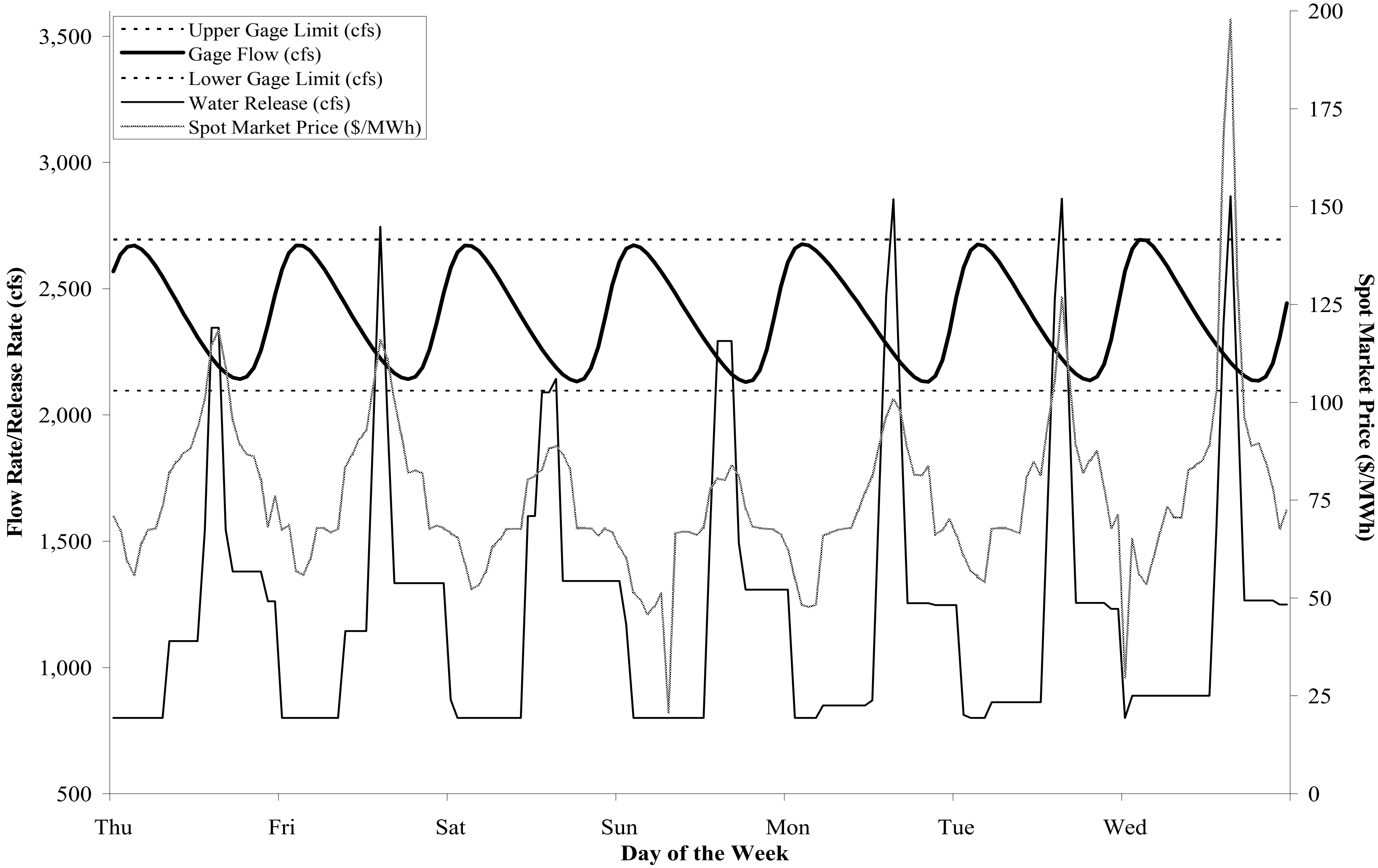

Figure 4.10. Flaming Gorge Releases and Simulated Jensen Gauge Flows for the Final Iteration.

The violation level, *VL*, can be either positive or negative. A positive value indicates a violation while a negative value indicates that the GenOpt model is over complying with gauge flow limits. Over compliance occurs when the difference between SSARR model simulated flow and the limit is greater than a user specified tolerance level and slack values for gauge constraint equations from GenOpt results are zero.

The adjustment parameter, *LAP*, changes or adapts among iterations. The number assigned to it is based on a set of rules that track the parameter's value relative to its previous assigned value and the number of directional changes (i.e., from + to – or vice-versa) of the violation, *LVL*, in all previous iterations. The rule set also places bounds on the adjustment parameter, *AP*, under various situations to ensure that the search space remains within a feasible region and to guide the convergence process.

Lower gauge limits are adjusted using a similar process in equation 4.24

$$ALGL_{i,d} = ALGL_{i-1,d} - (LAP_d \times LVL_d), \tag{4.24}$$

where

$ALGL_d$ = adjusted gauge upper flow limit (fraction) for day d and iteration i, where $ALGL_{1,d}$ is set equal to LGL_d;

LAP_d = upper flow limit adjustment parameter (fraction) for day d and iteration i; and,

LVL_d = maximum violation above the upper flow limit in day d (fraction).

This heuristic process does not guarantee an optimal result since the linear representation of Jensen Gauge flows is imperfect. However, it is well within the range of SSARR simulation error and future uncertainties such as spot market prices and hydrology forecasts. For the purposes of the FGEIS, the modeling process provides a good measure of the operational constraints that are required at Flaming Gorge to meet downstream flow requirements and the associated economic impacts on power systems.

4.7 Compatibility Issues and Boundary Conditions

GenOpt, SSARR, and WL algorithm runs are performed on a monthly basis whereby each month was assumed to be independent of the months that precede and follow it. This assumption was made since in some cases it is impossible to comply with Jensen Gauge constraints given the daily water releases from Flaming Gorge projected by the Green River model. In each of these cases, the compliance problem was due to an abrupt increase or decrease in daily releases between two consecutive days that were in two different months; for example, June 30, 2003 and July 1, 2003. Similarly, Green River model results also contained cases with abrupt Yampa inflow changes. These abrupt inflow changes between months also created gauge compliance problems.

By treating each month as an independent model run, the boundary problem between two successive months was alleviated. Other boundary conditions stemming from the long lag time between Flaming Gorge water releases and Jensen Gauge flows were also addressed. When these boundary conditions are not considered, Flaming Gorge releases at the beginning of a simulated month do not recognize water releases from the dam that occurred prior to the simulation month. These prior releases will affect gauge flows in the current period. Likewise, releases at the end of the month will affect gauge flows in the next month.

To deal with this boundary condition, monthly simulations were extended by 2 days. Yampa inflows and Flaming Gorge releases for the last day of the month were assumed to continue throughout the 2-day extension period. However, spot market price projected for the 2 days following the current simulation month were used. This assumption preserves weekly spot price patterns and resultant generation patterns. Conceptually the boundary condition at the beginning of a simulation month is treated in a similar manner except that the model includes a 2-day period prior to the current simulation month. These 2 days are assumed to have characteristics that are identical to the last 2 days of the first week in the month. GenOpt model results are only considered for the simulated month; that is, extension period results are not used.

Non-compliance problems also occurred in the modeling of Flaming Gorge releases when Yampa inflows change rapidly over a short time period. Therefore, the Yampa flows input into the model are based on monthly averages. This assumption is compatible with FGEIS alternatives that do not require Flaming Gorge operations to compensate for unpredictable Yampa inflows.

Another issue that arose during the modeling process involved Green River inflow forecast errors. Jensen Gauge flow constraints that specify a daily minimum and maximum level shown in tables 3.1 and 3.2 were not input into the GenOpt model for either alternative. Projected daily releases from the Green River model did not always comply with this requirement. Since the Green River model includes an inflow-forecast error, non-compliance events will occur. In most of these cases it is impossible for the GenOpt model to allocate a daily water release volume among hours of the day such that there are no violations at the Jensen Gauge.

5. FLAMING GORGE POWERPLANT CHARACTERISTICS

This section describes the methods that were used to estimate GenOpt input values for the Flaming Gorge powerplant. These characteristics are used by GenOpt to estimate the powerplant's generation capability and power conversion factors. As described in detail below, the powerplant's maximum generation level and conversion of turbine water releases (i.e., kinetic energy) to electricity are dynamic and change as a function of both reservoir elevation level and powerplant operations.

5.1 Powerplant Capacity and Capability

The Flaming Gorge Powerplant has three generating units each with an installed capacity of 50.65 MW for a total of 151.95 MW (***Form PO&M-59)***. However, due to turbine limitations the operable capability of the powerplant is approximately 141 MW; that is 47.0 MW per turbine **(*Larry Andersen, Email sent on 7/10/2002).*** Figure 5.1 shows the installed capacity and maximum recorded generation in a month as reported in PO&M 59. Prior to unit rewinds that began in March 1991, the powerplant's maximum generation level routinely exceeded the installed capacity. At that time, the powerplant was able to operate with overload factors of 25 percent without adversely affecting the turbines or generators. Once rewinds were completed in April 1992, maximum hourly generation levels did not increase significantly.

The capability of the powerplant is not only a function of the installed capacity and turbine limits, but also of several other factors. Some of these include:

(1) number of turbines in operation,
(2) turbine efficiency level,
(3) turbine overload capability,
(4) the maximum turbine flow rate,
(5) plant's power factor,

(6) reservoir elevation level, and
(7) tail water elevation.

This analysis uses equation 5.1 to estimate the capability of the Flaming Gorge Powerplant; that is, the maximum continuous generation level that the plant can sustain without adverse effects on the equipment.

$$PCAP_h = \text{Min}\{47.0 \times NT_h, FML_h\}, \tag{5.1}$$

where

$PCAP_h$ = powerplant capability (MW) in hour *h*;

NT_h = number of operating turbines in hour *h*; and

FML_h = capability (MW) limited by the turbine's maximum flow rate in hour *h*.

The powerplant capability is constrained by the turbine operational limit of 47 MW each and by the maximum flow rate through the turbines.

The maximum flow rate through a turbine and hence the computed value for *FML* in equation 5.1 is a function of the net head. The net head is computed by subtracting the tail water elevation from the reservoir elevation, where the tail water elevation is estimated by equation 5.2. This equation is identical to the one that is in the RiverWare model.

$$TWE_h = 5600.2 + (1.709 \times DR_h) - (0.2039 \times DR_h^{\ 2}) + (0.01147 \times DR_h^{\ 3})\}, \tag{5.2}$$

where

TWE_h = tail water elevation (ft) in hour *h*; and

DR_h = water release (cfs) including both turbine and non-turbine releases in hour *h*.

As shown in figure 5.2, the tail water elevation level rises as the flow rates from the dam increases. Flows include both turbine and non-turbine releases.

The maximum flow through the Flaming Gorge Powerplant is estimated by equation 5.3. This equation is also contained in the RiverWare model.

$$TRMax_h = [593.8 + (2.222 \times N_h) + (0.0002616 \times N_h^{\ 2})] \times NT_h, \tag{5.3}$$

where

$TRMax_h$ = maximum water release rate (cfs) through operational turbines in hour *h*; and,

N_h = net head (ft) in hour *h*.

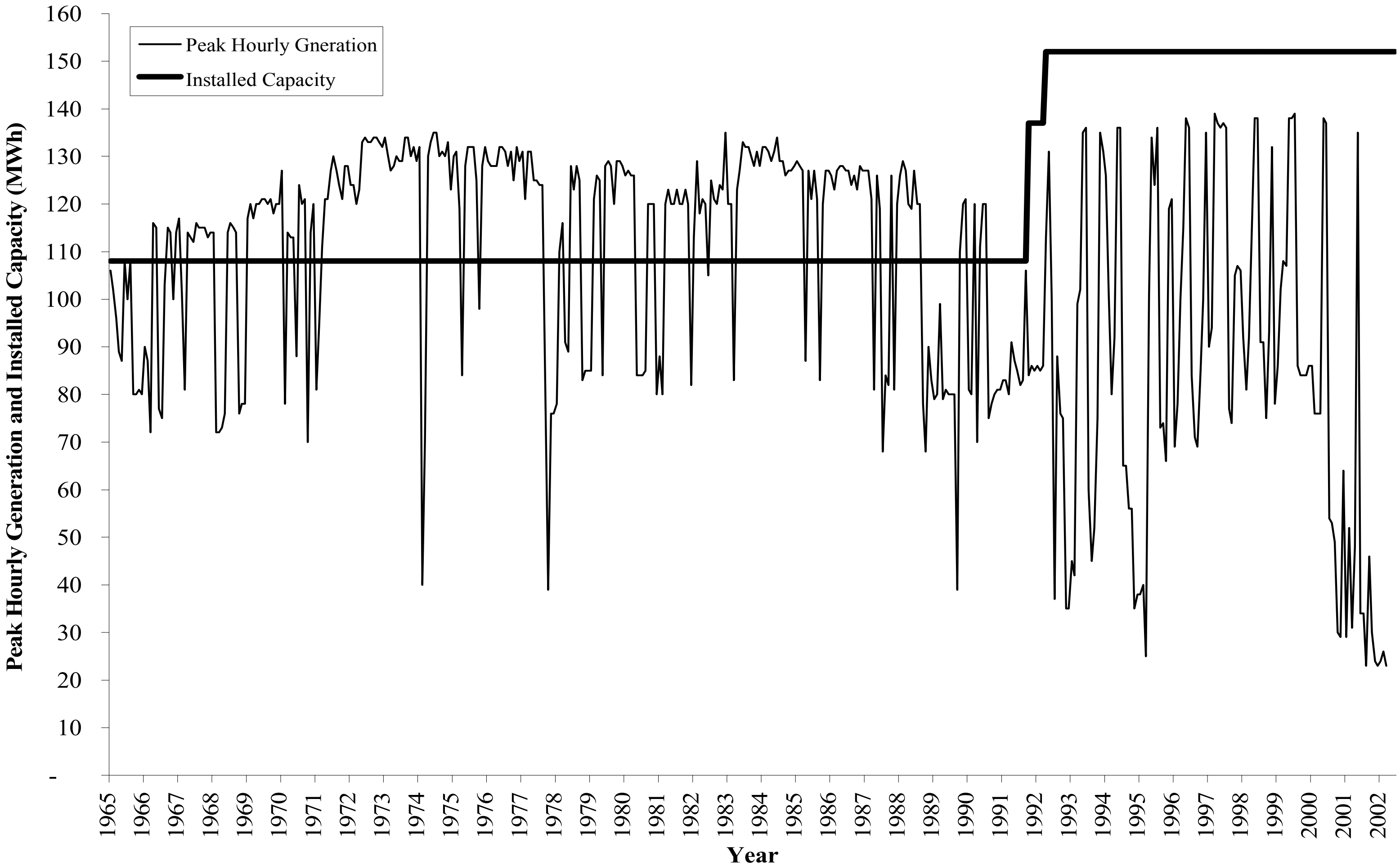

__Figure 5.1. Comparison of Capacity and Maximum Recorded Generation in Each Month.__

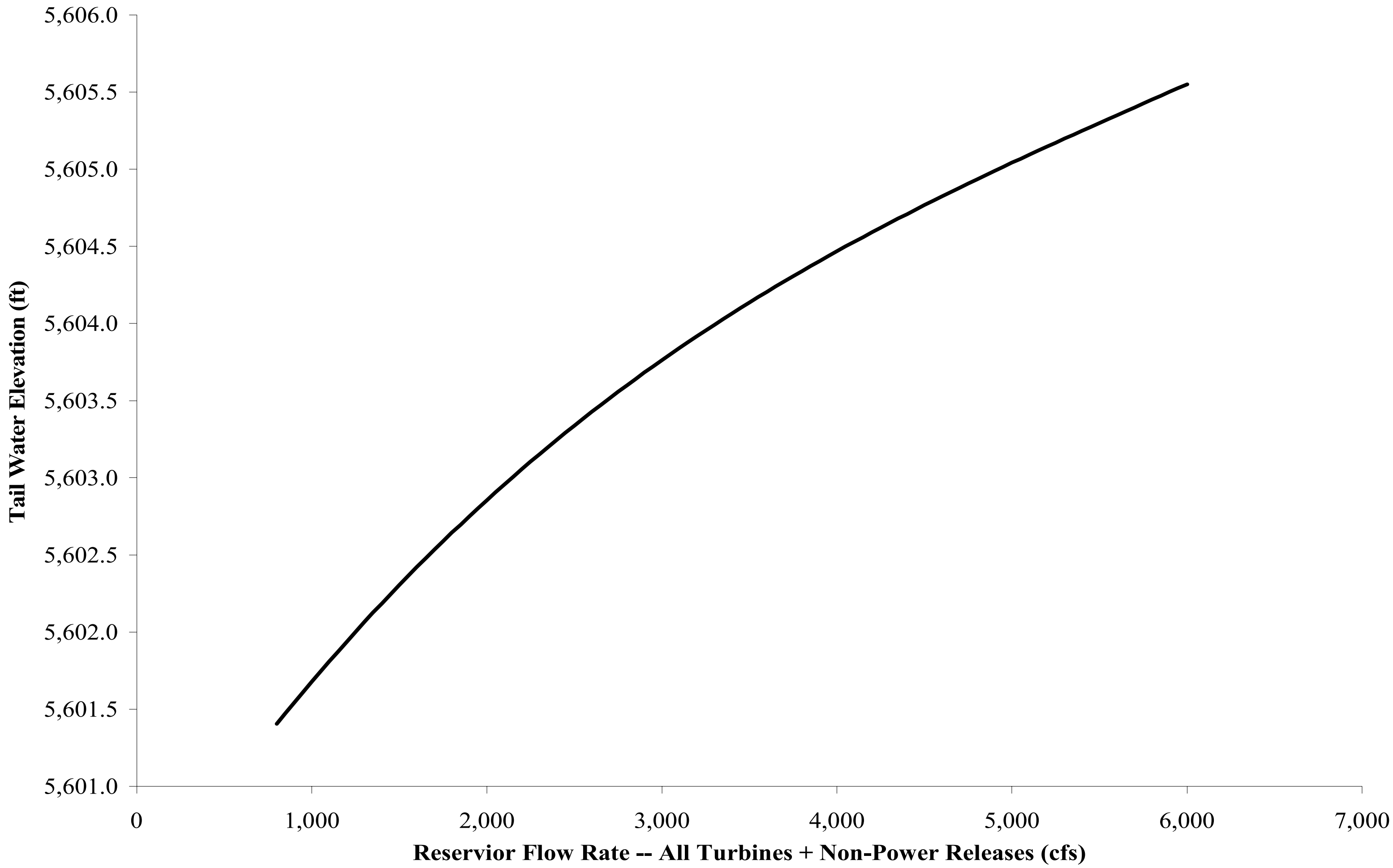

Figure 5.2. Flaming Gorge Tail Water Elevation as a Function of Total Dam Releases.

As shown in figure 5.3, the maximum turbine flow increases with higher heads. However, the turbines are not usually operated at the higher flow rates since it would produce more energy than the powerplant's generating capability (i.e., 47 MW x *NT*) resulting in potential damage to turbines and related power equipment.

Based on the net head and the turbine flow rate limit, the maximum generation level is computed by equation 5.4 (i.e., universal power equation) (***Modeling Hourly Operations at the Glen Canyon Dam GCPS09 version 1.0, September 1996, p. 47)***.

$$FML_h = (SWW \times EFF \times PF \times TRMax_h \times N_h)/(hptokw \times 1000), \tag{5.4}$$

where

SWW = 62.4, the specific weight of water at 50 degrees Fahrenheit (lb/ft^3);

EFF = turbine efficiency (fraction);

PF = plant's power factor (fraction); and

hptokw = 737.5 conversion factor (kw/ft-lbs).

For this analysis, the plant's power factor, *PF*, is set equal to 0.95. This value is based on historic reactive power requirements (***Personal Communication, Larry Andersen)***.

As shown in figure 5.4, the turbine efficiency parameter is a function of both turbine output level, in terms of horsepower (HP), and net head. Equations 5.5 through 5.7 are used to estimate the turbine efficiency curves for three net head levels that include 400, 420, and 440-feet, respectively. When the reservoir elevation is not at one of these three levels, the turbine efficiency is based on linear interpolation. The equations are based on curves contained in Reclamation's Hydraulic Turbine Data profiles for the Flaming Gorge Powerplant **(No. 2512 4-20-62)**. This profile is provided in Appendix A1.

$$\begin{aligned} EFF400 &= 25.098 + (6.6653 \times PHP) - (0.3259 \times PHP^2) + (8.36312\text{e-}03 \times PHP^3) \\ &\quad - (1.01932\text{e-}04 \times PHP^4) + (4.51414\text{e-}07 \times PHP^5), \end{aligned} \tag{5.5}$$

where

PHP = powerplant output (HP); and

EFF400 = turbine efficiency for at a net head of 400 feet (fraction).

$$\begin{aligned} EFF420 &= 6.86486 + (8.41418 \times PHP) - (0.39346 \times PHP^2) + (9.5572\text{e-}03 \times PHP^3) \\ &\quad - (1.11467\text{e-}04 \times PHP^4) + (4.83267\text{e-}07 \times PHP^5), \end{aligned} \tag{5.6}$$

where

EFF420 = turbine efficiency for at a net head of 420 feet (fraction).

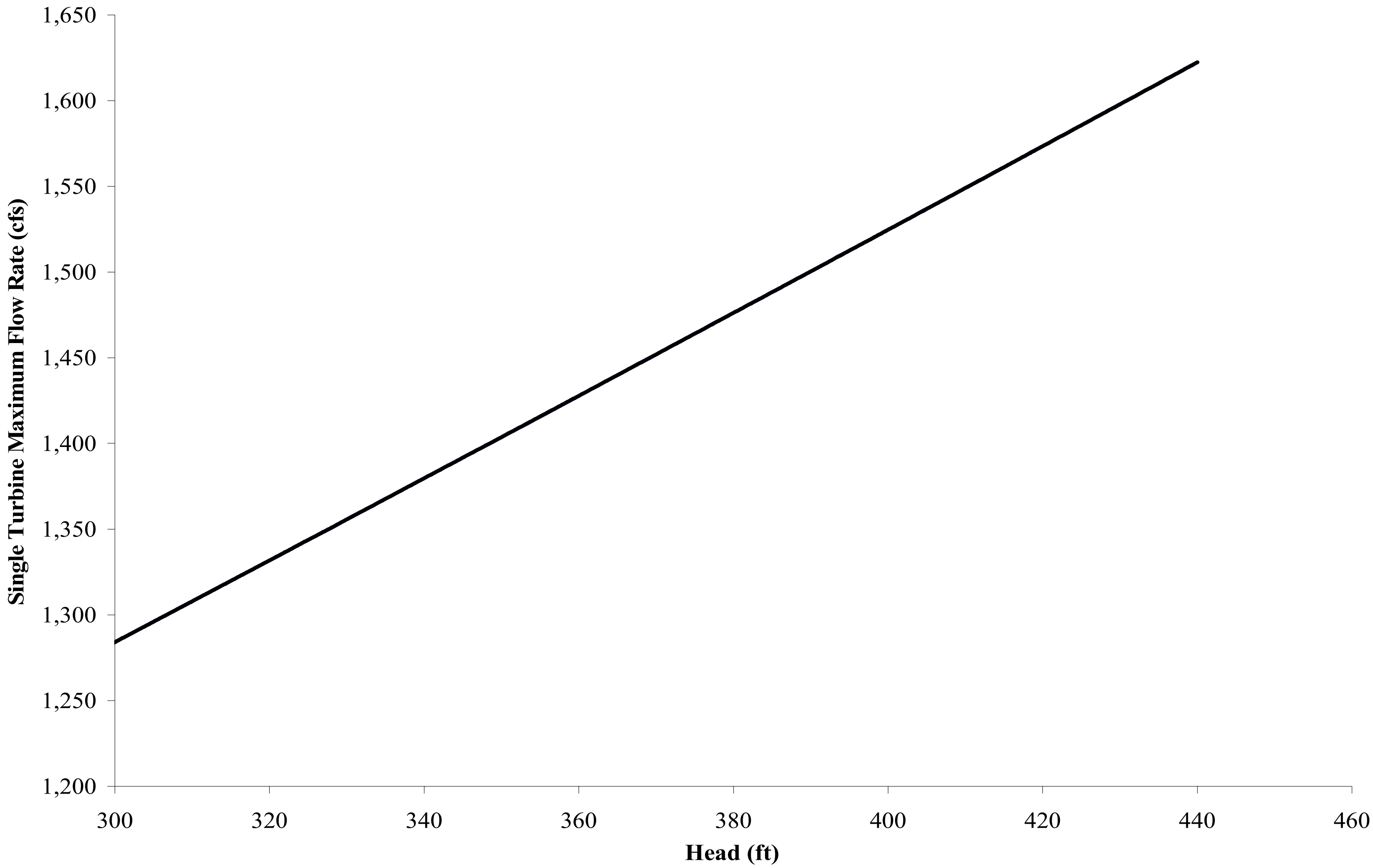

Figure 5.3 Maximum Flow Rate through a Single-Turbine as a Function of Head.

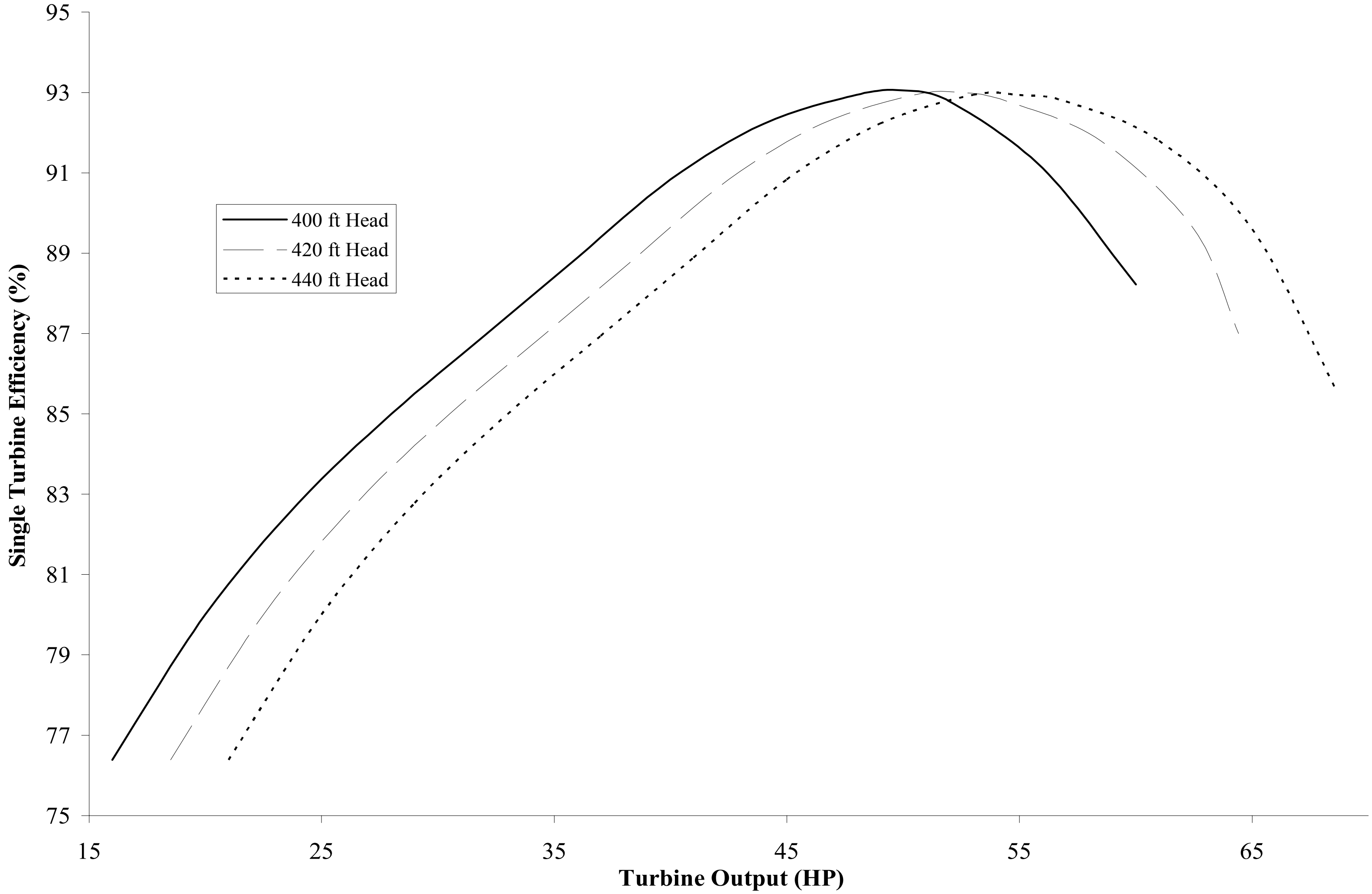

Figure 5.4. Turbine Efficiency as a Function of Flaming Gorge Power Output.

$$EFF440 = -20.69 + (11.1294 \times PHP) - (0.500487 \times PHP^2) + (1.15304e-02 \times PHP^3) - (1.28141e-04 \times PHP^4) + (5.35890e-07 \times PHP^5), \quad (5.7)$$

where

EFF440 = turbine efficiency for at a net head of 440 feet (fraction).

Figure 5.5 shows the results of equation 5.1 and compares it to historical maximum generation levels for the range of reservoir elevations that are projected by the Green River model through the year 2026. The figure shows that for a few observations the hourly maximum generation level was slightly higher than the ones computed by equation 5.1. This may have been the result of low reactive power requirements during this time period and therefore a higher power factor than the 0.95 assumed in this study.

The number of turbines operating, *NT*, in equation 5.3 is typically set to 3. However, each unit is taken off-line for approximately 2 weeks annually to perform routine maintenance. For both the No Action and Action Alternatives, most future years have periods when flows are at minimum level (i.e., 800 cfs) for a four-week period or longer. It is assumed that maintenance will be performed during this time since only one unit is typically operated when the dam release level is 800 cfs. However, there is a 4-year period from 2016 through 2019 when the representative trace has daily flows that exceed the minimum all year long. The assumed time periods for scheduling the maintenance during this 4-year period are shown in table 5.1. These maintenance periods were selected since monthly release levels were very low (i.e., barely above the minimum). When daily releases from the dam are similar for 2 or more months, periods that have lower projected spot market prices are selected for the maintenance period.

Table 5.1. Assumed Maintenance Periods

Year	Alternative	
	No Action	Action
2016	Jan 19 - Feb 29	Jan 19 - Feb 29
2017	Feb 18 - Mar 31	Jan 18 - Feb 28
2018	Mar 4 - Apr 14	Feb 1 - Mar 14
2019	Feb 18-Mar 31	Feb 15 - Feb 28 & Dec 4 - Dec 31

5.2 Power Conversion and Generation

The Flaming Gorge Dam has injected more than 20,235 GWh of electricity into the power grid from November, 1963 through the end of June, 2002 (***based on Form PO&M-59 data)***. Between 1964, the first full year of operation, and 2001 the Flaming Gorge Powerplant generated an average of about 528.9 GWh of electricity annually. However, as shown in figure 5.6, the powerplant has historically displayed a large degree of annual variability. Generation levels were as low as 251.6 GWh in 1990 and as high as 877.1 GWh in 1984; that is, generation varied by a factor of almost 3.5.

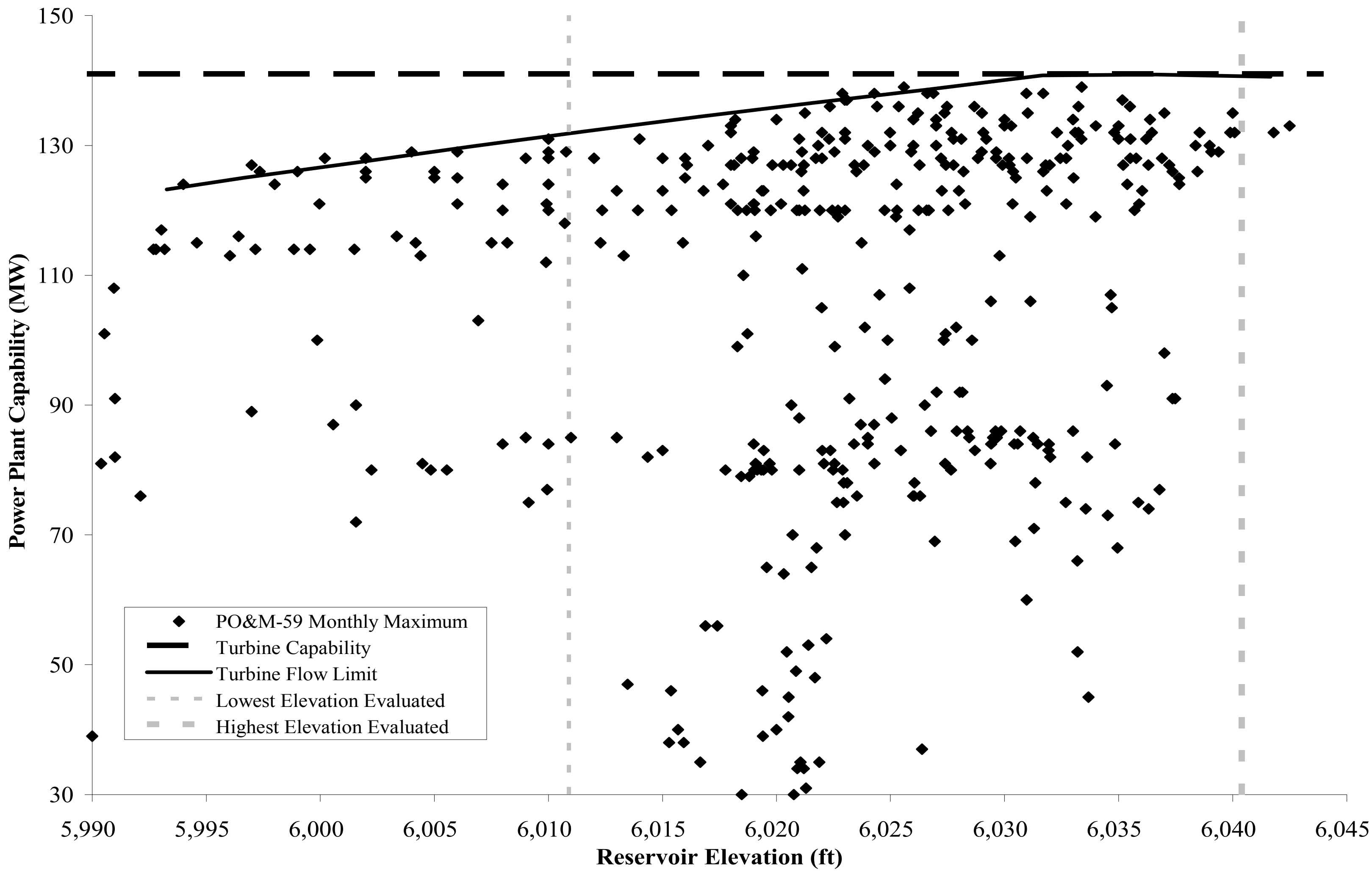

Figure 5.5. Comparison of Historical Monthly Maximum Generation and the Plant Capability Curve.

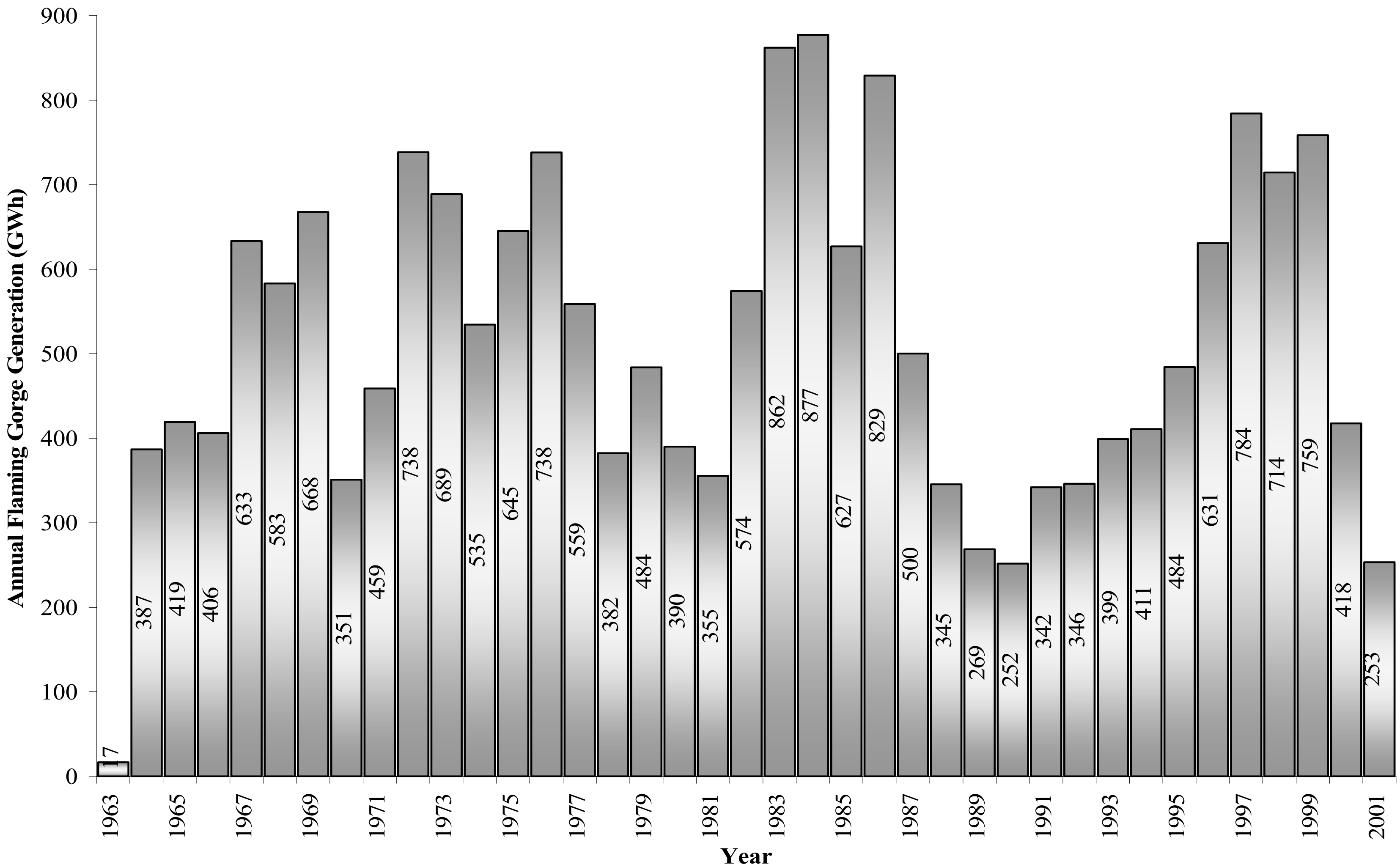

Figure 5.6. Annual Generation from the Flaming Gorge Dam.

Alternatives will affect monthly water release volumes and reservoir elevations at Flaming Gorge. Therefore, operable capability blocks and associated power conversion factors were estimated monthly for each alternative. Estimates are based on the universal power equation, equations 5.2 and 5.3, and equations 5.5 through 5.7. The sum of the capability blocks equals the amount computed by equation 5.1.

Although the powerplant is modeled in GenOpt as a single entity, power conversion factors and capability blocks were based on unit-level computations. An algorithm was written that optimizes generation and water releases through each turbine given a total water release from the dam. The algorithm uses a cellular automata procedure that contains a lattice of three cells (i.e., columns) each of which represent a single turbine. The cellular automata procedure also uses simple rules for allocating water among the three turbines based on the state of the neighboring cell (i.e., turbine) as it proceeds from one discrete step to the next (i.e., rows). Through this process all possible states for allocating a fixed amount of water among turbines are tested in a water volume increment that is specified by the user (***Melanie Mitchell, "An Introduction to Genetic Algorithms").***

Conceptually, the turbines are lined up in a single row. In the initial state all of the water release is allocated to the rightmost turbine (refer to step 1 below). To advance to the next step one increment of water release (e.g., 1 cfs) is reallocated from the rightmost turbine to the turbine (i.e., cell) on the left (step 2 below). If it is not possible to remove water from the rightmost turbine (i.e., zero or minimum turbine flow rate as in step 4 below), then a search is performed to locate the nearest turbine containing a non-zero water release. An increment of water is then reallocated from this non-zero release turbine to the turbine on the left. The remaining turbine water is then reallocated to the rightmost one (step 5 below). The final step occurs when all of the water is allocated to the leftmost turbine (step 10 below).

An example pattern for a dam with three turbines and a total flow of 3 cfs is as follows:

Step 1: [0-0-3]

Step 2: [0-1-2]

Step 3: [0-2-1]

Step 4: [0-3-0]

Step 5: [1-0-2]

Step 6: [1-1-1]

Step 7: [1-2-0]

Step 8: [2-0-1]

Step 9: [2-1-0]

Step 10: [3-0-0]

For each step, the amount of water that is shifted to a non-power release is determined after initial turbine water release allocations have been performed. If a turbine is allocated more water than its physical maximum flow or generation capability, then the excess water is also reallocated to non-power releases. Total powerplant generation is calculated with the equations presented in this section. The step (i.e., combination of turbine releases) with the highest generation is selected as the optimal allocation of water releases.

Results from this algorithm for dam releases ranging from 800 cfs to the maximum powerplant rate are shown in figure 5.7. The graph, which is based on a full reservoir condition (i.e., maximum head), shows that generation as a function of flow rate is non-linear. At low release rates all of the water is routed through a single turbine. However, as the release rate increases to a level that is near the maximum of a single turbine, some of the water is routed through a second turbine. The third turbine is put into operation when doing so will produce higher generation levels than the level that can be achieved by running only two turbines.

Generation levels using the cellular automata procedure and engineering equations described above were compared to actual operations as documented on Western's web site (***site address: http://www.wapa.gov/crsp/operatns/fgSCADAdata.htm).*** Table 5.2 shows that the computed estimates of generation are very similar to the recorded values for a large range of flow rates and reservoir elevation levels. Power equations underestimate generation levels at most by 5 MW and overestimate generation levels by as much as 4 MW. This difference can be attributed to a number of factors including measurement errors at the powerplant, power factor errors (i.e., actual value may not be 0.95), equation coefficient inaccuracies, and powerplant operators who allocate water among turbines differently from the cellular automata routine. Also, the tail water equation has a tendency to underestimate the tail water elevation by about 1 ft as compared to the recorded value.

As described in section 4.4, the GenOpt model separates the powerplant into generation blocks. Block level generation capabilities and incremental power conversion factors for full-reservoir conditions were estimated from the curve in figure 5.7. The first block is set equal to the power that is produced at the minimum release rate; that is, 800 cfs. As shown in figure 5.8, the second block is loaded to the point where the incremental conversion factor is at a maximum (i.e., first derivative of the curve is at a

Table 5.2. Comparison of Recorded Generation Levels and Computed Estimates

Power Release (cfs)	Date	Hour	Reservoir Elevation (ft)	Tail Water Elevation (ft)	Head (ft)	Recorded Generation (MW)	Estimated Generation (MW)	Generation Difference (MW)
800	07/02/01	4 AM	6013.5	5602.6	410.9	22	23	1
970	12/31/00	6 PM	6020.3	5602.8	417.5	28	30	2
1,030	09/04/00	3 AM	6021.3	5602.9	418.4	30	32	2
1,560	03/09/00	3 AM	6026.2	5603.4	422.8	44	46	2
1,700	01/10/00	4 AM	6027.4	5603.5	423.9	49	51	2
1,910	08/03/99	10 PM	6033.5	5603.8	429.7	62	59	-3
2,000	12/21/99	8 AM	6028.4	5603.9	424.5	60	62	2
2,120	08/04/99	12 PM	6033.5	5604.0	429.5	65	67	2
2,400	12/09/98	1 AM	6032.7	5604.3	428.4	74	77	3
2,470	12/26/99	4 PM	6028.1	5604.3	423.8	75	78	3
2,780	12/25/99	7 PM	6028.2	5604.4	423.8	86	86	0
2,820	02/19/99	7 PM	6028.6	5604.4	424.2	86	87	1
3,250	07/15/99	8 AM	6032.5	5605.0	427.5	100	99	-1
3,320	02/21/99	9 PM	6028.5	5605.2	423.3	101	96	-5
3,500	04/12/99	1 PM	6024.9	5605.3	419.6	106	110	4
3,500	04/03/99	6 AM	6025.6	5605.3	420.3	107	110	3
4,450	07/04/99	3 AM	6031.6	5605.6	426.1	135	136	1
4,550	05/17/99	7 AM	6025.4	5605.7	419.7	135	135	0

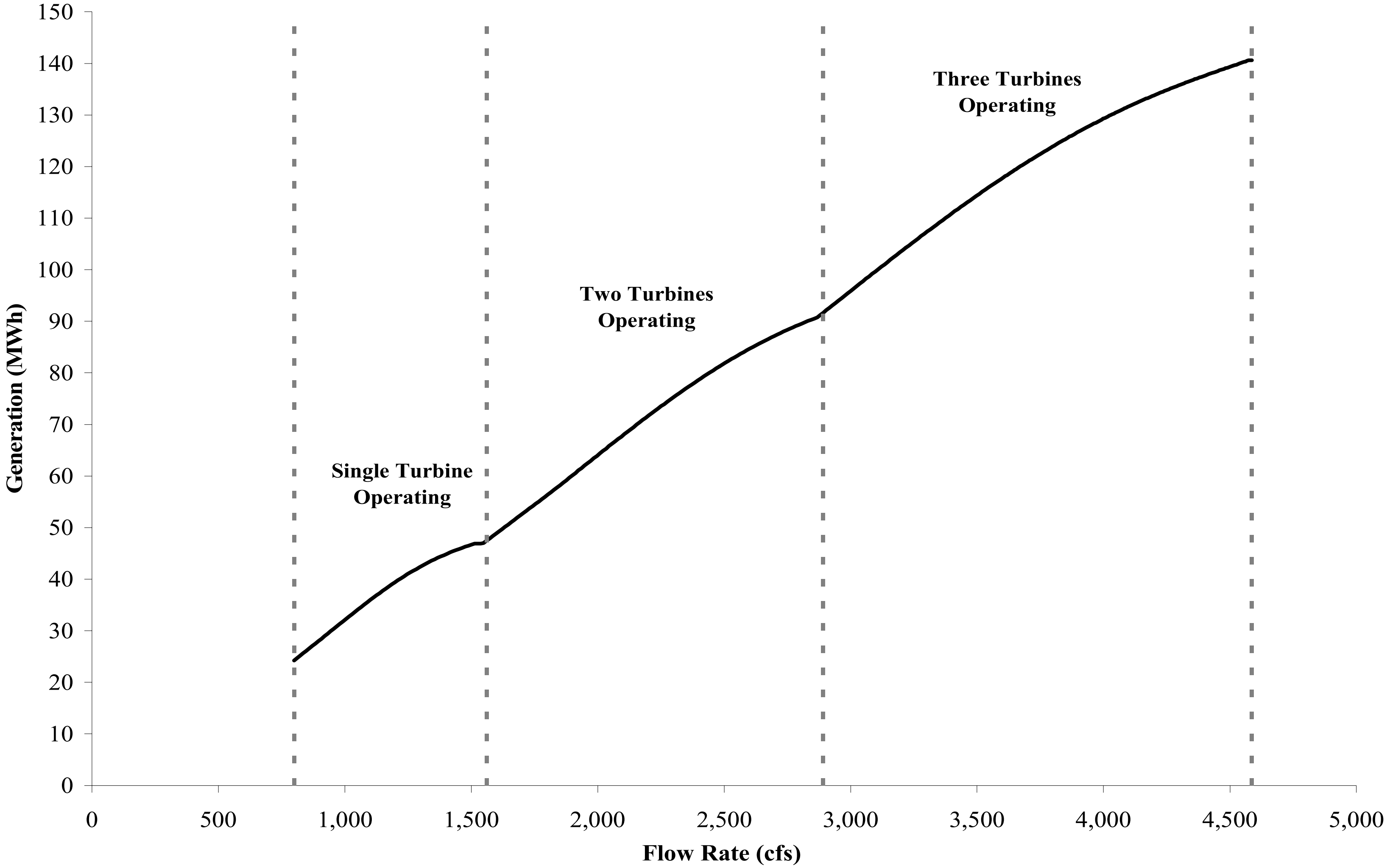

Figure 5.7. Optimal Unit Loading and Generation Level as a Function of Flaming Gorge Release Rate.

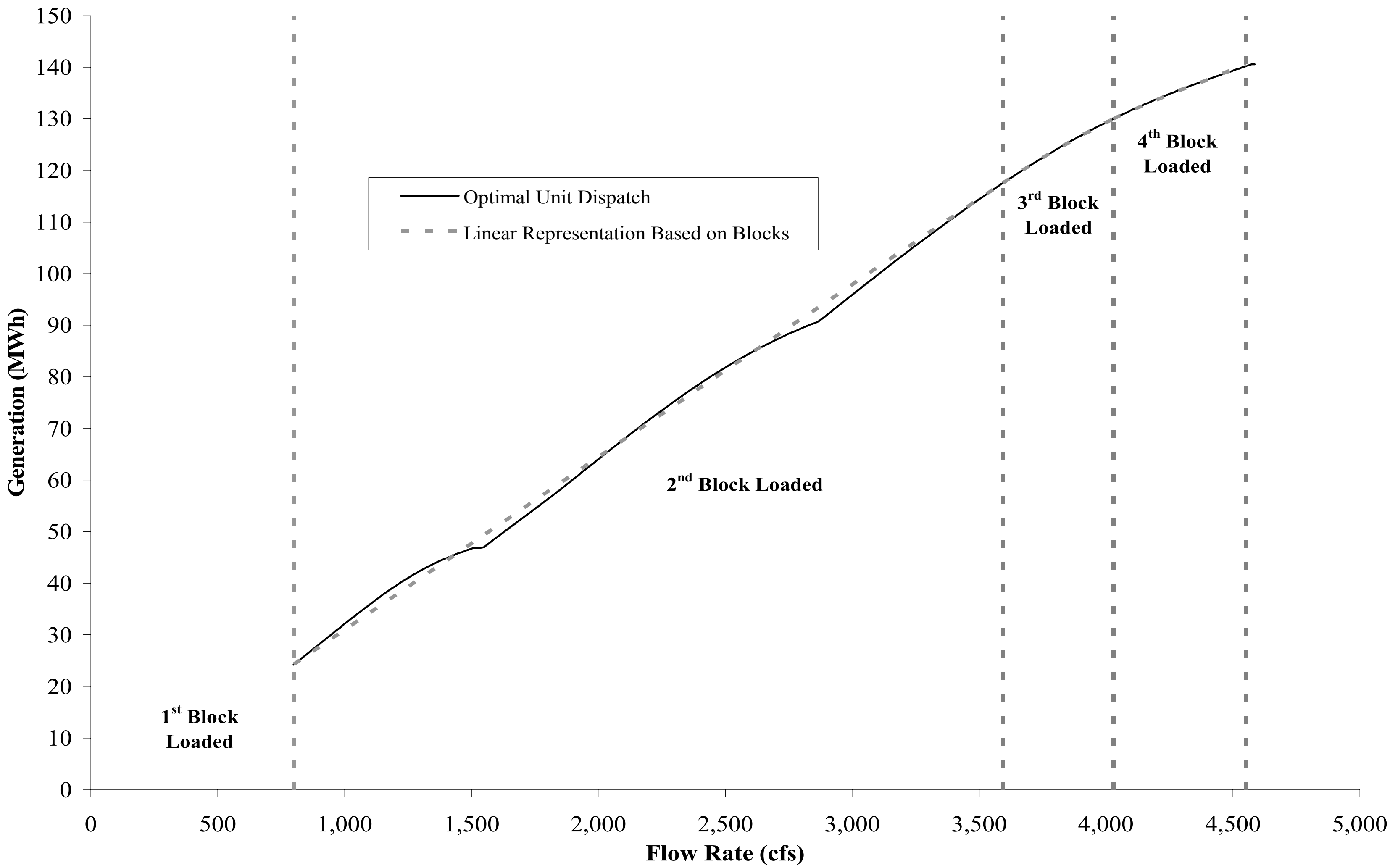

Figure 5.8. Power Block Representation for the Flaming Gorge Powerplant.

maximum). The fourth block ends at the generating capability of the plant and extends backwards to approximately the midpoint between the plant capability and the end of the second block. The third block lies between the second and the fourth. Using this approach, incremental block conversion factors decrease after the second block. The advantage of the blocked capability approach is that it can easily be represented in the GenOpt modeling framework. However, it can lead to computational errors.
Figure 5.8 shows that the optimal unit dispatch curve and the piecewise-linear curve based on blocked capabilities are very similar. The maximum generation error of about 2 MW is at point where a second turbine is brought into operation. An error of approximately the same magnitude occurs at the point where the third turbine is brought on-line.

Power production estimates for three operational turbines similar to the one in figure 5.7 were made for 10 Flaming Gorge reservoir elevations that span the range projected by the Green River model. Block-level generation capabilities and associated power conversion factors associated with these 10 reservoir elevation levels are shown in table 5.3. When the reservoir elevation for a month is not at one of these levels, block capabilities and incremental power conversion factors are estimated by linear interpolation.

Since units are put into maintenance, power production for the 10 reservoir elevation levels were also made for two other conditions; namely, one turbine in operation and two turbines in operation.

Table 5.3. Capability Blocks and Associated Conversion Factors

	Block 1		Block 2		Block 3		Block 4	
Reservoir Elevation (ft)	Incremental Capability (MW)	Incremental Conversion Factor (MWh/10^3 cfs)	Incremental Capability (MW)	Incremental Conversion Factor (MWh/10^3 cfs)	Incremental Capability (MW)	Incremental Conversion Factor (MWh/10^3 cfs)	Incremental Capability (MW)	Incremental Conversion Factor (MWh/10^3 cfs)
5993	21.9	27.3	80.3	29.6	12.1	25.0	9.0	18.6
5997	22.0	27.6	81.0	29.9	12.5	25.1	9.6	19.3
6002	22.3	27.9	82.0	30.3	13.1	25.2	10.0	19.6
6007	22.6	28.2	83.4	30.7	13.5	25.4	10.3	19.9
6012	22.8	28.5	85.2	31.0	13.7	25.7	10.5	19.7
6017	23.1	28.8	86.7	31.4	14.5	26.0	10.3	19.3
6022	23.3	29.1	88.5	31.8	14.6	26.3	10.2	18.7
6027	23.6	29.4	90.0	32.2	15.0	26.4	10.1	22.3
6032	23.8	29.7	91.1	32.6	14.4	27.0	11.5	18.6
6037	24.0	30.0	92.2	33.0	13.7	27.7	11.0	18.6
6042	24.3	30.3	93.3	33.4	12.5	28.6	10.6	20.2

Block-level generation capabilities and associated power conversion factors for both of these combinations of turbine outages were also derived and input in the GenOpt model.

The conversion factors generated by the methodology described above were compared to historical values. Figure 5.9 shows historical power conversion factors as computed from PO&M–59 data. It also shows calculated conversion factors as a function of reservoir elevation at minimum flows and at the point of highest efficiency.

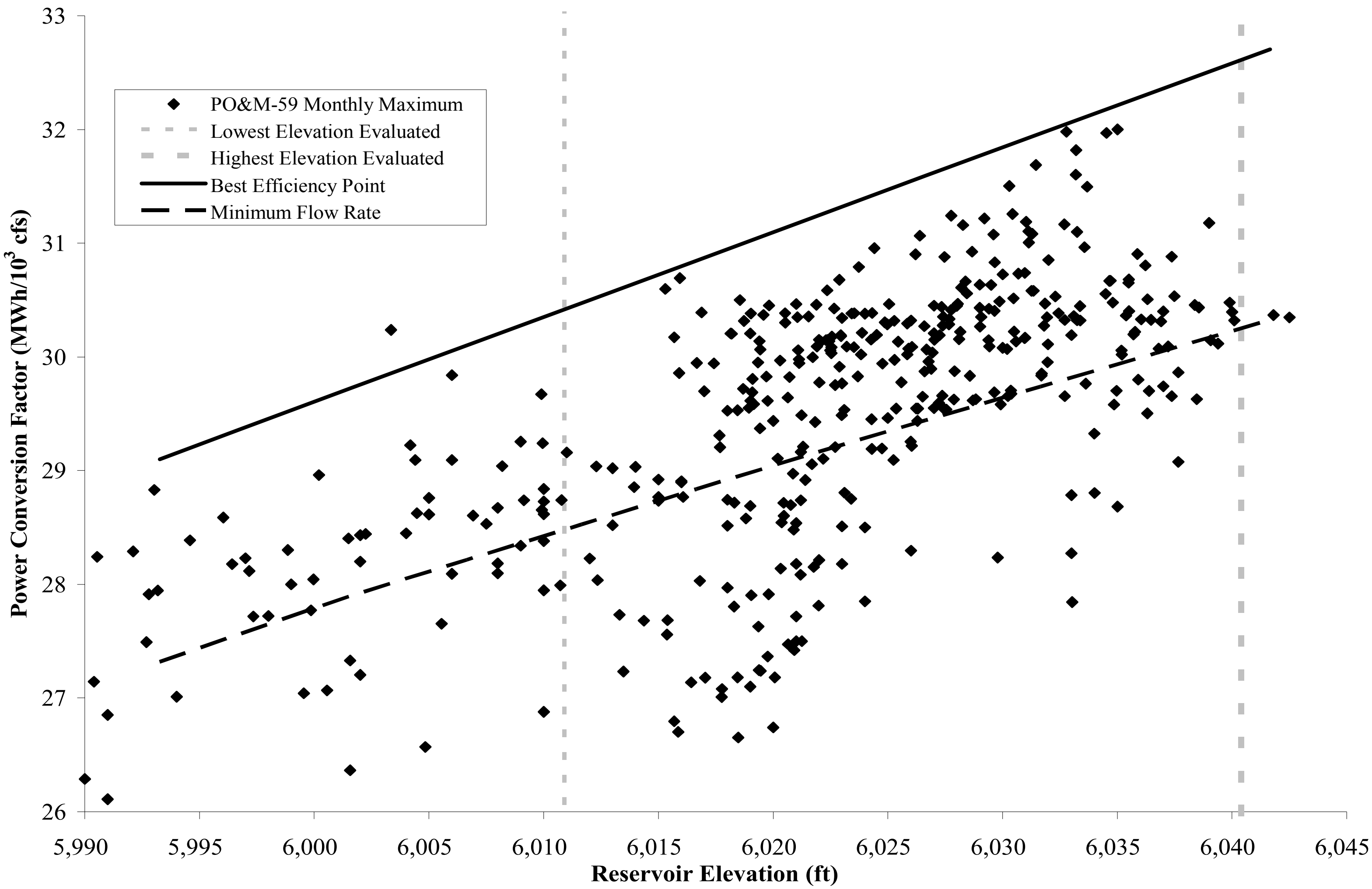

Figure 5.9. Comparison of Historical Power Conversion Factors and Computed Efficiency Curves.

6. PROJECTED SPOT MARKET PRICES

The projected economic value of electricity generated from the Flaming Gorge powerplant is closely tied to the estimated price of electricity on the spot market. The AURORA Model was used to estimate spot prices for various delivery points into the WSCC grid. For this analysis, AURORA spot price forecasts for Four Corners were used to compute the economic value of Flaming Gorge energy. It was assumed that the operations of Flaming Gorge would not affect spot market prices. This assumption is generally true since it makes a very small contribution to the total supply of the WSCC system.

6.1 Average Annual and Seasonal Prices

Average annual spot market prices for the Four Corners delivery point in nominal dollars are shown in figure 6.1 The figure shows that the average price is expected to decrease from the year 2002 through 2005. Prices increase thereafter through 2020, the last AURORA projection year. From 2020 through 2026 it was assumed that spot prices would remain constant. The maximum spot price during a year typically occurs during the summer months when electricity demands are the highest. As shown in the figure, peak spot prices can be more than 10 to 20 times the annual average. On the low price side, projected spot prices are about one-fourth of the average. These lower prices typically occur during the night and very early morning hours.

Prices not only change annually over time, but also have a very distinct seasonal pattern. Figure 6.2 shows average monthly prices used in this analysis. Averages are based on hourly values from the 2002 to 2026 time period. Prices are typically the highest in July and August with relatively low prices in the springtime. A secondary peak price season occurs during the wintertime. As described in section 7, this seasonal variation in spot prices along with the amount of water that is released in each month has a significant impact on the projected economic value of the Flaming Gorge power resource.

6.2 Daily Spot Market Price Patterns

Spot market prices not only change as a function of year and season but also by the time of the day and by the type of day. Figure 6.3 shows projected average hourly prices in January 2005 for weekdays and weekends. The price pattern is typical for the wintertime with relatively high prices in the morning and evening hours. Prices dip during midday hours and are the lowest during the nighttime. Weekend prices typically follow the same pattern as the weekday but are noticeably lower during peak demand hours. The one-hump release restriction at Flaming Gorge will not allow dispatchers to respond to the winter two-hump price pattern.

Projected spot market prices for April 2005 are generally less expensive and have less volatility compared to other times of the year. Demand is relatively low and energy is typically supplied by resources with low production costs such as hydro powerplants, nuclear units, and coal-fired steam generators. The two-hump price pattern that is characteristic of the wintertime continues in the springtime but it is less pronounced. Weekend prices are relatively flat ranging from about 20 to 26 $/MWh.

During the summer months the projected price pattern changes to a one-hump pattern that peaks in the late afternoon. Figure 6.5 shows that in July 2005 spot market prices are projected to peak at 4 PM during both weekdays and weekends. Flaming Gorge can follow this price pattern more easily than the wintertime two-hump pattern. Since demands are typically lower on the weekend, spot prices are expected to be significantly lower. Figure 6.6 shows hourly average prices projected by the AURORA model for October 2005. Relative to the summer, prices in October are significantly lower, but remain somewhat higher than prices in the springtime.

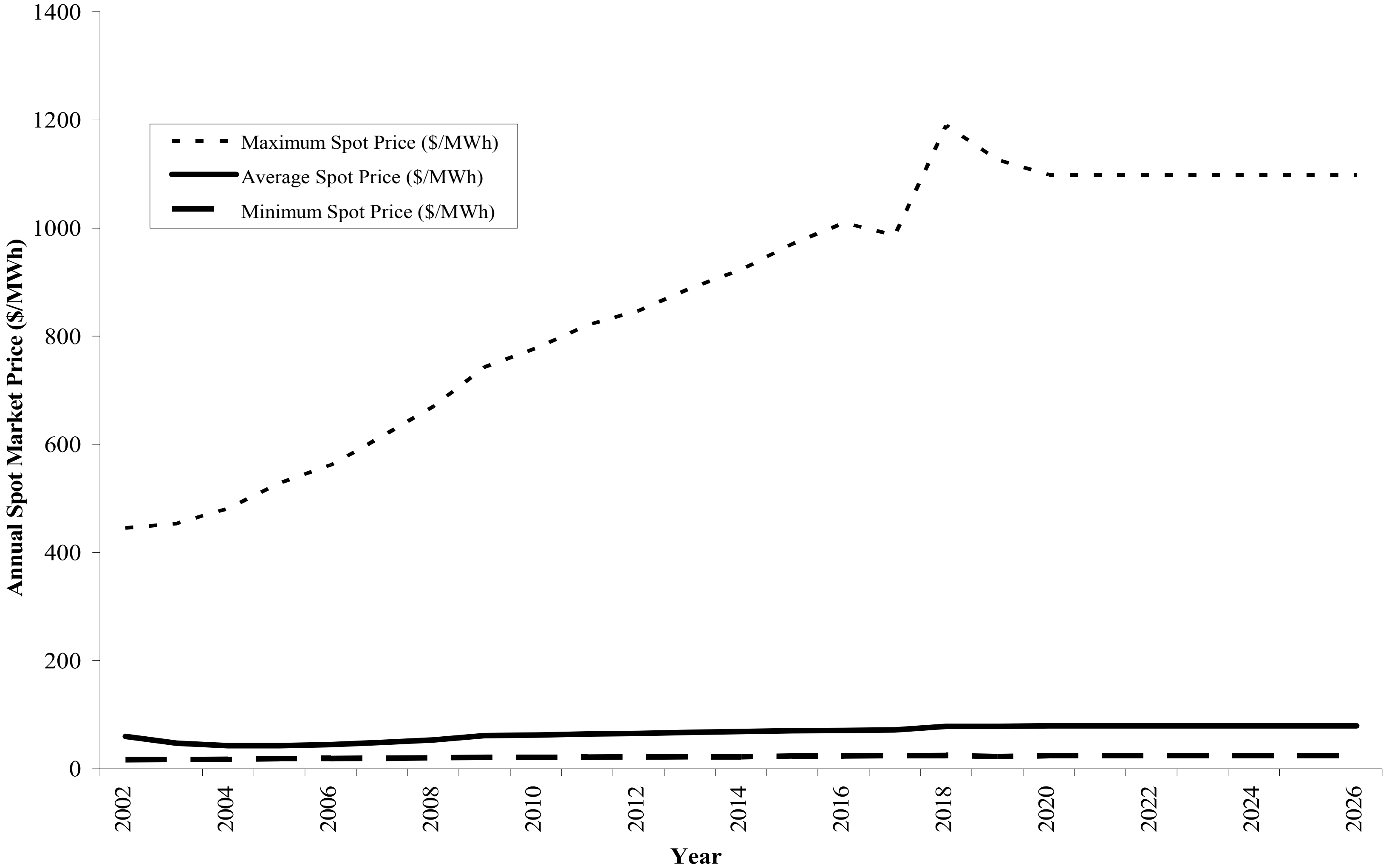

Figure 6.1. Average Annual Spot Market Prices Projected by the AURORA Model.

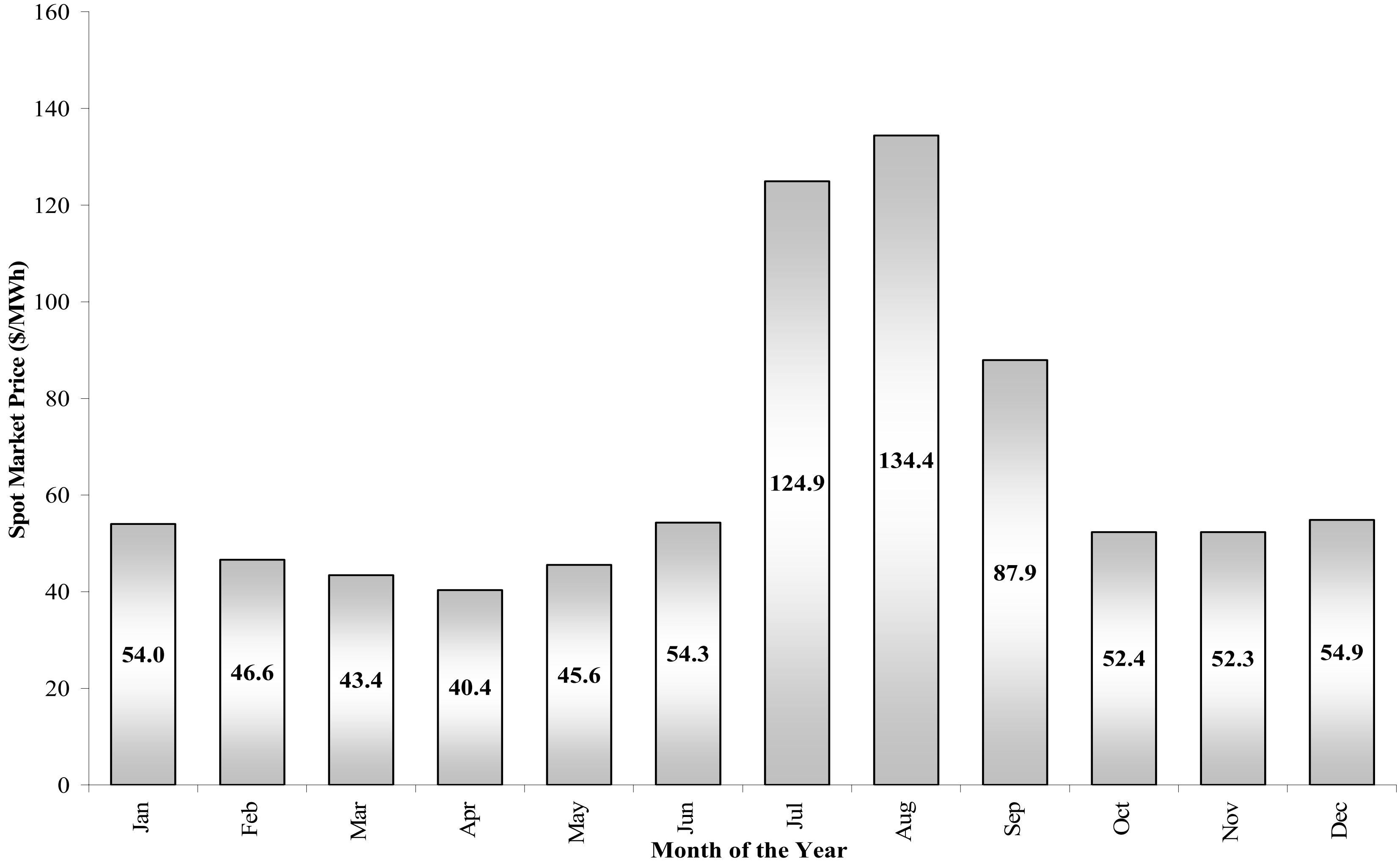

Figure 6.2. Average Monthly Spot Market Prices Over the Study Period.

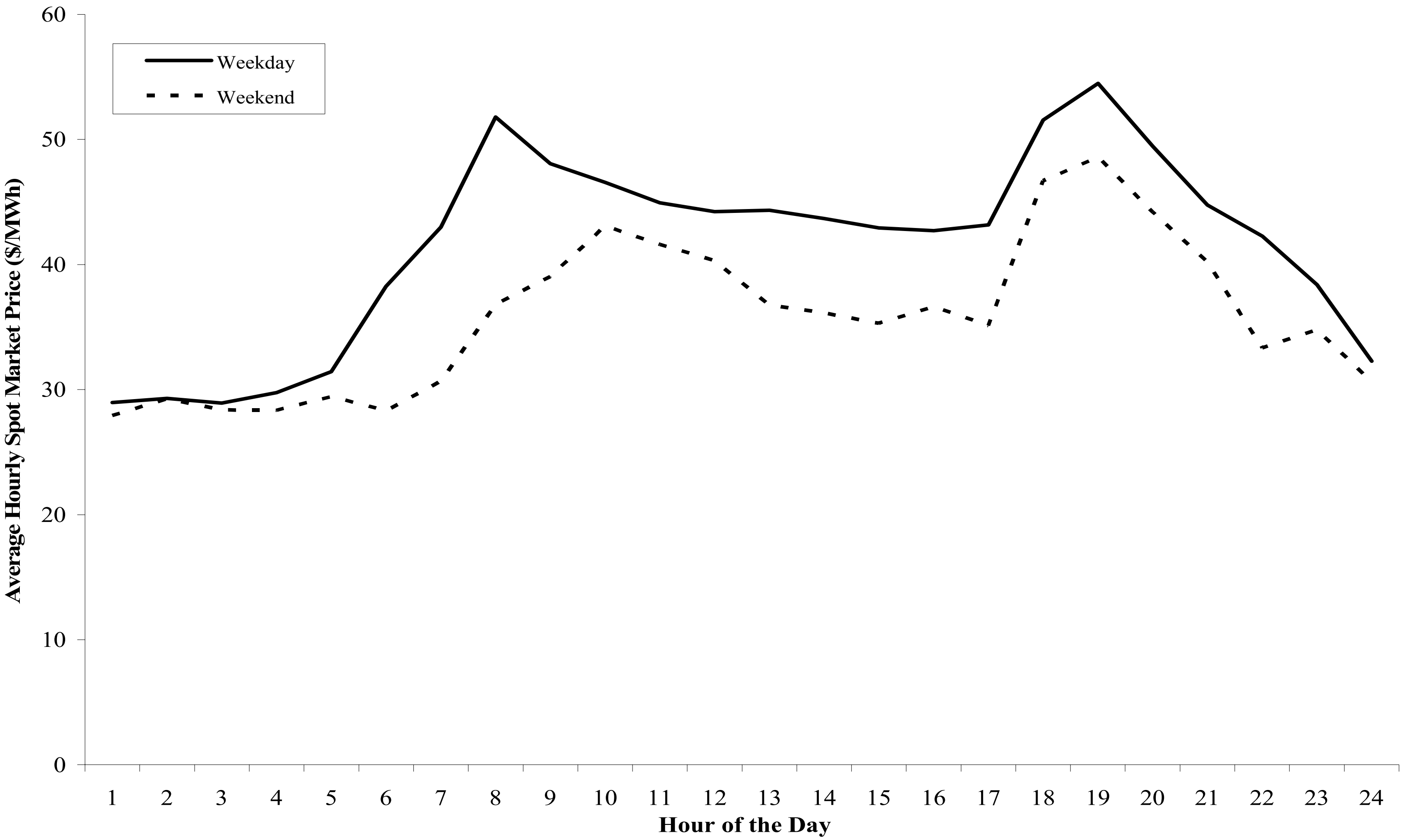

Figure 6.3. Projected Average Spot Market Prices for a Weekday and Weekend in January.

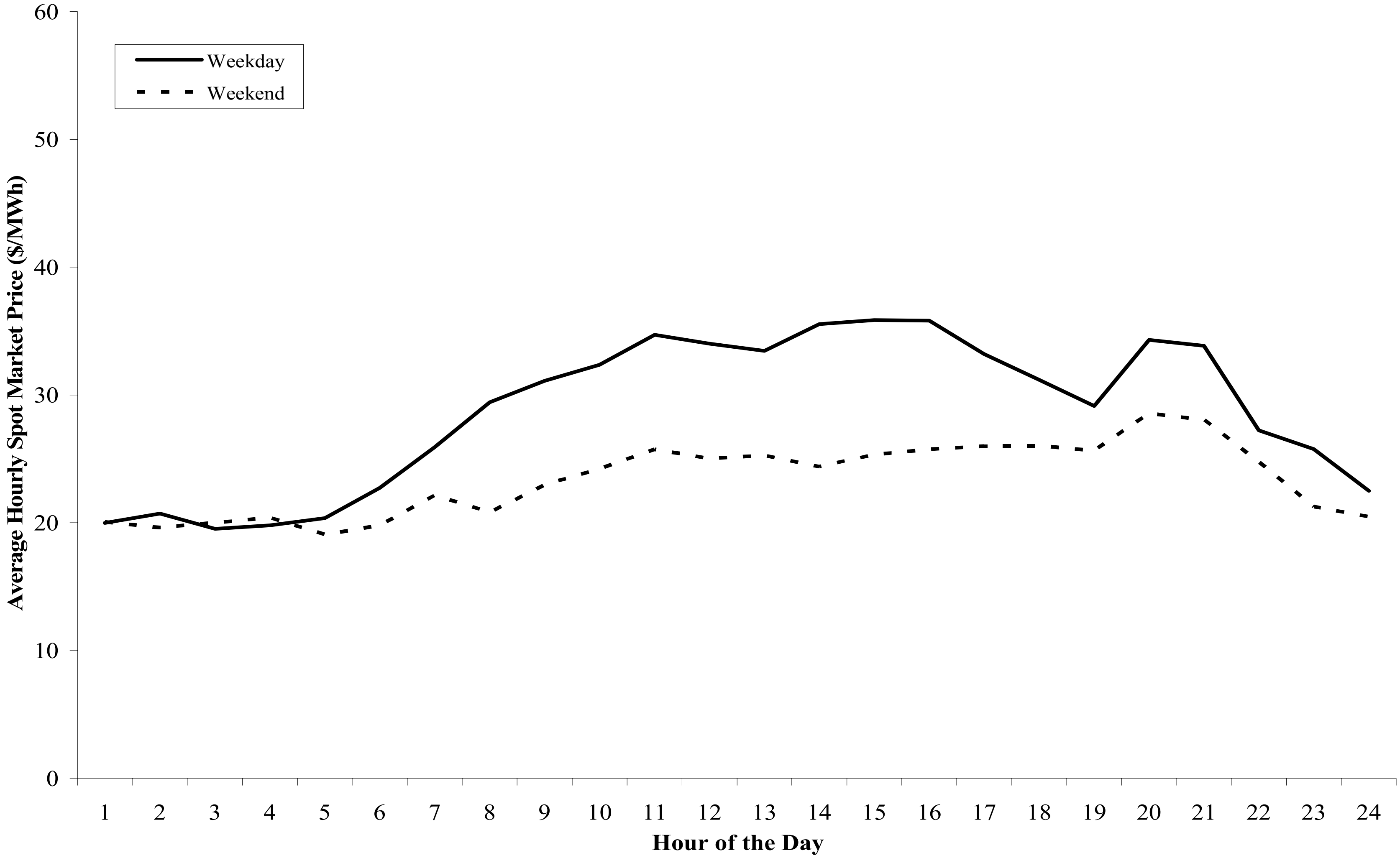

Figure 6.4. Projected Average Spot Market Prices for a Weekday and Weekend in April.

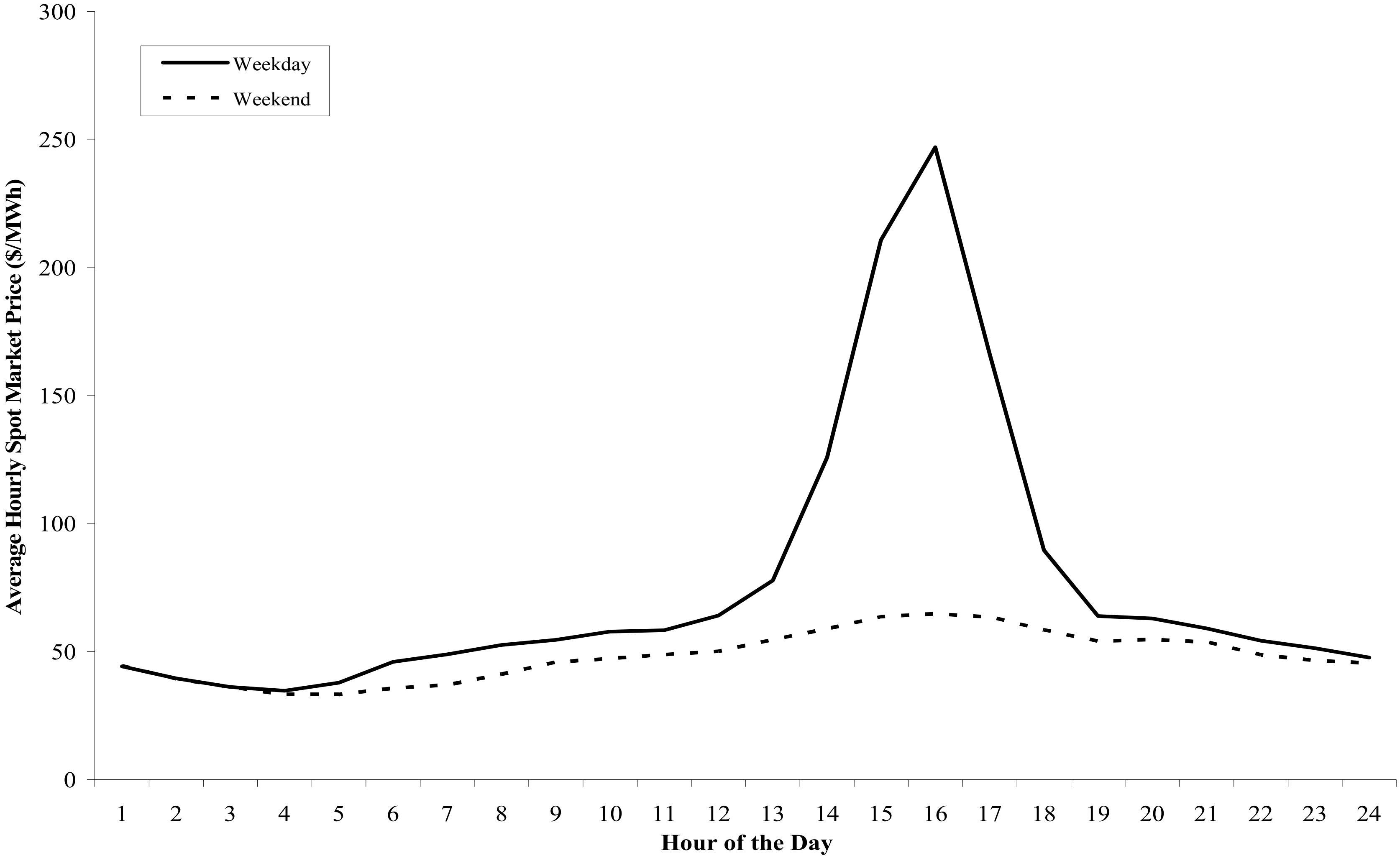

Figure 6.5. Projected Average Spot Market Prices for a Weekday and Weekend in July.

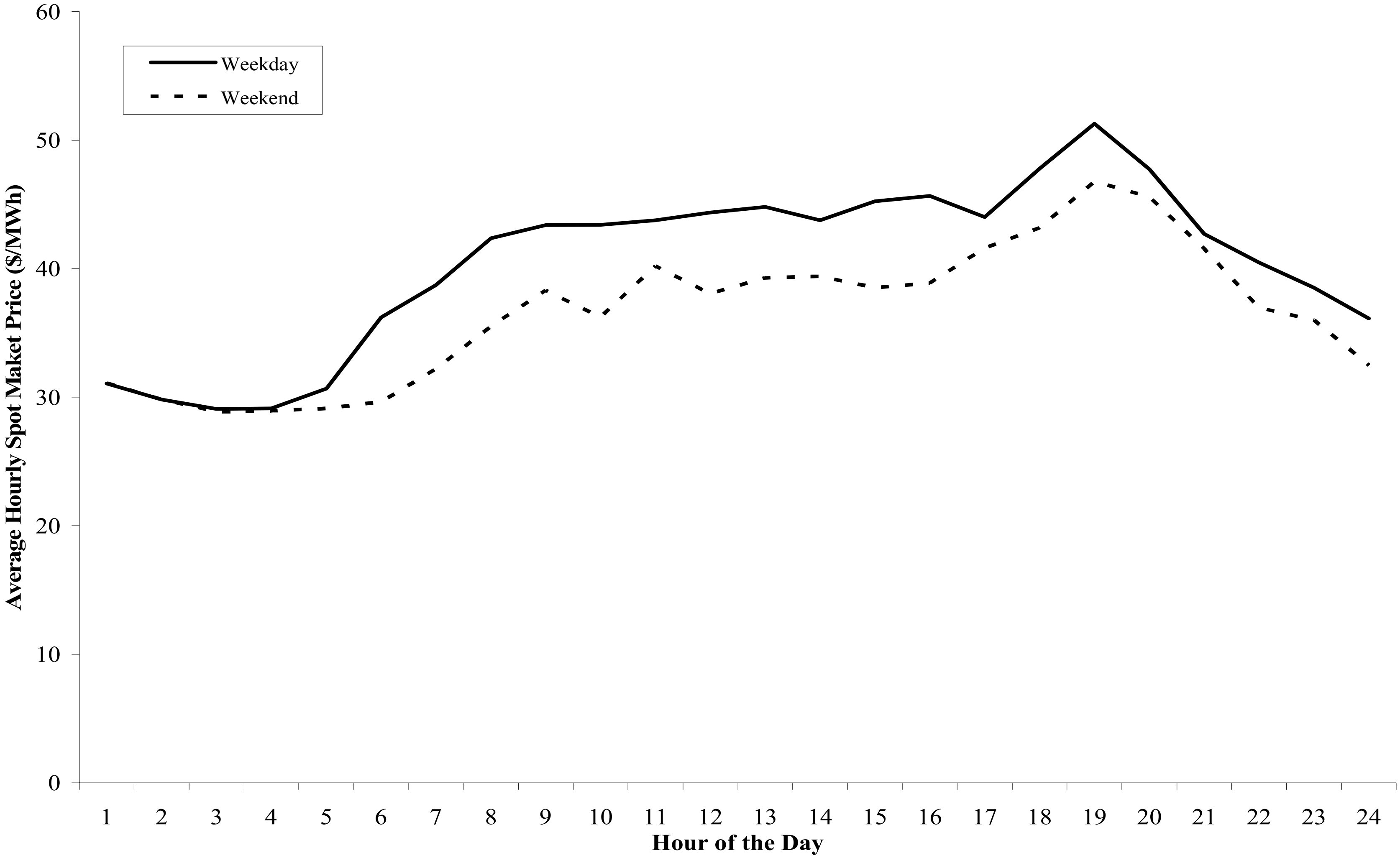

Figure 6.6. Projected Average Spot Market Prices for a Weekday and Weekend in October.

Spot market prices during the past 2 years in the WSCC have been very volatile and were subject to a number of market forces and rule modifications in the California market that heavily influenced WSCC prices. The forecasts presented in this section are much higher than current spot market prices. However, the projections were more consistent with prices at the time the AURORA model runs were performed.

Future prices in the open market may significantly differ from those used for this analysis. Although prices are uncertain, the general seasonal pattern of higher prices in the winter and summer with lower prices in the spring and autumn has persisted in the past and is expected to continue into the future. Also, the daily price patterns that are exhibited in figures 6.3 through 6.6 are reasonable.

Since the same forecast is used for both alternatives the relative differences between the two alternatives in terms of percentage is a more robust measure of the economic impacts of the alternative than the absolute dollar values.

7. MONTHLY FLAMING GORGE OPERATIONS AND YAMPA INFLOWS

The Green River model simulates water releases from the Flaming Gorge Dam on a daily basis and estimates the reservoir elevation level at the end of each month. Both water releases and reservoir elevations influence the economic value of the Flaming Gorge power resource. To a large extent daily water releases dictate the amount of energy that will be generated. For the No Action Alternative, the sum of the daily water releases in a month constrains monthly generation levels. The reservoir elevation level directly influences both the generation capability and power conversion factors.

7.1 Flaming Gorge Reservoir Elevations

Forecasts of end-of-month (EOM) Flaming Gorge reservoir elevations for the representative trace for both the No Action and Action Alternatives are shown in figure 7.1. The average EOM reservoir elevation level over the 25-year study period is about 6026 feet above sea level for both alternatives. However, the No Action Alternative has a higher range of elevations from 6010.9 to 6040.4 feet versus a range of 6015.6 to 6037.4 feet for the Action Alternative.

The higher degree of reservoir variability is also evident by comparing the annual minimum and maximum elevation levels shown in figures 7.2 and 7.3 for the No Action and Action Alternatives, respectively. These two figures also show that the annual average reservoir elevation has a higher degree of variability under the No Action Alternative.

Reservoir elevation levels predicted under both alternatives are well within historical extremes after full operations began in November 1967 (***Flow Recommendations Report, Pages 3-4)***. In April 1970, the reservoir elevation reached a low at approximately 5967 feet and in June 1983 the reservoir elevation was over 6042 feet (***PO&M-59)***.

7.2 Flaming Gorge Water Releases

The Green River model also projects a high degree of variability for monthly water releases. Figure 7.4 shows average monthly water release rates in terms of cfs for both alternatives. Average water releases

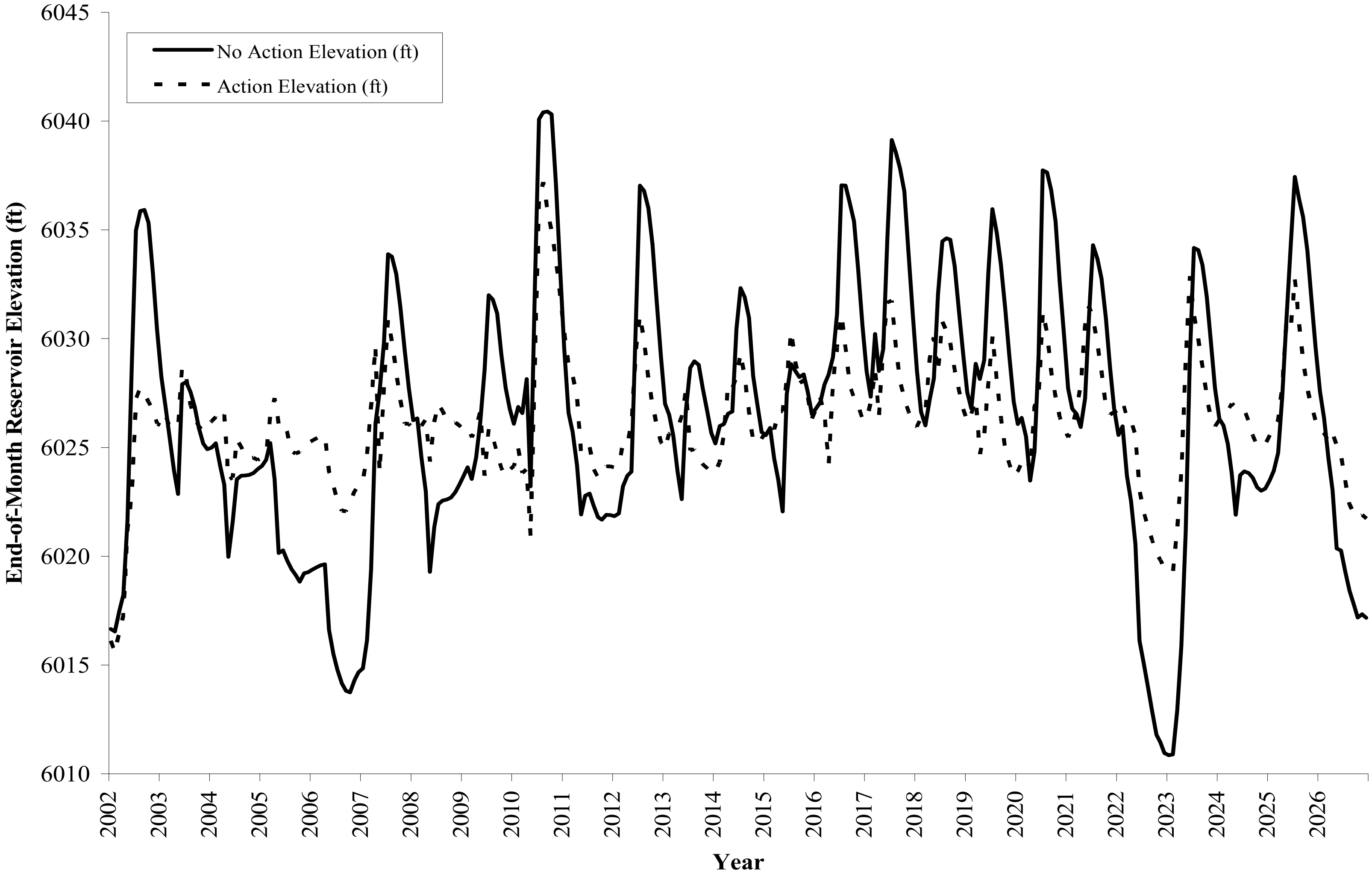

Figure 7-1. Monthly Reservoir Elevations Projected by the Green River Model for the No Action and Action Alternatives (Representative Trace – Run 36).

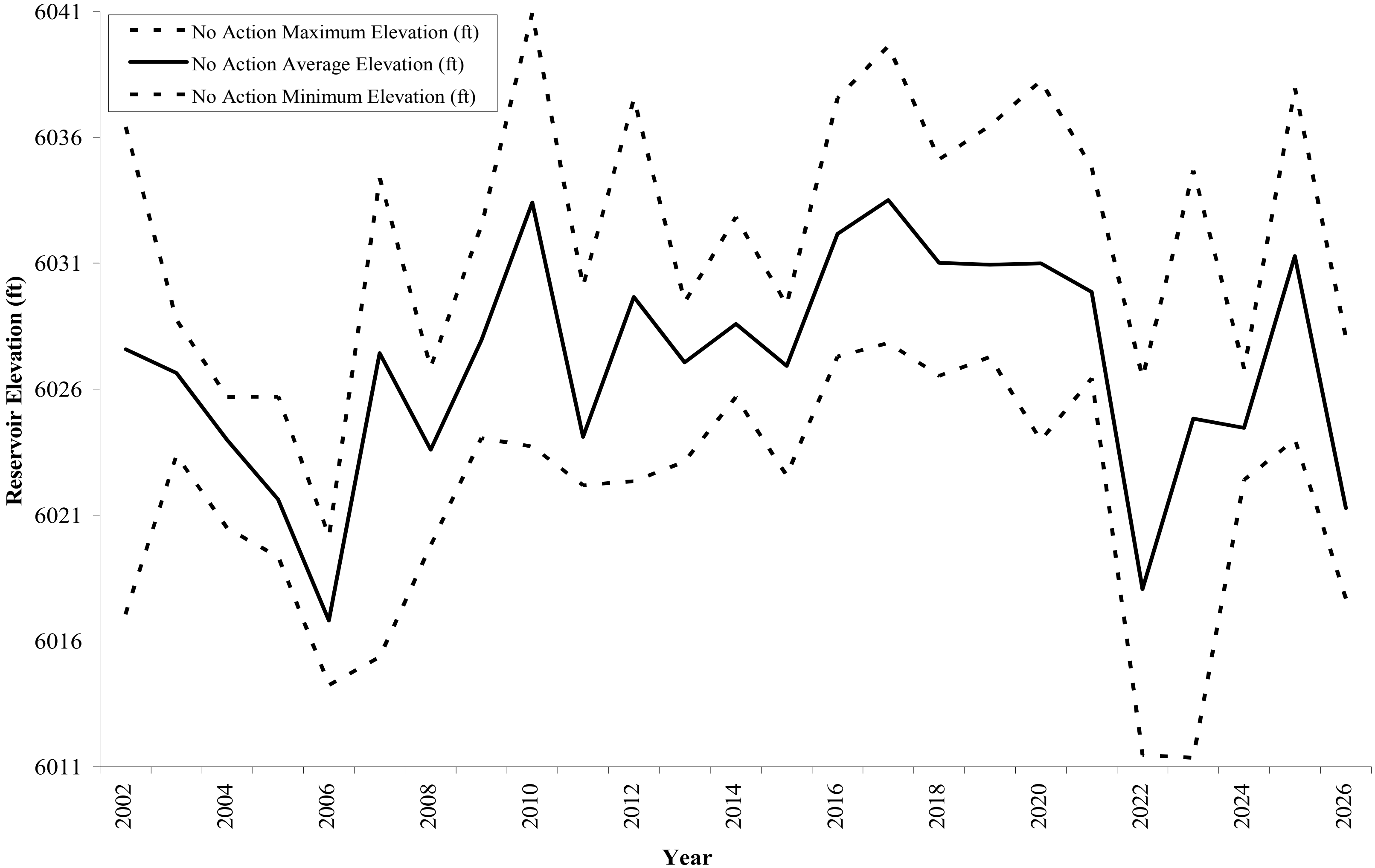

Figure 7-2. Average and Range of Monthly Reservoir Elevations Projected by the Green River Model for the No Action Alternative (Representative Trace — Run 36). Alternatives (Representative Trace – Run 36).

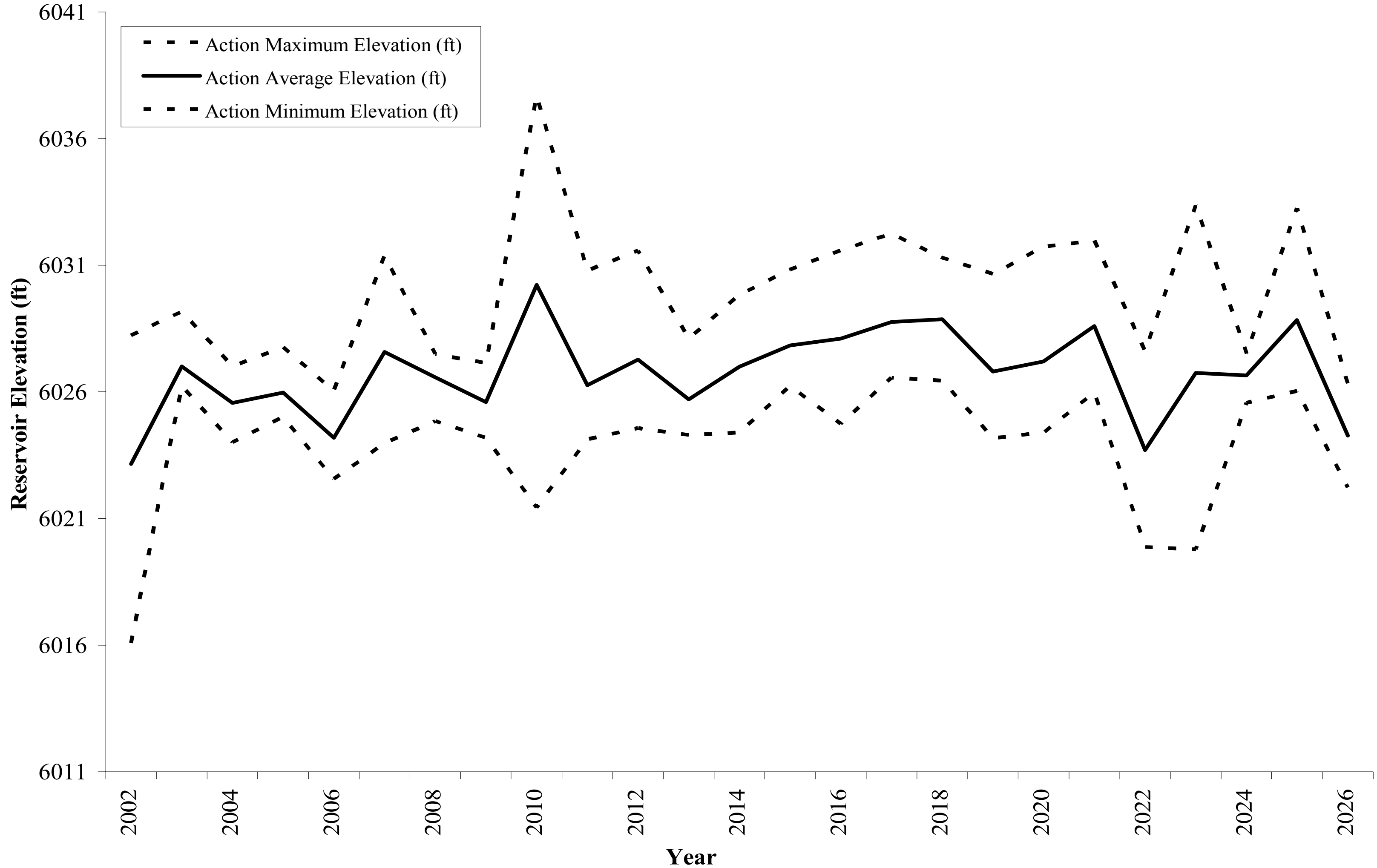

Figure 7-3. Average and Range of Monthly Reservoir Elevations Projected by the Green River Model for the Action Alternative (Representative Trace — Run 36). Alternatives (Representative Trace – Run 36).

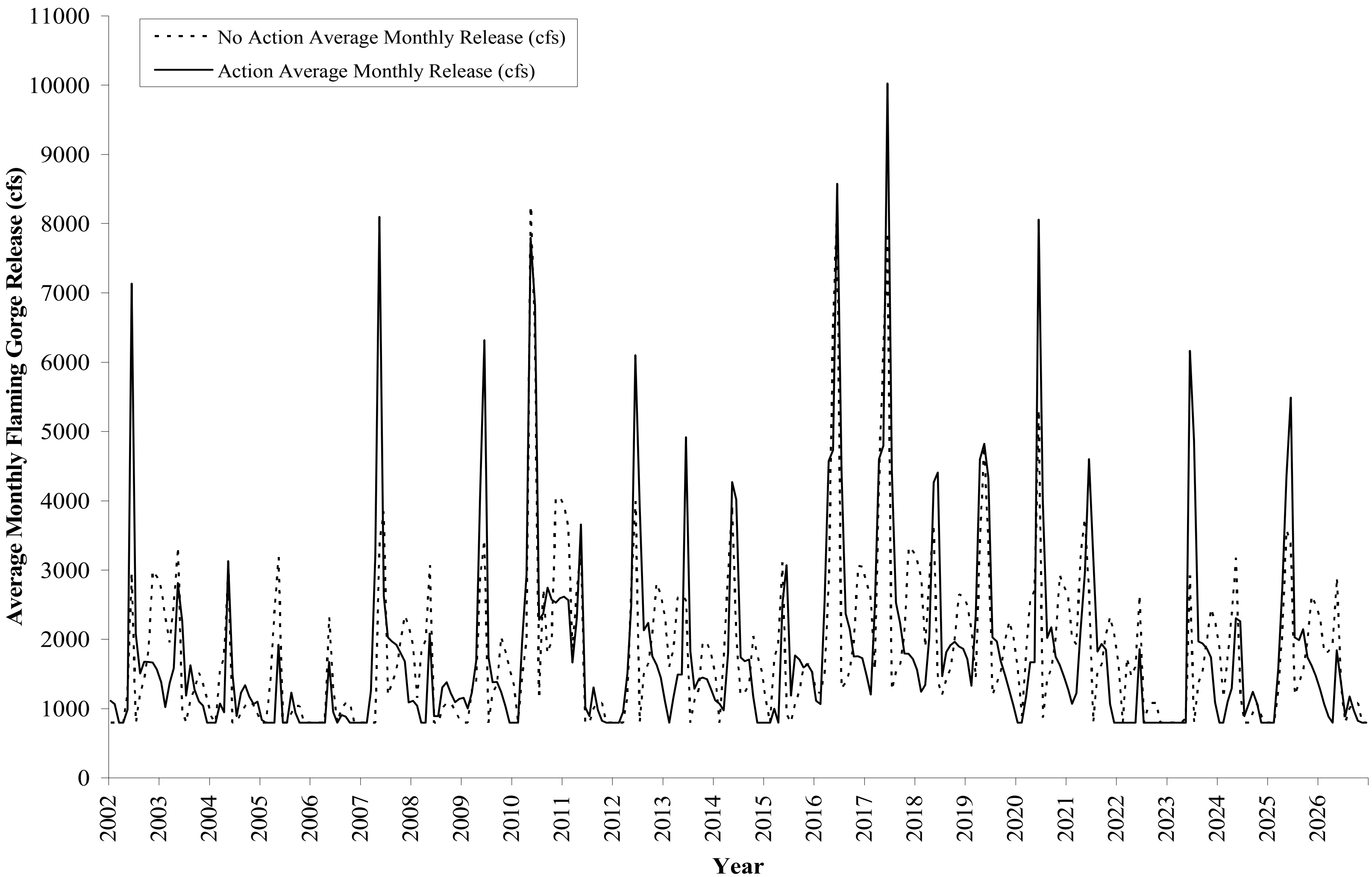

Figure 7-4. Monthly Releases from Flaming Gorge Projected by the Green River Model for the No Action and Action Alternatives (Representative Trace – Run 36).

over the study period are nearly identical for the alternatives at about 1,840 cfs. For the Action Alternative, monthly water releases range from 800 to 15,000 cfs. Monthly releases for the No Action Alternative range from 800 cfs to 11,500 cfs. Since the maximum powerplant release is less than 5,000 cfs, it is projected that both alternatives will have non-power water releases. Most of these spills occur during spring spike periods.

During periods of low releases when the release level is 800 cfs, the powerplant has very little operational flexibility since this equals the minimum flow requirement. The only flexibility that the operator has is to decide which turbine(s) to release the water through. There is no operational flexibility during very high release periods when all of the turbines are operated at the maximum flow rate. Under both extreme cases there are no differences between the two alternatives. The largest economic and operational differences occur when releases are at a more moderate level.

Figures 7.5 and 7.6 show average water releases and the range of flows by month over the study period for the No Action and Action Alternatives, respectively. For both alternatives, the lowest average monthly flow rates are about 800 cfs. Only 2 months, September and October, under the No Action Alternative have minimum flow rates that slightly exceed 800 cfs. The highest flow rates occur during May and June under both alternatives. These high maximum flow rates extend into July under the Action Alternative. In general, the range of flow rates is highest during the late spring and early summer period.

On average the Action Alternative releases more water during times of the year when power generation has the greatest value. Table 7.1 shows that during the 3 months with the highest spot market prices (i.e., July, August, and September) the Action Alternative has significantly higher water releases. This is most noticeable for the month of July when releases for the Action Alternative are on average more than twice those of the No Action Alternative. On the other hand, releases for the Action Alternative are on average lower during the other months of the year when spot prices are less expensive.

Table 7.1 Average Monthly Spot Market Prices and Water Release Rates from the Flaming Gorge Dam for the No Action and Action Alternatives

Month	No Action Average Release Rate (cfs)	Action Average Release Rate (cfs)	Average Spot Market Price ($/MWh)
Jan	1,675	1,108	54
Feb	1,350	1,006	47
Mar	1,493	1,286	43
Apr	2,153	1,900	40
May	3,445	3,213	46
Jun	2,884	4,223	54
Jul	937	2,054	125
Aug	1,267	1,650	134
Sep	1,357	1,633	88
Oct	1,668	1,444	52
Nov	1,970	1,328	52
Dec	1,862	1,205	55
Average	1,838	1,838	66

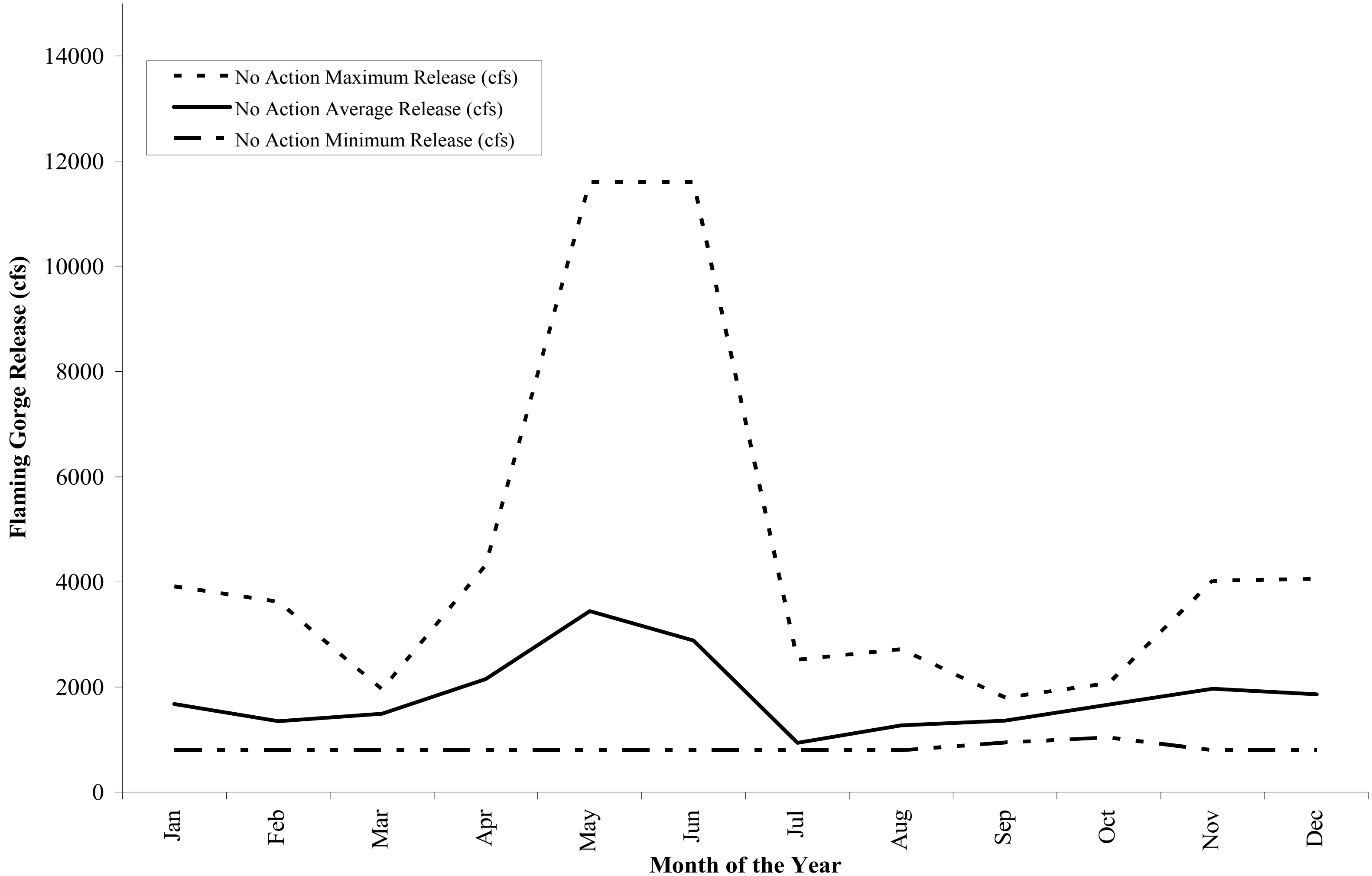

Figure 7-5. Average and Range of Monthly Releases Projected by the Green River Model for the No Action Alternative (Representative Trace – Run 36).

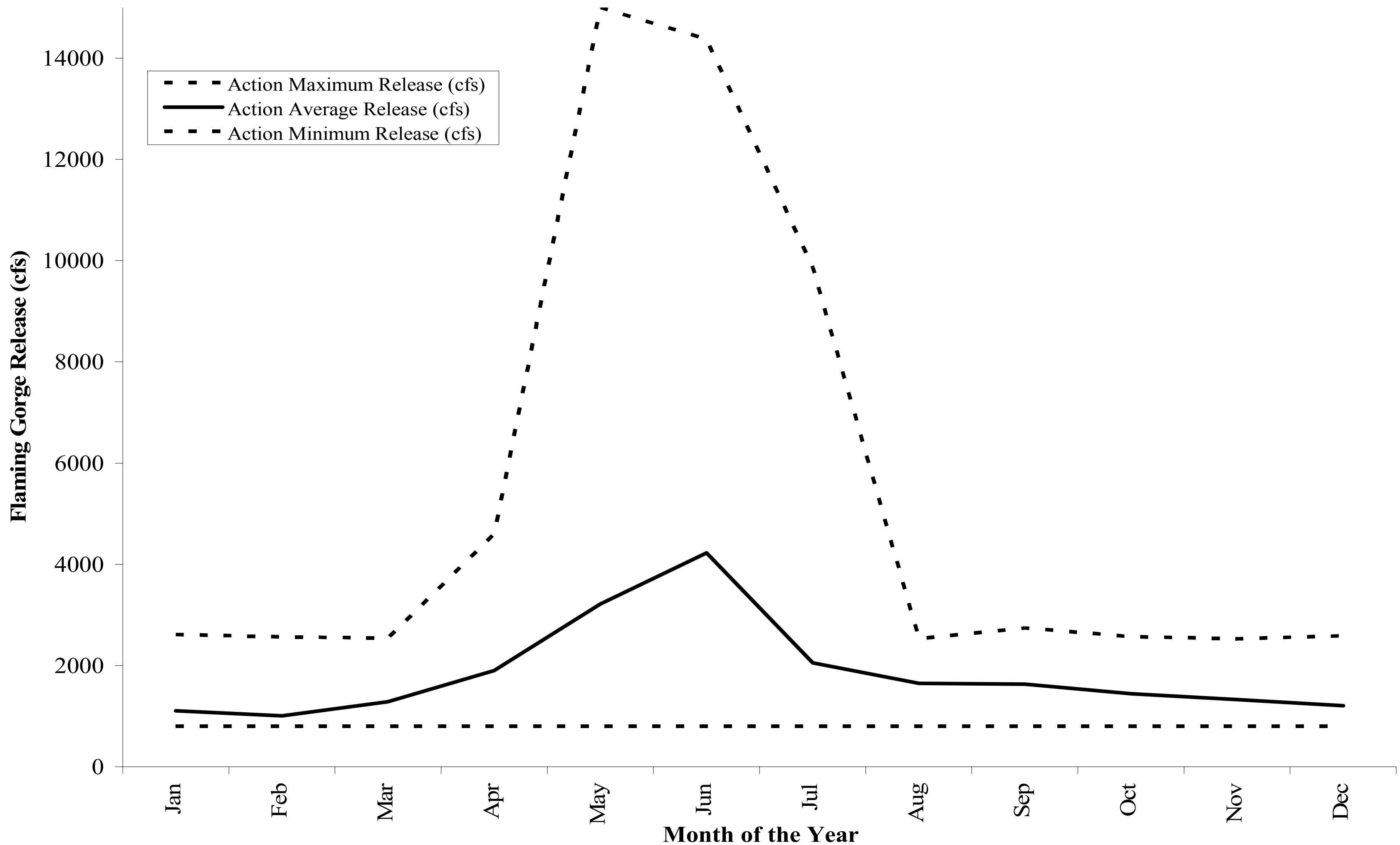

Figure 7-6. Average and Range of Monthly Releases Projected by the Green River Model for the Action Alternative (Representative Trace – Run 36).

7.3 Yampa Inflows

Figure 7.7 shows monthly Yampa inflows for the 2002 through 2026 study period. Inflows are highly cyclical with large inflows during the late spring and early summer and very low inflows during the rest of the year. Although this strong cyclical pattern exists, the figure also shows that annual peak inflows vary significantly among years.

The cyclical pattern and annual variability are highlighted in figure 7.8. In the month of May, Yampa inflows range from about 1,800 cfs to more than 21,700 cfs. In contrast the inflow range in January is from about 110 to 700 cfs. Yampa variability is very high largely due to the fact that it is not regulated (i.e., there are no dams) and that it carries significant amounts of snowmelt from the mountains.

8. ECONOMIC COMPUTATIONS AND RESULTS

The economics of the No Action and Action Alternatives are based on net present value (NPV) calculations of the hourly value of Flaming Gorge generation over the 25-year study period. The value of generation is computed by multiplying hourly electricity production by the hourly spot market price. All NPV calculations are based on an annual discount rate of 5.5 percent. The nominal value of Flaming Gorge hourly generation is totaled for a weekly period and discounted to the beginning of the simulation year from the middle of the week. The annual beginning of year revenues are then discounted to January 1, 2002.

The economic impact of implementing flow recommendations under the Action Alternative is measured as the difference in the NPV between the Action and the No Action Alternatives. Table 8.1 shows that operating under Action Alternative constraints will increase the economic value of the Flaming Gorge Powerplant by approximately 5.5 percent above the No Action Alternative. The Action Alternative has a higher economic value despite projected higher non-turbine releases and lower generation levels. Table 8.2 shows that non-power releases for the Action Alternative are projected to be almost twice as much as the No Action Alternative. This is the main factor that leads to a total reduced power output of about 4.5 percent over the 2002-2026 study period.

Table 8.1. Comparison of the Economic Benefits of the Flaming Gorge Powerplant under the No Action and Action Alternatives

	No Action Alternative	Action Alternative	Increase Above the No Action Alternative (%)
Nominal Value (10^6 $)	806	851	5.5
NPV (10^6 $)	403	423	5.0

Table 8.2. Comparison of the Water Release and Generation from the Flaming Gorge Powerplant under the No Action and Action Alternatives

	No Action Alternative	Action Alternative	Increase Above the No Action Alternative (%)
Average Water Release (cfs)	1,839	1,839	0.0
Average Non-turbine Release (cfs)	64	125	94.6
Generation (GWh)	11,904	11,374	-4.5

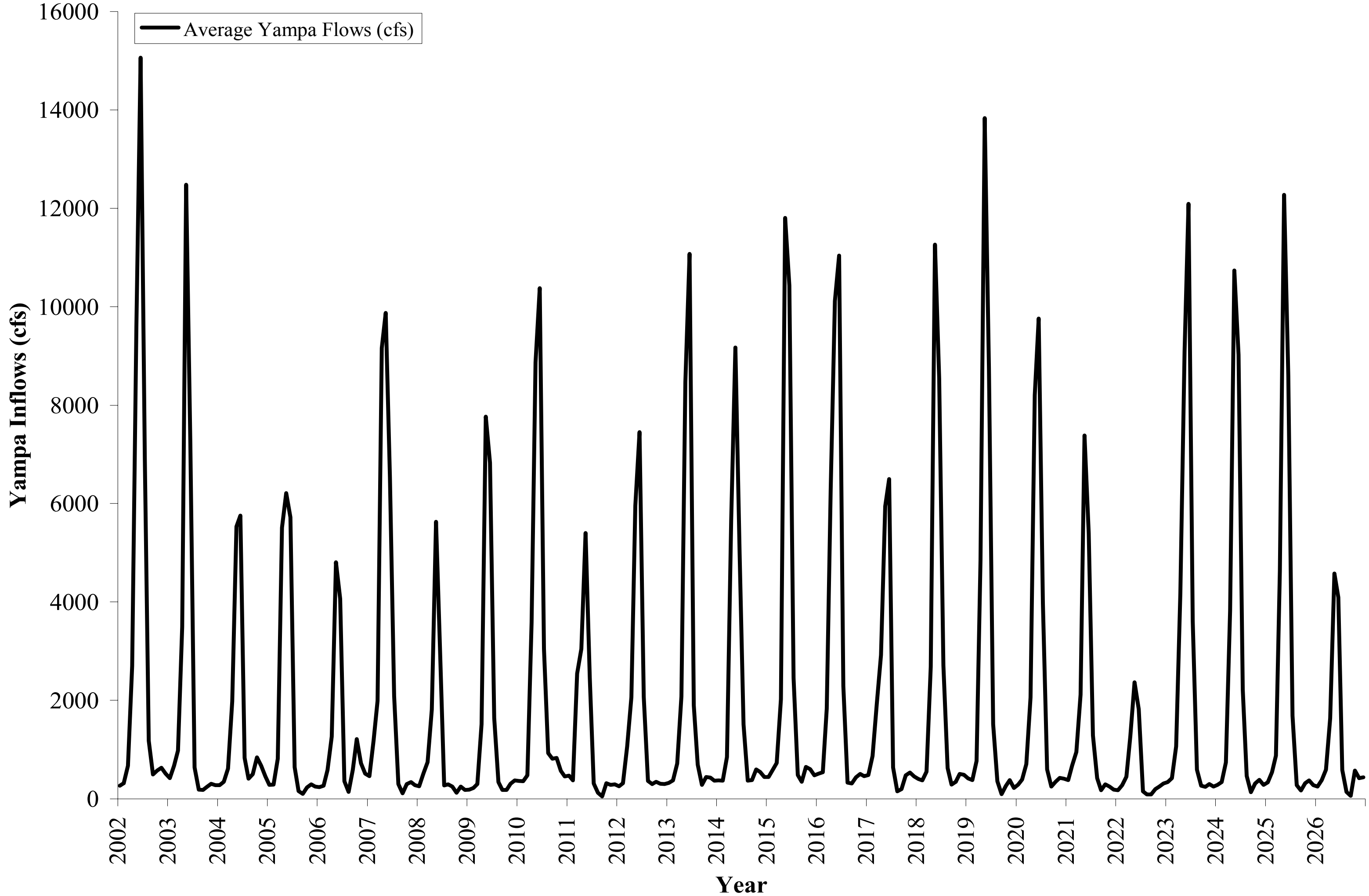

Figure 7-7. Monthly Yampa Inflow Projections from the Green River Model (Representative Trace – Run 36).

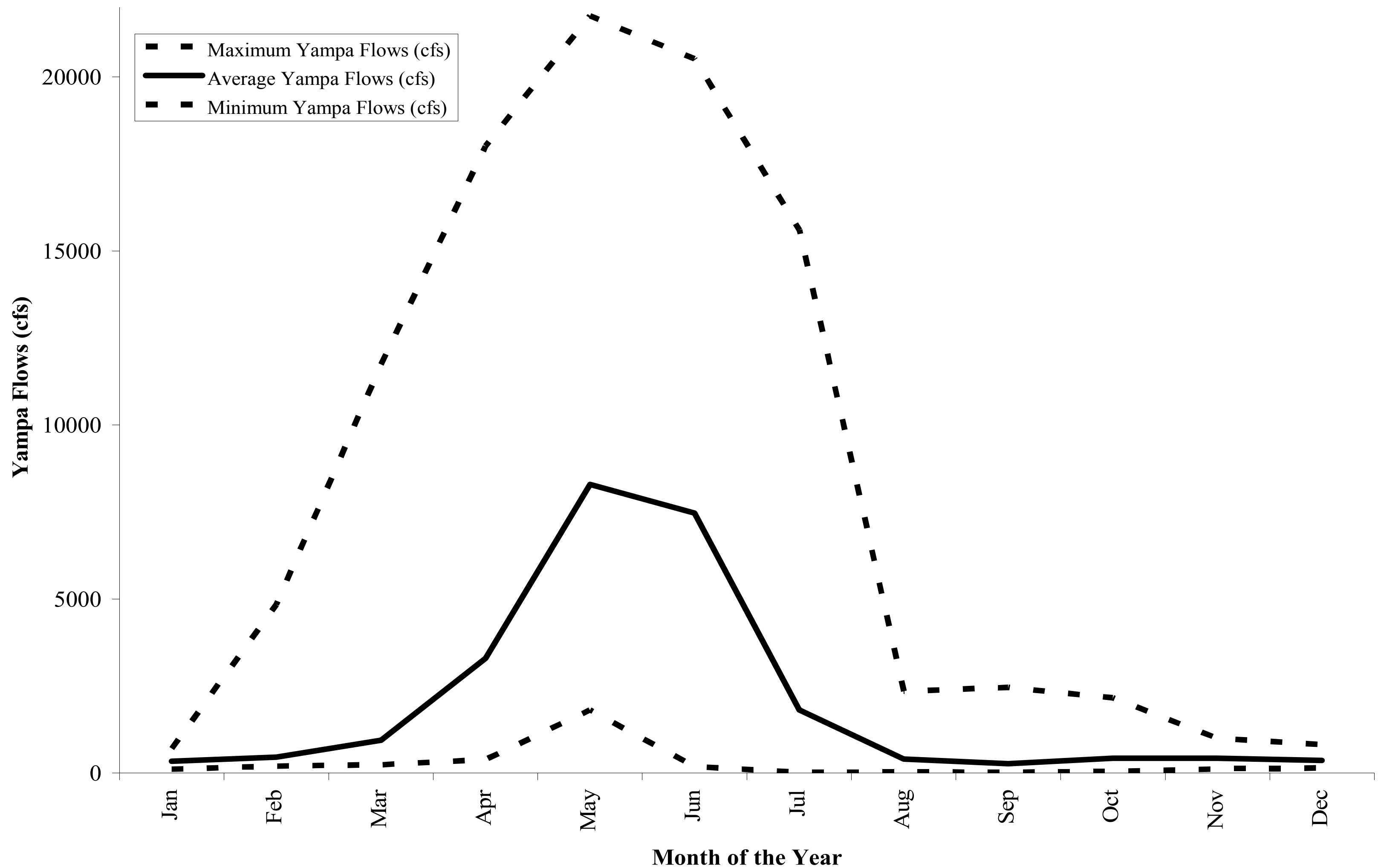

Figure 7-8. Average and Range of Monthly Yampa Inflows Projected by the Green River Model for the No Action Alternative (Representative Trace – Run 36).

Although the Action Alternative is projected to have an overall higher economic benefit, there are some years that the benefits are expected to be negative. Table 8.3 shows that the Action Alternative has lower nominal revenues during 10 years of the 25-year study period. In each of these years annual generation for the No Action Alternative is significantly higher than for the Action Alternative.

Table 8.3 Comparison of the Annual Economic Benefits of the Flaming Gorge Powerplant under the No Action and Action Alternatives

		No Action Alternative			Action Alternative				
Year	Average Spot Market Price ($/MWh)	Average Power Release (cfs)	Annual Generation (GWh)	Nominal Value (Millions $)	Average Power Release (cfs)	Annual Generation (GWh)	Nominal Value (Millions $)	Generation Above the No Action Alternative (GWh)	Nominal Value Above the No Action Alternative (Million $)
2002	60.0	1,548	415.8	26.0	1,631	428.9	27.4	13.1	1.5
2003	47.5	1,750	471.0	21.8	1,456	386.3	18.9	-84.8	-2.8
2004	42.6	1,222	321.3	13.5	1,257	330.2	14.5	8.9	1.1
2005	42.7	1,233	322.3	13.3	947	245.8	11.0	-76.5	-2.3
2006	44.9	1,036	264.6	12.3	903	233.0	10.8	-31.6	-1.5
2007	48.6	1,760	470.1	24.2	1,981	530.2	27.2	60.0	3.0
2008	53.3	1,381	366.2	18.9	1,150	304.0	18.1	-62.2	-0.8
2009	61.1	1,619	431.4	25.9	1,674	441.0	29.1	9.6	3.2
2010	62.3	2,540	687.0	46.0	2,452	666.2	45.8	-20.8	-0.2
2011	64.2	1,805	484.0	27.5	1,616	432.7	26.7	-51.3	-0.8
2012	65.4	1,771	476.4	31.5	1,981	526.6	41.1	50.2	9.6
2013	67.6	1,875	506.0	32.3	1,620	427.4	32.6	-78.6	0.3
2014	68.6	1,843	495.6	35.1	1,766	467.5	35.6	-28.0	0.5
2015	70.3	1,467	391.0	27.2	1,510	401.0	32.7	10.0	5.5
2016	70.9	2,327	630.4	44.9	2,739	728.9	56.6	98.5	11.8
2017	71.6	2,793	757.3	51.5	2,812	749.2	58.4	-8.0	7.0
2018	78.5	2,275	622.3	50.2	2,027	545.4	46.7	-76.9	-3.5
2019	78.3	2,272	614.6	48.0	2,372	628.7	50.9	14.2	2.9
2020	79.3	2,138	580.4	46.0	1,985	528.8	50.9	-51.6	4.9
2021	79.4	2,218	602.2	46.6	2,001	534.3	48.6	-68.0	2.0
2022	79.4	1,288	335.8	27.8	887	228.2	18.1	-107.6	-9.7
2023	79.4	1,447	385.9	32.8	1,744	461.3	46.3	75.4	13.5
2024	79.3	1,406	373.5	28.2	1,204	316.7	28.1	-56.8	-0.1
2025	79.4	1,886	509.7	43.7	2,069	556.2	49.5	46.5	5.8
2026	79.4	1,472	389.5	30.9	1,060	275.9	24.9	-113.6	-6.1

The primary reason that the Action Alternative has a higher overall economic value despite lower generation levels is that more power is being generated when it has the highest economic value. As shown on figure 8.1, average weekly generation for the Action Alternative is significantly higher during the high priced summer months as compared to the No Action Alternative. Note that throughout the summer price spike period for weeks 26 through 40 that the average generation level is always higher for the Action Alternative. On the other hand, generation levels during much of the rest of year are lower under the Action Alternative.

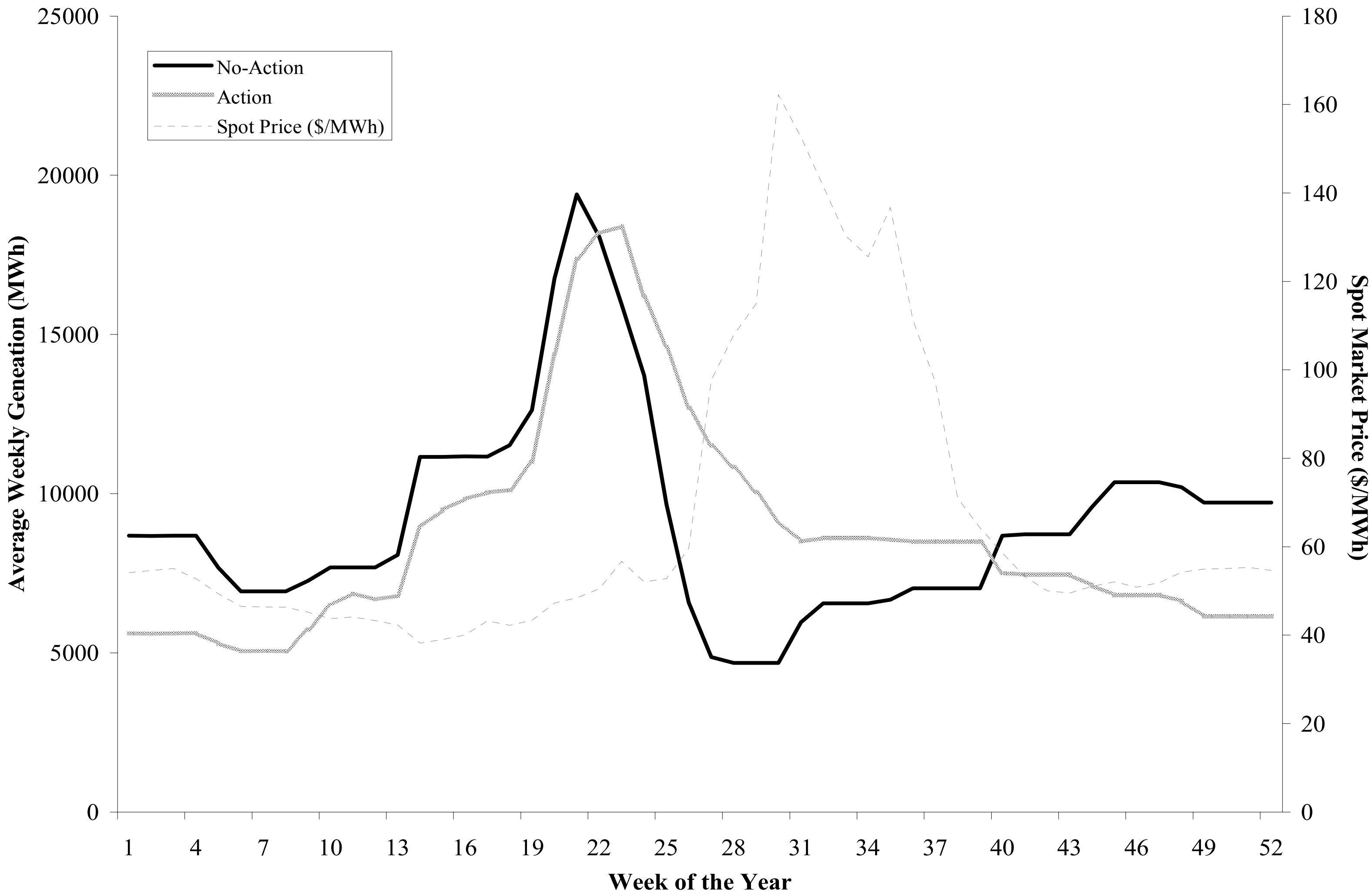

Figure 8-1. Average Weekly Generation Levels and Spot Market Prices for the No Action and Action Alternatives.

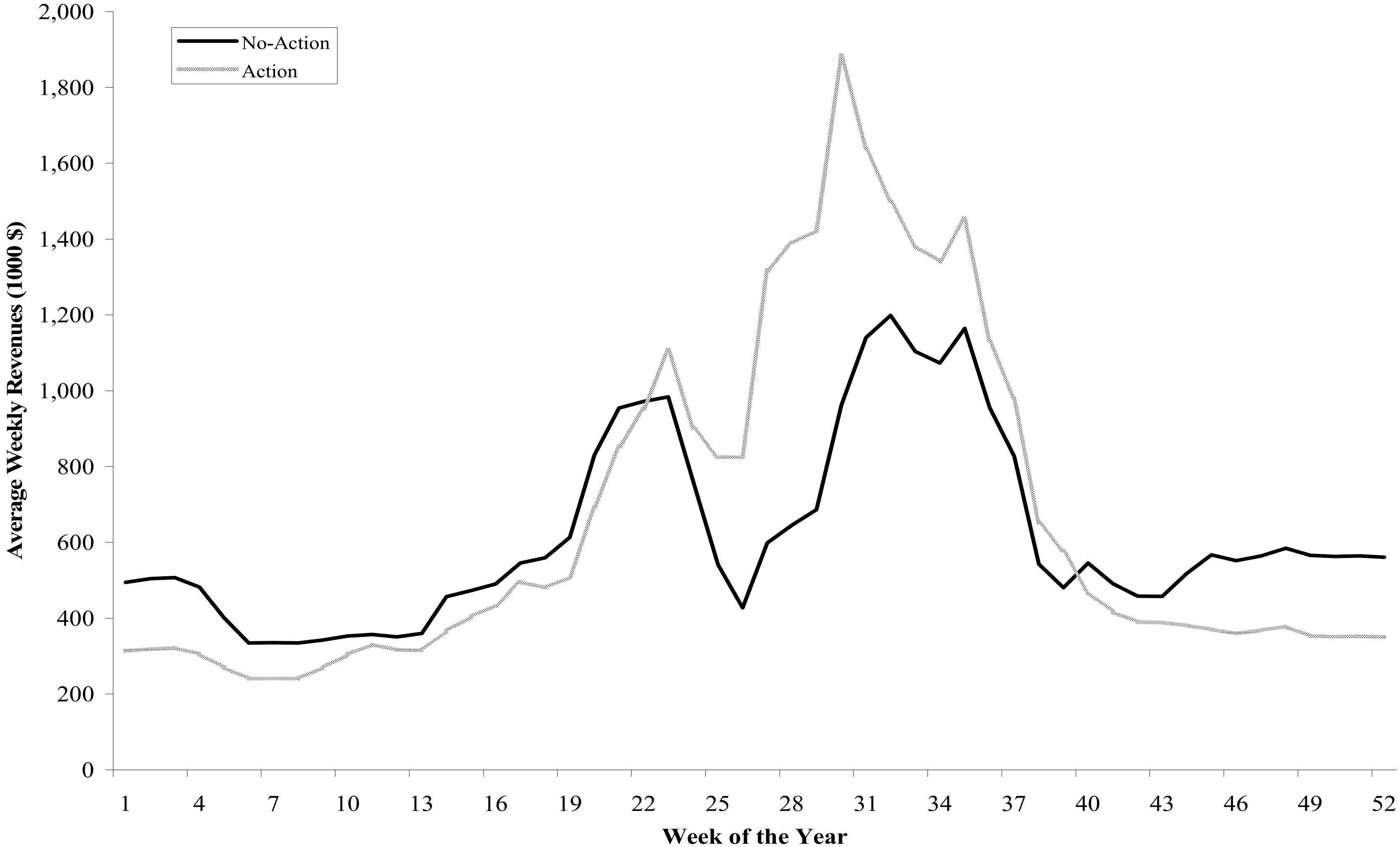

Figure 8-2. Average Weekly Revenues for the No Action and Action Alternatives.

Average nominal revenues for the two Alternatives are shown in figure 8.2. Consistent with the weekly distribution of generation levels and spot market prices, the Action Alternative has much higher revenues during the summer. These gains more than offset lower revenue streams during the other seasons. If price differences among the seasons of the year were projected to be smaller, then the Action Alternative would have a lesser economic advantage relative to the No Action Alternative and under some spot price scenarios an economic disadvantage.

With similar monthly release levels, hourly operations under the two alternatives are alike. Figures 8.3 and 8.4 show Flaming Gorge release patterns and resultant Jensen Gauge flows under average hydropower conditions for the No Action and Action Alternatives, respectively. The figure shows that release patterns and hence generation for both alternatives are able to respond to market price signals. During the most expensive spot market hours water releases are relatively high. In general, however, release levels for the No Action Alternative fluctuate slightly more than for the Action Alternative. This is partially due to a slightly larger average release rate over the week for the No Action Alternative (i.e., 2,722 cfs) compared to the Action Alternative (i.e., 2,370 cfs). Also, the No Action Alternative has a slightly larger Jensen Gauge flow window compared to the Action Alternative.

The upper bounds of the gauge flow window for the No Action Alternative are fixed through the simulated week at +/- 12.5 percent of the average weekly flow rate. As shown in figure 8.4. the gauge flow rate window is somewhat smaller for the Action Alternative

Similar release patterns in response to market prices and gauge constraints are displayed under both wetter and drier hydropower conditions. Figures 8.5 and 8.6 show generation patterns for relatively dry conditions for the No Action and Action Alternatives, respectively. For both alternatives release rates are at the minimum allowable levels (i.e., 800 cfs) when prices are at their lowest levels. Peak dam releases occur during the daytime when prices are high, but ramp rate and the single-hump limitations constrain release levels well below the turbine maximum. Only two of the three turbines would be operated under these conditions.

When hydropower conditions are relatively wet, the powerplant is mainly limited by operational constraints for the No Action Alternative. Figure 8.7 shows that Jensen Gauge flows do not approach either the upper or lower limits during most the simulated week. Instead ramp-rate and the one-hump limitations along with turbine constraints dictate the release pattern. For the Action Alternative, gauge limitations are more constraining, as shown in figure 8.8. However, the economic impact of these limitations is minor since the powerplant is operating at its maximum level most of the time. Releases are only slightly lower during the lowest priced hours.

The hourly Flaming Gorge release patterns presented in this section are based on a relatively complex search routine that seeks to maximize the economic benefits of hydropowerplant operations. In doing so the mathematical algorithms find solutions that are often at the edge of compliance with little or no margin for error. Historically, operators have not used this type of approach and have been more conservative by operating the Flaming Gorge Dam well within the gauge flow limits. Given a more conservative approach the economic difference between the two alternatives may be smaller.

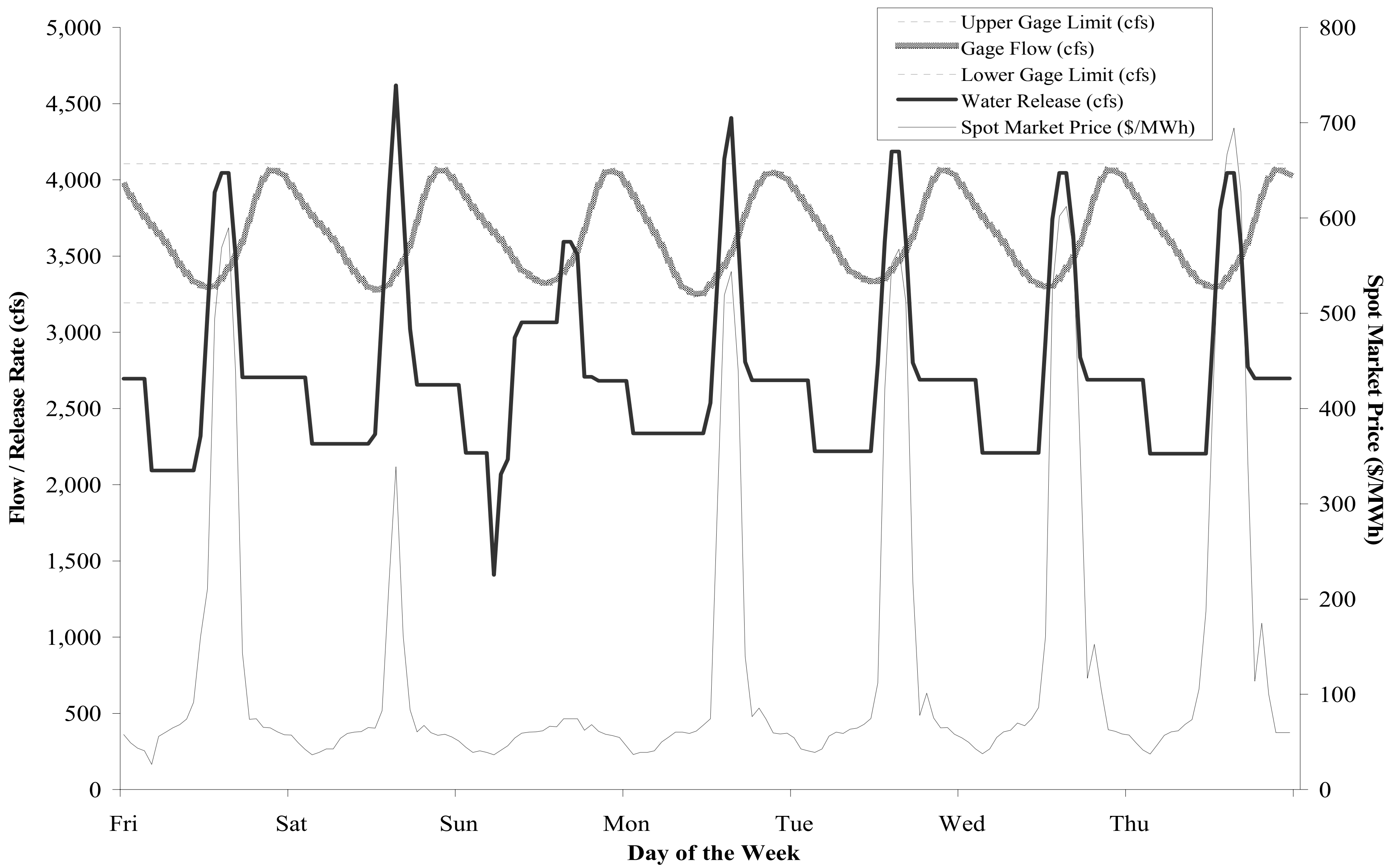

Figure 8-3. Hourly Flaming Gorge Dam Operations and Resultant Gauge Flows for the No Action Alternative Under Average Hydropower Conditions.

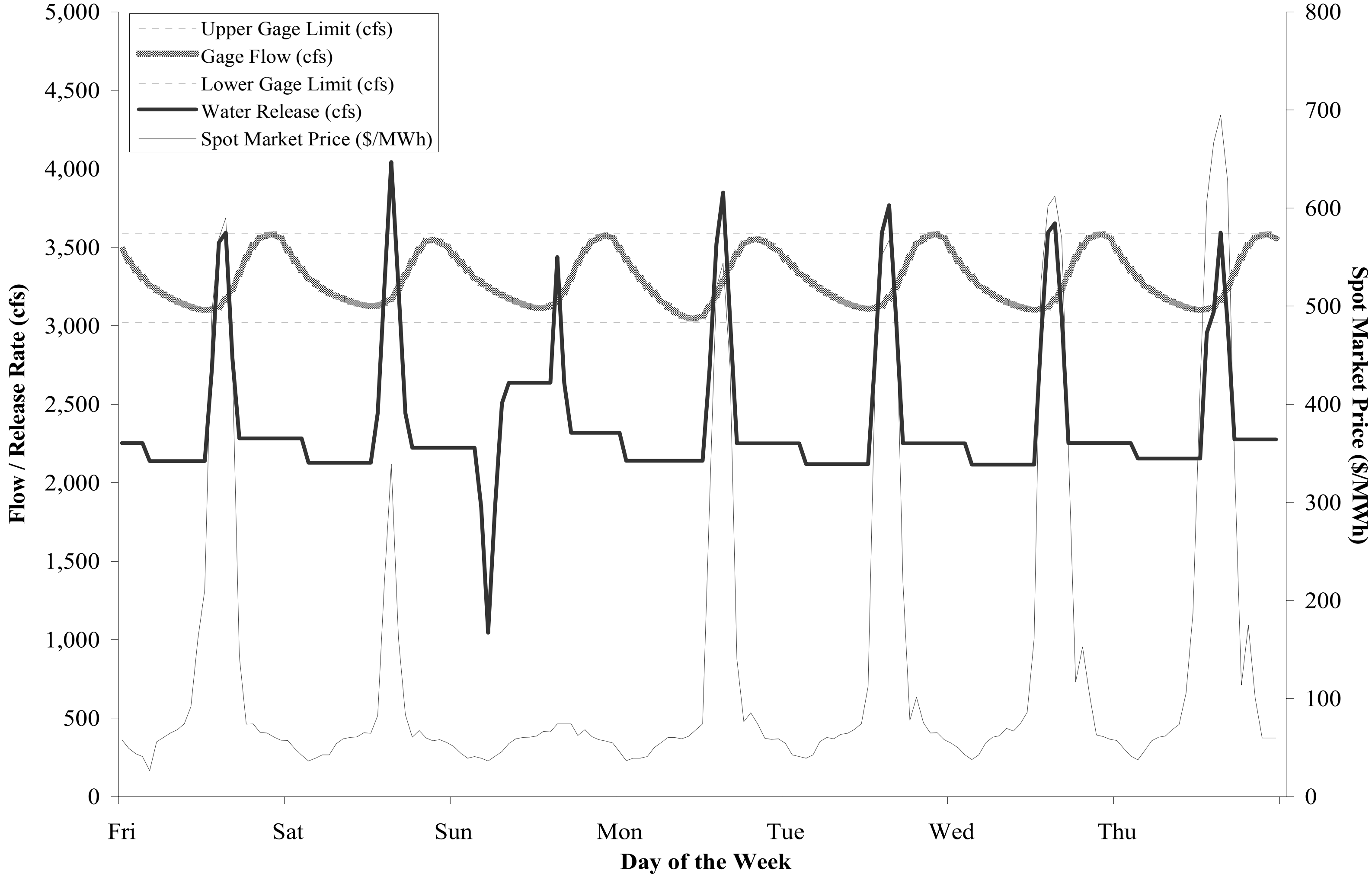

Figure 8-4. Hourly Flaming Gorge Dam Operations and Resultant Gauge Flows for the Action Alternative Under Average Hydropower Conditions.

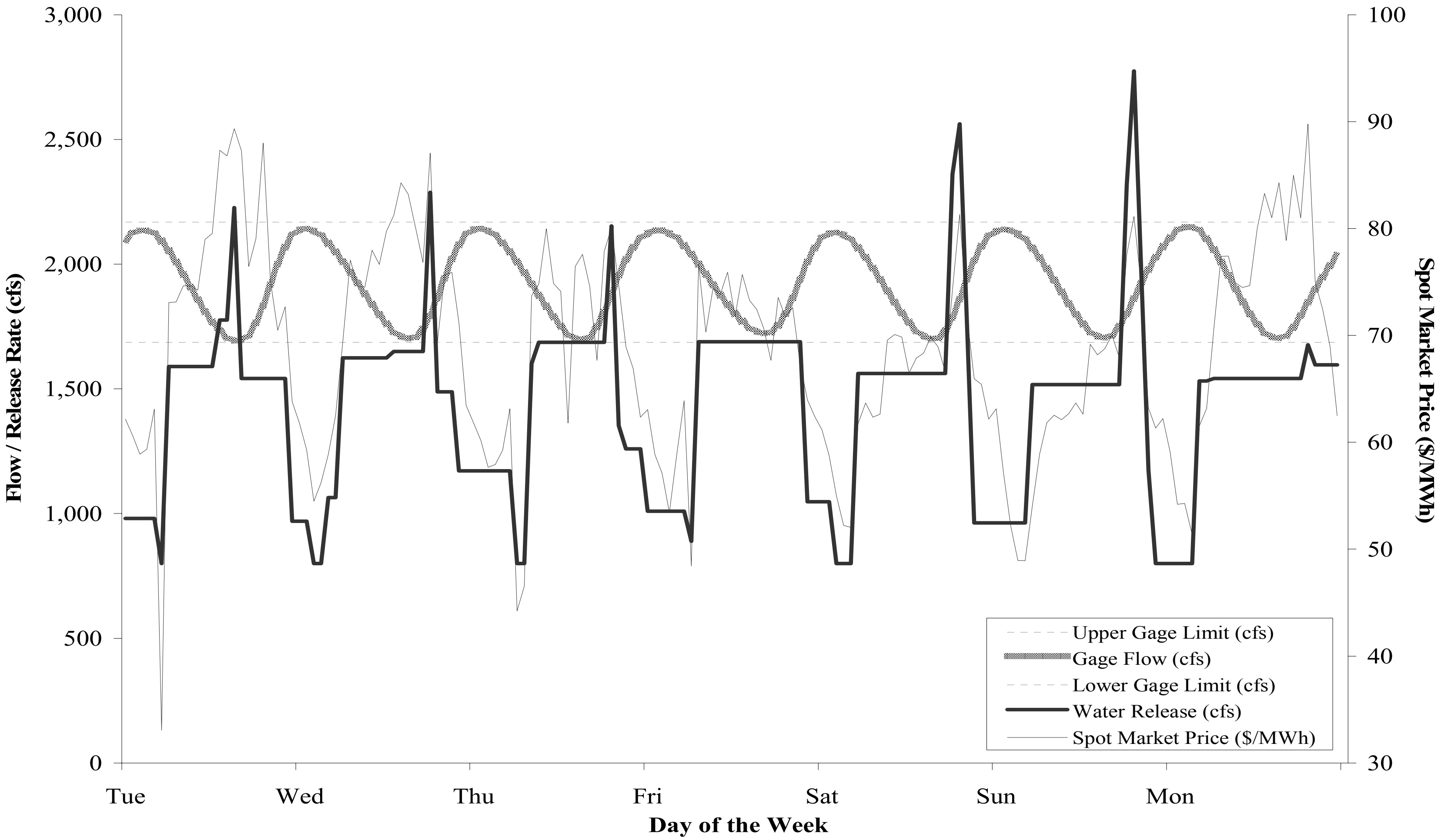

Figure 8-5. Hourly Flaming Gorge Dam Operations and Resultant Gauge Flows for the No Action Alternative Under Relatively Dry Hydropower Conditions.

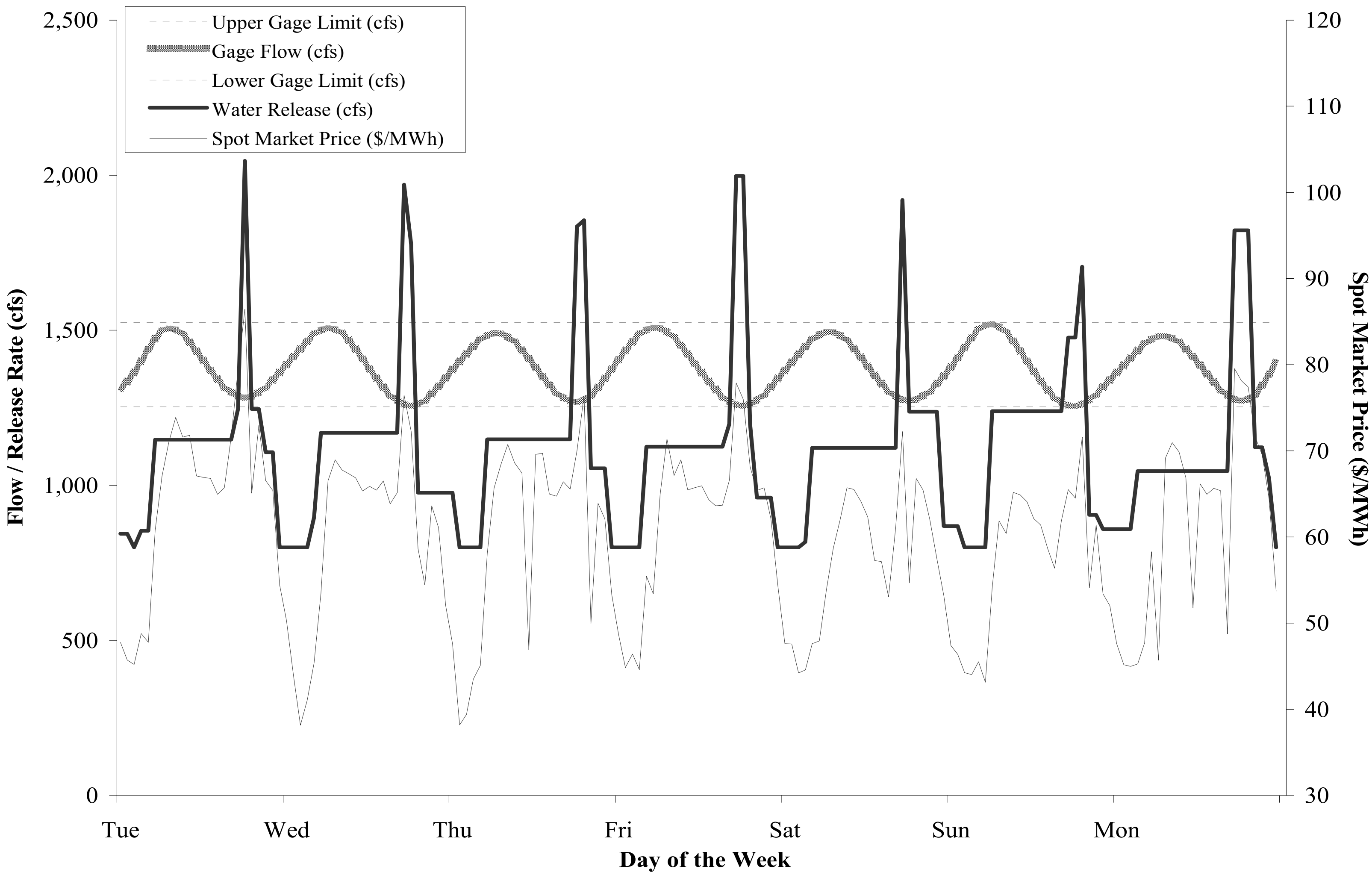

Figure 8-6. Hourly Flaming Gorge Dam Operations and Resultant Gauge Flows for the Action Alternative Under Relatively Dry Hydropower Conditions.

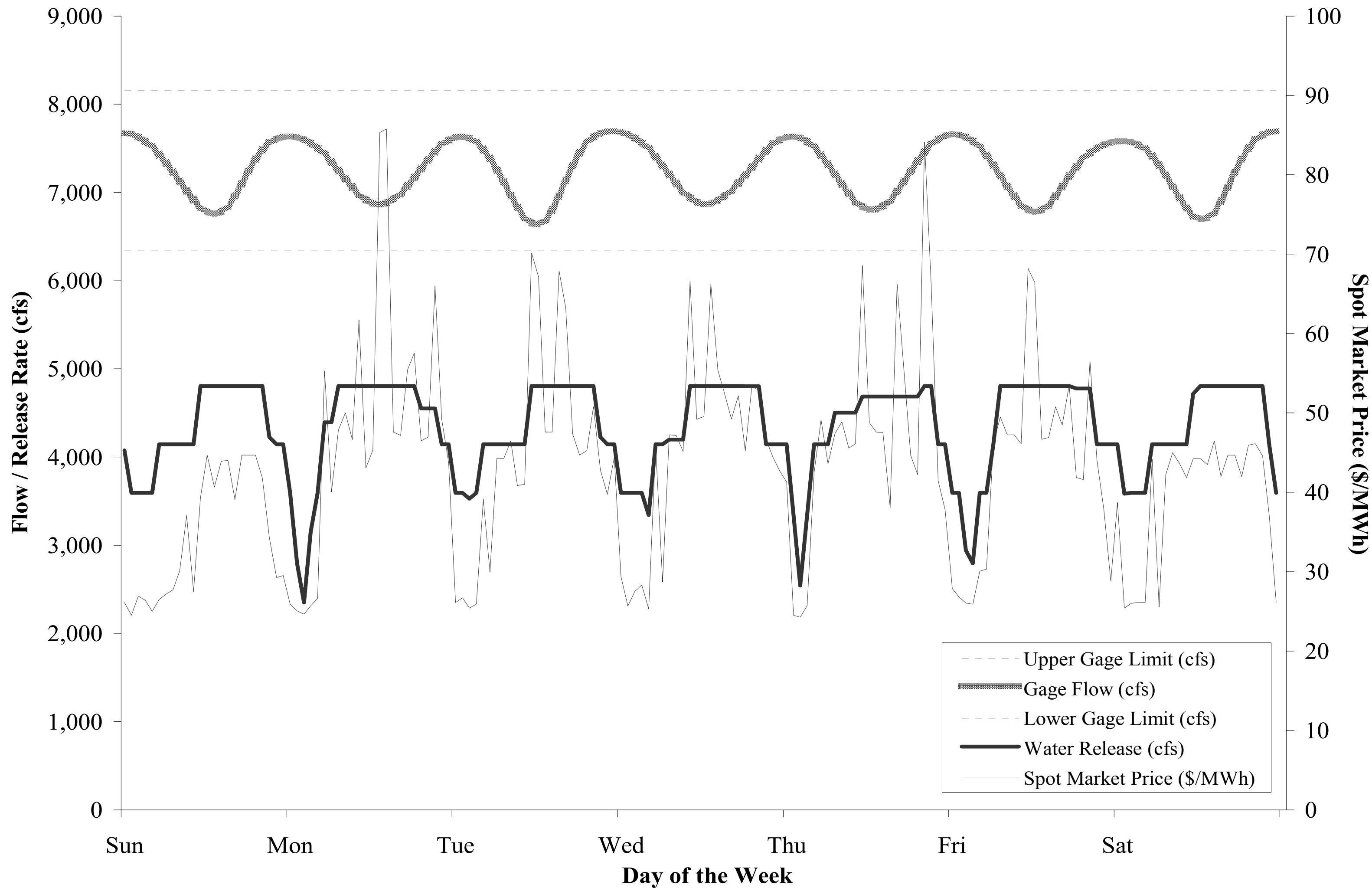

Figure 8-7. Hourly Flaming Gorge Dam Operations and Resultant Gauge Flows for the No Action Alternative Under Relatively Wet Hydropower Conditions.

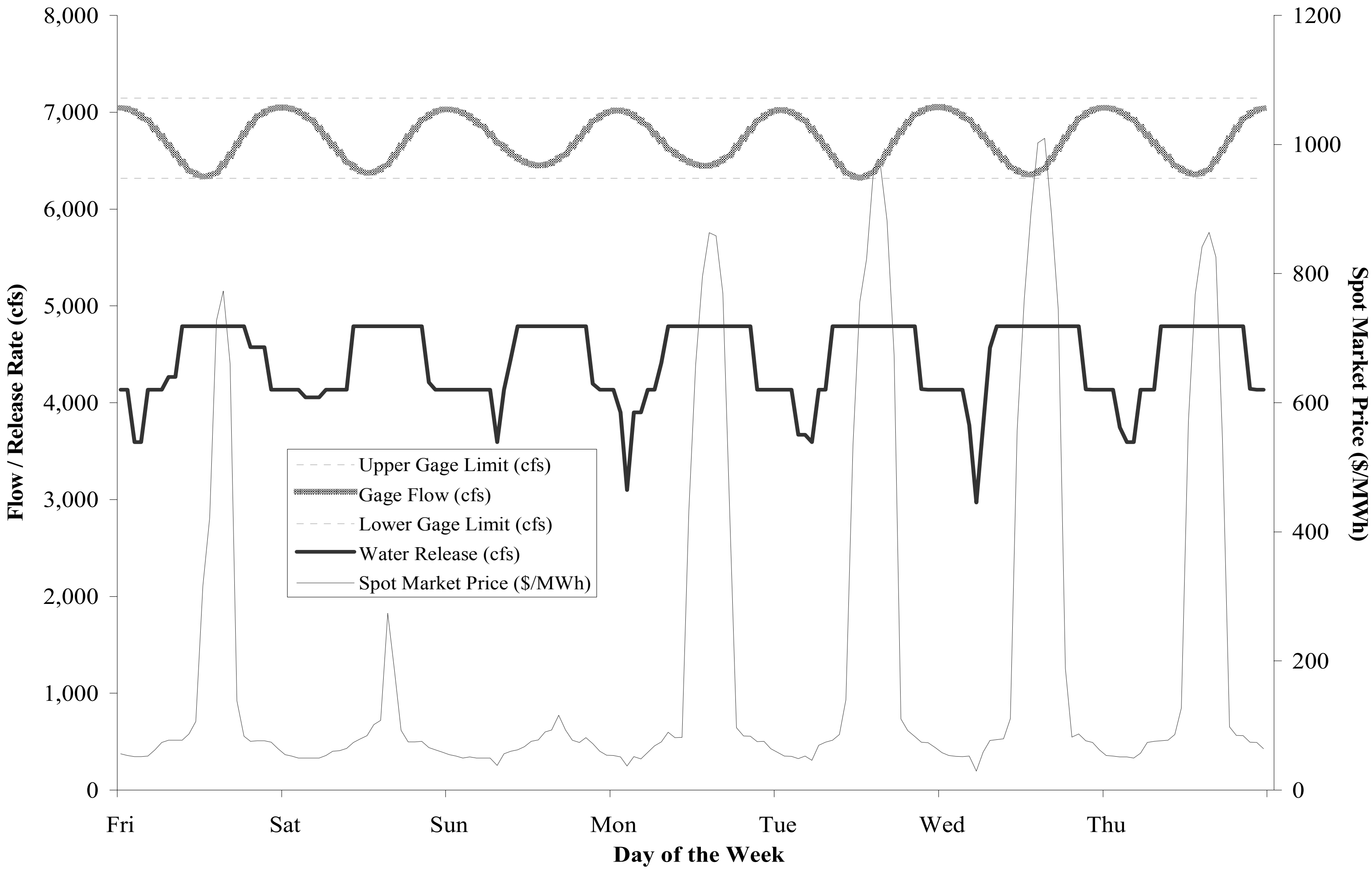

Figure 8-8. Hourly Flaming Gorge Dam Operations and Resultant Gauge Flows for the Action Alternative Under Relatively Wet Hydropower Conditions.

9. CUMULATIVE IMPACT

An additional hydropower analysis was performed to estimate the cumulative economic costs of environmental regulations associated with Flaming Gorge Powerplant operations. The Cumulative Impact Scenario assumes that there are no biological constraints except for the 800 cfs minimum flow requirement. This scenario is for comparison purposes only and is not an alternative under consideration. Instead, it reflects the economic impacts on the economic value of power from environmental constraints enacted since 1973. Power simulations of the Cumulative Impact Scenario are performed using the same model systems approach as the No Action and Action Alternatives. Also, an additional run of the Green River model was made to reflect the removal of biological constraints.

9.1 Green River Simulations

Green River model simulated monthly water releases volumes for the Cumulative Impact Scenario are guided by a drawdown target that is set to 6,026 ft for April 1st. The fill target for August 1st is set to 6,033 ft. During the spring, forecast errors do not affect decisions regarding operational planning. Therefore, when the forecast is lower than the actual hydrology the elevation will exceed the 6,033 ft. target. On the other hand, a high forecast will result in a lower reservoir elevation on April 1st. During the base flow it is assumed that there are no forecast errors. The outflow is always limited to powerplant capacity except when the spillway gates are in danger of being overtopped. A model parameter is specified such that non-power releases occur when the elevation exceeds 6040 ft. (i.e., the top of the spillway gates). Spills and turbine releases are scheduled such that reservoir elevation is lowered to 6,040 ft.

Average monthly water releases over the study for the Cumulative Impact Scenario and the No Action Alternative are shown in figure 9.1. On average, water releases during the summer months are significantly higher for the Cumulative Impact Scenario. Note that these are the months that have the highest value of electricity. In addition to having higher water releases during the summer months, water releases among days of a simulated month were not restricted; that is, only monthly water volumes constrain powerplant operations. This allows for greater water releases and generation levels during days of the month that have the highest electricity prices.

9.2 Powerplant Operations

Powerplant operations for the Cumulative Impact Scenario not only benefit from larger water releases during the summer months, but there are significantly fewer non-power water releases. Most of the non-power releases for the Alternatives are attributable to spring spike flows. Table 9.1 shows that non-power release for the No Action Alternative is more than five times higher than the Cumulative Impact Scenario. Lower spills and more operational flexibility translate into a 2.7% higher generation level.

Ramp-rate constraints and the single daily hump requirement do not restrict hourly generation patterns for the Cumulative Impact Scenario. Therefore, operations respond more quickly and efficiently to market price signals. Figure 9.2 shows typical operations for a summer day. Generation levels quickly increase from the minimum flow level (i.e., energy produced by 800 cfs) to the point of maximum water-to-power conversion efficiency when prices begin to increase in the morning. When prices spike in the afternoon, generation levels increase to the maximum powerplant capability.

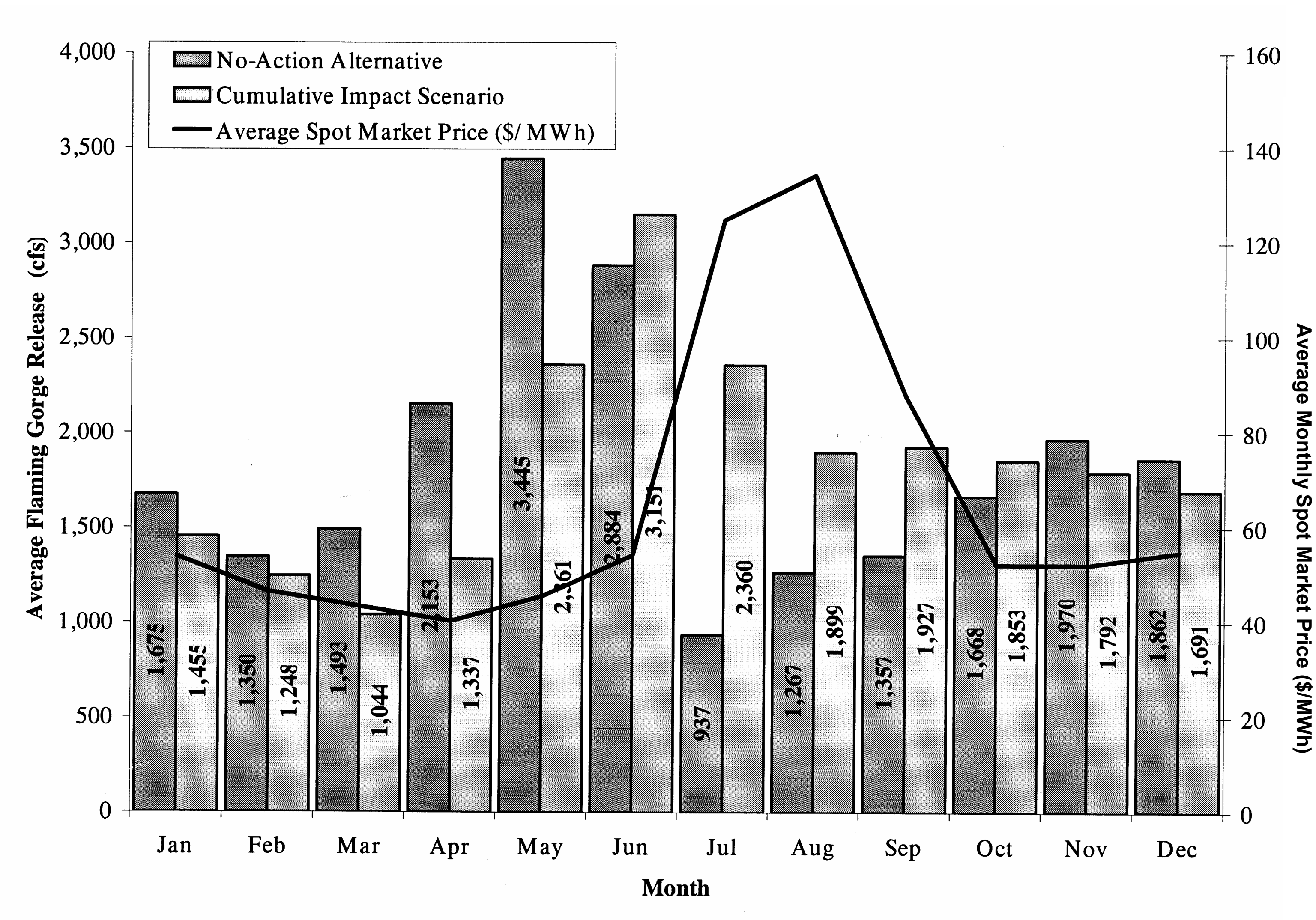

Figure 9-1. Comparison of Monthly Average Water Releases for the No Action Alternative and the Cumulative Impact Scenario.

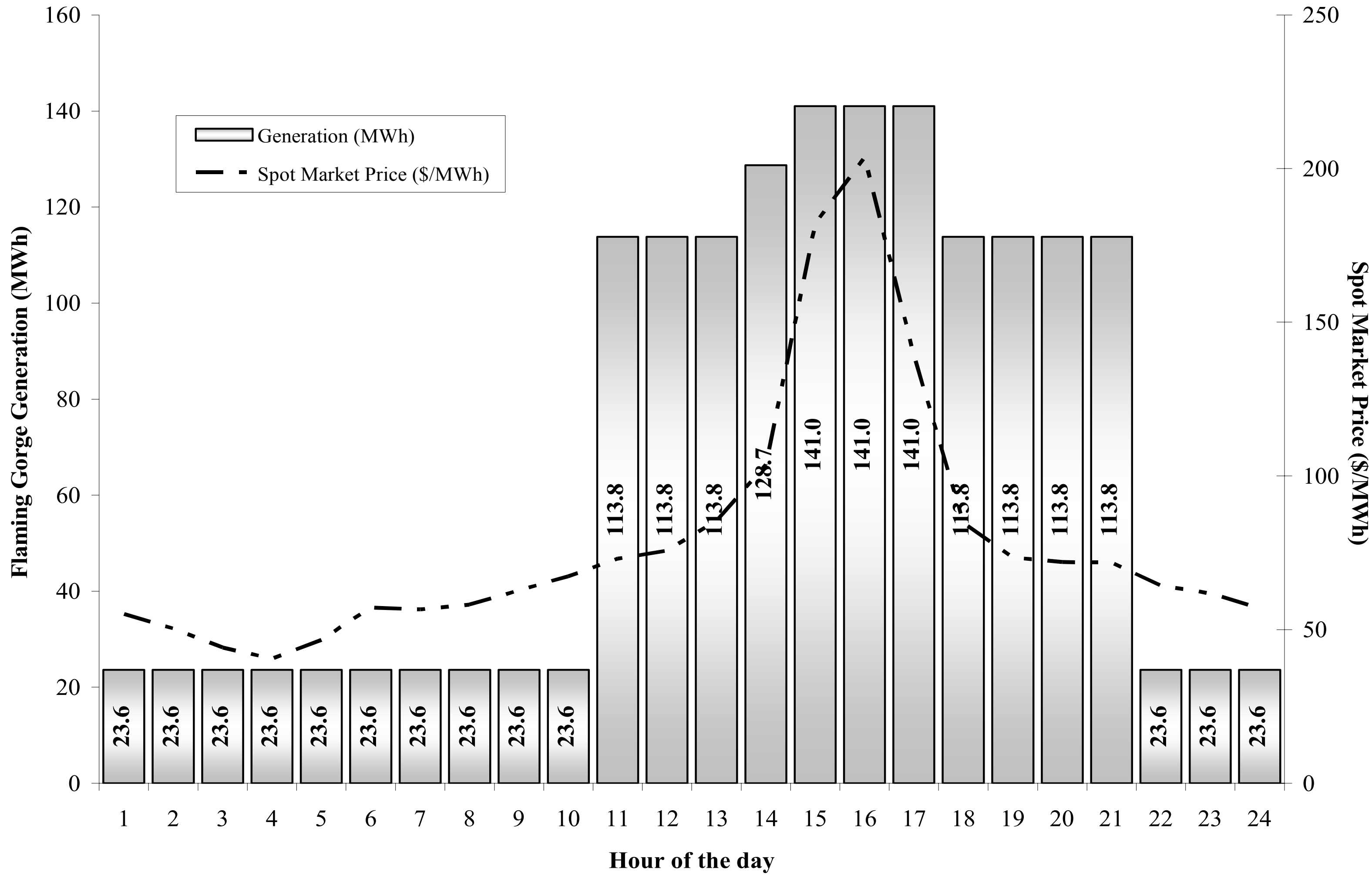

Figure 9-2. Typical Daily Generation Pattern During a Summer Weekday for the Cumulative Impact Scenario.

Table 9.1. Comparison of the Water Release and Generation from the Flaming Gorge Powerplant between the No Action Alternative and the Cumulative Impact Scenario

	No Action Alternative	Cumulative Impact Scenario	Increase Above the No Action Alternative (%)
Average Water Release (cfs)	1,839.2	1,843.7	0.2
Average Non-turbine Release (cfs)	64.4	11.6	-81.9
Generation (GWh)	11,904.1	12,229.7	2.7

With environmental constraints removed, the economic value of power production over the 25-year simulation period is significantly greater as compared to both the No Action and Action Alternatives. As shown in table 9.2, the Cumulative Impact simulation has an economic value that is about 29% higher than the No Action Alternative.

Table 9.2. Comparisons of the Economic Value of EIS Alternatives and the Cumulative Impact Scenario

	No Action Alternative (millions $)	Action Alternative (millions $)	Cumulative Impact (millions $)	Comparison of Cumulative Impact to No Action (%)
Nominal	$806.1	$850.6	$1,065.1	32.1
NPV	$403.1	$423.1	$521.4	29.3

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APPENDIX A:

HYDRAULIC TURBINE DATA FOR FLAMING GORGE

FLAMING GORGE POWER PLANT COLORADO RIVER STORAGE PROJECT.
SPECIFICATIONS NO. DS-5263 UNITS 1, 2 AND 3 DATE May 17, 1960
TURBINE NAMEPLATE RATING: H.P. 50,000; HEAD 365 FT.; SPEED 240 R.P.M.
GENERATOR RATING IN KV-A 40,000 POWER FACTOR 90 PERCENT.
Turbine mfr. The James Leffel Co. Type Francis
Cost per unit f.o.b. factory $266,183.33 Weight 310,000 lbs.
Cost per h.p. $4.38 Weight per hp. 5.10 lbs.
Type of scroll case Welded plate steel spiral. Weight heaviest part 50,000 lbs.
Type of draft tube Elbow with plate steel liner-one pier
Weight of runner 21,500 lbs. Weight of rotating parts 45,000 lbs.
Weight of turbine parts including hydraulic thrust to be carried by generator thrust bearing 225,000 lbs. New; 310,000 lbs. Worn rings
Governor capacity in foot-lbs. 105,000 Pipe size 3 inches.
Gov. mfr. Woodward Governor Co. Time element 5 seconds.
Cost per unit f.o.b. factory $39,758.33 Weight 15,550 lbs.
Generator mfr. Westinghouse Electric Corp.
Generator WR^2 7,000,000 lbs. at one foot radius.
Turbine WR^2 160,000 lbs. at one foot radius.
Regulating constant of unit ($\overline{R.P.M.}^2 \times WR^2 \div$ Design H.P.) 6,990,000
n_s of runner 29.9 at 400 ft. design head when delivering 50,000 h.p. (Best eff. gat
N_s of runner 33.1 at 400 ft. design head when delivering 60,800 h.p. (Full gate).
H.P. at 400 ft. (Design head) 60,800; at 100 percent of design head; 1530 c.f.s.
H.P. at 440 ft. (Max. head) 69,400; at 110 percent of design head; 1620 c.f.s.
H.P. at 260 ft. (Min. head) 30,600; at 65 percent of design head; 1190 c.f.s.
H.P. at 350 ft. (Mfrs. Rated Hd.) 50,000; at 87.5 percent of design head; 1400 c.f.s.
H.P. at best efficiency equals 82.2 percent of h.p. at full gate.
Runaway speed at 440 ft. hd. 445 r.p.m. equals 185 percent of normal speed.

DIMENSIONS OF TURBINE:

Unit spacing 36.0 ft. Dia. of shaft 26 inches.
Max. dia. of runner 8.50 ft. Dia. of cover plate 12.05 ft.
Dia. of gate circle 9.75 ft. Number of wicket gates 20
Height of distributor case 1.615 ft. Number of stay vanes 19
Dia. at scroll case inlet flange 8.00 ft. Dia. at top of draft tube 7.80 Ft=D
Outside radii of stay vanes 6.92 to ft. Distributor ℄ Elev. 5601 Ft.
Distance from center line of distributor to top of draft tube 2.29 ft.
Depth of draft tube 22.5 ft. equals 289 percent of dia. D_3.
Length of draft tube 31.58 ft. equals 405 percent of dia. D_3.
Width of draft tube 29.00 ft. equals 372 percent of dia. D_3.
Distance from center line of turbine to center line of scroll case inlet 11.25 ft.
Distance from center line of distributor to minimum tailwater, (Elev. 5601.6 ft.) (One unit operating at full load) -0.6 ft.
Pressure regulator mfr. None Type Size inches.
Cost per unit f.o.b. factory Weight lbs.
REMARKS:
Placed in operation

Figure A.1. Listing of Turbines, Generator, and Related Equipment Characteristics at the Flaming Gorge Powerplant.

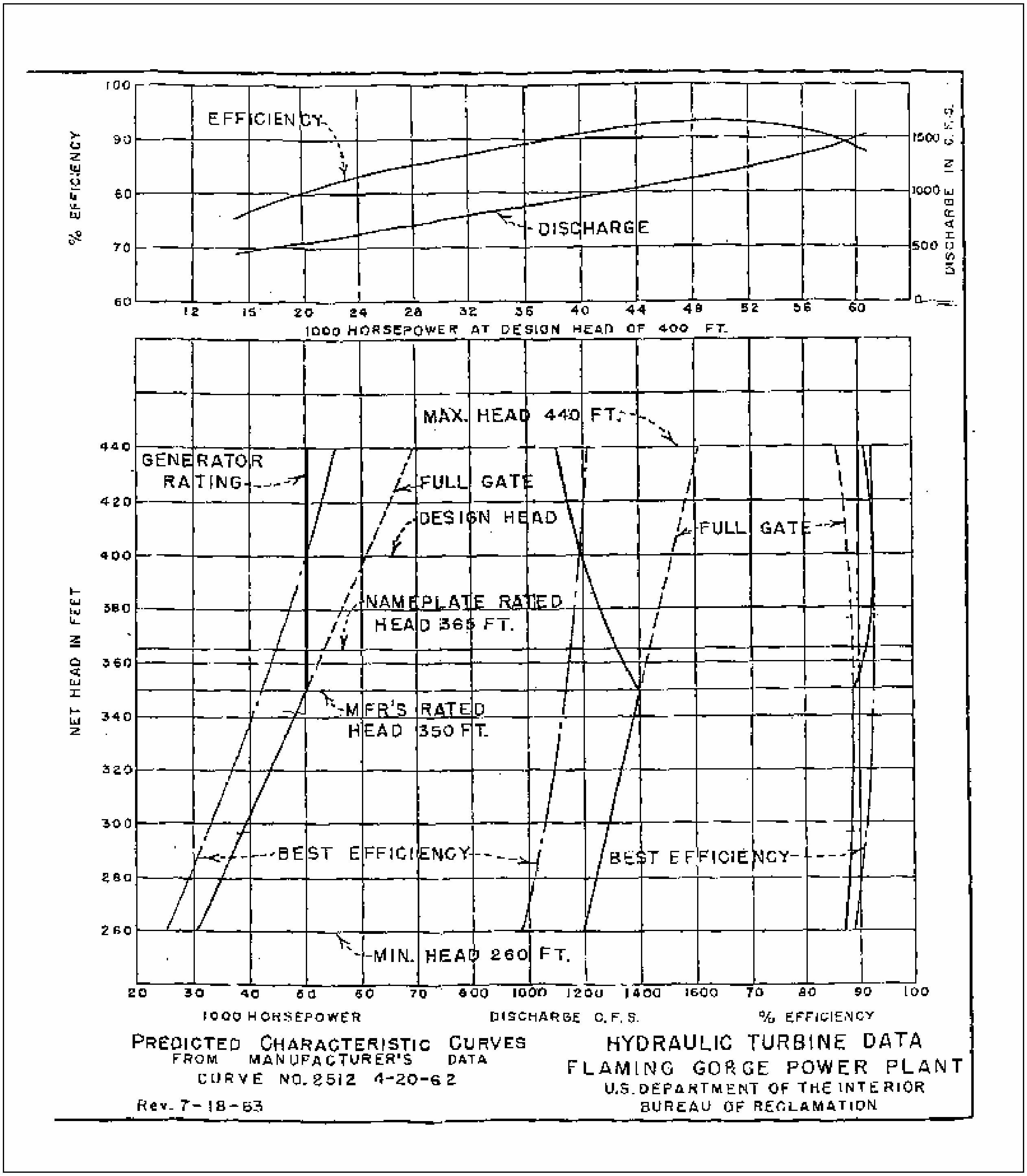

Figure A.2. Predicted Characteristic Curves and Hydraulic Turbine Data for the Flaming Gorge Powerplant.