Appendix D

Methodology for Analyzing the Impacts of Aspinall EIS Alternatives on Power Economics

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S. Clayton Palmer, Wayne Cook, and Thomas Veselka[1]
Western Area Power Administration
Colorado River Storage Project Management Center
and Argonne National Laboratory

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Introduction

The Western Area Power Administration's (Western) Colorado River Storage Project (CRSP) Management Center markets CRSP power resources as well as the hydroelectric power plants of the Collbran and Rio Grande projects. The 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. Electricity produced by SLCA/IP resources also serves the energy requirements of specific project uses, such as irrigation. When energy production exceeds firm contractual obligations, the excess electricity is sold on the spot market. In addition, SLCA/IP hydropower plants provide the grid with ancillary services including regulation and spinning reserves. In support of an Environmental Impact Statement (EIS), this document focuses on the methods that were developed for evaluating the economics of a cascade of three CRSP hydropower plants: Crystal, Blue Mesa, and Morrow Point. Located on the Gunnison River, these hydropower plants and their associated reservoirs are collectively referred to as the Aspinall Cascade.

Aspinall Storage and Power Characteristics

The Aspinall Cascade is a part of the CRSP authorized by a Congressional Act of April 11, 1956, under Public Law 485, 84th Congress, 70 Stat. 105. As shown on the map in Figure 1, the Aspinall Cascade is located along a 40-mile section of the Gunnison River between the towns of Gunnison and Montrose, Colorado. The Blue Mesa Dam and hydropower plant is at the top (i.e., highest elevation level) of the cascade, followed by Morrow Point and then Crystal. Water storage capacities, in terms thousand-acre-feet (TAF) for these three reservoirs are shown in Figure 2. The Blue Mesa reservoir has the largest water storage capacity which is more than 8 times larger than the Morrow Point reservoir and more than 36 times larger than the Crystal.

The secondary y-axis of Figure 2 shows power plant generating nameplate capacity in terms of Mega-watt (MW). The cascade has a total generating capacity of 291.7 MW with the Morrow Point power plant having the largest generating capacity at 173.3 MW. The Blue Mesa's power plant capacity is about one-half as large followed by Crystal with a capacity of 32 MW.

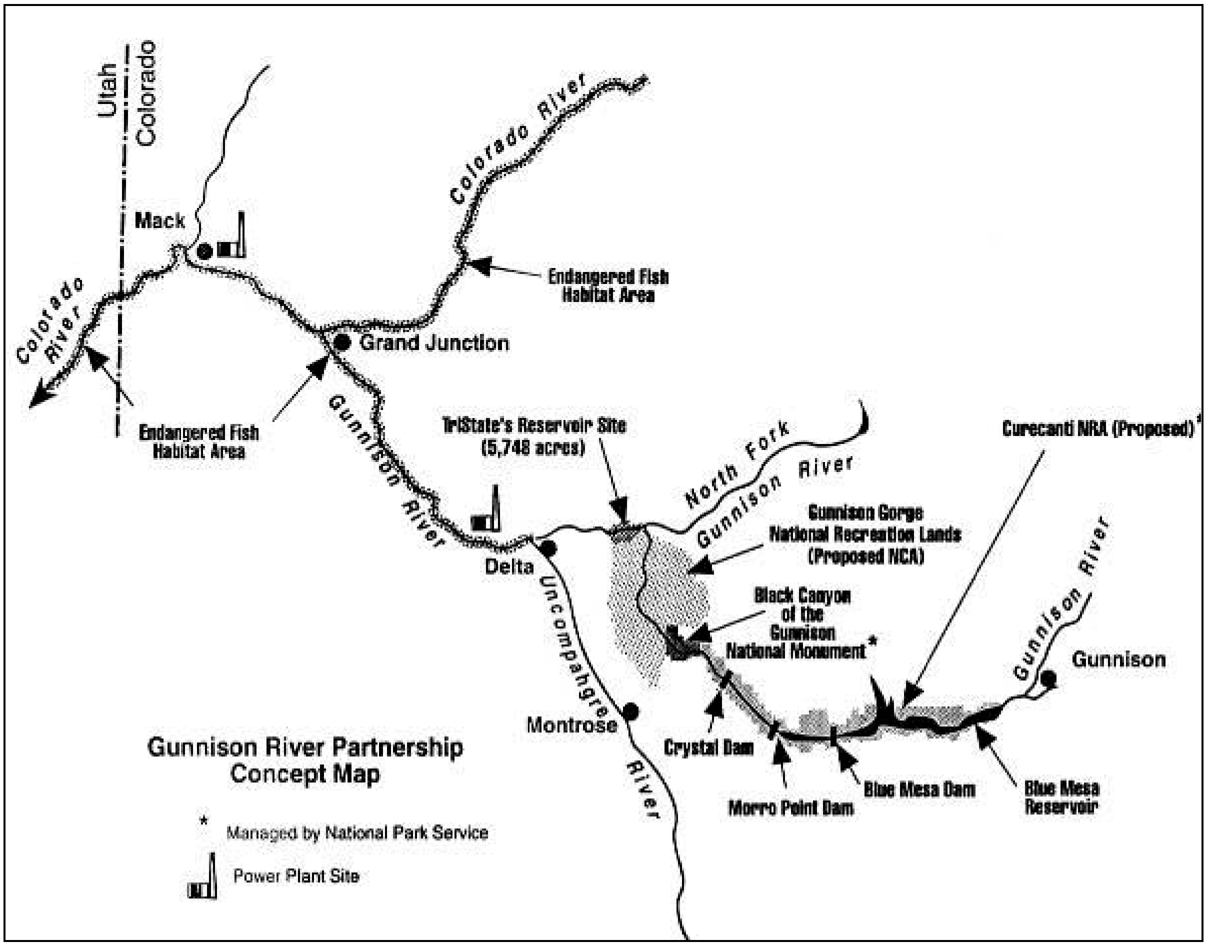

FIGURE 1 Map of the Aspinall Cascade and Surrounding Area

The Aspinall Cascade is operated as a tightly-coupled multi-purpose system. Its primary purpose is to furnish the long-term regulatory storage needed to states in the upper Colorado River Basin to meet its flow obligation at Lees Ferry, Arizona, as defined in the Colorado River Compact. Operation of the Aspinall Cascade consider power generation, projected inflows to its reservoirs, flood control needs, existing water rights, minimum instream flows, target elevations for reservoirs, flow needs for endangered fish and other resources, recreation, hydropower needs and other factors. Table 1 contains a summary of reservoir, dam, and power plant characteristics in the Aspinall Cascade.

Hydropower plant output levels in the cascade can be ramped up or down from zero production levels to maximum capability in a matter of minutes without adverse affects on the power equipment. This attribute makes it well suited to provide the interconnected grid with various ancillary services such as spinning and non-spinning reserves, regulation, and voltage support.

The Blue Mesa Dam is on the Gunnison River about 30 miles below Gunnison, Colorado. The dam is a zoned earthfill embankment with a structural height of 390 feet and a crest

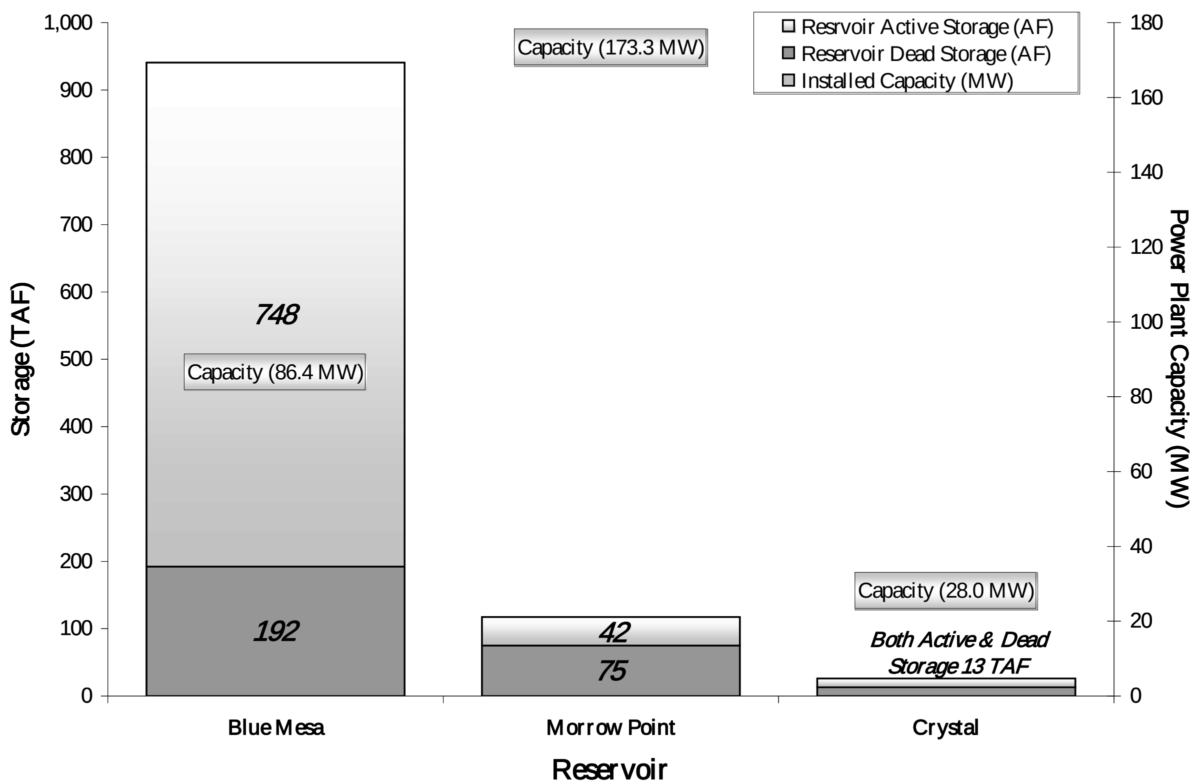

FIGURE 2 Chart of Aspinall Cascade Reservoir and Power Plant Capacities

length of 785 feet. It contains 3,093,000 cubic yards of materials. The maximum discharge of the spillway is 34,000 cubic feet per second (cfs). Blue Mesa's primary function is water storage. The reservoir has a total storage capacity of 940,800 acre-feet (AF) and an active capacity of 748,500 AF. At maximum water surface elevation, the reservoir occupies 9,180 acres.

Power generation from Blue Mesa was initially produced by a single 30 MW generator that was put into service in September 1967. Two months later, a second 30 MW unit was brought online. Both generators were uprated to 43.2 MW in 1988. The generators are driven by two 41,500-horsepower (HP) turbines. The power plant operates in a peaking mode with large hourly fluctuations in power production over the course of a day with a potential output range from zero to maximum capacity in one hour.

The Morrow Point Dam is located 12 miles downstream from the Blue Mesa Dam. It is the Bureau of Reclamation's (Reclamation) first thin-arch, double curvature dam. Constructed of 365,180 cubic yards of concrete, the dam is 468 feet high and 52 feet thick at the base, with a crest length of 724 feet. The maximum capacity of the spillway is 41,000 cfs. The reservoir capacity behind the Morrow Point Dam is 117,190 AF at maximum water surface elevation, with an active storage capacity of 42,120 AF. The surface area of the Morrow Point Reservoir is 817 acres at an elevation of 7,160 ft. The power plant produced electricity from its two 60-MW generators for the first time in 1970. The generators were uprated from 60 MW to a sustained operational level of 82.5 MW in 1992 and 1993 for a total plant capacity of 165 MW. Three single-phase transformers were replaced during water year (WY) 1996 and a 230-kilovolt (kV) cable was replaced during WY 1998.

Similar to the Blue Mesa power plant, Morrow Point is also well suited to provide the interconnected grid with various ancillary services. As shown on Table 1, these services include spinning and non-spinning reserves, regulation, voltage support, and system black start.

TABLE 1 Characteristics of Aspinall Cascade Resources

Dam, Reservoir and Power Plant Characteristics	Blue Mesa	Morrow Point	Crystal
Dam Type	Earthfill Embankment	Double-Curvature Thin-Arch	Double-Curvature Thin-Arch
Primary Purpose	Water Storage	Power Production	Flow Regulation
Dam Height (ft)	502.0	468.0	323.0
Spillway Crest Elevation (ft)	7,487.9	7,123.0	6,756.0
Crest Elevation (ft)	7,528.0	7,165.0	6,772.0
Active Reservoir Capacity (AF)	748,500	42,120	13,000
Surface Area (acres)	9,180	817	340
Power Plant In Service Year	1967	1970	1978
Total Installed Capacity (MW)	86.4	173.334	32.0
Number of Turbines	2	2	1
Typical Production Mode	Peaking	Peaking	Base Load
Maximum Annual Generation 1992-2001 (GWh)	372	517	218
Minimum Annual Generation 1992-2001 (GWh)	205	271	151
Spinning Reserve	Yes	Yes	Yes[1]
Non-Spinning Reserve	Yes	Yes	Yes[1]
Replacement Reserve	Yes	Yes	Yes[1]
Regulation/Load Following	Yes	Yes	Yes[1]
Black Start	Yes	Yes	Yes[1]
Voltage Support	Yes	Yes	Yes[1]

[1] The Crystal power plant is physically capable of providing these ancillary services but institutional and environmental constraints preclude Crystal from operating in a mode such that these services can be sold on the market

The Crystal Dam is located 6 miles downstream from the Morrow Point Dam and approximately 20 miles east of Montrose, Colorado. Its operations stabilize the flow of water through Gunnison National Park, in addition to functioning as a power generation unit. The dam is a double-curvature thin-arch type, 323 feet high, with a crest length of 635 feet. The dam contains 147,000 cubic yards of materials. The reservoir storage capacity behind the Crystal Dam is 26,000 AF at maximum water surface elevation, with an active capacity of 13,000 AF. Its surface area is 340 acres at full reservoir.

Power generation from the Crystal plant began in July 1978. The plant currently has an installed capacity of approximately 32 MW from one unit driven by a 39,000-HP hydraulic turbine. Although the Crystal power plant has the physical capability to provide all types of ancillary services (see Table 1), the flat flow requirement precludes it from rapidly changing power output from one hour to the next.

Model Process Overview

The economic evaluation of Aspinall power resources is a multi-step procedure consisting of data processing and computer simulations. Computer simulations and economic calculations are performed for each EIS alternative. A flow diagram depicting the major components of this procedure and component interactions is displayed in Figure 3. The process begins with RiverWare simulations that were performed by Reclamation and sent to both Western and Argonne National Laboratory (Argonne). RiverWare produces daily RiverWare results for each of the three hydropower plants in

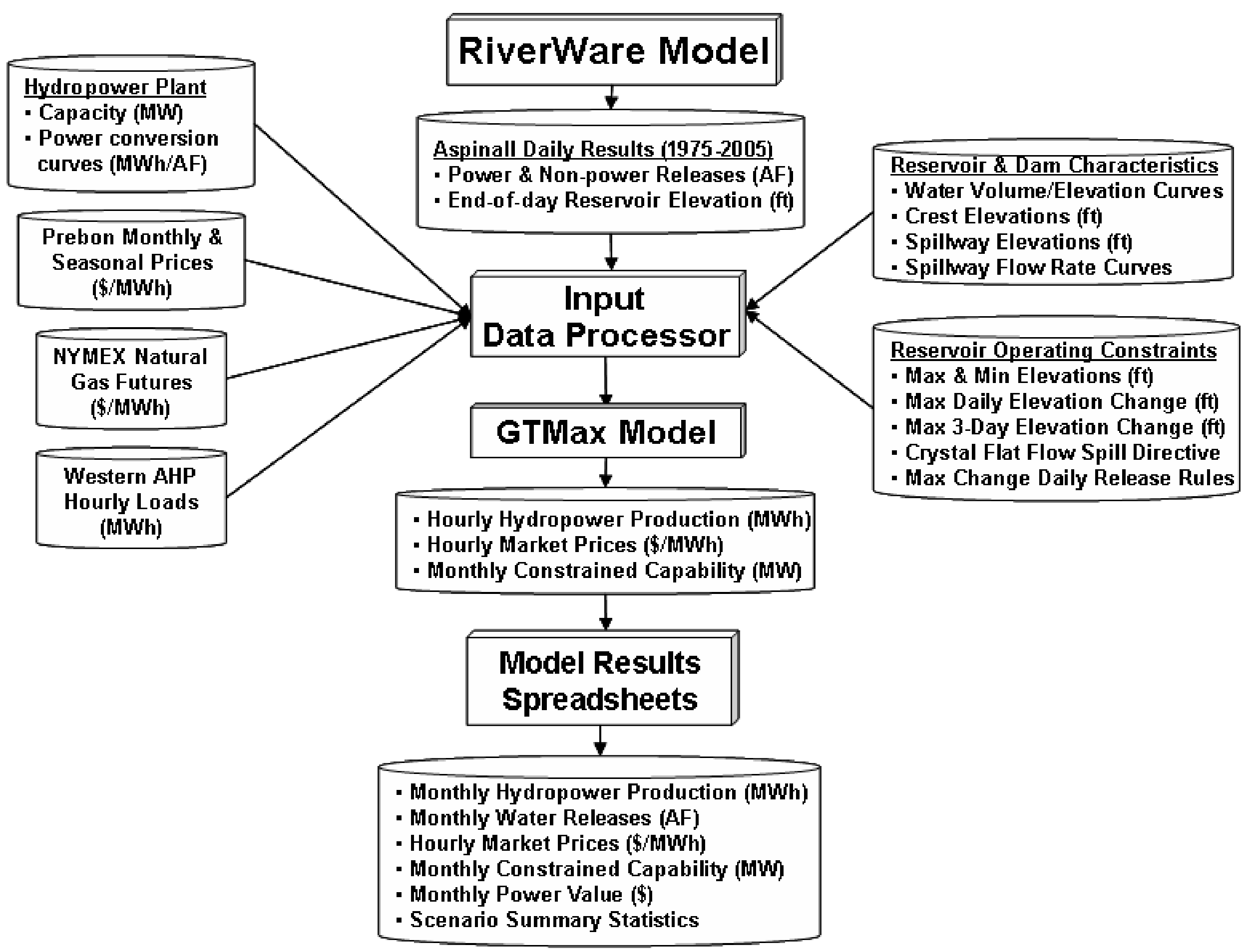

FIGURE 3 Diagram Depicting Major Modeling Components and Processes

the cascade that include Blue Mesa, Morrow Point, and Crystal. For each of the six EIS alternatives, RiverWare results used for power economics analyses include daily turbine water releases, bypass tube releases, and water that is released via spillways. RiverWare data for reservoir forebay elevations are also utilized for power economic computations.

RiverWare results along with hydropower plant information, reservoir characteristics, market prices, load profiles, and operating constraints are input into an Excel spreadsheet that prepares data for the Generation and Transmission Maximization (GTMax) model. The spreadsheet uses RiverWare reservoir elevation levels to estimate average weekly power conversion factors expressed in terms of electricity production in units of Mega-Watt-hours (MWh) per acre-feet (AF) of turbine water release. It also contains selected RiverWare data required for computations of both power production and economics.

A customized version of GTMax, specifically developed for the Aspinall EIS, simulates hourly hydropower generation at the each of the three Aspinall power plants. It determines the hourly operation schedule over a one-week period (i.e., 168 hours) that maximizes the economic value of Aspinall hydropower resources. The operation schedule produced by the model is within the physical limitations of each power plant and associated reservoir. It also complies with all environmental and institutional regulations. GTMax results include an estimate of the economic value of Aspinall energy production over the simulation period. It also estimates hydropower plant maximum production capability taking into account all operational constraints in the cascaded system. These results are summarized and displayed in tables and graphs with via drop-down menus in Excel Results spreadsheets. More detailed information on major processes used for modeling the Aspinall Cascade is provided in the following sections.

RiverWare Model

The RiverWare model mimics operational decisions that are made for CRSP reservoirs at a daily time step. For the Aspinall Cascade, operational considerations such as meeting seasonal, monthly and daily reservoir water volumes are contained in the model. Since EIS alternatives have unique criteria, each simulation contains alternative-specific operating rules.

In addition to the influencing the timing of water releases for power production, EIS alternatives also affect reservoir forebay elevations and the amount of water that circumvent turbines via bypass tubes and spillways. The forebay elevation determines the hydraulic head and is the primary factor that influences the amount of energy that is produced per volume of water released through the turbines. High forebay elevations typically translate into more power production per AF of turbine water releases as compared to power production at lower forebay elevations. However, maintaining full or nearly full reservoirs increases the risk of releasing water through bypass tubes and spillways. Sudden unexpected inflows under a full reservoir condition may require reservoir releases that exceed maximum turbine flow rates, resulting in water releases without power production. On the other hand, maintaining lower reservoir levels will reduce the risk of non-turbine water releases during flood conditions, but it will also result in lower power conversion factors and increase the risk of lowering the forebay elevation below turbine inlet tubes during droughts. When this occurs, both power production and the plant capacity are zero. Operating rules must balance the risks associated with either having too much or not enough water stored in Aspinall reservoirs.

Balancing risks in a basin with large variations of water inflows, such as the Aspinall Cascade, require a full-spectrum examination of hydrological conditions. Therefore, the RiverWare model was run for a sequence of historical inflows that occurred from the beginning of 1975 through the end of 2005. RiverWare results include scenario-specific estimates of daily water releases and reservoir elevations throughout the analysis period.

Monthly release patterns affect the economic value of the hydropower resource since electricity prices are highly sensitive to seasonal and hourly variations in market forces. Typically market prices are the highest in the summer and winter seasons. Therefore, from a myopic power viewpoint that only considers the Aspinall Cascade, water releases would ideally be concentrated during these two seasons. However, from a broader perspective, power benefits must be weighted against other operational objectives, such as flood control, irrigation, municipal and industrial water supplies, recreation, and the environment.

Input Data Processor

The Input Data Processor spreadsheet translates RiverWare results into a form that can be utilized by the GTMax model. It also contains other vital information that is transferred to and utilized by GTMax. For example, the spreadsheet aggregates daily water releases into weekly total amounts and it computes average weekly power conversion factors based on RiverWare reservoir elevation levels.

For each GTMax simulation, the Input Data Processor prepares data for the following three time periods: previous events including initial conditions, a principal simulation week, and a one week extension period. The previous time period can be either actual historical events or events that were simulated by GTMax in a prior run. The Aspinall EIS utilizes simulated results for a prior modeled time period. For example, when modeling the second week in January, the Input Data Processor retrieves GTMax results for the first week in January.

The spreadsheet prepares data for a two week time period, since for each GTMax run 14 days of operations are simulated. The first seven days are referred to as the principal time period and the second seven days is the one week extension period. Although results for only the principal time period is used in the economic analysis, the extension period is important since it significantly reduces modeling boundary problems associated with end-effects. If the simulation were only run for seven days, model results would be valid, but results for the end states (i.e., last simulation hours) may be in a position that is detrimental for operating efficiently in the following week. By running 14 days instead of just seven, the model recognizes that operations in the principal time period have consequences on following week perations. Data that are prepared by the spreadsheet for both weeks include hourly inflows into the Blue Mesa reservoir, hourly side flows for

Morrow Point and Crystal, power conversion factors and weekly water releases from each reservoir. Operational constraints for both the reservoir and power plant operations are also determined and input into GTMax by the Input Data Processor

The following example illustrates this process. When determining simulation results for the second week in January, both the first (principal period) and second week (extension period) are simulated. A simulation of the third week in January uses results from the second week model run to determine what occurred in the previous week and both the third and fourth weeks in January are simulated. Note that the third week in January is simulated twice; that is, it is first simulated as an extension period and then as the principal week in the second run. Results for the all extension periods are discarded.

Accounting for events that took place in the past is necessary since the Crystal reservoir forebay elevation cannot fluctuate by more than a specified level in any three day period. Therefore, when simulating the future during the principal simulation period, Crystal reservoir conditions that occurred during the past three days restrict reservoir operations in the future. There is also a similar restriction that limits Crystal operations over a one day period. The Input Data Processor spreadsheet computes daily maximum and minimum historical Crystal reservoir elevations and passes this information to GTMax. The spreadsheet also determines initial conditions for all three reservoirs. Initial conditions serve as a starting point for computing future elevations.

GTMax hourly simulation of the Aspinall Cascade must consider numerous limitations as summarized in Table 3. The spreadsheet determines limitations placed on Morrow Point and Crystal that vary by period. Limits on the changes in Crystal's reservoir elevation over time help maintain the reservoir storage quality. When soil on the reservoir shoreline is saturated in the springtime, it becomes unstable and rapid water elevation changes may result in landslides.

TABLE 3 Short-term Operational Restrictions for Aspinall Reservoirs

Blue Mesa	**Jan - Mar**	**Apr - Dec**
Minimum Elevation (ft.)	7,393.0	7,393.0
Maximum Elevation (ft.)	7,490.0	7,519.4
Morrow Point	**Jun – Sep**	**Oct - May**
Minimum Elevation (ft.)	7,151.0	7,143.0
Maximum Elevation (ft.)	7,160.0	7,160.0
Crystal	**Apr – Jun**	**Jul - Mar**
Maximum Change per Day (ft.)	4	10
Maximum Change per 3 Days (ft.)	6	15
Elevation (ft.) for 1/2 ft. / Day Max Change	6,748	6,733

The Aspinall reservoirs are also operated to meet the delivery requirements of the Uncompahgre Valley Project and to keep a minimum of 300 cfs of water flowing through the Black Canyon of the Gunnison National Park. Operations must also maintain a minimum summertime flow of 300 cfs below the Redlands Diversion Dam. It is located on the Gunnison River, 2.3 miles upstream of the confluence with the Colorado River. This requires that hourly water releases from the Crystal reservoir are nearly constant. Minor fluctuations of approximately 50 cfs occur due to limitations in the automatic control equipment at Crystal. Under very wet hydrological conditions, when spillway releases are required at Crystal, releases from Morrow Point must also be constant in order maintain constant water releases from Crystal.

The Input Data Processor also contains detailed data that describe the characteristics of the Aspinall Cascade in terms of water storage, power production and the market in which it operates. Reservoir and hydropower plant characteristics are summarized in Table 1.

Figures 4 through 6 contain graphs of Aspinall reservoir elevations as a function of water volume. These functions are all non-linear and are described by fourth-order polynomial equations contained in the spreadsheet. Coefficients of polynomial equations that describe curve shapes are provided in Table 4.

TABLE 4 Polynomial Coefficients for the Reservoir Elevation Function

Reservoir	Intercept	Slope	2nd Order	3rd Order	4th Order
Blue Mesa	7.37E+03	3.49E-04	-4.13E-10	3.53E-16	-1.24E-22
Morrow Point	7.02E+03	1.17E-03	3.09E-10	0.0	0.0
Crystal	6.67E+03	7.13E-03	-1.65E-07	2.14E-12	0.0

The GTMax model uses Linear Programming (LP) techniques to maximize the value of Aspinall resources. Therefore, the non-linear reservoir representation described by the polynomial equations cannot be directly entered into the model. Therefore, the Input Data Processor approximates the elevation and water storage relationship for an Aspinall reservoir into a single linear function, written in slope-intercept form. While the linear equation does not capture the exact relationship, it is an accurate approximation when the linear function is used to represent a small segment of the non-linear curve.

The Input Data Processor determines the segment of the curve that will be applicable for each simulated week by examining daily reservoir elevations provided by RiverWare. The slope of the relationship is based on a straight line that connects the minimum and maximum elevation levels that are expected to occur within each simulated weekly period. Elevation inaccuracies associated with this technique are almost always less than two-tenths of an inch for the Blue Mesa Reservoir. Errors for the Morrow Point and Crystal Reservoirs are somewhat larger, but almost always less than an inch. For the purposes of this analysis, the linear reservoir representation is a reasonably accurate representation considering potentially large errors in other model variables such as seasonal and hourly market price profiles.

The Input Data Processor generates hourly market prices for the GTMax model based on prices that were current at the time when the study was initially conducted in the summer of 2007. Average seasonal on-peak and off-peak prices were obtained from Prebon which, along with NYMEX natural gas futures, were used to estimated the monthly prices shown in Table 5.

Using hourly customer loads for a typical Saturday, Sunday, and weekday as a guide, estimates of hourly market prices were approximated using a pricing heuristic that is part of the Input Data Processor. The heuristic uses monthly derived on-peak and off-peak prices to produce a set of 168 values for each simulated week. Prices produced by the routine have a shape that is similar to the load patterns. However, based on observations that the supply curve is typically steeper at higher load levels as compared to prices at lower loads, market prices during high load periods are typically more expensive than prices during off-peak times. The final result of the procedures shown in Figure 7 is a set of hourly prices that have an average value that is nearly identical to the monthly on and off-peak prices shown in Table 5. The pricing procedure used in this analysis is identical to the one that Western uses each month forecast future purchase requirements.

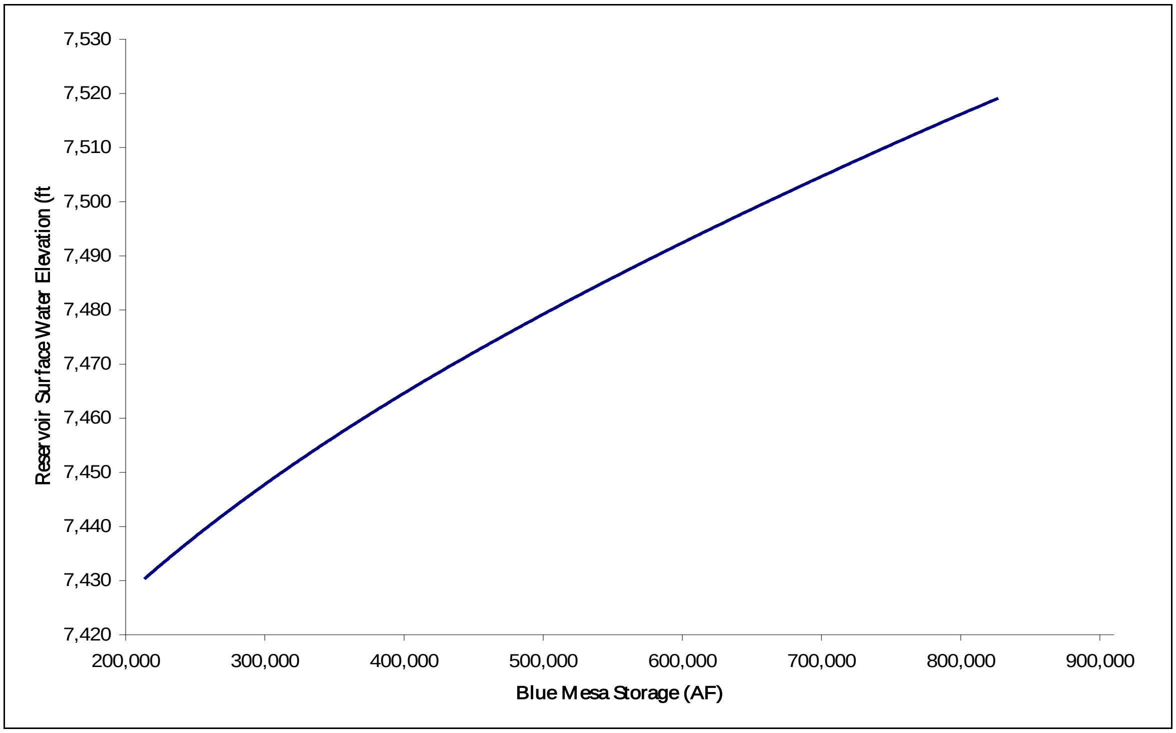

FIGURE 4 Blue Mesa Reservoir Elevation as a Function of Water Storage

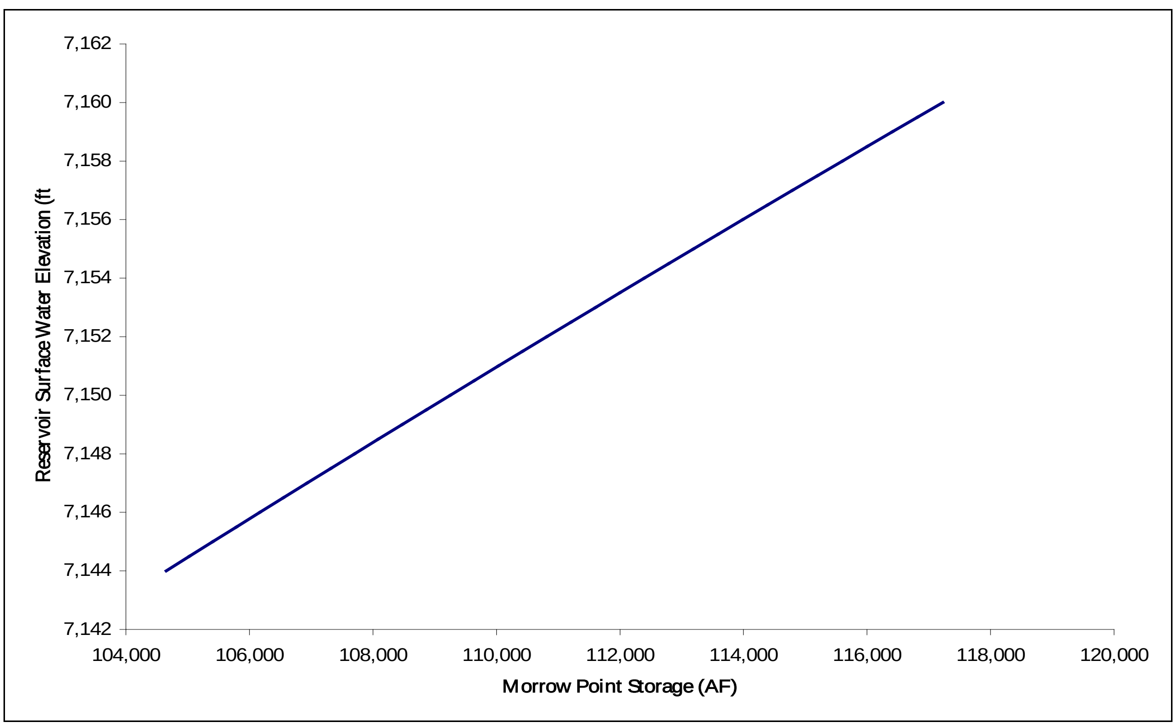

FIGURE 5 Morrow Point Reservoir Elevation as a Function of Water Storage

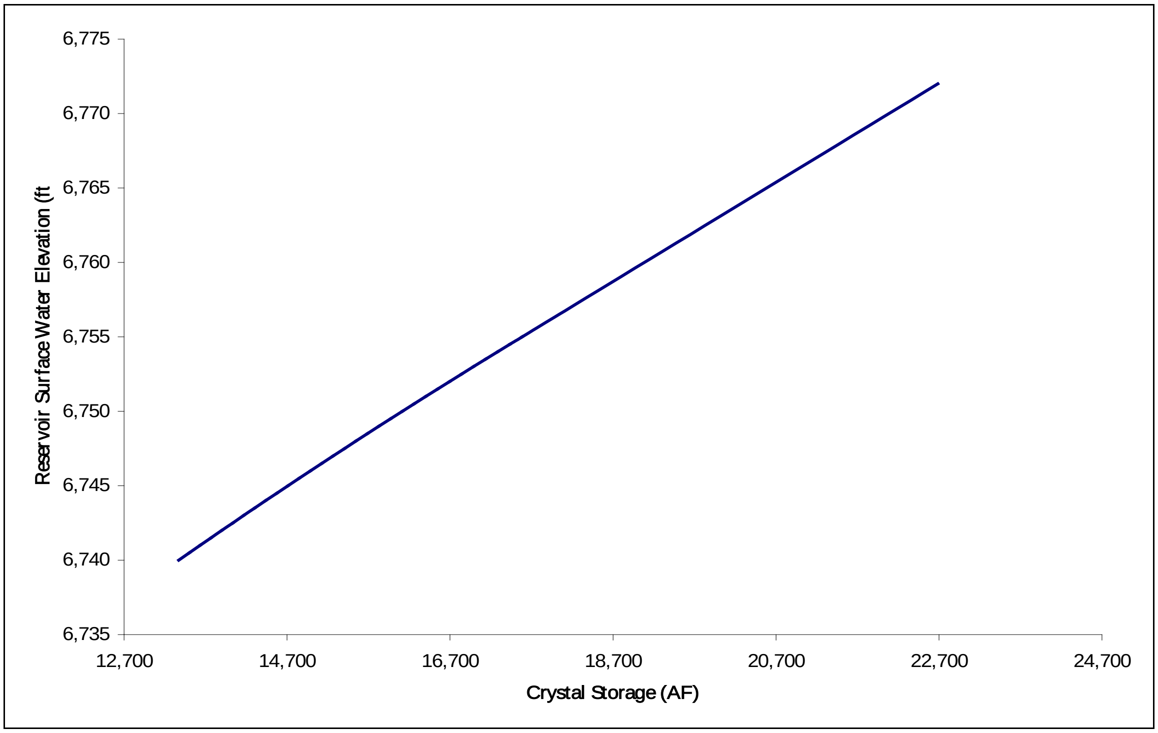

FIGURE 6 Crystal Reservoir Elevation as a Function of Water Storage Volume

TABLE 5 Short-term Operational Restrictions for Aspinall Reservoirs

Quarter	Month	Prebon Price ($/MWh)		Nymex Nat. Gas Futures ($/MMBtu)	GTMax Average Monthly Price ($/MWh)	
		On-Peak	Off-Peak		On-Peak	Off-Peak
NA	June	$ 75.50	$ 54.10	7.682	$ 75.50	$ 54.10
Q3 07	July	$ 91.25	$ 65.39	7.823	$ 91.25	$ 65.39
	August	$ 93.13	$ 66.73	7.915	$ 93.13	$ 66.73
	September	$ 73.62	$ 52.75	8.059	$ 73.62	$ 52.75
Q4 07	October	$ 69.00	$ 49.44	8.804	$ 69.00	$ 49.44
	November	$ 69.00	$ 49.44	9.534	$ 74.72	$ 53.54
	December	$ 69.00	$ 49.44	9.889	$ 77.50	$ 55.54
Q1 08	January	$ 75.75	$ 54.28	9.887	$ 75.75	$ 54.28
	February	$ 75.75	$ 54.28	9.662	$ 74.03	$ 53.04
	March	$ 75.75	$ 54.28	8.652	$ 66.29	$ 47.50
Q2 08	April	$ 72.75	$ 52.13	8.407	$ 72.75	$ 52.13
	May	$ 72.75	$ 52.13	8.317	$ 71.97	$ 51.57
	June	$ 72.75	$ 52.13	8.404	NA	NA

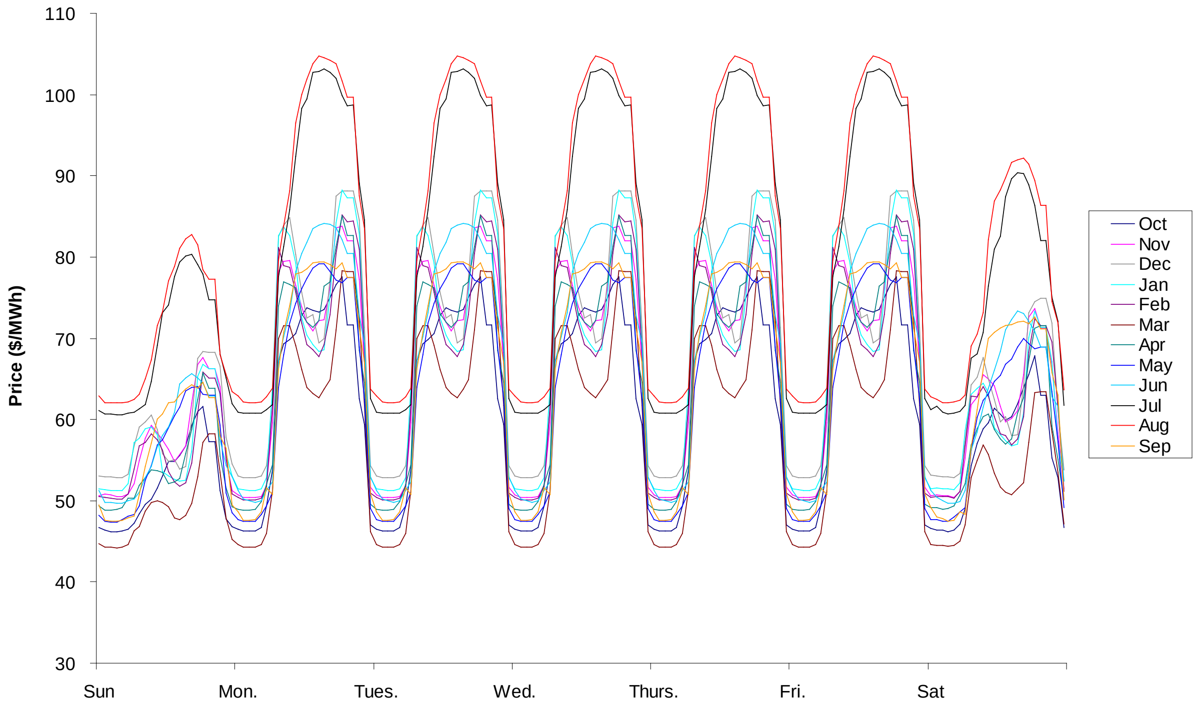

FIGURE 7 Hourly Market Prices for 12 Typical Weeks in the Year

Economic Value

The economic value or benefit of hydropower production for the modeling frameworks is based on the operation of Aspinall power plants in the context of a large interconnected power system. In GTMax, the value of a power resource is set equal to the market price of electricity illustrated in Figure 7 multiplied by the amount of energy produced by the power plant. It is assumed that market prices reflect the marginal cost of producing electricity. Therefore the economic calculations measure the costs of the additional resources that would be needed by the interconnected system to replace the services provided by the power plants in the Aspinall Cascade. In this context, the value of Aspinall hydroelectricity equals the hourly generation from Aspinall power plants times the hourly marginal system cost of power replacement. This marginal system cost serves as a general measurement of the willingness to pay for the project's output.

The main short-run economic benefit of a hydropower resource is that it serves loads that would otherwise be satisfied by running thermal generator that have much higher marginal production costs. Therefore, the economic value of hydropower production is typically measured in terms of the system-wide production cost savings from displacing thermal power production. When hydropower plants displace expensive thermal generation, its economic value is relatively high. A lower value of hydropower is placed on generation that displaces relatively inexpensive thermal generation. The cost of energy replacement for replacing generation from power plants in the Aspinall Cascade is a function of the demand for electricity and the slate of generating resource that can satisfy this demand.

Given limited water resource, one simple strategy for maximizing the economic value of hydropower resources involves using the limited weekly water allocation to produce and sell electricity when market prices are the highest. Electricity up to its maximum generation capability is first sold during the peak priced hours. If additional water is available for generation, power releases are scheduled during the next highest priced hours. This process continues until the allocated amount of water that can be released over a period has been exhausted. However, technical, institutional, and environmental considerations may make this simple “sell high” strategy infeasible. The constant flow requirement at Crystal along with limitations on the operation of reservoirs in the cascades places constraints on the timing of water releases and therefore power production. In general, the more control (i.e., less physical and institutional restrictions) that operators and power marketers have over the timing of water releases to follow the “sell high” model the greater the value of the resource.

The modeling frameworks presented in this report assume that the market price of energy accurately reflects the marginal value of energy. Power producers sell power into the market at the system marginal production cost and do not attempt to “game” the market. It is also assumed that power production from the cascade does not significantly affect market prices. That is the system lambda is the same with or without Aspinall power generation. Given that the Aspinall Cascade is a very small supplier in the Western interconnect, it influence on price under all but the most extreme situations (e.g., supply shortage) is negligible.

GTMax Model

Argonne simulated the operation of hydropower plants in the Aspinall Cascade on an hourly time step with the GTMax modeling software. The GTMax objective function is to produce the hourly generation schedule that maximizes the economic value of the hydropower resources. The model determines how much water to release in each hour of the simulation period and how much electricity to generate from each power plant. A driving force in modeling the Aspinall Cascade is to support decision makers through simulating cascade operations under a number of diverse rules, hydrological conditions, and power market conditions.

Market prices input into the model convey the economic value of hydropower generation. These prices heavily influence the hourly generation schedule produced by the model when optimizing hydropower plant resources. To the extent possible, the GTMax model uses limited energy resources to first generate electricity during on-peak hours when it has the highest economic value. Any remaining energy is scheduled during lower-priced hours. Aspinall power plant operations are subject to a set of constraints. These include a physical operating capability and a limit on the total weekly electricity production. These constraints are consistent with RiverWare model results. In addition to physical operating constraints, the GTMax model also complies with reservoir operating restrictions.

Figure 8 contains a depiction of a reservoir, dam, and hydropower plant along with major variables that govern the physical processes of the system. In the modeling frameworks described below, there are two types of variables. These include variables that are solved through the modeling process (black filled circles) and others that are given or assumed to occur (white filled circles).

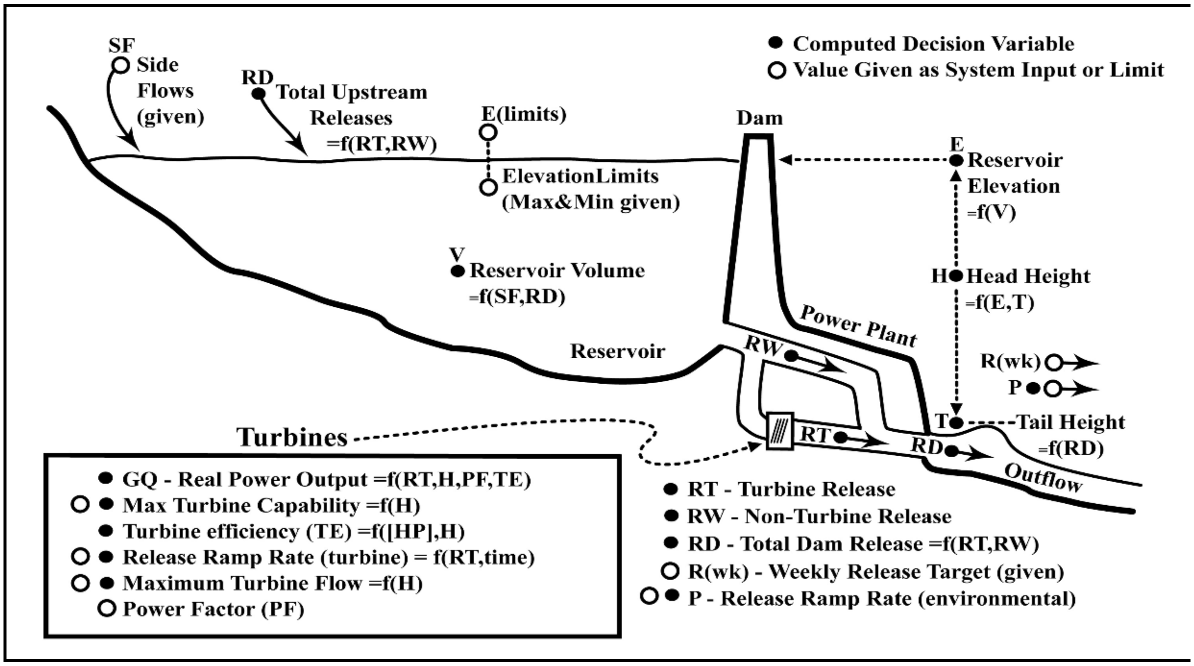

FIGURE 8 Variables and Functions for a Single Hydropower Plant

The dam regulates water inflows from upstream sources and stores water in a reservoir. Total inflows into a reservoir consist of water released from upstream reservoirs *RD* and from side flows *SF*. A side flow is a source of water that enters the stream in-between two reservoirs or a water source that feeds directly into the downstream reservoir. It can also represent water that is extracted from a reservoir. For example, a negative *SF* value indicates that water is taken out from either the stream or reservoir through seepage, by evaporation, or for uses such as irrigation. Side flows are input (i.e., a given variable based on RiverWare results) into the model. Water is released from the reservoir (referred to as outflows) through the penstock and past turbine blades *RT* to produce power or through bypass tubes and spillways in which no power is produced *RW*. Both the timing and routing of water releases (i.e., power and non-power releases) are solved by the model and are the most critical variables for optimizing the economic value of hydropower resource. Values for *RT, RW, RD,* and *SF* are expressed in terms of total water release in AF from the end of hour *h*-1 to the end of hour *h*. It is assumed that the instantaneous flow rates over the simulated hour are constant.

The volume of water stored in a reservoir *V* at any simulated hour *h* is computed by the model as a linear water balance equation. Variables included in the mass balance equation are the initial reservoir volume at hour h_o (i.e., given state of the reservoir before the first simulation hour), reservoir inflows from hour *h*-1 to hour *h*, and reservoir outflows from hour *h*-1 to hour *h*. The time-step used for modeling the Aspinall Cascade is one hour and computed values for the reservoir volume are at the end of each hour.

The elevation of the water surface in the reservoir *E*, is a function of the amount of water that it stores. The model computes the forebay elevation based on the reservoir volume. At a low reservoir elevation a small change in water storage results in a relatively large elevation change and when the reservoir is full a small decrease in reservoir water storage results in a relatively small change in reservoir elevation. The reservoir elevation level is typically constrained such that it remains within a given range (referred to as *E*(limits) in Figure 8). Since the reservoir volume *V* is at the end of hour *h*, the computed reservoir elevation at the end of each hour.

The Crystal reservoir is constrained by the rate of reservoir elevation change over time. As shown on Table 3, the Crystal reservoir has limits on both daily and three day reservoir elevation changes. Both reservoir elevation limits and the rate of elevation change are operating rules that are established to maintain the reservoir storage quality. Computations of the reservoir water levels are not only important for ensuring compliance with reservoir operating rules, but are also key factors that determine power output from hydropower plants.

The relationships among the physical components of the Aspinall Cascade in terms of key modeling variable are shown in Figure 9. It illustrates that any action, usually in the form of a water release, at a reservoir will not only affect the current and future output level of its power plant, but it will also impact the operation of other cascade components over time. For example, when an AF of water is released from Blue Mesa in hour *h*, Blue Mesa’s reservoir will be slightly lower thereby affecting power production throughout the remainder of the simulated period. On the other hand, the Blue Mesa release will increase the reservoir elevation at Morrow Point and impact its power production over time. Therefore, maximizing the economic value of a tightly coupled cascade requires that the optimization be preformed across both time and space.

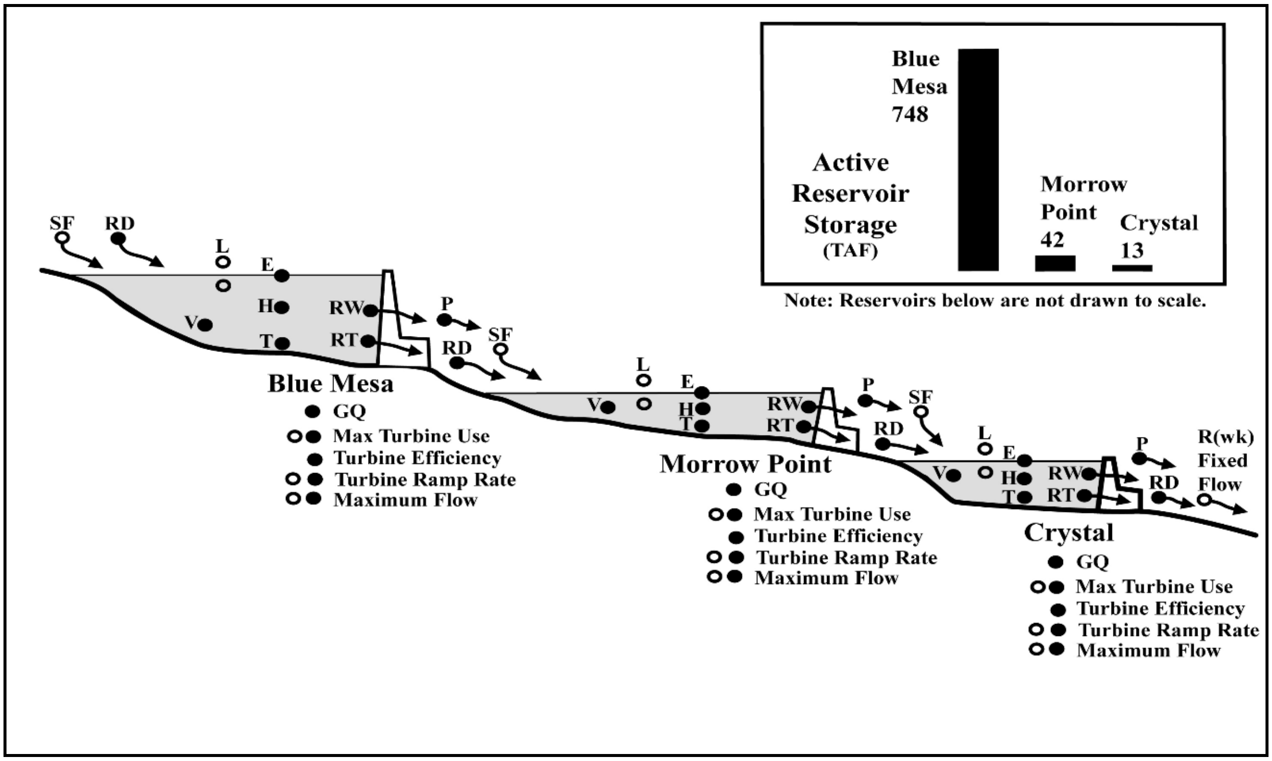

FIGURE 9 Aspinall Cascade Interdependencies

GTMax Mathematical Formulation

The GTMax model describes the Aspinall Cascade and its operations as a set of mathematical equations. These equations, provided in Table 6, consist of an objective function that is subject to a set of constraints. Equation 1, the objective function, is to maximize the value of Aspinall hydropower resources. It is set equal to the market price of electricity times the generation from all cascade power plants located at dams *d* and over all hours *h* during a two week simulation period. Although not shown in Equation 1, the objective function also contains other terms that give some actions preference over others. For example, water releases through hydropower plant turbines has a higher priority than releasing water through non-power outlets such as bypass tubes and spillways. The index *d* in the objective function equation represents cascade dams where 1 is used for Blue Mesa, 2 is for Morrow Point, and 3 is for Crystal. The hour index *h* spans 336 hours in the simulation period.

The maximization objective is subject to a set of constraints that restrict the operation of power plants and reservoirs in the cascade by the following means:

(1) limits the total water release volume from each reservoir during each simulated week;

(2) maintains a “conservation of mass” or “mass water balance” in tracking the water as it flows into and through the cascade;
(3) limits reservoir elevation levels and changes in forebay elevation levels over time and thus, operational water volumes in the reservoirs;

(4) limits hourly changes in reservoir water releases;

(5) constrains water releases through hydropower turbines; and,

(6) relates attributes such as reservoir forebay elevations to water volumes and turbine generating performance.

Optimizing Aspinall Cascade operations is a complex problem involving a combination of reservoir operations and scheduling power production. Modeling the system is further complicated by the myriad of potential reservoir operating rules that may be adopted. The challenge lies in the fact that each reservoir in the cascade can have a very large number of potential states at any one point in time. Aspinall reservoir states can become prohibitively large as the number of feasible states that must be examined grows rapidly as the simulation period increases and as the system becomes more complex. Cascade components are also highly interdependent such that operations at one reservoir have an effect on the other reservoirs in the system.

The LP formulation used by GTMax is well suited for efficiently solving the series of mathematical equations that describe the Aspinall system since all variables are simultaneously solved throughout the cascade over time. The problem formulation is "linear" since the objective function and all of the constraints are stated as strict continuous linear equations. Given the mathematical statement of the problem, the LP solution is guaranteed to be optimal.

In reality, many of the relationships in the cascade are *not* strictly linear. Therefore, a non-linear statement is approximated with one or more bounded linear equations. Non-linear functions include computations of reservoir water forebay elevations and power conversion factors.

The continuity constraint shown in Equation 2 maintains that total hourly water releases over all days *day* from each dam *d*, in a week will exactly equal the given weekly release target for the dam. Based on RiverWare model results, weekly target release volumes for GTMax are computed by the Input Data Processor spreadsheet such that the two models release the same amount of water each week. Separate values are computed and applied to the principal simulation period (wk=1, h=1 through 168) and extension weekly period (wk=2, h=169 through 336).

The total water release from dam *d* during day *day* is the sum of all hourly *h* releases beginning at midnight through the end of the day. It includes both turbine releases and spilled energy (non-turbine) releases at a dam in Equation 3. Hourly non-turbine water releases include releases through both the bypass tubes and spillways as described in Equation 4. It should be noted that GTMax daily water releases are not restricted and may therefore differ from daily values generated by the RiverWare model. However, as stated by Equation 3, both models have identical weekly water releases.

The maximum hourly water flows through turbines at a power plant for electricity production is limited by the generating capacity of the turbines at a dam and the power conversion factor as described by Equation 5. Maximum turbine flow rates are computed separately for the principal simulation period and the extension period. Hourly releases above the maximum power plant level are released through the bypass tubes and spillways. The GTMax model is formulated such that non-power water is first released through bypass tubes up to a maximum level described by Equation 6. Releases via spillways are used as a last resort.

The power conversion factor is a function of the forebay elevation level using a second order polynomial equation (Equation 7). Coefficients that describe the shape the power conversion curve for each hydropower plant in the Aspinall Cascade were jointly derived by Western and Reclamation (see Table 7). The coefficients are based on monthly historical values of end-of-month (EOM) reservoir elevations, monthly power production levels, and monthly turbine water releases as documented in PO&M-59 reports.

Estimated by Equation 8, hourly generation equals the weekly power conversion factor multiplied by turbine water releases. The average weekly reservoir elevation used in the equation is computed by the Input Data Processor spreadsheet using information from the RiverWare model. It should also be noted that the power conversion factor is held constant throughout a simulated week. In reality, reservoir elevations will fluctuate on an hourly basis, but these fluctuations tend to be small, especially at Blue Mesa and Morrow Point, having only a minimal affect on power conversion factors. These releases are constrained by Equation 5 which guarantees that power production levels do not exceed the power plant capacity. The timing of turbine water releases and hence generation is paramount to the optimization problem. Note that the hourly value of power in Equation 1 is given and therefore only hourly generation is solved for by GTMax.

Releases are restricted by numerous reservoir operating constraints. One set of restrictions limit forebay elevations and changes in elevations over time. The GTMax model first computes water storage levels in each reservoir and then estimates the reservoir elevation level. To track the water volume stored in a reservoir, Equation 9 is used to compute the volume in the first simulation hour for the Blue Mesa Reservoir (d=1). Equation 10 is used for all other simulated hours. These two equations maintain a “conservation of mass” for water in the Blue Mesa reservoir which is positioned at the top (i.e., highest elevation) of the Aspinall Cascade. The current water volume stored in the reservoir at the end of any hour h equals the stored water at the end of the previous hour minus the water released from it in the current hour plus all inflows into the reservoir during the current hour.

The flow of water through the cascade is tracked on an hourly basis and the water mass is conserved as it flows from Blue Mesa, first to the Morrow Point (d=2), and then to the Crystal (d=3) reservoir. Water volumes in lower reservoirs are first initialized for the first hour with Equation 11 and then computed for all subsequent hours with Equation 12. The volume of water at a lower reservoir (i.e., d>1, Morrow Point and Crystal) in the first hour equals the given initial volume at the reservoir plus releases from the reservoir immediately above it during the current hour plus the total side flows into it during the current hour minus the total release from the reservoir in the current hour. Note that a release from an upstream dam *d* in hour *h* will reach the reservoir below it (i.e., *d+1*) during the same hour *h*. This is consistent with observed swift water flow rates in the Gunnison and the close proximity of the dams in the Aspinall Cascade.

Reservoir water surface elevation must be tracked in order to ensure that the change in reservoir elevation at Crystal does not exceed set limits between midnight and midnight of each day and during rolling three day periods. Also, the reservoir elevation along with turbine capacities and power conversion factors are used to limit the maximum flow through electric turbines at all three reservoirs.

Reservoir elevation is tracked as a function of reservoir volume. The model formulation addresses the relationship between reservoir elevation and water storage volume for an Aspinall reservoir as a single linear function, written in slope-intercept form with Equation 13. The water forebay elevation at a dam's reservoir *d* during each hour *h* must remain within the preset maximum and minimum bounds given in Table 3. Equation 14 ensures that the elevations are compliant with these bounds. The elevation of each reservoir is expressed through its observed relationships with the reservoir volume. As describe in a previous section, some minor errors are introduced by linear reservoir elevation functions.

Additional constraints are needed to comply with reservoir elevation fluctuations at Crystal for each midnight-to-midnight period and for fluctuations over three day periods. Restrictions in daily fluctuations are formulated through at two-step process. First, daily minimum and maximum forebay elevation levels are computed by Equations 15 and 16, respectively. Then the difference between the maximum and minimum is computed by Equation 17. Equations 15 through 17 are extended backwards in time to restrict reservoir elevations during the first two simulated days based on reservoir elevations prior (historical or modeled) to the start of the simulated week. Note that the starting value for the day index *day* begins with -2.

Equation 18 constrains reservoir elevation fluctuations each day. Day elevation changes are limited during the entire 14 day simulation period; however, the limit may differs from one weekly period to the next. Equations 19 through 22 constrain three day reservoir elevation changes at Crystal. Operations are constrained by not only dependent on the 14 day simulation period, but also past operations as indicated by the negative day index.

Note that the daily elevation change equation is written only for the period from midnight-to-midnight. This is consistent with current regulations. However, in this form, there is no guarantee that a larger fluctuation might not occur during any 24-hour period. For example, a 24-hour period that begins at 9:00 AM and ends at 9:00 AM on the following day. However, since Crystal's release rate is flat and Morrow Point's turbine flow rate is also limited, the degree to which the rolling 24-hour fluctuation is greater than the midnight-to-midnight fluctuation tends to be very small.

The hourly ramp rate describes the change in water release from one hour to the next as computed by Equation 23. The ramp rate is given as the difference in releases between two consecutive hours from dam *d*. A positive ramp rate indicates the generation is increasing over time and a negative value indicates that it is decreasing. Hourly ramp rate limits are constrained by Equation 24. In the current formulation, the ramp rate limit at Crystal Dam is set equal to zero in most hours; that is, water releases remain constant from hour to hour. However, between mid-night and 1 AM, Crystal release changes at are unconstrained. At all other dams the ramp rates are essentially unlimited; that is, constraints that limit temporal changes in releases are non-binding under all conditions.

In addition to limiting changes in releases from one hour to the next, GTMax also constrains changes in total daily release volumes as computed by Equation 25. The ramp rate is computed as the difference in releases between two consecutive days from dam *d*. Daily ramp rate limits are constrained by Equation 26. Under EIS restrictions the daily ramp rate only limits operations at the Crystal Dam. Under all scenarios, daily ramping is limited to increases in 500 AF per day and decreases of 400 AF per day. Changes in daily releases are also constrained on a percentage basis by Equations 27 and 28. Daily releases are restricted to an increase of 25 percent and a decrease of 15 percent. One exception is the No Action Alternative in which case the up ramp increase is limited to 15 percent.

TABLE 6 Equations for Converting ROD Operating Criteria and RiverWare Output

Description	**GTMax Mathematical Formulation**	
Objective Function	$Maximize\ Z = \sum_d \sum_h (GQ_{d,h} \times SP_h) \quad \forall\ d,\ h = 1,\ 2,...336$	Eq. 1
Weekly Water Release	$WR_{d,wk} = \sum_{day=(wk-1)\times 7+1}^{wk\times 7} DR_{d,day} \quad \forall\ d, wk$	Eq. 2
Daily Water Release	$DR_{d,day} = \sum_{h=(day-1)\times 24+1}^{day\times 24} RT_{d,h} + RW_{d,h} \quad \forall\ d, day$	Eq. 3
Hourly Non-Power Release	$RW_{d,h} = RB_{d,h} + RS_{d,h} \quad \forall\ d, h$	Eq. 4
Max Turbine Flow Rate	$RT_{d,h} \leq PCAP_d / CF_{d,wk} \quad \forall\ d, wk, h = (wk-1)\times 168 + 1 ... wk \times 168$	Eq. 5
Max Bypass Flow Rate	$RB_{d,h} \leq RB_d^{\max} \quad \forall\ d, h$	Eq. 6
Conversion Factor	$CF_{d,wk} = C_{d,0} + C_{d,1} \times E_{d,wk}^{ave} + C_{d,2} \times E_{d,wk}^{ave\ 2} \quad \forall\ d, wk$	Eq. 7
Power Plant Generation	$GQ_{d,h} = CF_{d,wk} \times RT_{d,h}^{2} \quad \forall\ d, wk, h = (wk-1)\times 168 + 1 ... wk \times 168$	Eq. 8
Blue Mesa 1st hr Storage	$V_{1,1} = V_{0,1} - RD_{1,1} + SF_{1,1} \quad \forall\ d = 1,\ h = 1$	Eq. 9
Other hr Blue Mesa Storage	$V_{1,h} = V_{1,(h-1)} - RD_{1,h} + SF_{1,h} \quad \forall\ d = 1, h > 1$	Eq. 10

Down Steam Reservoirs 1st hr Storage	$V_{d,1} = V_{d,0} + RD_{(d-1),1} - RD_{(d,1)} + SF_{d,1} \quad \forall\ d > 1, h = 1$	Eq. 11
Other hr Down Steam Reservoir Storage	$V_{d,h} = V_{d,(h-1)} + RD_{(d-1,h)} - RD_{(d,h)} + SF_{d,h} \quad \forall\ d > 1, h > 1$	Eq. 12
Reservoir Elevation	$E_{d,h} = \left(E_d^{Slope} \times V_{d,h}\right) + E_d^{Int} \quad \forall\ d, h$	Eq. 13
Max & Min Reservoir Elevations	$E_{d,wk}^{MIN} \le E_{d,h} \le E_{d,wk}^{MAX} \quad \forall\ d = 3, wk, h$	Eq. 14
Daily Min Reservoir Elevation	$E_{d,day}^{Day\min} \le E_{d,h} \quad \forall\ d = 3, day = -2 \ldots 14, h = (day-1) \times 24 + 1 \ldots day \times 24$	Eq. 15
Daily Max Reservoir Elevation	$E_{d,day}^{Day\max} \ge E_{d,h} \quad \forall\ d = 3, day = -2 \ldots 14, h = (day-1) \times 24 + 1 \ldots day \times 24$	Eq. 16
Crystal Reservoir Elevation Daily Change	$E_{d,day}^{DayChange} = \left(E_{d,day}^{Day\max} - E_{d,day}^{Day\min}\right) \quad \forall\ d = 3, day = \text{-}2 \ldots 14$	Eq. 17
Crystal 1 Day Elevation Change Limit	$E_{d,wk}^{DayCMax} \ge E_{d,day}^{DayChange} \quad \forall\ d = 3, wk, day = (wk-1) \times 7 + 1 \ldots wk \times 7$	Eq. 18
3 Day Min Reservoir Elevation	$E_{d,day3}^{3Day\min} \le E_{d,day}^{Day\min} \quad \forall\ d = 3, day3 = 1 \ldots 14, day = day3 - 2 \ldots day3.$	Eq. 19
3 Day Max Reservoir Elevation	$E_{d,day3}^{3Day\max} \ge E_{d,day}^{Day\max} \quad \forall\ d = 3, day3 = 1 \ldots 14, day = day3 - 2 \ldots day3$	Eq. 20
3 Day Crystal Reservoir Elevation	$E_{d,day}^{3DayChange} = \left(E_{d,day3}^{3Day\max} - E_{d,day3}^{3Day\min}\right) \quad \forall\ d = 3, day = 0 \ldots 14, day3 = day - 2..day$	Eq. 21
Crystal 3 Day Elevation Change Limit	$E_{d,wk}^{3DayCMax} \ge E_{d,day3}^{3DayChange} \quad \forall\ d = 3, wk, day3 = (wk-1) \times 7 + 1 \ldots wk \times 7$	Eq. 22
Hourly Release Ramp Rate	$RR_{d,h} = DR_{d,h} - DR_{d,(h-1)} \quad \forall\ d = 3, h = 1 \ldots 336$	Eq. 23
Release Ramp Rate Limits	$-RR_d^{Down\max} \le RR_{d,h} \le RR_d^{Up\max} \quad \forall\ d = 3, h = 1 \ldots 336$	Eq. 24
Daily Release Ramp Rate	$DRR_{d,day} \le DR_{d,day} - DR_{d,day-1} \quad \forall\ d = 3,\ day = 1 \ldots 14$	Eq. 25
Limit Daily Water Release Ramp Rates	$-DRR_d^{Down\max} \le DRR_{d,day} \le DRR_d^{Up\max} \quad \forall\ d = 3,\ day = 1 \ldots 14$	Eq. 26
Limit % Daily Water Release Change Up	$0 \le DR_{d,day} \times DRR_d^{\%Up\max} - DRR_{d,day} \quad \forall\ d = 3,\ day = 1 \ldots 14$	Eq. 27
Limit % Daily Water Release Change Down	$0 \le DR_{d,day} \times DRR_d^{\%Down\max} + DRR_{d,day} \quad \forall\ d = 3,\ day = 1 \ldots 14$	Eq. 28

where,

d = dam index
h = hour index
day = day index
$day3$ = three day index
wk = week index
$WR_{d,wk}$ = weekly water release (AF) from dam d during week wk
$DR_{d,day}$ = daily water release (AF) from dam d during day day
$RT_{d,h}$ = hourly turbine water release (AF) from dam d during hour h
$RW_{d,h}$ = hourly non-turbine water release (AF) from dam d during hour h
$RB_{d,h}$ = hourly bypass water release (AF) from dam d during hour h
$RS_{d,h}$ = hourly spillway water release (AF) from dam d during hour h
$PCAP_{d}$ = hydropower plant generating capacity (MW) located at dam d
$CF_{d,wk}$ = power conversion factor (MWh/AF) for the plant located at dam d during week wk
$RB_{d}^{\max}$ = hourly bypass maximum release (AF) from dam d
$C_{d,x}$ = power conversion factor polynomial coefficient x for dam d
$GQ_{d,h}$ = hourly electricity generation (MW) for the plant located at dam d during hour h
SP_{h} = hourly price of electricity ($/MWh) during hour h
$V_{d,h}$ = water storage volume (AF) in the reservoir located behind dam d during hour h
$SF_{d,h}$ = sideflows (AF) into the reservoir located behind dam d during hour h
$E_{d,h}$ = forebay water elevation (ft) at the reservoir located behind dam d during hour h
E_{d}^{Slope} = slope of the forebay elevation equation (ft/AF) for dam d
E_{d}^{int} = intercept of the forebay elevation equation (ft) for dam d
$E_{d,wk}^{MIN}$ = minimum allowable elevation (ft) for dam d during week wk
$E_{d,wk}^{ave}$ = estimated average elevation (ft) for dam d during week wk
$E_{d,wk}^{MAX}$ = maximum allowable elevation (ft) for dam d during week wk
$E_{d,day}^{Day\min}$ = minimum reservoir elevation (ft) at dam d during day day
$E_{d,day}^{Day\max}$ = maximum reservoir elevation (ft) at dam d during day day
$E_{d,day}^{Daychange}$ = reservoir elevation change (ft) at dam d during day day
$E_{d,wk}^{DayC\max}$ = maximum allowable daily elevation change (ft) at dam d during week wk

$E_{d,day}^{3Day\min}$ = minimum reservoir elevation (ft) at dam d during a 3 day period	
$E_{d,day}^{3Day\max}$ = maximum reservoir elevation (ft) at dam d during a 3 day period	
$E_{d,day}^{3Daychange}$ = reservoir elevation change (ft) at dam d during a 3 day period	
$E_{d,wk}^{3DayC\max}$ = maximum allowable 3 day elevation change (ft) at dam d during week wk	
$RR_{d,h}$ = hourly water release ramp rate (AF/hr) at dam d during hour h	
$RR_{d}^{Down\max}$ = maximum allowable release down ramp rate (AF/hr) at dam d	
$RR_{d}^{Up\max}$ = maximum allowable release up ramp rate (AF/hr) at dam d	
$DRR_{d,day}$ = daily ramp rate (AF/day) at dam d	
$RR_{d}^{Down\max}$ = maximum allowable daily release decrease (AF/day) at dam d	
$RR_{d}^{Up\max}$ = maximum allowable daily release increase (AF/day) at dam d	
$RR_{d}^{Up\max}$ = maximum allowable percent daily release increase at dam d	
$RR_{d}^{\%Down\max}$ = maximum allowable percent daily release decrease at dam d	
$RR_{d}^{Up\max}$ = maximum allowable percent daily release increase at dam d	

TABLE 7 Polynomial Coefficients for Estimating Power Conversion Factor

Reservoir	$C_{d,0}$	$C_{d,1}$	$C_{d,2}$
Blue Mesa	323.1037	-0.087097359	5.87424E-06
Morrow Point	15,213.3109	-4.254332337	0.000297433
Crystal	2,736.1149	-0.811931703	6.02382E-05

Economic and Financial Analysis and Results

This section describes the analysis and results of the model runs completed using the methodology described above. It includes introductory pieces on generating and marketing of power from the Aspinall Units and of meeting reliability standards. It also describes the customers who contract for Aspinall electrical power through the SLCA/IP marketing.

Power Generation

Hydropower generation is directly related to the net effective head on the generating units and the quantity of water flowing through the turbines. The net effective head is the difference between the elevation of the water in the forebay behind the dam and the elevation of the water in the tailrace below the dam. The head and the quantity of water flowing through the turbines influence the maximum power output capacity of the powerplant, measured in megawatts (MW); capacity is the total powerplant generation capability at any point in time. In general, the powerplant capacity increases as a function of increasing head. However, turbine capacities or other equipment limitations may limit powerplant output levels.

Electrical power is measured in terms of capacity and energy. Electricity must be available the instant consumers need it. Capacity is important to meet consumers' instantaneous demand as they turn on lights, appliances and motors. Energy is the amount of electricity delivered over time and is measured in kilowatt-hours or megawatt-hours. One kilowatt-hour of energy delivered over one hour requires one kilowatt of capacity.

The capacity of each Aspinall Unit facility and historic average annual energy generation is summarized below:

Facility	Capacity (MW)	Average Annual Generation (MWH)
Blue Mesa	86.4	264,329
Morrow Point	165.0	343,450
Crystal	31.5	167,771

Power System Operations

Reclamation and Western work together on a daily basis in scheduling water releases and in coordinating maintenance outages. Western dispatches power generation at each facility to ensure compliance with minimum and maximum flow requirements, and comply with other constraints set by Reclamation in consultation with other Federal, State, and local entities. The CRSP Act states "The hydroelectric powerplants and transmission lines authorized by this Act to be constructed, operated, and maintained by the Secretary shall be operated in conjunction with other Federal powerplants, present and potential, so as to produce the greatest practicable amount of power and energy that can be sold at firm power and energy rates, but in the exercise of the authority hereby granted he shall not affect or interfere with the operation of the provisions of the

Colorado River Compact, the Upper Colorado River Compact, the Boulder Canyon Project Act, the Boulder Canyon Project Adjustment Act, and any contract lawfully entered into under said Compacts and Acts. Subject to the provisions of the Colorado River Compact, neither the impounding nor the use of water for the generation of power and energy at the plans of the Colorado River Storage Project shall be precluded or impair the appropriation of water for domestic or agricultural purposes pursuant to applicable state law."

In dispatching power generation, Western must also consider its power system responsibilities associated with North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC) criteria. WECC, as a regional council of the NERC, has responsibility for coordinating and promoting electric system reliability in the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between.

NERC and WECC operating criteria require Western and Reclamation to meet scheduled load changes by ramping the generators up or down beginning at 10 minutes before the hour and ending at 10 minutes after the hour. Ramping is the change in the water release from the reservoir through the turbine to meet the electrical load (or power demand). Both scheduled and unscheduled ramping are crucial in load following, ancillary services, power system regulation, emergency situations, and variations in real time (what actually happens compared to what was scheduled) operations.

Typically, power demand increases during the daylight hours as residences, commercial establishments, agriculture and industry put electricity to use. Hydropower generation can react instantaneously to the load – a pattern called load following. By comparison, coal- and nuclear-based resources have a relatively slow response time; consequently, they generally have limited load following capability in the WECC.

As a control area operator, Western regulates the transmission system within a prescribed geographic area. Western is required to react to moment-by-moment changes in electrical demand within this area, adjusting the electrical power output of hydroelectric generators within the area in response to changes in the generation and transmission system to maintain the scheduled level of generation in accordance with prescribed NERC criteria. Automatic Generation Control (AGC) is a process whereby the control system automates the water releases in a manner that follows the power system's actual dynamic demands on a moment-to-moment (typically a four-second-interval) basis.

Regulation depends on being able to ramp releases up or down quickly in response to system conditions. In addition, each utility is required to have sufficient generating capacity – in varying forms of readiness – to continue serving its customer load, even if the utility loses all or part of its own largest generating unit or largest capacity transmission line. This reserve capacity ensures electrical service reliability and an uninterrupted power supply.

Generating capacity that is connected to the power system and is in excess of the load on the system is called spinning reserve. Spinning reserves are used to quickly replace lost electrical generation resulting from a forced outage, such as the sudden loss of a major transmission line or generating unit. Additional off-line generating units are also used to replace generation shortages, but they cannot replace lost generation capacity as quickly as spinning reserves.

The two uppermost powerplants of the Aspinall Unit (Blue Mesa and Morrow Point) are critical to Western's operations in that they can be operated to provide load following to meet peak power demands. Blue Mesa and Morrow Point Powerplants operate in a peaking mode with large hourly fluctuations in power production over the course of a day with potential ranges from zero to maximum capacity in one hour. Crystal Reservoir serves as a regulation reservoir to stabilize flows to the Gunnison River; consequently, fluctuations in power generation at Crystal are minimal. The flexibility offered by the three dams of the Aspinall Unit is very important for meeting peaking, automation generation control, system reliability, and reserve sharing obligations of CRSP.

Power Marketing

Interconnecting transmission lines, both public and private, carry the power from generating facilities to major metropolitan areas and rural areas throughout the West. Western's power marketing responsibility, in most cases, begins at the switchyard of Federal hydroelectric power facilities and includes Federal transmission systems, while the hydroelectric plants are operated by Reclamation. Any power surplus or deficit affects all Salt Lake City Area Integrated Projects customers since the CRSP marketing area is within the WECC region, which is one large interconnected system.

Western markets CRSP power and administers the power contracts for power generated from Reclamation-owned and operated hydropower facilities in the Upper Colorado Region except for a small amount of power used on Reclamation projects. Marketing of electricity is based on capacity and energy. Energy and capacity are important to meeting consumers' continuing need for electricity. With the delivery of electricity, capacity and energy are both present; however, they can be marketed and billed separately. Western's power rates usually include individual charges for capacity and energy. Currently, a CRSP power customer pays $4.43 per kilowatt –month for electrical capacity. This capacity fee is paid every month regardless of the electricity a customer actually buys. It is a fee to reserve an amount of capacity that can be called upon by the customers to generate the electricity the customer may call upon during the month. Additionally, a CRSP power customer pays 10.43 mills per kWh for electrical energy delivered. Overall, while not an additional charge to the customer, the "combined rate" for energy and capacity is 25.28 mills per kilowatt hour.

Power is marketed in terms of firm and non-firm power. Firm power is capacity and energy that is guaranteed to be available to the contractor, in accordance with the terms of the contract. A sufficient portion of the generation capacity is held in reserve to enable continued delivery of firm power even if an outage occurs at a powerplant. The amount of power that is held in reserve is established by various power pooling agreements and reliability criteria. The majority of CRSP power is sold under long-term firm power contractual arrangements.

Non-firm power is capacity and energy that is not guaranteed to be available to the contractor. Non-firm power is sold to wholesale customers that would rather purchase non-firm energy that is less expensive than the cost of their own generation or cost of alternative sources of supply. Non-firm energy is usually sold with the requirement that the sale can be stopped on short notice and the buyer must have the resource available to meet its own load. Rates for non-firm energy only include a charge for the energy delivered, since the customer has the capacity to meet its loads, if necessary. Western does not sell non-firm power on a long-term basis. CRSP power in excess of that needed to meet long-term contractual requirements can be sold on a short term basis to wholesale customers as either firm or non-firm power.

Western allocates long-term firm capacity and energy from the various Federal powerplants, including the Aspinall Unit powerplants, in the Western States. The Salt Lake City Area Integrated Projects (SLCA/IP) is a group of Reclamation hydroelectric facilities marketed by Western which includes CRSP power and power from the Rio Grande Project and the Collbran Project. Electric capacity and energy from these hydropower plants, along with power purchased by Western, is provided to Western's power customers under contracts. Most such agreements are long-term firm contracts that specify the amounts of capacity and energy that Western agrees to deliver to its customers. Currently, the twenty year contracts for SLCA/IP power expire in 2024.

SLCA/IP Customers

Western markets SLCA/IP power, through its CRSP – Management Center Office in Salt Lake City, that serves approximately 5.8 million retail customers in rural areas and small towns in Wyoming, Utah, Nevada, Arizona, New Mexico, Colorado and Nebraska. Figure 1 shows areas served by CRSP. CRSP power customers purchasing wholesale electricity from Western are: 1) small and medium-sized towns that operate publicly owned electrical systems, 2) irrigation cooperatives and water conservation districts, 3) rural electrical associations or generation and transmission co-operatives who are wholesalers to these associations, 4) federal facilities such as Air Force bases, 5) universities and other state agencies and 6) Indian tribes. The reliance on CRSP power varies considerably among customers, with some customers receiving virtually all of their electrical service from the CRSP, to utilities in which CRSP resource is a small percentage of their total needs

Figure 10 shows the service areas for the SLCA/IP customers. Included are those areas with rural service areas as well as the service area of towns and municipalities (shown as red dots). Note that a significant portion of the Rocky Mountain states and states of the Desert Southwest receive some electrical power from the SLCA/IP power resources – including the Aspinall Units.

For the most part, the electrical power generated at the Aspinall Units, marketed by Western as part of the SLCA/IP electrical resource, serve rural areas of middle Western states. Western has estimated that 5.8 million retail customers that receive some portion of their electrical power from the SLCA/IP electrical facilities which include the Aspinall Units.

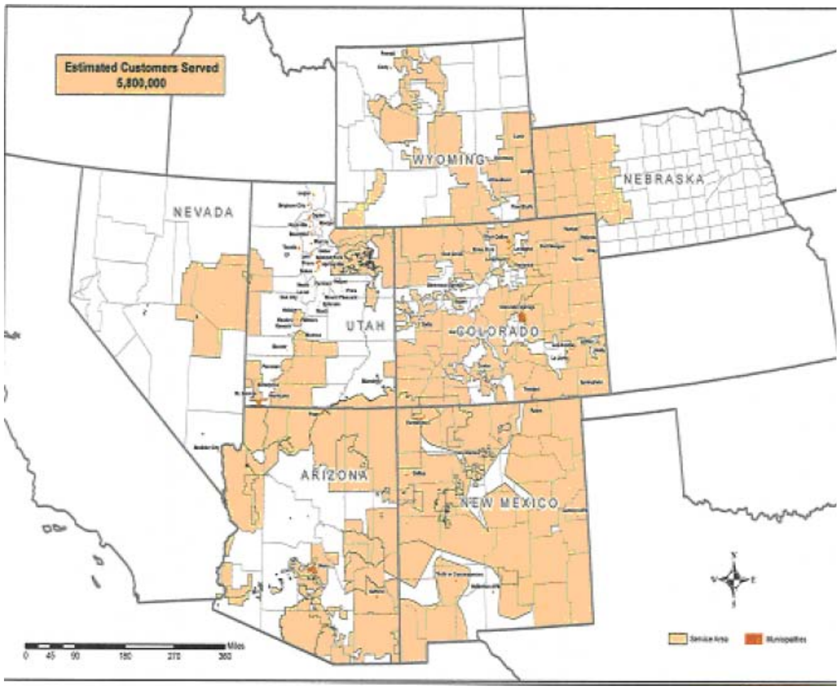

Figure 10 Service Areas of SLCA/IP customers.

SLCA/IP customers are allowed under the terms of their contracts, to schedule electrical energy to respond to changes in electrical use within their service territories. Western specifies the maximum amount of electrical energy that can be used by a customer within a month, the maximum amount that can be called upon in any given hour and the minimum amount that must be scheduled by a customer “around the clock”. Otherwise, SLCA/IP customers schedule electrical power to meet the needs of its retail customers.

Firm capacity and energy levels are guaranteed to the customer. If Western is unable to supply contracted amounts of firm capacity or energy from Reclamation hydroelectric resources, it must purchase the deficit from other (primarily non-hydropower) resources for delivery. Depending on the type of service offered, expense for this purchased power is either shared by all contractors, leading to a general increase in the overall rate, or it is passed through to individual customers. In addition, customers may choose to purchase some or all of this deficit on their own, in which case there would be financial impacts to the customers above and beyond those impacts shared by the CRSP customers or passed through by Western.

Power Generation Impacts

Hydropower generation analyses are based on two methodologies. The first is an economic analysis that represents the effects on a national perspective for each alternative. The results from the economic analysis provide values that reasonably represent national economic benefits. The second analysis is a financial analysis representing the impact to the wholesale rates paid by the utility customers who purchase the electricity generated by Aspinall Unit powerplants.

Economic Impacts

The impact of the alternatives on the production of power, or electrical generation, at the Aspinall Unit power system is shown in Table 8. This table illustrates the average impact over the 31-years modeled for this economic analysis.

The base year used for economic analysis purposes in this EIS is 2008 and the power impacts occur over a 31-year period. As further described in Appendix D, some additional calculations were carried out to reflect the time value of money. The power prices used in this analysis are from 2007. These values were escalated to 2008 dollars using an escalation rate of 2.2 percent. Observations occurring after 2008 were escalated by 2.2 percent per year and then discounted by 4.875 percent, the current Federal discount rate. This process places the estimated power economic impacts, which occur in different years, on a commensurate 2008 present value basis. The economic results, measured in 2008 dollar terms, are reported in the narrative and results tables which follow.

Table 8.0
Impact of Alternatives on the Aspinall Unit Power System
(Difference from No Action)

Alternative	Annual Average Economic Impact (Thousands of 2008$)	Average Annual Generation (GWh)	Power Releases (TAF)	Average Annual Non-Power Releases (TAF)
A	-$11	-1.181	-7.277	7.890
B	-$622	-9.914	-41.089	41.969
C	-$-2,050	-37.690	-140.892	142.979
D	-$484	-7.360	-31.117	31.873

For each alternative, Table 8 shows changes from No Action. Calculations were made from modeled average annual results of the economic impact, the Aspinall Unit generation, the release of water through the Aspinall powerplants (power release), the release of water that bypassed the powerplant (bypass tubes and spillway), and the total release. A negative number denotes a reduction as compared to No Action. A positive number denotes an increase as compared to No Action.

As shown in Table 8, all alternatives result in a loss in electric generation as well as an economic loss from the Aspinall power system relative to No Action when considered on an average annual basis. The economic losses recorded in column two of Table 8 are especially influenced by the "retiming" of electrical generation. Generally, all of the alternatives, to one degree or another, move water release and subsequently, electrical generation, to the spring (May). The added water release in the spring required that water be moved from other months of the year that have a greater demand – or economic value – for electrical power.

As displayed in Table 8, the average economic impact of Alternative A is insignificant at $11 thousand when compared to the economic value of around $42 million produced by the Aspinall Unit each year. The economic impacts of Alternatives B and D are larger at $622 thousand and $484 thousand, respectively, on an average annual basis but are also considered insignificant. The impact of Alternative C, reported as an economic loss on an average annual basis of $2.050 million, is nearly a five percent reduction in economic value and is considered significant. The 30-year impact of Alternative C would be over $63 million.

The economic impact to the Aspinall power system on an average annual basis is a measure of impact that can overlook significant variations that occur on a year-to-year basis. Thirty one years were modeled for the power analysis of the alternatives. The variation among years of the economic impact within an alternative is more pronounced than the average difference between any two alternatives. Economic impacts for Alternatives A, B and D that are considered insignificant on an average basis can show significant impacts in a subset of years as compared to No Action.

Table 9 shows a summary of the results of the modeling of the alternatives on electrical generation for each of the 31 years analyzed. Annual values displayed for each of the four action alternatives as compared to the No Action alternative. As shown in Table 9, the impact of the action alternatives on electrical generation at the Aspinall Unit varies significantly among alternatives. In 1975, for example, Alternative A produces more electrical generation than the No Action alternative (approximately 14,000 MWh), while Alternatives B, C and D produce about 9,000 MWh less In comparison, on an average basis, the alternatives all produce slightly less electricity than the No Action Alternative. Since the amount of water released over the period of study is the same for all alternatives modeled, including the No Action case, the generation differences would be the result of production efficiency, i.e., releasing water through the Aspinall Unit powerplants when the reservoirs are at higher elevation.

Table 10 displays the impact of the alternatives in terms of economic cost or economic value. The alternatives differ significantly from each other when looked at annually. For example, in 1978, in comparison to the No Action Alternative, Alternative A decreases the value of electrical generation, Alternatives B and D increase the value of electrical generation by $1.26 million and Alternative C increases the value of electrical generation by nearly $5 million.

The differences between alternatives are affected by the economic value of power. This is because generation is not valued the same in each month of the year. An alternative that produces considerably more electrical power in May could have this increased power generation offset by a slight decrease of electrical power in August. This is because the value of power in August is considerably higher than in May.

TABLE 9
Impacts of Alternatives on Total Aspinall Unit Electrical Generation by Year
(Difference from No Action)

	Total Generation (MWh)			
Year	**Alt A**	**Alt B**	**Alt C**	**Alt D**
1975	13,784	(8,816)	(8,816)	(8,816)
1976	290	2,718	13,622	2,718
1977	25,236	24,606	23,436	24,606
1978	(3,960)	34,785	87,311	34,784
1979	(15,682)	(110,449)	(77,463)	(110,449)
1980	(180)	(43,127)	(99,396)	(43,127)
1981	13,250	13,708	(13,066)	13,708
1982	(10,895)	(28,300)	(291,448)	(28,300)
1983	(2,340)	(11,489)	(23,406)	(4,429)
1984	(7,400)	(4,205)	(134,734)	(5,338)
1985	2,067	2,330	(26,014)	2,161
1986	(3,070)	(17,693)	(102,853)	(17,686)
1987	(1,953)	(490)	(4,361)	(490)
1988	3,520	9,080	27,359	3,990
1989	1,717	1,700	(9,845)	(2,431)
1990	(3,810)	(11,910)	(18,596)	696
1991	(3,632)	(13,543)	(40,046)	(5,173)
1992	(21)	(5,430)	(14,756)	560
1993	(18,183)	(20,632)	(39,960)	(16,141)
1994	16	(7,111)	(26,091)	(126)
1995	(21,537)	(10,755)	(157,020)	(11,835)
1996	4,477	(45,469)	(69,070)	(45,573)
1997	675	2,523	(85,348)	2,523
1998	(2,134)	3,183	(2,602)	3,183
1999	(13)	(13,563)	(39,460)	(7,994)
2000	(21)	4,298	(6,838)	(334)
2001	(47)	(43,290)	(6,228)	(531)
2002	19,366	15,771	16,417	18,874
2003	50,963	64,412	80,347	46,209
2004	(5,844)	13,498	41,779	(6,195)
2005	(71,258)	(103,680)	(161,232)	(67,219)
Total	(36,622)	(307,341)	(1,168,377)	(228,174)
Average	**(1,181)**	**(9,914)**	**(37,690)**	**(7,360)**

TABLE 10
Impacts of Alternatives on Total Aspinall Economic Value by year
2008 Dollars (Difference from No Action)

Difference from No Action				
Year	**Alt A**	**Alt B**	**Alt C**	**Alt D**
1975	$1,649,043.44	($744,574.41)	($744,576.30)	($744,576.30)
1976	($445,804.58)	($560,867.64)	($107,327.92)	($560,867.08)
1977	$1,844,412.82	$1,796,962.53	$1,705,736.43	$1,796,961.66
1978	($222,690.11)	$1,260,991.69	$4,820,656.54	$1,260,989.39
1979	($993,932.22)	($7,261,204.67)	($4,523,834.30)	($7,261,205.03)
1980	$116,354.85	($2,516,619.69)	($6,076,651.05)	($2,516,619.25)
1981	$843,837.83	$886,874.68	($908,066.40)	$886,875.72
1982	($693,226.66)	($2,068,096.52)	($18,096,299.04)	($2,068,097.12)
1983	($141,413.45)	($722,601.02)	($1,381,020.53)	($429,663.95)
1984	($445,689.33)	($236,907.31)	($6,972,752.65)	($297,485.91)
1985	($68,616.63)	($125,902.35)	($1,605,533.75)	($136,668.54)
1986	($214,650.35)	($1,390,622.62)	($6,089,356.61)	($1,390,106.55)
1987	($98,192.42)	($41,589.48)	($305,964.36)	($41,566.36)
1988	$230,955.01	$407,206.28	$1,048,137.35	$256,430.18
1989	$92,905.80	($69,469.28)	($862,513.27)	($85,643.14)
1990	($162,958.51)	($597,131.55)	($955,909.01)	$76,281.78
1991	($176,027.75)	($714,234.43)	($2,067,896.77)	($326,745.61)
1992	$6,079.16	($332,466.64)	($1,028,165.10)	$36,504.81
1993	($734,214.32)	($828,785.33)	($1,618,107.80)	($625,551.13)
1994	$3,761.35	($476,742.40)	($1,590,130.58)	($5,412.26)
1995	($942,069.78)	($456,825.34)	($6,071,368.46)	($510,836.03)
1996	$120,867.95	($2,202,669.54)	($3,394,304.06)	($2,206,548.35)
1997	($23,613.11)	$11,545.35	($3,723,665.91)	$11,547.74
1998	($138,832.36)	$149,557.65	($127,873.65)	$149,543.02
1999	($36,425.20)	($708,437.84)	($1,834,257.18)	($465,762.88)
2000	$13,913.36	($159,791.16)	($373,465.51)	$6,690.98
2001	($2,248.41)	($1,777,892.43)	($350,989.44)	($20,619.98)
2002	$751,099.73	$630,365.26	$650,594.48	$732,627.73
2003	$1,982,426.67	$2,423,555.58	$2,943,264.53	$1,824,406.00
2004	($177,706.17)	$435,544.10	$1,298,832.53	($192,370.56)
2005	($2,275,176.01)	($3,283,608.79)	($5,213,926.40)	($2,151,539.97)
Total	($337,829.40)	($19,274,437.32)	($63,556,734.19)	($14,999,026.99)
Average	($10,897.72)	($621,756.04)	($2,050,217.23)	($483,839.58)
Percent Difference	-0.03%	-1.47%	-4.86%	-1.15%

The differences between alternatives are affected by the economic value of power. This is because generation is not valued the same in each month of the year. An alternative that produces considerably more electrical power in May, may have this gain offset by a slight decrease of electrical power in August. This is because the value of power in August is considerably higher than in May.

Impacts analyzed on an annual average basis can hide the effect of monthly changes in electrical generation. In order to release water through the Aspinall powerplants over the course of a year, the releases are patterned over the year in terms of monthly targets. The alternatives differ significantly regarding the monthly pattern over a year of water release and electrical generation. This monthly variation in releases, coupled with seasonal variations in the economic value of power, can mask detrimental economic impacts within a given year even though the average annual impact appears to be of little significance. Such monthly or annual variations in available generation could make it necessary for Western and its customers to purchase replacement power to meet contract commitments. Power revenues available for deposit in the Basin Fund could be reduced and thus impact the amount of funding available for operation and maintenance of facilities, including support for environmental programs, and also reduce repayment capability of the Basin Fund.

Financial Analysis Method and Results

Hydropower is generally less expensive to produce than alternative technologies since there is no fuel cost. The SLCA/IP rates include assistance to water development projects. Currently, about one third of future revenues projected in the SLCA/IP rate are programmed to financially assist the development and construction costs of authorized water projects.

While the SLCA/IP rate for wholesale power is relatively inexpensive, retail rates of SLCA/IP electrical coop & irrigation customers are typically higher than in privately owned utility service areas. This is the case, to a great extent, because rural areas require larger investments in transmission and distribution lines for each commercial, industrial or residential load served.

Western sells SLCA/IP electricity under long-term firm contract. It charges for capacity contracted and for energy used. These are separate charges. Often, for ease of display or understanding, Western reports a “composite” rate – a combination of the capacity and energy prices charged. The financial impacts are reported as changes in the composite rate.

The SLCA/IP electrical power is marketed on a cost-based basis. Table 11 displays the impact of the alternatives on the SLCA/IP firm-power rate. A positive number indicates an increase in the SLCA/IP rate as a result of the implementation of an alternative. A negative number indicates a decrease in this rate as a result of an alternative. The rate change in Table 11 is shown in mills (one thousandth of a dollar) per kilowatt hour. All but one of the alternatives (Alternative A) would require an increase in the SLCA/IP rate.

Table 11
Impacts to the SLCA/IP rate

Alternative	Change in SLCA/IP rate (mills/kWh)
No Action	0.00
Alternative A	- 0.03
Alternative B	0.16
Alternative C	0.53
Alternative D	0.14

Again, these numbers are based on an “all other things equal” assumption. An actual change in the SLCA/IP rate, if any, would be triggered by changes in a variety of variables, including modifications of the operation of the Aspinall Units.