TECHNICAL MEMORANDUM NO. 1
CONCERNING ANALYSIS OF ALTERNATIVE 1A, EXPANDED COORDINATED RESERVOIR OPERATIONS OF GREEN MOUNTAIN RESERVOIR, REDUCED WINTER POWER OPERATIONS

PRODUCED FOR:

Colorado Water Conservation Board

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EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 1 is to present the results of an investigation of Alternative 1a, Reduced Green Mountain Reservoir Power Operations, to the Executive Committee for review. This investigation has analyzed the impact of Alternative 1a on: (1) existing projects' yields, (2) existing projects' operations and maintenance costs and (3) existing projects' operational flexibility or reliability. The intent of the review by the Executive Committee is to make sure that the following components of the investigation are acceptable to the Executive Committee or if changes are necessary to: (1) the assumptions and ground rules, (2) the data sets, (3) the models/tools, and (4) the analysis methodologies. If these components are found to be acceptable, subsequent analysis of the other alternatives will be initiated using the same or similar assumptions and ground rules, data sets, models/tools, and methodologies.

Alternative 1a, Reduced Green Mountain Reservoir Power Operations, is one of 17 alternatives recommended for further investigation in *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River* report. This alternative would shift up to 20,000 acre-feet of water from release from Green Mountain Reservoir for power generation during the period November 1 through April 1 to release during a 10-day period in late May or early June.

The effects on other existing projects from this proposed change in Green Mountain Reservoir operations was investigated using StateMod and the C1 data set for a 1975-91 study period.

The investigation indicated the following impacts of Alternative 1a on: (1) existing projects' yields, (2) existing projects' operations and maintenance costs and (3) existing projects' operational flexibility or reliability:

1. **Shoshone power production.** The largest estimated impact, of any kind, on an existing project from implementation of Alternative 1a was the reduction in average annual potential power production at the Shoshone Power plant by 1.7 percent, or 2140 MWhr/year. The estimated value of power generation forgone at the Shoshone Power Plant as a result of the alternative operating policy is approximately $2,960,000 for the 17-year study period. This averages approximately $174,000 less per year as compared to the base case.

2. **Shoshone priority calls.** The frequency and duration of Shoshone priority calls were not altered to any significant degree by implementation of the Alternative 1a operations policy for the 1975-91 study period. The duration of the Shoshone priority call was potentially increased for an estimated 1-2 weeks in December 1985 as a result of implementing the Alternative 1a operating policy. This was the only period in which the duration of the Shoshone priority call would have been increased. The duration of the Shoshone priority call would have been potentially decreased in August 1978 by implementing the Alternative 1a operating policy. Investigation results did not indicate that the frequency of Shoshone calls would be increased by implementation of the Alternative 1a operating policy.

3. **Green Mountain power production.** For Green Mountain Reservoir power production, Alternative 1a operating policy: (a) increased annual average power production at Green Mountain Reservoir by approximately 1.9 percent (1050 KWhr/year) and (b) shifted production of power generated from the 20,000 acre-feet from the winter period of November 1 through April 1 to the later part of May and/or early June. The estimated value of power generation foregone at Green Mountain Reservoir as a result of this alternative operating policy is approximately $607,000 over the 17-year study period, or an average of approximately $36,000 per year, as compared to the base case. The fact that there would have been more kilowatt hours of power generated with the alternative operating policy as compared to the base case but reduced revenue from power generation results because of the difference in timing of when the power was generated under the two scenarios.

4. **Green Mountain Reservoir storage.** Filling Green Mountain Reservoir was not affected by the new operating policy (see Figure 4). The reservoir filled in every year it historically filled and in those years when it did not fill historically (1977 and 1981), the Alternative 1a operating policy resulted in higher storage than occurred historically.

5. **Dillon and Williams Fork Reservoirs.** Total storage in Dillon and Williams Fork Reservoirs was unaffected by implementation of the Alternative 1a operating policy for the study period with the exception of: (a) 1977 when Dillon was required to release approximately 18,000 acre-feet of water to Green Mountain Reservoir under the C1 scenario and was not required to make this release under the Alternative 1a operating policy and (b) a slight decrease in total storage (approximately 6,000 acre-feet) in April 1982. Other than these two events, total storage in Dillon and Williams Fork Reservoirs was almost exactly the same under the two operating policies.

6. **Granby Reservoir**. Storage in Granby Reservoir was unaffected by imposition of the Alternative 1a operating rule as compared to storage under the C1 Scenario for the study period.

7. **Orchard Mesa Power Plant.** The Alternative 1a operating policy for Green Mountain Reservoir did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternative 1a operating policy.

8. **Check Case settlement.** Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternative 1a operations policy will make releases of the 20,000 acre-feet. Under Alternative 1a, decreased releases from Green Mountain Reservoir will only occur during the November 1 through March 31 winter period. Consequently, implementation of the Alternative 1a operations policy should not affect the Check case settlement.

9. **Physical feasibility of Green Mountain Reservoir releases.** Results indicate that releases for the recovery program would be made in only six years (1975, 1978, 1979, 1980, 1985 and 1986) during the 1975-91 study period. In all other years, the spring peak flows at the head of the 15-Mile Reach were less than 12,900 cfs or greater than 26,600 cfs and a release would not be required. In these six years in which the 20,000 acre-feet release was required, it was possible to make the release at a rate of 1,000 cfs for a period of 10 days from Green Mountain Reservoir.

10. **Channel capacity constraints.** Restrictions on Blue River channel capacity or Colorado River channel capacity downstream from Green Mountain Reservoir would not have limited the 1,000 cfs release in any of the six years in which the release was required for the 1975-91 study period

11. **Release 20,000 acre-feet in two additional years.** In 1982 and 1991, spring peak flows were close to the 12,900 cfs lower limit at which the 20,000 acre-feet release would be made. Investigations were carried out to determine the effects on other projects from making releases of 20,000 acre-feet in these two additional years. These investigations demonstrated that the only effects on other water rights from making the 20,000 acre-feet releases in the two additional years was to have approximately 2400 acre-feet less storage in Green Mountain Reservoir in June 1982 and 2200 acre-feet less in July 1991 as compared to the scenario in which these additional releases were not made. Green Mountain Reservoir filled in both 1982 and 1991 in the original scenario (releases in six years) as well as in the scenario in which releases of the 20,000 acre-feet were made in eight years.

INTRODUCTION AND PURPOSE

Several options for revising Green Mountain Reservoir operations to produce flows contributing to the average annual 20,000 acre-feet target were developed in Phase 1 of this investigation. These alternatives include:

- Reduced winter power operations (see section 3.2.1.1 in *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River*
- Green Mountain Reservoir conjunctive pool operations (section 3.2.1.2 in the Phase 1 Study)
- Green Mountain Reservoir preemptive releases (section 3.2.1.3 in the Phase 1 Study)
- Release of water carried over in Green Mountain Reservoir (section 3.2.1.4 in the Phase 1 study).

This reduced winter power operations alternative shifts up to 20,000 acre feet of water from release from Green Mountain Reservoir for power generation during the period November 1 through April 1 to release during a 10 day period in late May or early June. In many years there is an opportunity to reduce winter power releases from Green Mountain and carry that water over for release on the spring peak. Under this alternative, Green Mountain Reservoir would enter the fill season at storage levels 20,000 acre-feet higher than the historical 50,000 to 80,000 acre-feet.

The purpose of this Technical Memorandum is to present: (1) the methodology used to analyze Alternative 1a, Green Mountain Reservoir Reduced Winter Power Operations and (2) the results of this analysis. After review by the CWCB and the Executive Committee, necessary changes will be made in the analysis methodology in response to comments and suggestions from the CWCB and the Executive Committee and the Green Mountain Reservoir winter power operations alternative will be reanalyzed accordingly. Subsequent to reanalysis of Alternative 1a, the other Green Mountain Reservoir alternatives detailed above will be analyzed. The results of this analysis and calculations will be presented in the Phase 2 report.

Specific concerns that are addressed in this engineering analysis of Alternative 1a include:

- The frequency with which the 20,000 acre-feet per year target can be provided in those years when the expected peak spring flow at the head of the 15-Mile Reach is between 12,900 cfs and 26,600 cfs.
- The effect on Green Mountain Reservoir filling each year as a result of entering the fill season (approximately April 1) with an additional 20,000 acre-feet of water in storage.
- The effect on the operation and yield of other projects as a result of Green Mountain Reservoir entering the fill season with an additional 20,000 acre-feet of water in storage and then releasing that 20,000 acre-feet over a 10 day period at a rate of approximately 1,000 cfs in those years when the spring peak flow at the head of the 15-Mile Reach is expected to be greater than 12,900 cfs and less than 26,600 cfs. Analysis must look specifically at whether this Alternative 1a will increase Denver Water's risk of releasing water from Dillon Reservoir to assure a Green Mountain Reservoir fill under the Blue

River Decree and subsequent agreements among Denver Water, Reclamation, NCWCD and the Colorado River Water Conservancy District.

- The effect on hydropower generation at Green Mountain Reservoir, Shoshone Power Plant, and the Orchard Mesa Power Plant.
- The effect on flooding in downstream reaches of the Blue and Colorado Rivers from releasing this additional 1,000 cfs on to the peak of the spring runoff hydrograph.
- The physical feasibility of releasing the 20,000 acre-feet at a rate of 1,000 cfs over a 10-day period from Green Mountain Reservoir.

Other legal/institutional concerns exist concerning Alternative 1a; these concerns are not addressed in this Technical Memorandum, but will be addressed by our crack legal team and discussed in the Phase 2 report. The ongoing controversy regarding Reclamation's authority to release water from Green Mountain Reservoir for piscatorial purposes is an example of these legal/institutional issues. The Federal Government asserts that Senate Document No. 80 and the Green Mountain Reservoir water rights give the Reclamation the necessary authority to release water for endangered fish. The State of Colorado and various water users submit that releases for piscatorial purposes are not allowed under the Green Mountain Reservoir water rights decree. Changes to the Green Mountain Reservoir water rights decree may be necessary.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following procedures and assumptions were employed in the analysis of Alternative 1a:

1. The StateMod surface water model and C1 dataset were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000)*. These components of RIPRAP flows include:

   - 5,000 acre-feet per year from Ruedi Reservoir,
   - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
   - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
   - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
   - 6,000 acre-feet per year from Wolford Mountain Reservoir,
   - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated on the C1 dataset but not modeled.

3. Flow Targets: Releases of 20,000 acre-feet over a 10 day period were made from Green Mountain Reservoir when the expected spring peak flow at the head of the 15-Mile Reach was between 12,900 cfs and less than 26,600 cfs. If the 20,000 cfs was not released to enhance the spring peak flows, it was booked over to storage in the Historic Users Pool and no attempt was made to release this water in the late summer or early fall for purposes of augmenting low flows.

4. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee determine after their review and the consultant makes necessary changes that the methodology and calculations employed in the analysis of Alternative 1a are acceptable, the necessary sensitivity analysis will be completed.

CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

5. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

6. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

   The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

7. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,
   - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
   - A reservoir fill according to the criteria of the Blue River Decree.

   The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

   Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

   Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

8. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
   - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and

- Sufficient HUP Surplus water exists to make the release.

Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. Releases of HUP Surplus water under the Municipal Recreational Agreement are not explicitly modeled by StateMod and the C1 data set and there is no demand specified at a node for the Municipal Recreational water.

STATEMOD ANALYSIS

Green Mountain Reservoir is modeled in the C1 scenario using five separate pools including the Historic Users Pool (HUP), the Colorado Big Thompson Pool (CBT), the contract pool, the Silt Project Pool, and the Inactive Pool. Details of the method of modeling Green Mountain Reservoir in the C1 scenario can be found in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).*

The C1 scenario was modified by adding full reservoir targets in Green Mountain Reservoir for the months of September and October. This prevented surplus water hydropower releases until after the irrigation season. In addition, monthly demands of 20,000 acre-feet were added to diversion ID #952001 corresponding to the projected 20,000 acre-feet releases to enhance the spring runnoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1985 and 1986. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water in the stream when available. This was the basis for the baseline scenario for evaluating alternatives.

For Alternative 1a, the baseline scenario was modified in two ways. First, the reservoir end of month storage targets in March and April were increased by 20,000 acre-feet to account for the increased water stored in the winter. Secondly, the operating rule which allowed releases from the HUP account to Diversion ID# 952001 (the 15-Mile Reach fish requirement) was turned on. These two changes maintained an additional 20,000 acre-feet of water in the HUP account and released that amount in those years when it would be required.

Several spreadsheets were then developed to allow side by side comparison of every aspect of the analysis in the two StateMod runs including reservoir storage, diversions, streamflows and operating releases.

RESULTS

RELEASES

Releases for the Recovery Program would be made in only six years (1975, 1978. 1979, 1980, 1985, and 1986) during the 1975-91 study period. In all other years, the spring peak flows at the head of the 15-Mile Reach were less than 12,900 cfs or greater than 26,600 cfs (see Figure 1).

RELEASES THROUGH THE SPILLWAY

In the six years in which the 20,000 acre-feet release was required, it was possible to make the release at a rate of 1,000 cfs for a period of 10 days from Green Mountain Reservoir. In three of those years (1980, 1985 and 1986) it would have been necessary, and possible, to make a portion of this release through the spillway because the total release would have exceeded the 1500 cfs turbine capacity (see Table 1). In June 1980, it would have been necessary to release an average monthly flow of approximately 1057 cfs over the spillway in addition to the 1500 cfs passing through the turbines. In June 1985, it would have been necessary to release an estimated average monthly flow of 366 cfs over the spillway in addition to the 1500 cfs passing through the turbines. In June 1986, it would have been necessary to pass an estimated 25 cfs over the spillway in addition to the 1500 cfs through the turbines.

BLUE RIVER CHANNEL CONSTRAINTS

Restrictions on Blue River channel capacity downstream from Green Mountain Reservoir would not have limited the 1,000 cfs release in any of the six years in which the release was required for the 1975-91 study period. The Bureau of Reclamation is reluctant to make releases greater than 3,000 cfs from Green Mountain Reservoir because of localized downstream flooding from flows greater than approximately 3000 cfs. Total Green Mountain releases did not exceed 3000 cfs in any of the years in which a release of 1,000 cfs for a period of 10 days was made (see Table 1).

COLORADO RIVER CHANNEL CONSTRAINTS

Review of *Coordinated Reservoir Operations Bypasses for Endangered Fish Annual Summary of Operations for 1997 to Benefit the Endangered Fishes of the Upper Colorado River Basin* provides information concerning flooding from the main stem Colorado River that occurred in 1997 in the Kremmling, Cameo and Grand Valley areas. This report contains locations and extent of flooding that occurred in early June, 1997 when the spring hydrograph peaked at 26,500 cfs at the Palisade gauge and 37,200 cfs at the State line gauge. Data provided in this report indicate only minimal flooding of rural floodplain areas and high water on the I-70 bridge downstream from Fruita with no indication of property damage from these flows.

The recorded 1997 peak Colorado River flow at the Palisade gauge of 26,500 cfs is very close to the upper limit for making releases to the fish of 26,600 cfs. For practical purposes, therefore, it would appear feasible to develop operations rules that would require reduction or cessation of releases for the fish when flows at the Palisade gauge approached, say 25,000 cfs. Selection of this upper cutoff number should allow 2 to 3 days travel time from Green Mountain Reservoir to the Palisade gauge to insure that releases for the fish would not be responsible for additional flooding above the approximately 26,000 cfs flow at the Palisade gauge.

PINCH POINTS AND CHANNEL CONSTRAINTS IN GENERAL

The above referenced 1997 Coordinated Reservoir Operations Review recommended that additional investigations of channel capacity constraints ("pinch points") in the Colorado River basin in Colorado are necessary. Specifically:

- Work with the State of Colorado and National Weather Service to resolve differing flood stage levels or determinations at stream gages.
- Obtain aerial photography downstream of all participating reservoirs and in the 15-Mile Reach to determine “pinch points” on the system when out-of-bank flooding is close to occurring and document the benefits of peak flows to critical habitat.
- Work with the State of Colorado and National Weather Service to identify high flow levels and locations potentially flooded or adversely affected by the Coordinated Reservoir Operations Study.

Implementation of these recommendations would be of significant assistance in facilitating releases from reservoirs for the endangered fishes without creating additional damage from flooding.

GREEN MOUNTAIN RESERVOIR POWER GENERATION

Results of the analysis indicate that the principal effect of the Alternative 1a operating policy for Green Mountain Reservoir power generation was the shift in timing of power generated from the 20,000 acre-feet from the winter period of November 1 through April 1 to the later part of May and/or early June (see Figure 7).

Calculations were completed to determine the difference in total megawatt hours generated between historic operation of Green Mountain Reservoir and the proposed change in operations with Alternative 1a. These calculations produced the following results and conclusions:

- For the six years when the 20,000 acre-feet was released, this 20,000 acre-feet would have entirely passed through the turbines at Green Mountain Reservoir in three of these years (1975, 1978 and 1979) and generated power during May and June (see Table 1). In two of these release years (1985 and 1986, the 1,000 cfs release would have been released during a period when releases exceeded turbine capacity (1500 cfs) and only a portion of the 1,000 cfs release would have passed through the turbines: an average of 634 cfs would have

passed through the turbines in June, 1985 and 975 cfs in June 1986. In June 1980, the entire 1,000 cfs would have passed over the spillway and not generated electric power.

- For the study period of October 1974 through September 1991, an estimated 874,118 MWhr of electric power would have been generated based on the C1 hydrology scenario. During this same period, 890,942 MWhr of electric power would have been generated during the 16-year study period under the Alternative 1a operating policy. Therefore, an estimated 16,824 MWhr of additional electric power would have been generated over the 16-year study period under the Alternative 1a operating policy as compared to the base case of the C1 hydrology scenario. This increase in power generation under the Alternative 1A operating policy occurs because:

  (a) Green Mountain Reservoir would have higher storage levels, and consequently high hydraulic head, for power generation in May and June when the 20,000 acre-feet is released under the Alternative 1a operating policy as compared to the C1 Scenario which makes releases for power generation during November through March when the 20,000 acre-feet would have been released under the C1 scenario.

  (b) The 20,000 acre-feet will pass through the turbines for power generation under the Alternative 1a operating policy except in those few years (3 in the 16-year study period) when turbine capacity is exceeded and all, or a portion of, the 20,000 acre-feet will go over the spillway.

- The value of power generation forgone at Green Mountain Reservoir as a result of this alternative operating policy is presented in Table 2. Results in Table 2 indicate that approximately $607,000 less power would have been generated at Green Mountain Reservoir over the 17-year study period, or an average of approximately $36,000 per year, with this alternative operating policy as compared to the base case. The fact that there would have been more kilowatt hours of power generated with the alternative operating policy as compared to the base case but reduced power revenue results because of the difference in timing of when the power was generated under the two scenarios.

SHOSHONE POWER GENERATION

Shoshone power operations were reduced for the study period during the winter months using the changed operating policy (see Figure 2). Historically, the Shoshone power plant has had insufficient flows in the winter to satisfy its two decrees and thus could not operate at peak capacity. The changed operating policy would further reduce the flow in the river at Shoshone during these winter months. Figure 2 shows the reduced flow available to Shoshone during the winter months under Alternative 1a (red line) as compared to the base case of the C1 Scenario.

Calculations were completed to estimate the total electric power generated at Shoshone under the C1 scenario and under the Alternative 1a operating policy for the study period. The results of these calculations are presented in Figure 8 and indicate that an estimated 2,047,187 KWhr of electric power could have been generated under the C1 scenario and that 2, 012,921 KWhr could have been generated with the Alternative 1a operating policy representing an estimated reduction of

34,266 MWhr over the 16-year study period or an average annual reduction of approximately 2140 MWhr as a result of Alternative 1a.

This approximately 1.7 percent reduction in power generation occurred because there was 20,000 acre-feet less water in the Colorado River at Shoshone during the low flow months of November through March when this water could be used for power generation and 20,000 acre-feet more water in the Colorado River during the May and June period when Colorado River flows at Shoshone often exceeded turbine capacity.

Table 3 presents the results of calculations to estimate the value of power generation forgone at the Shoshone Power Plant as a result of the alternative operating policy. Results in this table indicate that there would have been approximately $2,960,000 less power generated over the 17-year study period at the Shoshone Power Plant with the alternative operating policy as compared to the base case. This would average approximately $174,000 less per year.

SHOSHONE PRIORITY CALLS

Figure 3 is a graphical presentation of estimated shortages of water available for diversion by the Shoshone Power Plant where "shortage" is defined as: legally available Shoshone diversion (acre-feet/month) - physically available Shoshone diversion (acre-feet/month). This graphical presentation of shortages provides a mechanism to determine the frequency and duration of potential priority calls by the Shoshone water rights.

As long as the estimated shortages under the C1 base run (blue hydrographs in Figure 3) are contained entirely within the red hydrographs (Alternative 1a) and both hydrographs start to rise on the ascending limb at approximately the same time and come back together on the falling limb at approximately the same time, there is little potential for a priority call of increased duration from Shoshone under the Alternative 1a operations policy as compared to the C1 base case.

Only during those periods when the red hydrograph (Alternative 1a) starts to rise on the ascending limb of the hydrograph at a point in time earlier than the blue hydrograph (C1 base case) and/or the red hydrograph returns to the zero shortage level at a point in time later than the Blue Hydrograph is there any potential for a priority call of increased duration or magnitude. Data for August 1977 and December 1985 in Figure 3 provide the only two identifiable examples of situations during the study period which could potentially produce a priority call of increased duration.

When the red line (Alternative 1a) is above the blue line (C1 base case) during the period the November 1 through March 31 period, this situation demonstrates the effect of releasing 20,000 acre-feet less water under the Alternative 1a operating policy as compared to the C1 Scenario. This situation indicates:

- The 20,000 acre-feet of reduced releases from Green Mountain Reservoir during the period November 1 through March 31 decreases the physical availability to Shoshone by approximately 20,000 acre-feet.

- Physical availability to Shoshone is less than Shoshone's legal availability under either the base case (C1) or Alternative 1a. Furthermore, if Shoshone was calling during these periods of shortage, it was not able to get its full decreed amount under either the C1 scenario or Alternative 1a.

Results presented in Figure 3 also demonstrate that the frequency and duration of the Shoshone priority call can be decreased under the Alternative 1a Green Mountain Reservoir operating policy as compared to the C1 base run. Results in Figure 3 indicate that in August 1978, the Shoshone priority call would likely have been on with the C1 Scenario conditions but not in the case of Alternative 1a. This situation resulted because:

1. In the C1 scenario in October 1977, Dillon Reservoir made a release to Green Mountain Reservoir in order to allow Green Mountain Reservoir to fill. The effect of this release from Dillon Reservoir to Green Mountain Reservoir on Green Mountain Reservoir storage can be seen in Figure 4 in October 1977. The C1 base case (blue line) indicates the increase in Green Mountain Reservoir storage in October 1977.

2. Under Alternative 1a in 1977, Green Mountain Reservoir achieved its fill without the need for a release from Dillon. This situation resulted because the 20,000 acre-feet of additional stored water in Green Mountain Reservoir that was not released in May-June 1977 allowed Green Mountain Reservoir to fill without a release from Dillon Reservoir. The 20,000 acre-feet was not released in May-June 1977 because the peak spring discharge in 1977 was substantially less than the 12,900 cfs minimum expected spring hydrograph peak required to release the 20,000 acre-feet. The absence of a release from Dillon Reservoir in October 1977 under Alternative 1a can be seen in Figure 4 (redline is Alternative 1a).

3. Therefore, Dillon filled earlier in 1978 under Alternative 1a as compared to the C1 scenario. By August 1978 under Alternative 1a, there was more water passing through Dillon Reservoir to Green Mountain Reservoir and Green Mountain Reservoir had already filled. Consequently, this water was passed through Green Mountain Reservoir to Shoshone, thereby eliminating the need for Shoshone to make a priority call in August 1978 with the Alternative 1a operating policy.

Conclusions from this analysis include:

- During the study period, the only time that the frequency or duration of the Shoshone call would have been potentially increased by the Alternative 1a operating policy was December 1985.
- Because of the monthly time step employed in the StateMod model runs, it is not possible to estimate exactly the increased duration of a potential Shoshone call in December 1985 as a result of implementing Alternative 1a as compared to the C1 base run. We would estimate, based on the above analysis, that the increased duration would be a matter of 1-2 weeks, and not months, 1985.
- There is one period, August 1978, when the Alternative 1a operating policy would have potentially decreased the duration of the Shoshone priority call.

- There is one example, October 1977, when the Alternative 1a operating policy would have allowed Green Mountain Reservoir to fill without requiring a release from Dillon Reservoir.
- Therefore, it is concluded that the frequency and duration of Shoshone priority calls were not altered to any significant degree by implementation of Alternative 1a for the 1975-91 study period.

GREEN MOUNTAIN RESERVOIR STORAGE

Green Mountain Reservoir filled in every year with Alternative 1a operating policy that it filled under the C1 Scenario (see Figure 4). In those years in which Green Mountain Reservoir did not fill under the C1 scenario (1977 and 1981), it filled to a higher level under the Alternative 1a operating policy.

As reported above, in October 1977, Dillon Reservoir was required to release over 18,000 acre-feet to Green Mountain Reservoir from its out-of-priority account since Green Mountain Reservoir did not achieve a fill under the baseline scenario. In the Alternative 1a operating policy, this release was not required resulting in a decrease in storage in Green Mountain Reservoir. This difference was gone by spring of 1978 when both scenarios were releasing water to generate power.

DILLON, WILLIAMS FORK AND GRANBY RESERVOIR STORAGE

For practical purposes, there were no effects on storage in Dillon, Williams Fork or Granby Reservoirs (see Figures 5 and 6). In 1977, Dillon Reservoir released over 18,000 acre-feet of water stored out of priority to Green Mountain Reservoir. This was not required under the changed operating policy resulting in an increase in Dillon storage of this amount until 1978. The StateMod model of the Colorado River did not allow the flexibility of the Denver Water Board making releases from Williams Fork Reservoir to cover HUP depletions. Consequently, there are some differences in storage in both Dillon and Williams Fork Reservoirs between the C1 Scenario and the Alternative 1a operating policy. However, the total storage in these two reservoirs remained unchanged in the two runs except for an increase in storage in 1977 (described above) and a slight decrease (6000 acre-feet) in April 1982. As shown in Figure 6, Granby Reservoir was unchanged between the two scenarios during the study period.

RELEASE 20,000 ACRE-FEET IN TWO ADDITIONAL YEARS

As indicated in Figure 1, there are two years, 1982 and 1991, in which the peak spring flows were close to the lower limit of the 12,900-26,600 cfs flow range for making releases of 20,000 acre-feet for the fish. In 1982, the estimated peak flow at the head of the 15-Mile Reach was 12,670 cfs and in 1991, 11,750 cfs. If 1,000 cfs (1,000 cfs is the constant release rate for releasing 20,000 acre-feet over a period of 10 days) were released from Green Mountain Reservoir for the fish during these periods in 1982 and 1991, these releases should increase flows at the head of the 15-Mile Reach to levels above or near the 12,900 cfs lower limit.

Additional investigations were carried out to determine the overall effects on other water rights from making these additional releases of 20,000 acre-feet for the fish in 1982 and 1991. The results of this further investigation indicated that the only effects on other water rights from making the 20,000 acre-feet releases in the two additional years was to have 2387 acre-feet less storage in Green Mountain Reservoir in June, 1982 and 2210 acre-feet less in July, 1982 as compared to the computer run which did not make releases in the two additional years. Green Mountain Reservoir, however, filled in both 1982 and 1991 in the original scenario (releases in six years) as well as in the scenario in which releases of the 20,000 acre-feet were made in eight years. Consequently, making the 20,000 acre-feet releases in the two additional years had no practical effects on other water rights or on the operation of structures in the Colorado Basin.

ORCHARD MESA HYDROPOWER

An investigation was completed to determine the effects of the proposed Alternative 1a Scenario on Orchard Mesa Power Plant hydropower generation. This investigation focused on the non-irrigation period from November 1 through March 31 because this is the period when there will be reduced Colorado River flows as a result of the Alternative 1a operating policy for Green Mountain Reservoir. During the irrigation season, the Alternative 1a Green Mountain Reservoir operating policy will result in additional flows in the Colorado River thereby obviating any potential for reduced hydropower generation at the Orchard Mesa Power Plant during the irrigation season.

The Orchard Mesa Power Plant has a capacity of 800 cfs. Consequently, we reviewed availability of flow for diversion to the Orchard Mesa Power Plant during the non-irrigation season to determine if the Alternative 1a operating policy for Green Mountain Reservoir would increase the frequency and duration of periods when the flows avail able for diversion to the power plant would be less than 800 cfs.

The results of this analysis indicate that Alternative 1a operating policy did not increase the frequency and/or duration of flows less than 800 cfs that would have been available for diversion to the Orchard Mesa Power Plant l during the non-irrigation season. This result occurred because:

- Under both the C1 scenario and under the Alternative 1a Scenario, Green Mountain Reservoir begins increased releases for power purposes starting approximately November 1 and this increased release helps provide the 800 cfs at the Orchard Mesa Power Plant diversion.
- As indicated above in the Shoshone Priority Calls section, Alternative 1a had no discernible effect (as estimated by StateMod with a monthly time step) on the duration and frequency of the Shoshone priority calls. Therefore, because Orchard Mesa Power Plant is downstream and junior to Shoshone and is only 800 cfs as compared to Shoshone's approximately 1408 cfs, it appears that similar results can be expected at Orchard Mesa Power Plant.

AUGMENTATION OF LOW FLOWS IN LATE SUMMER AND EARLY FALL

The Phase 1 report characterizes the low flow targets as follows (Section 2.3.4):

> "If some portion of the average annual 20,000 acre-feet remains after augmentation of the spring peak discharge and this water can not be carried over for use in the succeeding spring, this water may be used for augmenting low flows during the July 15 through October 31 period. Augmentation of low flows in late summer and fall is second priority to augmenting the spring peak discharge during the 7 to 10 day spring peak period.
>
> The following characterize the low flow target:
>
> - During the July 15 through October 31 period, the goal will be to maintain minimum flows at the head of the 15-Mile Reach as specified by the Service (U.S. Fish and Wildlife Service, May 1995).
> - During years of above average precipitation (i.e., precipitation greater than the 50th percentile), efforts would be made to maintain flows at or around 1,630 cfs.
> - During years of low precipitation (i.e., precipitation less than the 50th percentile), efforts would be made to maintain flows at or greater than 1,240 cfs.
> - During drought years (the lowest 20th percentile), efforts would be made to maintain flows at or greater than 810 cfs."

The low flow targets described above have not been considered in this investigation. For purposes of this investigation any portion of the 20,000 acre-feet which was not released in May and June, was simply considered to be storage in Green Mountain Reservoir and was not further reserved for release to the endangered fishes.

In order to reserve any unused portion of the 20,000 acre-feet for release in the late summer or early fall, or for carry over for the next spring would require reservation of this water specifically for this purpose.

Before proceeding further with this matter it will be necessary to obtain guidance from the Executive Committee, Bureau of Reclamation and the CWCB on how they would like to proceed with this matter.

FURTHER WORK

1. There are several idiosyncrasies in the results in the results due to the limitations of representing the river system and administration within StateMod. For example, Denver has the ability to provide make-up water for Green Mountain Reservoir from Williams Fork Reservoir via releases for HUP depletions. The current model only allows this make-up water to be supplied from Dillon Reservoir. This may result in greater storage in Williams Fork Reservoir and less in Dillon Reservoir than would actually occur. This happened in the model in April 1982 when the model showed a large increase in total

storage in Williams Fork Reservoir and a large decrease in storage in Dillon Reservoir. The total storage in both reservoirs only showed a 6000 acre-feet decrease in the total storage.

2. Windy Gap Reservoir is not modeled separately in the State supplied C1 scenario; Windy Gap storage is included with Granby Reservoir. This may need to be altered in order to determine the effect of the new operating policy on Windy Gap operations. Individual water rights of the Windy Gap project are included in the current model.

3. As indicated above, direction from the Executive Committee with respect to how they want the matter of the late summer and early fall low flow targets to be handled is necessary before further proceeding with this matter.

4. If directed by the Executive Committee, Alternative 1a will be subjected to further sensitivity analysis to determine if feasibility of the alternative is affected by the 120,000 acre-feet per year of future depletions in the baseline hydrology.

5. It is unclear at this time if it would be beneficial to convert the current model to a daily time step. The vast majority of data included in the model is only available on a monthly time step and a daily model would simply prorate these monthly values uniformly to daily ones.

REFERENCES

U.S. Bureau of Reclamation, October 1996, *Grand Valley Water Management Analysis of Potential Historical Savings 1974-1991*, Grand Junction, Colorado.

U.S. Bureau of Reclamation, September 1998, *Grand Valley Water Management Final Environmental Assessment,* Upper Colorado Region Western Colorado Area Office, Grand Junction, Colorado and Great Plains Region, Eastern Colorado Area Office, Loveland, Colorado.

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

TABLE 1
SUMMARY OF ALT. 1A CALCS CONCERNING ABILITY TO RELEASE FROM GR. MTN. RES. (CFS)

Year	Month	Base Case Release	Peak 10 Day Release	EOM Storage (AF)	Comments	Release Limited by Channel Constraint
1975	June	174	1174	129,003		No
1978	June	285	1285	129,025		No
1979	May	86	1086	92,939	Could not have used spillway, but not necessary.	No
1980	June	1557	2557	131,382	Exceeded turbine capacity by 1057cfs. 1057 cfs over spillway.	No
1985	June	866	1866	131,372	Exceeded turbine capacity by 366 cfs. 366 cfs over spillway.	No
1986	June	525	1525	131,372	Exceeded turbine capacity by 25 cfs. 25 cfs over spillway	No

Notes:

1. There is 111,000 acre-feet of storage in Green Mountain Reservoir below the spillway crest.
2. Releases can be made over the spillway at the same time 1500 cfs (maximum capacity) is flowing through the turbines.
3. The spillway cannot, however, be used when releases through the turbine bypasses are being made.
The turbine bypasses are only used on an infrequent basis when repairs are being made or there is an emergency situation.
4. When releases from Gr.Mtn Reservoir exceed approximately 3,000 cfs, the Water Commissioner and Division 5 Engineer are notified and some limited actions may be taken concerning a bridge over the Blue River immeditely upstream from Kremmling and a few ranchers notified concerning the need to move stock.

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues

			Base							Alt1a								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	11357	115846	7930.56	241.56	184.70	1501	58	0	0.03878
1974	NOV	Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	17320	108426	7926.25	237.25	291.07	2793	182	-54	0.06502
1974	DEC	Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	15758	101369	7921.92	232.92	256.28	2277	240	-78	0.10541
1975	JAN	Jan-75	18019	82713	7909.22	220.22	293.05	2409	313	14019	94712	7917.61	228.61	227.99	1772	230	-83	0.13
1975	FEB	Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	13044	88642	7913.47	224.47	234.87	1584	103	-35	0.065
1975	MAR	Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	11937	83716	7909.96	220.96	194.13	1119	50	-19	0.045
1975	APR	Apr-75	12710	60889	7891.43	202.43	213.60	867	39	12696	80847	7907.84	218.84	213.36	1277	57	18	0.045
1975	MAY	May-75	5289	75493	7903.76	214.76	0.00	0	0	5289	95387	7918.06	229.06	0.00	0	0	0	0.045
1975	JUN	Jun-75	10360	129047	7937.76	248.76	174.10	1475	80	30256	129003	7937.74	248.74	508.46	6183	335	255	0.05416
1975	JUL	Jul-75	84336	152997	7949.70	260.70	1371.57	18600	1149	84292	152997	7949.70	260.70	1370.86	18600	1149	0	0.06176
1975	AUG	Aug-75	27765	150691	7948.60	259.60	451.55	5963	638	27765	150691	7948.60	259.60	451.55	5963	638	0	0.10693
1975	SEP	Sep-75	23444	143784	7945.26	256.26	393.98	4821	283	23444	143784	7945.26	256.26	393.98	4821	283	0	0.05866
1975	OCT	Oct-75	11432	141023	7943.89	254.89	185.92	1847	72	11432	141023	7943.89	254.89	185.92	1847	72	0	0.03878
1975	NOV	Nov-75	26434	124561	7935.37	246.37	444.23	5194	338	22434	128560	7937.50	248.50	377.01	4324	281	-57	0.06502
1975	DEC	Dec-75	23514	108470	7926.28	237.28	382.41	4167	439	19513	116470	7930.91	241.91	317.34	3398	358	-81	0.10541
1976	JAN	Jan-76	22347	92780	7916.31	227.31	363.43	3573	465	18347	104779	7924.05	235.05	298.38	2923	380	-85	0.13
1976	FEB	Feb-76	22018	77676	7905.45	216.45	382.78	3244	211	18018	93674	7916.92	227.92	313.24	2723	177	-34	0.065
1976	MAR	Mar-76	20867	64928	7895.03	206.03	339.36	2570	116	18065	83714	7909.95	220.95	293.79	2441	110	-6	0.045
1976	APR	Apr-76	13611	62615	7892.97	203.97	228.74	1089	49	13781	81192	7908.10	219.10	231.59	1516	68	19	0.045
1976	MAY	May-76	5289	84324	7910.40	221.40	0.00	0	0	5289	102842	7922.85	233.85	0.00	0	0	0	0.045
1976	JUN	Jun-76	20309	129027	7937.75	248.75	341.30	3829	207	38828	128987	7937.73	248.73	652.52	8212	445	237	0.05416
1976	JUL	Jul-76	24273	150202	7948.37	259.37	394.76	5100	315	24233	150202	7948.37	259.37	394.11	5090	314	-1	0.06176
1976	AUG	Aug-76	24579	149741	7948.15	259.15	399.73	5167	553	24579	148221	7947.42	258.42	399.73	5142	550	-3	0.10693
1976	SEP	Sep-76	26715	142820	7944.78	255.78	448.95	5597	328	26716	141303	7944.03	255.03	448.97	5570	327	-2	0.05866
1976	OCT	Oct-76	21293	136188	7941.46	252.46	346.29	4149	161	21293	134673	7940.68	251.68	346.29	4124	160	-1	0.03878
1976	NOV	Nov-76	20049	124693	7935.44	246.44	336.93	3697	240	15746	127481	7936.93	247.93	264.62	2727	177	-63	0.06502
1976	DEC	Dec-76	17772	113570	7929.26	240.26	289.03	2946	311	13469	120661	7933.25	244.25	219.05	2060	217	-93	0.10541
1977	JAN	Jan-77	16388	102846	7922.85	233.85	266.52	2445	318	12085	114240	7929.64	240.64	196.54	1646	214	-104	0.13
1977	FEB	Feb-77	15486	92708	7916.26	227.26	278.84	2190	142	11183	108403	7926.24	237.24	201.36	1470	96	-47	0.065
1977	MAR	Mar-77	16143	83715	7909.95	220.95	262.54	2026	91	11838	103702	7923.38	234.38	192.52	1433	64	-27	0.045
1977	APR	Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	25403	89422	7914.01	225.01	426.91	4211	189	24	0.045
1977	MAY	May-77	8191	76232	7904.33	215.33	133.21	186	8	8191	96116	7918.54	229.54	133.21	502	23	14	0.045
1977	JUN	Jun-77	9204	91191	7915.23	226.23	154.68	695	38	7693	112497	7928.64	239.64	129.28	649	35	-2	0.05416
1977	JUL	Jul-77	19715	84169	7910.28	221.28	320.63	2807	173	19624	105483	7924.48	235.48	319.15	3225	199	26	0.06176
1977	AUG	Aug-77	24562	72947	7901.74	212.74	399.46	3558	380	24562	94192	7917.26	228.26	399.46	4094	438	57	0.10693
1977	SEP	Sep-77	13059	67022	7896.84	207.84	219.46	1075	63	16489	84782	7910.73	221.73	277.10	2169	127	64	0.05866
1977	OCT	Oct-77	13233	76527	7904.56	215.56	215.21	1258	49	16561	75899	7904.08	215.08	269.33	1948	76	27	0.03878
1977	NOV	Nov-77	13832	71278	7900.39	211.39	232.45	1326	86	15032	69450	7898.89	209.89	252.62	1536	100	14	0.06502
1977	DEC	Dec-77	10829	69414	7898.86	209.86	176.11	612	64	13416	64999	7895.09	206.09	218.19	1049	111	46	0.10541
1978	JAN	Jan-78	9558	67943	7897.63	208.63	155.44	319	42	10315	62771	7893.11	204.11	167.75	368	48	6	0.13
1978	FEB	Feb-78	8630	66460	7896.36	207.36	155.39	261	17	7159	62760	7893.10	204.10	128.90	0	0	-17	0.065
1978	MAR	Mar-78	8643	64932	7895.03	206.03	140.56	72	3	7183	62694	7893.04	204.04	116.82	0	0	-3	0.045
1978	APR	Apr-78	11074	64804	7894.92	205.92	186.10	621	28	6393	67522	7897.27	208.27	107.44	0	0	-28	0.045
1978	MAY	May-78	5289	82774	7909.27	220.27	0.00	0	0	5289	85484	7911.23	222.23	0.00	0	0	0	0.045
1978	JUN	Jun-78	16929	129030	7937.75	248.75	284.50	3029	164	26019	129025	7937.75	248.75	437.26	5181	281	117	0.05416
1978	JUL	Jul-78	41368	150202	7948.37	259.37	672.78	9284	573	53631	150202	7948.37	259.37	872.21	12285	759	185	0.06176
1978	AUG	Aug-78	30914	149991	7948.27	259.27	502.76	6721	719	32645	147402	7947.02	258.02	530.91	7094	759	40	0.10693
1978	SEP	Sep-78	26756	140919	7943.84	254.84	449.64	5573	327	26756	138334	7942.55	253.55	449.64	5527	324	-3	0.05866
1978	OCT	Oct-78	15652	134864	7940.78	251.78	254.55	2779	108	15652	132282	7939.45	250.45	254.55	2742	106	-1	0.03878
1978	NOV	Nov-78	22372	119635	7932.68	243.68	375.97	4153	270	17856	121570	7933.74	244.74	300.08	3132	204	-66	0.06502
1978	DEC	Dec-78	21663	104776	7924.04	235.04	352.31	3673	387	17147	111227	7927.90	238.90	278.87	2763	291	-96	0.10541
1979	JAN	Jan-79	21438	90317	7914.63	225.63	348.65	3319	431	16922	101284	7921.87	232.87	275.21	2537	330	-102	0.13
1979	FEB	Feb-79	19827	76445	7904.50	215.50	357.00	2801	182	15311	91927	7915.73	226.73	275.69	2138	139	-43	0.065
1979	MAR	Mar-79	20487	63729	7893.97	204.97	333.18	2459	111	15968	83715	7909.95	220.95	259.69	1988	89	-21	0.045
1979	APR	Apr-79	14010	60610	7891.15	202.15	235.44	1122	51	13996	80569	7907.64	218.64	235.21	1549	70	19	0.045
1979	MAY	May-79	5289	89328	7913.95	224.95	0.00	0	0	21600	92939	7916.42	227.42	351.29	3412	154	154	0.045
1979	JUN	Jun-79	46276	131412	7939.00	250.00	777.68	10039	544	50719	131405	7939.00	250.00	852.35	11094	601	57	0.05416
1979	JUL	Jul-79	63957	152994	7949.70	260.70	1040.15	14897	920	63948	152994	7949.70	260.70	1040.00	14895	920	0	0.06176
1979	AUG	Aug-79	28239	150691	7948.60	259.60	459.26	6079	650	28239	150691	7948.60	259.60	459.26	6079	650	0	0.10693
1979	SEP	Sep-79	29407	136836	7941.79	252.79	494.19	6135	360	29407	136836	7941.79	252.79	494.19	6135	360	0	0.05866
1979	OCT	Oct-79	21557	125119	7935.67	246.67	350.59	4025	156	21480	125196	7935.71	246.71	349.33	4008	155	-1	0.03878
1979	NOV	Nov-79	22108	111842	7928.26	239.26	371.53	3949	257	18123	115903	7930.59	241.59	304.56	3103	202	-55	0.06502
1979	DEC	Dec-79	20727	98931	7920.37	231.37	337.09	3345	353	16742	106977	7925.38	236.38	272.28	2598	274	-79	0.10541
1980	JAN	Jan-80	21066	86421	7911.90	222.90	342.60	3150	409	17081	98451	7920.06	231.06	277.79	2521	328	-82	0.13
1980	FEB	Feb-80	19997	74497	7902.98	213.98	347.64	2741	178	16012	90510	7914.76	225.76	278.37	2222	144	-34	0.065
1980	MAR	Mar-80	19691	63729	7893.97	204.97	320.24	2297	103	15705	83716	7909.96	220.96	255.41	1932	87	-16	0.045
1980	APR	Apr-80	12046	61008	7891.55	202.55	202.44	737	33	12046	80953	7907.92	218.92	202.44	1139	51	18	0.045
1980	MAY	May-80	5289	83658	7909.91	220.91	0.00	0	0	5289	103541	7923.28	234.28	0.00	0	0	0	0.045
1980	JUN	Jun-80	92514	129028	7937.75	248.75	1500.00	18000	975	109997	131382	7938.98	249.98	1500.00	18000	975	0	0.05416
1980	JUL	Jul-80	40747	150202	7948.37	259.37	662.68	9132	564	44117	150198	7948.37	259.37	717.48	9956	615	51	0.06176
1980	AUG	Aug-80	23452	146821	7946.74	257.74	381.40	4844	518	23385	146817	7946.74	257.74	380.32	4828	516	-2	0.10693
1980	SEP	Sep-80	24612	137044	7941.89	252.89	413.61	4989	293	24612	137040	7941.89	252.89	413.61	4989	293	0	0.05866
1980	OCT	Oct-80	12204	133406	7940.03	251.03	198.48	1936	75	12204	133402	7940.03	251.03	198.48	1936	75	0	0.03878
1980	NOV	Nov-80	19891	122468	7934.23	245.23	334.27	3623	236	15890	126465	7936.39	247.39	267.04	2746	179	-57	0.06502
1980	DEC	Dec-80	17896	111901	7928.30	239.30	291.05	2946	311	13896	119899	7932.83	243.83	225.99	2148	226	-84	0.10541
1981	JAN	Jan-81	16154	101734	7922.15	233.15	262.72	2373	308	12153	113732	7929.35	240.35	197.65	1654	215	-93	0.13
1981	FEB	Feb-81	15190	92151	7915.89	226.89	273.51	2115	137	11189	108149	7926.09	237.09	201.47	1468	95	-42	0.065
1981	MAR	Mar-81	15583	83715	7909.95	220.95	253.43	1905	86	11581	103702	7923.38	234.38	188.34	1375	62	-24	0.045
1981	APR	Apr-81	25807	69337	7898.80	209.80	433.69	3766	169	25809	89282	7913.91	224.91	433.73	4296	193	24	0.045
1981	MAY	May-81	5289	83356	7909.69	220.69	0.00	0	0	5289	103239	7923.10	234.10	0.00	0	0	0	0.045
1981	JUN	Jun-81	5970	110359	7927.39	238.39	100.33	228	12	5970	128987	7937.73	248.73	100.33	435	24	11	0.05416
1981	JUL	Jul-81	7258	122403	7934.20	245.20	118.04	631	39	15291	134966	7940.84	251.84	248.68	2694	166	127	0.06176
1981	AUG	Aug-81	22273	109649	7926.98	237.98	362.23	3907	418	33152	118939	7932.29	243.29	539.16	6612	707	289	0.10693
1981	SEP	Sep-81	19446	98930	7920.37	231.37	326.80	3100	182	26725	108197	7926.11	237.11	449.12	4932	289	107	0.05866
1981	OCT	Oct-81	12966	92651	7916.23	227.23	210.87	1503	58	16097	101902	7922.26	233.26	261.79	2363	92	33	0.03878

			Base							Alt1a								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	NOV	Nov-81	14892	85877	7911.51	222.51	250.26	1845	120	13705	96325	7918.68	229.68	230.32	1773	115	-5	0.06502
1981	DEC	Dec-81	13695	79458	7906.80	217.80	222.72	1415	149	11457	92153	7915.89	226.89	186.33	1162	122	-27	0.10541
1982	JAN	Jan-82	13431	73438	7902.14	213.14	218.43	1237	161	11308	88263	7913.20	224.20	183.90	1063	138	-23	0.13
1982	FEB	Feb-82	11351	68007	7897.68	208.68	204.38	851	55	9030	85155	7911.00	222.00	162.59	655	43	-13	0.065
1982	MAR	Mar-82	10833	63968	7894.18	205.18	176.18	499	22	12185	80816	7907.82	218.82	198.17	1119	50	28	0.045
1982	APR	Apr-82	14858	58834	7889.46	200.46	249.69	1248	56	16022	74488	7902.97	213.97	269.25	1854	83	27	0.045
1982	MAY	May-82	5289	79716	7907.00	218.00	0.00	0	0	5289	95321	7918.01	229.01	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	129037	7937.75	248.75	100.33	435	24	15774	129004	7937.74	248.74	265.09	2755	149	126	0.05416
1982	JUL	Jul-82	56633	152997	7949.70	260.70	921.03	13098	809	40256	152997	7949.70	260.70	654.69	9073	560	-249	0.06176
1982	AUG	Aug-82	34304	150691	7948.60	259.60	557.89	7565	809	34364	150691	7948.60	259.60	558.87	7579	810	2	0.10693
1982	SEP	Sep-82	21382	148503	7947.55	258.55	359.33	4394	258	21382	148503	7947.55	258.55	359.33	4394	258	0	0.05866
1982	OCT	Oct-82	20961	142312	7944.53	255.53	340.89	4167	162	20961	142312	7944.53	255.53	340.89	4167	162	0	0.03878
1982	NOV	Nov-82	27691	123593	7934.85	245.85	465.36	5471	356	23691	127592	7936.99	247.99	398.13	4604	299	-56	0.06502
1982	DEC	Dec-82	25936	105244	7924.33	235.33	421.80	4650	490	21936	113243	7929.07	240.07	356.75	3899	411	-79	0.10541
1983	JAN	Jan-83	25060	87296	7912.52	223.52	407.56	4039	525	21060	99295	7920.60	231.60	342.50	3427	445	-80	0.13
1983	FEB	Feb-83	24106	69934	7899.29	210.29	434.05	3535	230	20105	85933	7911.55	222.55	362.00	3069	199	-30	0.065
1983	MAR	Mar-83	25007	53735	7884.44	195.44	406.69	3046	137	21005	73721	7902.36	213.36	341.61	2832	127	-10	0.045
1983	APR	Apr-83	17879	43588	7873.31	184.31	300.46	1384	62	17879	63532	7893.79	204.79	300.46	1978	89	27	0.045
1983	MAY	May-83	5289	68197	7897.84	208.84	0.00	0	0	5289	88075	7913.07	224.07	0.00	0	0	0	0.045
1983	JUN	Jun-83	110215	131459	7939.02	250.02	1500.00	18000	975	130093	131415	7939.00	250.00	1500.00	18000	975	0	0.05416
1983	JUL	Jul-83	127502	152994	7949.70	260.70	1500.00	18600	1149	127458	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62879	153088	7949.74	260.74	1022.61	14635	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	25870	153173	7949.78	260.78	434.75	5567	327	25870	153173	7949.78	260.78	434.75	5567	327	0	0.05866
1983	OCT	Oct-83	17200	151135	7948.81	259.81	279.73	3382	131	17200	151135	7948.81	259.81	279.73	3382	131	0	0.03878
1983	NOV	Nov-83	30874	131848	7939.23	250.23	518.85	6387	415	26874	135848	7941.29	252.29	451.63	5510	358	-57	0.06502
1983	DEC	Dec-83	31982	111436	7928.03	239.03	520.13	6168	650	27982	119436	7932.57	243.57	455.08	5420	571	-79	0.10541
1984	JAN	Jan-84	29642	91423	7915.39	226.39	482.07	5146	669	25642	103423	7923.21	234.21	417.02	4544	591	-78	0.13
1984	FEB	Feb-84	26794	71998	7900.98	211.98	465.81	4101	267	22794	87996	7913.02	224.02	396.27	3653	237	-29	0.065
1984	MAR	Mar-84	20592	61032	7891.57	202.57	334.89	2405	108	23884	73720	7902.36	213.36	388.43	3437	155	46	0.045
1984	APR	Apr-84	17808	58043	7888.71	199.71	299.27	1817	82	17928	70585	7899.83	210.83	301.29	2164	97	16	0.045
1984	MAY	May-84	91645	94702	7917.60	228.60	1490.44	18600	837	97915	100943	7921.65	232.65	1500.00	18600	837	0	0.045
1984	JUN	Jun-84	155457	131401	7938.99	249.99	1500.00	18000	975	161698	131387	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	127128	152994	7949.70	260.70	1500.00	18600	1149	127612	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	81017	153088	7949.74	260.74	1317.60	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	35687	153173	7949.78	260.78	599.73	7980	468	35687	153173	7949.78	260.78	599.73	7980	468	0	0.05866
1984	OCT	Oct-84	23558	153342	7949.86	260.86	383.13	4975	193	23558	153342	7949.86	260.86	383.13	4975	193	0	0.03878
1984	NOV	Nov-84	32940	135612	7941.17	252.17	553.57	6957	452	29870	138682	7942.72	253.72	501.97	6282	408	-44	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	29212	124062	7935.10	246.10	475.08	5803	612	-87	0.10541
1985	JAN	Jan-85	30448	98306	7919.97	230.97	495.18	5502	715	26216	109841	7927.09	238.09	426.36	4813	626	-90	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	24338	96204	7918.60	229.60	438.22	4218	274	-35	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	23235	83713	7909.95	220.95	377.88	3555	160	-3	0.045
1985	APR	Apr-85	26623	64819	7894.93	205.93	447.41	3798	171	25096	84779	7910.72	221.72	421.75	4030	181	10	0.045
1985	MAY	May-85	53155	98074	7919.82	230.82	864.47	10563	475	63136	108007	7926.00	237.00	1026.79	13184	593	118	0.045
1985	JUN	Jun-85	100470	131394	7938.99	249.99	1500.00	18000	975	110403	131372	7938.98	249.98	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	47306	150198	7948.37	259.37	769.35	10737	663	49026	150198	7948.37	259.37	797.32	11158	689	26	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	20206	148184	7947.40	258.40	339.57	4102	241	0	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	8954	151947	7949.20	260.20	145.62	1370	53	0	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	26187	138496	7942.63	253.63	440.08	5393	351	-57	0.06502
1985	DEC	Dec-85	28810	116555	7930.96	241.96	468.54	5552	585	25297	123922	7935.02	246.02	411.41	4881	515	-71	0.10541
1986	JAN	Jan-86	28596	98170	7919.88	230.88	465.06	5085	661	24385	109748	7927.04	238.04	396.58	4392	571	-90	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	22381	97357	7919.35	230.35	402.99	3807	247	-36	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	23238	84913	7910.82	221.82	377.92	3585	161	-14	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	16264	84778	7910.72	221.72	273.32	2120	95	20	0.045
1986	MAY	May-86	32194	98074	7919.82	230.82	523.58	5886	265	42174	108007	7926.00	237.00	685.88	8409	378	114	0.045
1986	JUN	Jun-86	103802	131394	7938.99	249.99	1500.00	18000	975	113734	131372	7938.98	249.98	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	54802	152994	7949.70	260.70	891.26	12648	781	56815	152415	7949.42	260.42	923.99	13126	811	30	0.06176
1986	AUG	Aug-86	19863	150691	7948.60	259.60	323.04	4028	431	19283	150692	7948.60	259.60	313.60	3886	416	-15	0.10693
1986	SEP	Sep-86	13432	150697	7948.61	259.61	225.73	2480	145	13434	150695	7948.60	259.60	225.76	2480	145	0	0.05866
1986	OCT	Oct-86	9607	151945	7949.20	260.20	156.24	1530	59	9605	151945	7949.20	260.20	156.21	1529	59	0	0.03878
1986	NOV	Nov-86	29317	134496	7940.59	251.59	492.68	6068	395	25317	138495	7942.63	253.63	425.46	5184	337	-58	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	23465	123921	7935.02	246.02	381.62	4452	469	-82	0.10541
1987	JAN	Jan-87	25065	97747	7919.61	230.61	407.64	4288	557	21064	109747	7927.03	238.03	342.57	3633	472	-85	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	20051	96157	7918.57	229.57	361.03	3265	212	-34	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	20637	83712	7909.95	220.95	335.62	2995	135	-5	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	10980	84779	7910.72	221.72	184.52	978	44	6	0.045
1987	MAY	May-87	8828	96476	7918.78	229.78	143.57	649	29	18800	106409	7925.04	236.04	305.75	3055	137	108	0.045
1987	JUN	Jun-87	37857	129001	7937.74	248.74	636.20	7982	432	47792	128980	7937.72	248.72	803.16	10333	560	127	0.05416
1987	JUL	Jul-87	8541	150202	7948.37	259.37	138.90	1250	77	8520	150202	7948.37	259.37	138.56	1245	77	0	0.06176
1987	AUG	Aug-87	26795	146955	7946.81	257.81	435.77	5660	605	26796	146955	7946.81	257.81	435.79	5661	605	0	0.10693
1987	SEP	Sep-87	26443	134964	7940.83	251.83	444.38	5391	316	26443	134964	7940.83	251.83	444.38	5391	316	0	0.05866
1987	OCT	Oct-87	21345	124088	7935.11	246.11	347.14	3957	153	21345	124088	7935.11	246.11	347.14	3957	153	0	0.03878
1987	NOV	Nov-87	21731	111018	7927.78	238.78	365.20	3847	250	17731	115018	7930.09	241.09	297.97	2997	195	-55	0.06502
1987	DEC	Dec-87	20232	98313	7919.97	230.97	329.04	3222	340	16232	106313	7924.98	235.98	263.98	2470	260	-79	0.10541
1988	JAN	Jan-88	19936	86008	7911.61	222.61	324.22	2895	376	15936	98008	7919.77	230.77	259.17	2257	293	-83	0.13
1988	FEB	Feb-88	18101	74291	7902.81	213.81	314.68	2337	152	14101	90289	7914.61	225.61	245.14	1799	117	-35	0.065
1988	MAR	Mar-88	17846	63980	7894.19	205.19	290.23	1928	87	14096	83715	7909.95	220.95	229.25	1585	71	-15	0.045
1988	APR	Apr-88	11855	64594	7894.74	205.74	199.23	776	35	12763	83381	7909.71	220.71	214.49	1338	60	25	0.045
1988	MAY	May-88	5289	89366	7913.97	224.97	0.00	0	0	5289	105713	7924.62	235.62	0.00	0	0	0	0.045
1988	JUN	Jun-88	50817	129016	7937.74	248.74	854.00	11050	598	67166	128981	7937.73	248.73	1128.75	14918	808	210	0.05416
1988	JUL	Jul-88	18685	149846	7948.20	259.20	303.88	3727	230	18752	149811	7948.18	259.18	304.97	3743	231	1	0.06176
1988	AUG	Aug-88	42120	130517	7938.53	249.53	685.01	8997	962	42120	130482	7938.51	249.51	685.01	8996	962	0	0.10693
1988	SEP	Sep-88	19530	122971	7934.51	245.51	328.21	3547	208	19530	122936	7934.49	245.49	328.21	3546	208	0	0.05866
1988	OCT	Oct-88	34701	98412	7920.04	231.04	564.35	6454	250	34701	98376	7920.01	231.01	564.35	6453	250	0	0.03878
1988	NOV	Nov-88	17808	90484	7914.75	225.75	299.27	2571	167	14185	94071	7917.18	228.18	238.38	1840	120	-48	0.06502
1988	DEC	Dec-88	14659	82913	7909.37	220.37	238.40	1690	178	10556	90603	7914.83	225.83	171.67	938	99	-79	0.10541
1989	JAN	Jan-89	14066	75742	7903.95	214.95	228.76	1418	184	10060	87437	7912.62	223.62	163.61	777	101	-83	0.13
1989	FEB	Feb-89	13103	69158	7898.65	209.65	235.93	1236	80	10696	83260	7909.62	220.62	192.59	985	64	-16	0.065
1989	MAR	Mar-89	15213	63402	7893.68	204.68	247.41	1378	62	15213	77493	7905.31	216.31	247.41	1698	76	14	0.045
1989	APR	Apr-89	14953	63422	7893.70	204.70	251.29	1381	62	9044	83387	7909.71	220.71	151.99	537	24	-38	0.045

			Base							Alt1a								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1989	MAY	May-89	5289	86101	7911.67	222.67	0.00	0	0	5289	105716	7924.62	235.62	0.00	0	0	0	0.045
1989	JUN	Jun-89	20765	129023	7937.75	248.75	348.96	3937	213	40381	128981	7937.73	248.73	678.62	8579	465	251	0.05416
1989	JUL	Jul-89	23784	149684	7948.12	259.12	386.80	4972	307	23995	149641	7948.10	259.10	390.24	5023	310	3	0.06176
1989	AUG	Aug-89	33587	146237	7946.46	257.46	546.23	7300	781	33594	146194	7946.44	257.44	546.35	7301	781	0	0.10693
1989	SEP	Sep-89	26675	134301	7940.49	251.49	448.28	5434	319	26675	134258	7940.47	251.47	448.28	5433	319	0	0.05866
1989	OCT	Oct-89	18083	127198	7936.78	247.78	294.09	3241	126	18083	127156	7936.76	247.76	294.09	3240	126	0	0.03878
1989	NOV	Nov-89	22957	113504	7929.22	240.22	385.80	4176	272	18948	117470	7931.47	242.47	318.43	3320	216	-56	0.06502
1989	DEC	Dec-89	21240	100178	7921.17	232.17	345.43	3485	367	17232	108153	7926.09	237.09	280.25	2730	288	-80	0.10541
1990	JAN	Jan-90	19161	87252	7912.49	223.49	311.62	2754	358	15152	99235	7920.57	231.57	246.42	2104	273	-85	0.13
1990	FEB	Feb-90	18046	74912	7903.30	214.30	324.93	2390	155	14038	90902	7915.03	226.03	252.76	1840	120	-36	0.065
1990	MAR	Mar-90	18967	63729	7893.97	204.97	308.46	2150	97	14957	83715	7909.95	220.95	243.25	1770	80	-17	0.045
1990	APR	Apr-90	22262	51153	7881.76	192.76	374.12	2481	112	22262	71097	7900.25	211.25	374.12	3079	139	27	0.045
1990	MAY	May-90	5289	64642	7894.78	205.78	0.00	0	0	5289	84521	7910.54	221.54	0.00	0	0	0	0.045
1990	JUN	Jun-90	14819	129071	7937.77	248.77	249.04	2530	137	34698	129027	7937.75	248.75	583.11	7235	392	255	0.05416
1990	JUL	Jul-90	21334	144638	7945.68	256.68	346.96	4294	265	21334	144594	7945.66	256.66	346.96	4293	265	0	0.06176
1990	AUG	Aug-90	46946	121500	7933.71	244.71	763.49	9893	1058	46946	121456	7933.68	244.68	763.49	9892	1058	0	0.10693
1990	SEP	Sep-90	32172	104471	7923.86	234.86	540.66	6084	357	32172	104427	7923.83	234.83	540.66	6082	357	0	0.05866
1990	OCT	Oct-90	21035	97691	7919.57	230.57	342.10	3388	131	21035	97647	7919.54	230.54	342.10	3387	131	0	0.03878
1990	NOV	Nov-90	19575	89909	7914.35	225.35	328.96	2946	192	16584	92855	7916.36	227.36	278.70	2348	153	-39	0.06502
1990	DEC	Dec-90	17604	82481	7909.05	220.05	286.30	2315	244	13341	89691	7914.20	225.20	216.97	1533	162	-82	0.10541
1991	JAN	Jan-91	15739	75454	7903.73	214.73	255.97	1765	229	12079	86324	7911.83	222.83	196.44	1197	156	-74	0.13
1991	FEB	Feb-91	13260	69014	7898.53	209.53	238.76	1265	82	9430	83713	7909.95	220.95	169.79	719	47	-35	0.065
1991	MAR	Mar-91	12626	63731	7893.97	204.97	205.34	859	39	11777	79267	7906.66	217.66	191.53	1002	45	6	0.045
1991	APR	Apr-91	16156	56562	7887.27	198.27	271.51	1447	65	16156	72067	7901.04	212.04	271.51	1829	82	17	0.045
1991	MAY	May-91	5289	85280	7911.09	222.09	0.00	0	0	5289	100083	7921.11	232.11	0.00	0	0	0	0.045
1991	JUN	Jun-91	29376	129025	7937.75	248.75	493.67	5975	324	44179	128993	7937.73	248.73	742.44	9478	513	190	0.05416
1991	JUL	Jul-91	21099	150202	7948.37	259.37	343.14	4323	267	21067	150202	7948.37	259.37	342.62	4315	267	0	0.06176
1991	AUG	Aug-91	29152	147328	7946.99	257.99	474.10	6241	667	29152	147328	7946.99	257.99	474.10	6241	667	0	0.10693
1991	SEP	Sep-91	30325	135777	7941.25	252.25	0.00	0	0	30325	135777	7941.25	252.25	0.00	0	0	0	0.05866
						Totals			$61,945,095							$61,338,018		
						Difference										-$607,076		
						Average Annual										-$35,710		

Table 3

SHOSHONE POWER PLANT

Foregone Power Revenues

			Base				Alt 1a					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	66970	1089	9208	357	0	0.04
1974	NOV	Nov-74	66071	1110	9085	591	62071	1043	8535	555	-36	0.07
1974	DEC	Dec-74	61830	1006	8502	896	57830	941	7952	838	-58	0.11
1975	JAN	Jan-75	59899	974	8236	1071	55898	909	7686	999	-72	0.13
1975	FEB	Feb-75	58476	1053	8040	523	54476	981	7490	487	-36	0.07
1975	MAR	Mar-75	61181	995	8412	379	57179	930	7862	354	-25	0.05
1975	APR	Apr-75	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1975	OCT	Oct-75	70098	1140	9638	374	70098	1140	9638	374	0	0.04
1975	NOV	Nov-75	79448	1335	10924	710	75448	1268	10374	675	-36	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	67743	1102	9315	982	-58	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	64497	1049	8868	1153	-71	0.13
1976	FEB	Feb-76	70614	1228	9709	631	66652	1159	9165	596	-35	0.07
1976	MAR	Mar-76	76631	1246	10537	474	72629	1181	9986	449	-25	0.05
1976	APR	Apr-76	82638	1389	11363	511	81424	1368	11196	504	-8	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1976	SEP	Sep-76	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1976	OCT	Oct-76	74383	1210	10228	397	74383	1210	10228	397	0	0.04
1976	NOV	Nov-76	59697	1003	8208	534	55394	931	7617	495	-38	0.07
1976	DEC	Dec-76	49447	804	6799	717	45144	734	6207	654	-62	0.11
1977	JAN	Jan-77	47151	767	6483	843	42848	697	5892	766	-77	0.13
1977	FEB	Feb-77	47230	850	6494	422	42927	773	5902	384	-38	0.07
1977	MAR	Mar-77	49872	811	6857	309	45567	741	6265	282	-27	0.05
1977	APR	Apr-77	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1977	MAY	May-77	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1977	JUN	Jun-77	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1977	JUL	Jul-77	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1977	SEP	Sep-77	52714	886	7248	425	52714	886	7248	425	0	0.06
1977	OCT	Oct-77	58234	947	8007	311	58234	947	8007	311	0	0.04
1977	NOV	Nov-77	45851	771	6304	410	45851	771	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	46458	756	6388	673	0	0.11
1978	JAN	Jan-78	45729	744	6288	817	44236	719	6082	791	-27	0.13
1978	FEB	Feb-78	39553	712	5438	353	38076	686	5235	340	-13	0.07
1978	MAR	Mar-78	53027	862	7291	328	51566	839	7090	319	-9	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	86576	1408	11904	1273	25	0.11
1978	SEP	Sep-78	65053	1093	8945	525	65053	1093	8945	525	0	0.06
1978	OCT	Oct-78	60476	984	8315	322	60915	991	8376	325	2	0.04
1978	NOV	Nov-78	63938	1074	8791	572	59860	1006	8231	535	-36	0.07
1978	DEC	Dec-78	53625	872	7373	777	49547	806	6813	718	-59	0.11
1979	JAN	Jan-79	49664	808	6829	888	45585	741	6268	815	-73	0.13

			Base				Alt 1a					
Year	Mo	Date	Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1979	FEB	Feb-79	50049	901	6882	447	45970	828	6321	411	-36	0.07
1979	MAR	Mar-79	61728	1004	8487	382	57647	938	7926	357	-25	0.05
1979	APR	Apr-79	80714	1356	11098	499	80700	1356	11096	499	0	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	64845	1090	8916	523	0	0.06
1979	OCT	Oct-79	64083	1042	8811	342	64083	1042	8811	342	0	0.04
1979	NOV	Nov-79	70132	1179	9643	627	66147	1112	9095	591	-36	0.07
1979	DEC	Dec-79	67970	1105	9346	985	63986	1041	8798	927	-58	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	63142	1027	8682	1129	-71	0.13
1980	FEB	Feb-80	62089	1079	8537	555	58104	1010	7989	519	-36	0.07
1980	MAR	Mar-80	63444	1032	8723	393	59458	967	8175	368	-25	0.05
1980	APR	Apr-80	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1980	JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980	AUG	Aug-80	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1980	SEP	Sep-80	70872	1191	9745	572	70907	1192	9750	572	0	0.06
1980	OCT	Oct-80	59823	973	8226	319	59839	973	8228	319	0	0.04
1980	NOV	Nov-80	63271	1063	8700	566	59278	996	8151	530	-36	0.07
1980	DEC	Dec-80	59613	969	8197	864	55618	905	7647	806	-58	0.11
1981	JAN	Jan-81	51581	839	7092	922	47584	774	6543	851	-71	0.13
1981	FEB	Feb-81	46680	841	6418	417	42682	769	5869	381	-36	0.07
1981	MAR	Mar-81	50048	814	6881	310	46047	749	6331	285	-25	0.05
1981	APR	Apr-81	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1981	MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981	JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981	JUL	Jul-81	76861	1250	10568	653	78115	1270	10741	663	11	0.06
1981	AUG	Aug-81	69790	1135	9596	1026	69790	1135	9596	1026	0	0.11
1981	SEP	Sep-81	63221	1062	8693	510	63224	1062	8693	510	0	0.06
1981	OCT	Oct-81	61933	1007	8516	330	63366	1031	8713	338	8	0.04
1981	NOV	Nov-81	51751	870	7116	463	52716	886	7248	471	9	0.07
1981	DEC	Dec-81	45812	745	6299	664	45993	748	6324	667	3	0.11
1982	JAN	Jan-82	44243	720	6083	791	44415	722	6107	794	3	0.13
1982	FEB	Feb-82	38976	702	5359	348	39291	707	5402	351	3	0.07
1982	MAR	Mar-82	50770	826	6981	314	53368	868	7338	330	16	0.05
1982	APR	Apr-82	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1982	MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982	JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982	JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982	AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982	SEP	Sep-82	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1982	OCT	Oct-82	82000	1334	11275	437	81986	1333	11273	437	0	0.04
1982	NOV	Nov-82	80279	1349	11038	718	76266	1282	10486	682	-36	0.07
1982	DEC	Dec-82	68395	1112	9404	991	64381	1047	8852	933	-58	0.11
1983	JAN	Jan-83	64588	1050	8881	1154	60574	985	8329	1083	-72	0.13
1983	FEB	Feb-83	60401	1088	8305	540	56387	1015	7753	504	-36	0.07
1983	MAR	Mar-83	68328	1111	9395	423	64313	1046	8843	398	-25	0.05
1983	APR	Apr-83	70275	1181	9663	435	70275	1181	9663	435	0	0.05
1983	MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983	JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983	JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983	AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983	SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06

			Base				Alt 1a					
Year	Mo	Date	Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1983	OCT	Oct-83	81342	1323	11184	434	81340	1323	11184	434	0	0.04
1983	NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983	DEC	Dec-83	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1984	JAN	Jan-84	75666	1231	10404	1353	71665	1166	9854	1281	-72	0.13
1984	FEB	Feb-84	74251	1291	10209	664	70249	1221	9659	628	-36	0.07
1984	MAR	Mar-84	71770	1167	9868	444	73861	1201	10156	457	13	0.05
1984	APR	Apr-84	79696	1339	10958	493	78416	1318	10782	485	-8	0.05
1984	MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984	JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984	JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984	AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984	SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984	OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984	NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984	DEC	Dec-84	85925	1397	11815	1245	81692	1329	11232	1184	-61	0.11
1985	JAN	Jan-85	80865	1315	11119	1445	76632	1246	10537	1370	-76	0.13
1985	FEB	Feb-85	76628	1380	10536	685	72395	1304	9954	647	-38	0.07
1985	MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985	APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985	MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985	JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985	JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985	AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985	SEP	Sep-85	75129	1263	10330	606	75128	1263	10330	606	0	0.06
1985	OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985	NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985	DEC	Dec-85	86576	1408	11904	1255	85667	1393	11779	1242	-13	0.11
1986	JAN	Jan-86	85651	1393	11777	1531	81434	1324	11197	1456	-75	0.13
1986	FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986	MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986	APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986	MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986	JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986	JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1986	AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986	SEP	Sep-86	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1986	OCT	Oct-86	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1986	NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986	DEC	Dec-86	78786	1281	10833	1142	74783	1216	10283	1084	-58	0.11
1987	JAN	Jan-87	69058	1123	9495	1234	65056	1058	8945	1163	-72	0.13
1987	FEB	Feb-87	66954	1206	9206	598	62952	1133	8656	563	-36	0.07
1987	MAR	Mar-87	77469	1260	10652	479	73468	1195	10102	455	-25	0.05
1987	APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987	MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987	JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987	JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987	AUG	Aug-87	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1987	SEP	Sep-87	62419	1049	8582	503	62418	1049	8582	503	0	0.06
1987	OCT	Oct-87	63624	1035	8748	339	63623	1035	8748	339	0	0.04
1987	NOV	Nov-87	79093	1329	10875	707	75092	1262	10325	671	-36	0.07
1987	DEC	Dec-87	68906	1121	9474	999	64905	1056	8924	941	-58	0.11
1988	JAN	Jan-88	70055	1139	9632	1252	66054	1074	9082	1181	-72	0.13
1988	FEB	Feb-88	64279	1117	8838	574	60278	1048	8288	539	-36	0.07
1988	MAR	Mar-88	71897	1169	9886	445	67894	1104	9335	420	-25	0.05
1988	APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988	MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05

			Base				Alt 1a					
Year	Mo	Date	Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1988	JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988	JUL	Jul-88	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1988	AUG	Aug-88	81837	1331	11252	1203	81837	1331	11252	1203	0	0.11
1988	SEP	Sep-88	56113	943	7715	453	56113	943	7715	453	0	0.06
1988	OCT	Oct-88	71010	1155	9764	379	71010	1155	9764	379	0	0.04
1988	NOV	Nov-88	60510	1017	8320	541	56888	956	7822	509	-32	0.07
1988	DEC	Dec-88	56962	926	7832	826	52859	860	7268	766	-59	0.11
1989	JAN	Jan-89	59364	965	8162	1061	55359	900	7612	990	-72	0.13
1989	FEB	Feb-89	52009	936	7151	465	49602	893	6820	443	-22	0.07
1989	MAR	Mar-89	76345	1242	10497	472	76345	1242	10497	472	0	0.05
1989	APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989	MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989	JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989	JUL	Jul-89	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1989	AUG	Aug-89	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1989	SEP	Sep-89	54165	910	7448	437	54165	910	7448	437	0	0.06
1989	OCT	Oct-89	51573	839	7091	275	51573	839	7091	275	0	0.04
1989	NOV	Nov-89	61037	1026	8392	546	57029	958	7841	510	-36	0.07
1989	DEC	Dec-89	61907	1007	8512	897	57899	942	7961	839	-58	0.11
1990	JAN	Jan-90	57901	942	7961	1035	53893	876	7410	963	-72	0.13
1990	FEB	Feb-90	49568	893	6816	443	45560	820	6264	407	-36	0.07
1990	MAR	Mar-90	62558	1017	8602	387	58548	952	8050	362	-25	0.05
1990	APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990	MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990	JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990	JUL	Jul-90	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1990	AUG	Aug-90	78519	1277	10796	1154	78519	1277	10796	1154	0	0.11
1990	SEP	Sep-90	62931	1058	8653	508	62931	1058	8653	508	0	0.06
1990	OCT	Oct-90	63305	1030	8704	338	63305	1030	8704	338	0	0.04
1990	NOV	Nov-90	60470	1016	8315	541	57479	966	7903	514	-27	0.07
1990	DEC	Dec-90	53934	877	7416	782	49671	808	6830	720	-62	0.11
1991	JAN	Jan-91	49706	808	6834	888	46046	749	6331	823	-65	0.13
1991	FEB	Feb-91	46476	837	6390	415	42646	768	5864	381	-34	0.07
1991	MAR	Mar-91	52128	848	7167	323	51280	834	7051	317	-5	0.05
1991	APR	Apr-91	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1991	MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991	JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991	JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991	AUG	Aug-91	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1991	SEP	9/1	71767	1206	9868	579	71767	1206	9868	579	0	0.06
			Totals			$ 137,670,795				$ 134,706,323		
			Difference							-$2,964,473		
			Average Annual							-$174,381		

Figure 1

Historic Flow into 15-Mile Reach

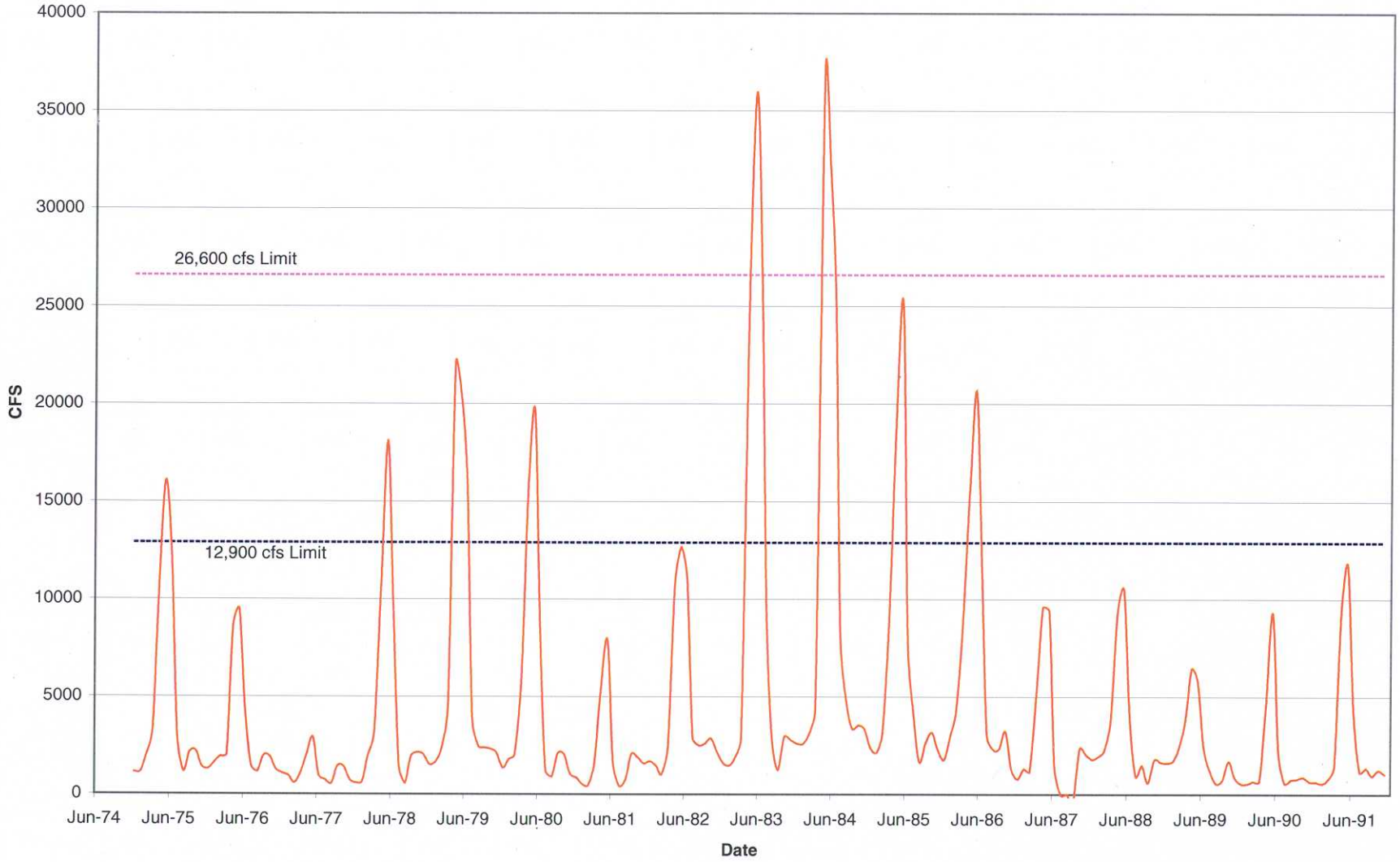


Figure 2
SHOSHONE POWER PLANT

Total Supply

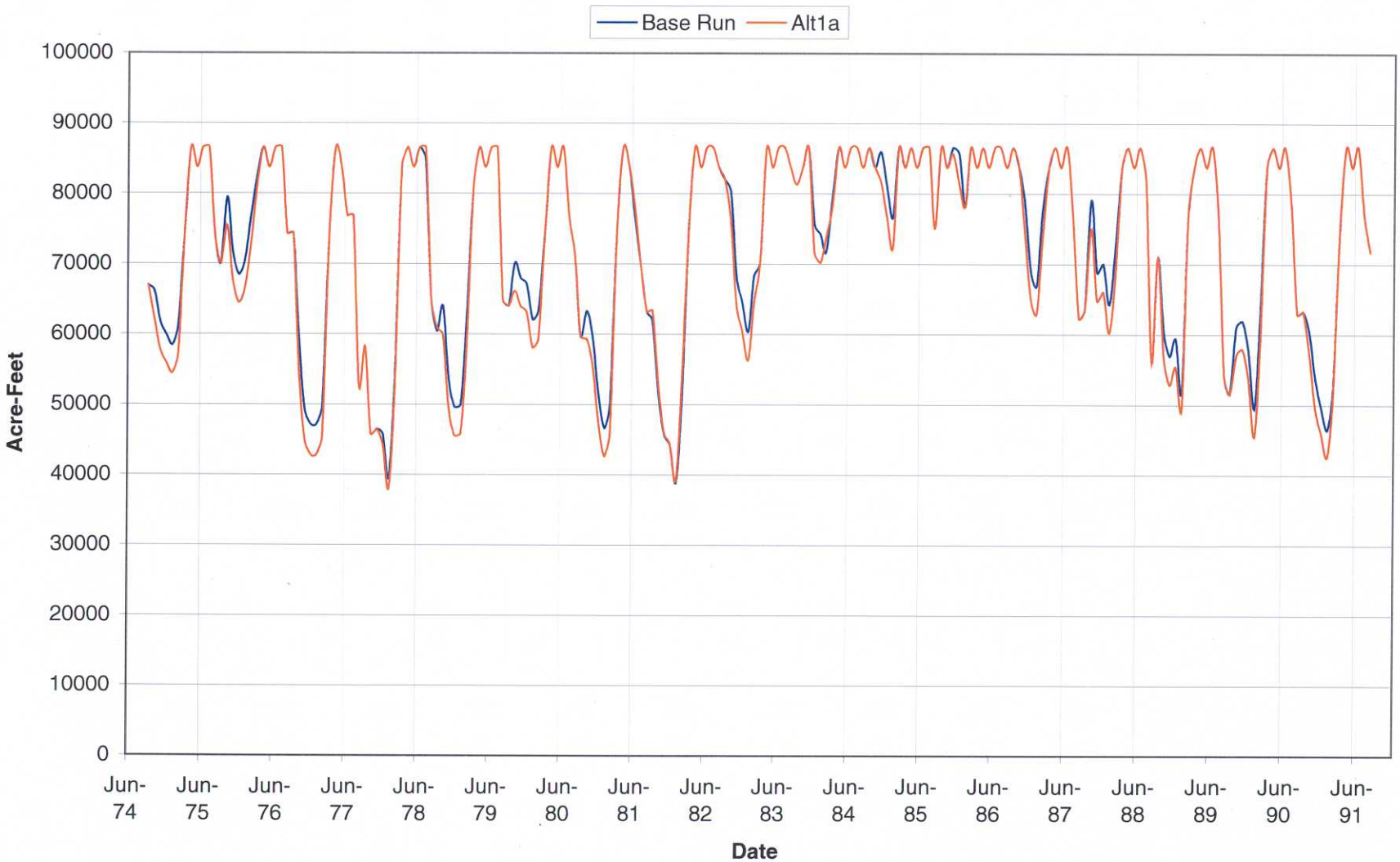


Figure 3

SHOSHONE POWER PLANT SHORTAGE

Short

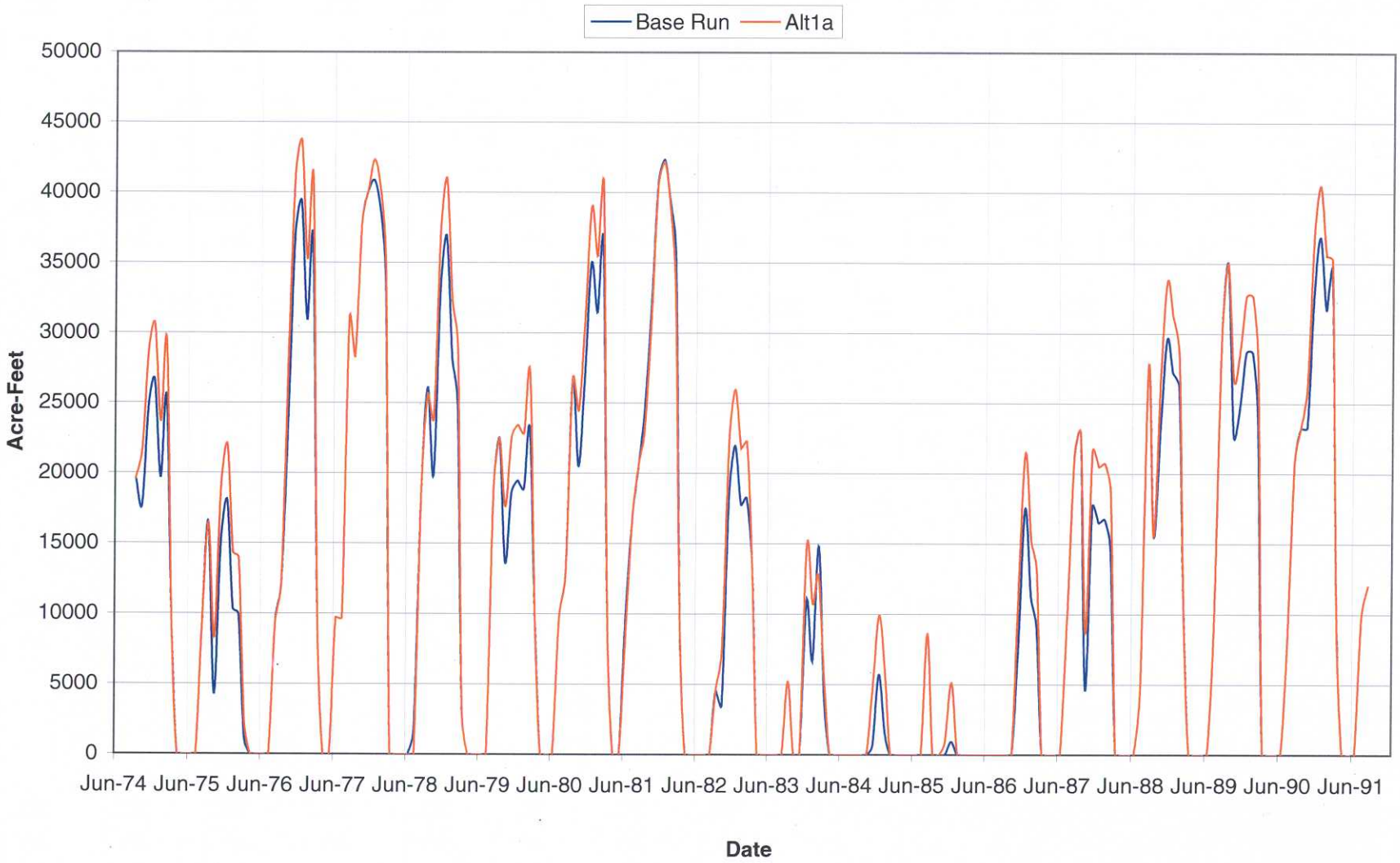


Figure 4

GREEN MOUNTAIN RESERVOIR

EOM Content

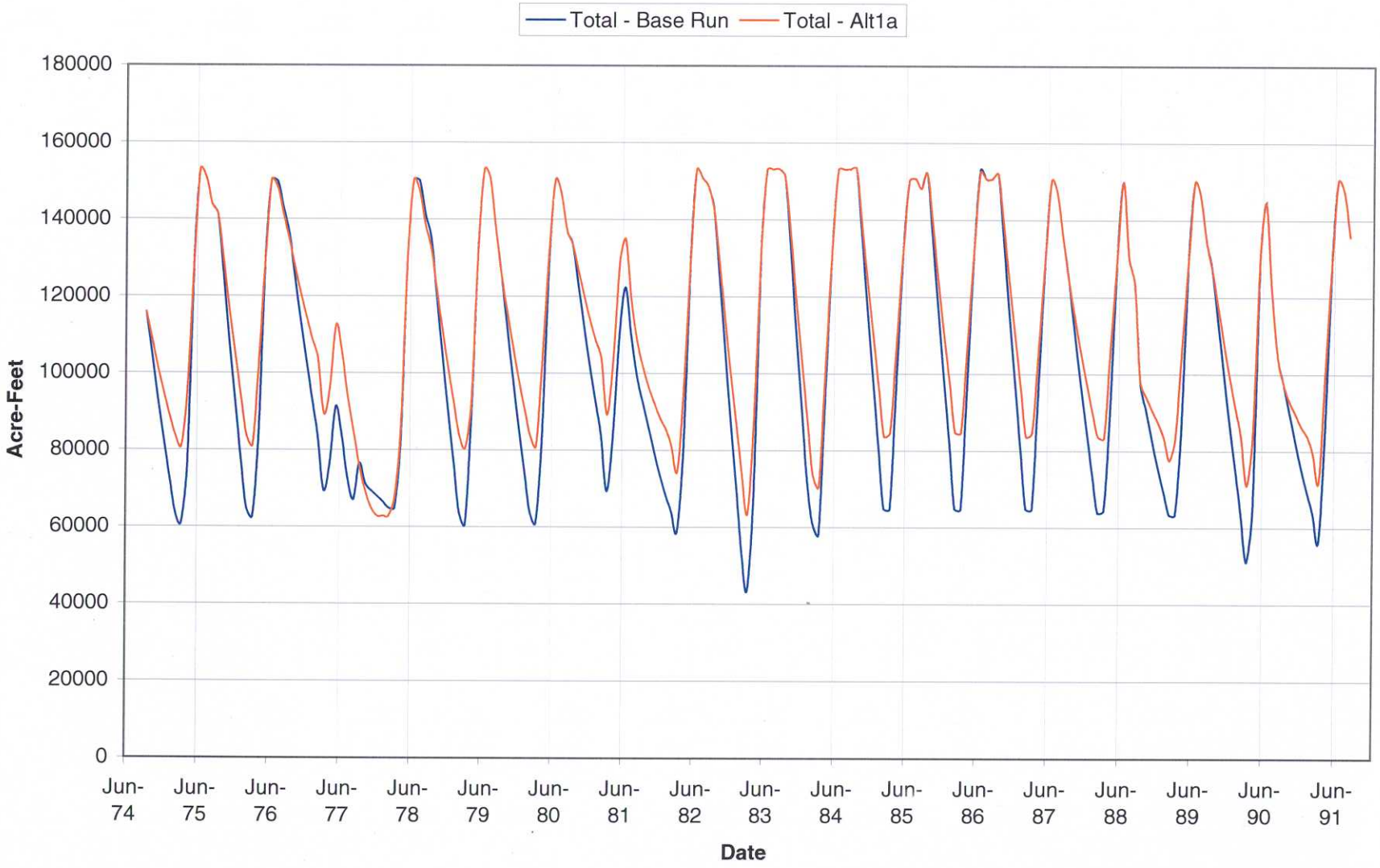


Figure 5

TOTAL STORAGE - DILLON RESERVOIR & WILLIAMS FORK RESERVOIR

EOM Content

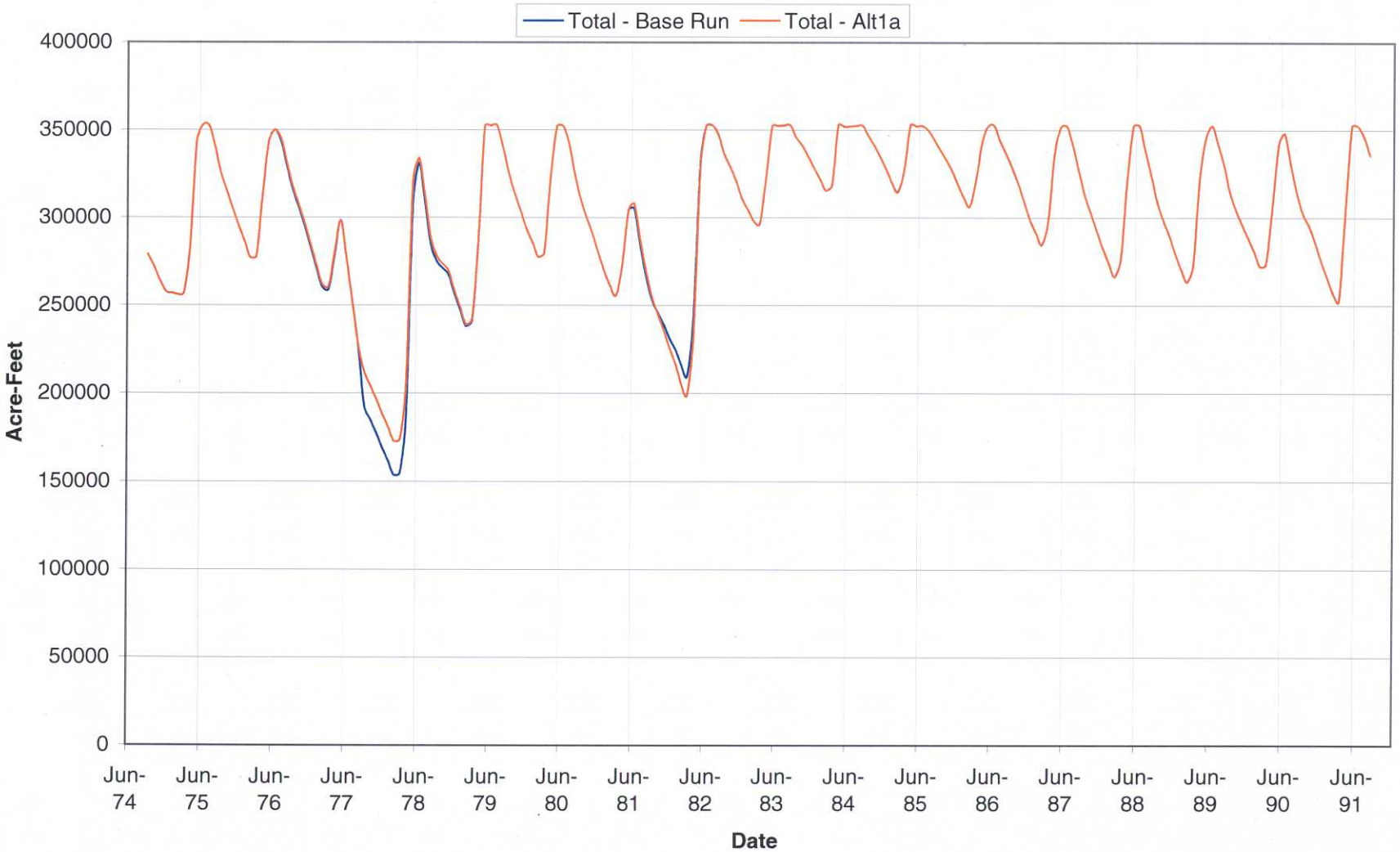


Figure 6

CBT GRANBY RESERVOIR

EOM Content

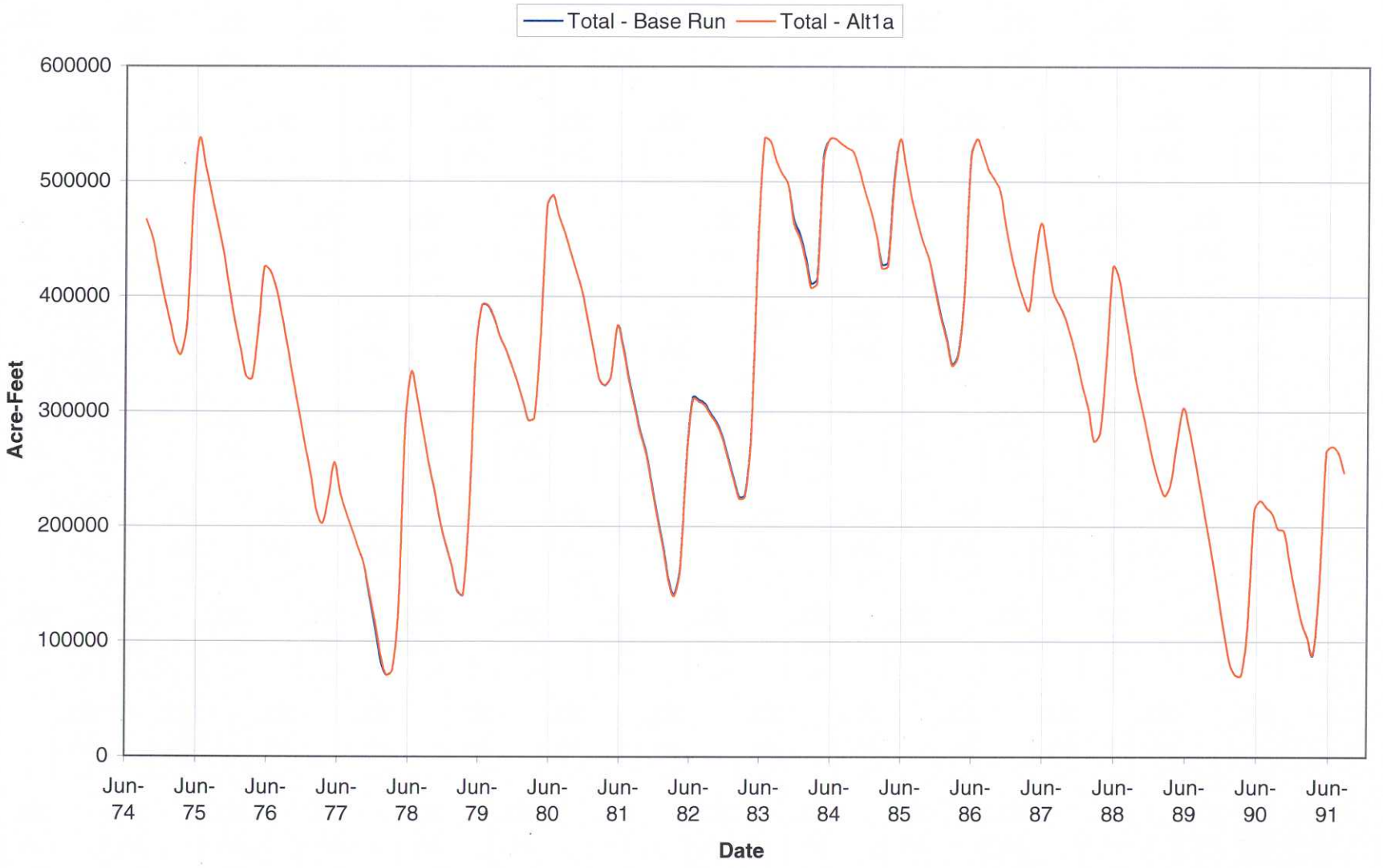


Figure 7
Power Production at Green Mountain Reservoir

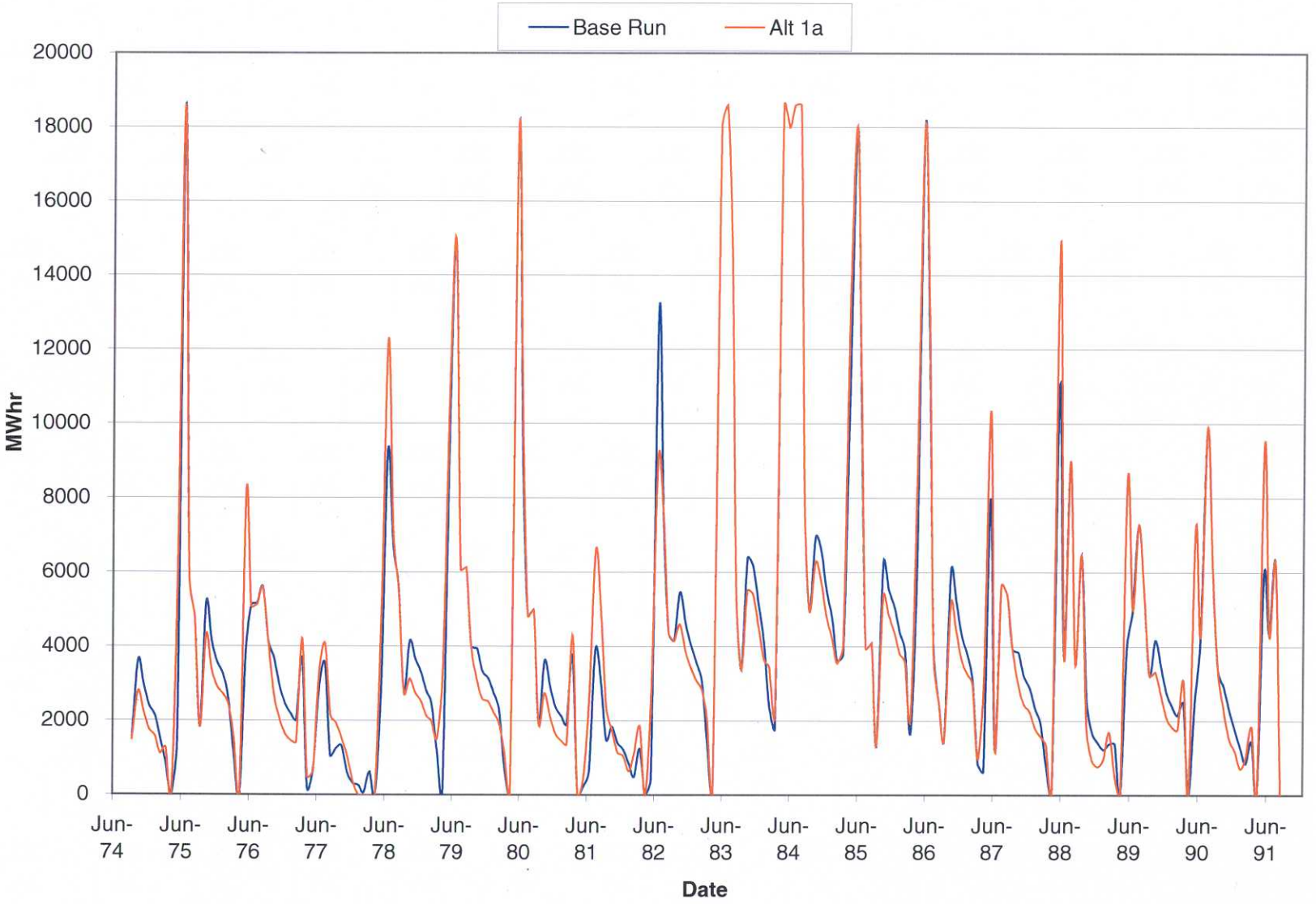
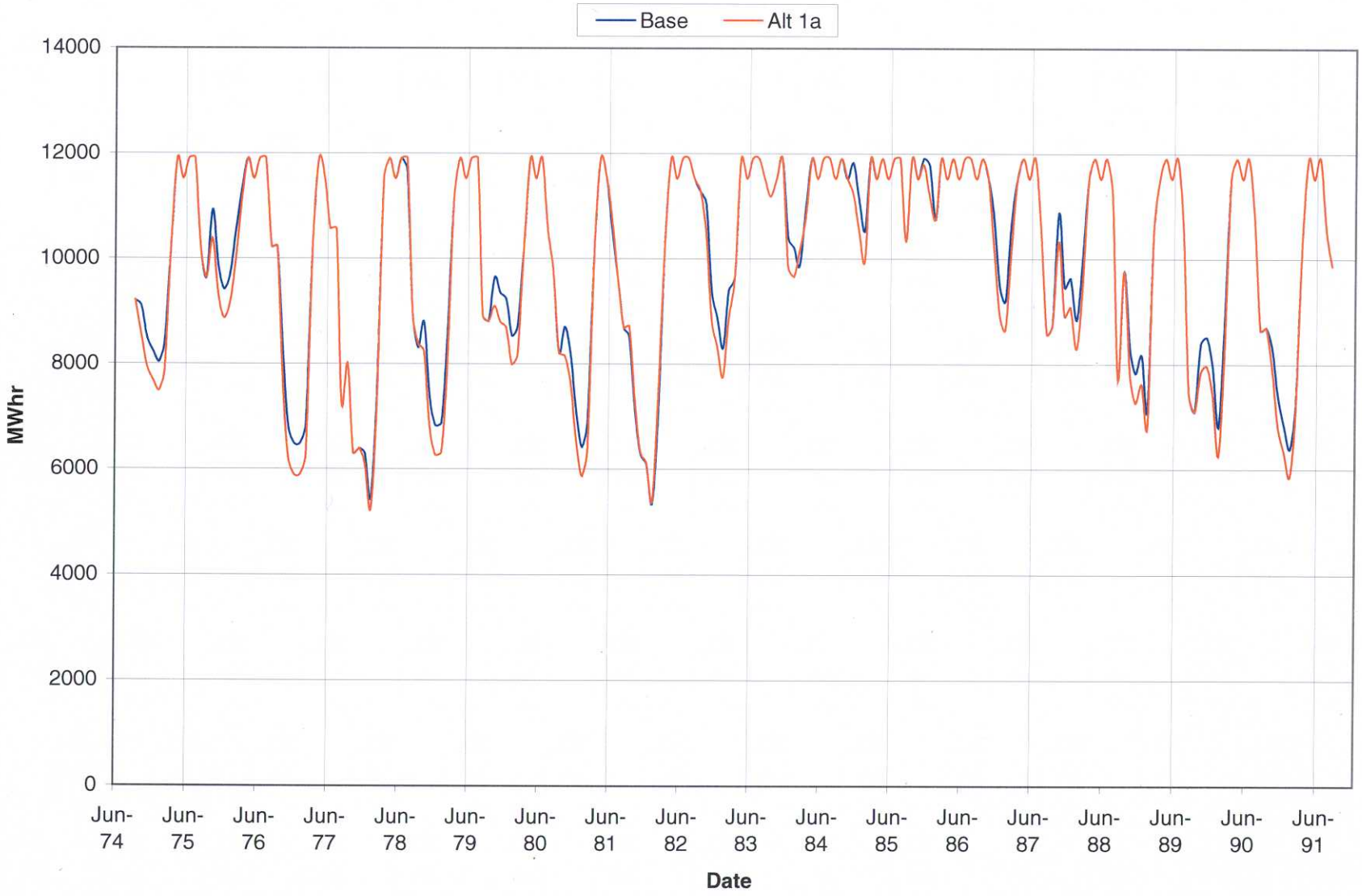


Figure 8
Shoshone Power Production



TECHNICAL MEMORANDUM 2:
ANALYSIS OF ALTERNATIVE 1A, EXPANDED COORDINATED RESERVOIR OPERATIONS OF GREEN MOUNTAIN RESERVOIR, INCLUDING GREEN MOUNTAIN RESERVOIR PREEMPTIVE RELEASE AND RELEASE OF WATER CARRIED OVER IN GREEN MOUNTAIN RESERVOIR

DRAFT

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March 2001
Revised October 2001

TECHNICAL MEMORANDUM 2:
ANALYSIS OF ALTERNATIVE 1A,
EXPANDED COORDINATED RESERVOIR OPERATIONS OF GREEN MOUNTAIN RESERVOIR, INCLUDING GREEN MOUNTAIN RESERVOIR PREEMPTIVE RELEASE AND RELEASE OF WATER CARRIED OVER IN GREEN MOUNTAIN RESERVOIR

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Figure 2. Inflow to 15-Mile Reach

Figure 3. Grand Valley Project Diversions

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Table 2. Inflow to 15-Mile Reach

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Table 4. Historic Grand Valley Project Diversions

EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 2 is to present the results of the investigation of another component of Alternative 1a, Expanded Coordinated Reservoir Operations. This component of Alternative 1a involves preemptive releases from Green Mountain Reservoir and release of water carried over in Green Mountain Reservoir to meet the 20,000 acre-feet per year target. This objective of this investigation is to perform a feasibility analysis of this component of Alternative 1a and to analyze the impact of this component on: (1) existing projects' yields, (2) existing projects' operations and maintenance costs and (3) existing projects' operational flexibility or reliability.

This component of Alternative 1a, Green Mountain Reservoir Preemptive Releases and Release of Water Carried Over in Green Mountain Reservoir, is one of 17 alternatives recommended for further investigation in *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River* report. This component involves:

(1) Implementing a project or program in the Colorado basin in Colorado which will result in decreased releases from the Green Mountain Reservoir Historic Users Pool (HUP),

(2) Storing the water saved from decreased HUP releases in the HUP and

(3) Using this stored water to either (a) replace a preemptive release from Green Mountain Reservoir to meet the 20,000 acre-feet target or (b) carrying over this increased storage in Green Mountain Reservoir for release in the following spring to meet the 20,000 acre-feet target.

The U.S. Bureau of Reclamation's Grand Valley Water Management Project was used as the project to produce decreased releases from the Green Mountain Reservoir HUP and consequent savings to the HUP which could be used for meeting the 20,000 acre-feet target release. The Grand Valley Water Management Project seeks to reduce operational spills and, therefore, diversions from the Colorado River by installation of seven new check structures in its canal system and other project features. Reducing river diversions reduces the need for releases from the HUP during periods when the Grand Valley Project water rights would otherwise be issuing a priority call, but are instead benefiting from Green Mountain HUP releases.

This feasibility investigation uses StateMod and the C1 data set for the 1975-91 study period. Estimated reduced monthly diversions for the Grand Valley Project as a result of the Grand Valley Water Management Project were developed by the U.S. Bureau of Reclamation (1996) for the study period. These estimated reduced monthly diversions for the Grand Valley Project were obtained from the Colorado Water Conservation Board and used in StateMod to estimate savings in reduced releases from the HUP as a result of the Grand Valley Water Management Project

The feasibility investigation produced the following results:

1. Estimated savings to the HUP as a result of the Grand Valley Water Management Project occurred in only five years during the 1975-91 study period:

    - 1977: 1,303 acre-feet,
    - 1978: 641 acre-feet,
    - 1981: 2,650 acre-feet,
    - 1988: 3,031 acre-feet,
    - 1989: 3,252 acre-feet

    In all other years during the study period (1975-1991), there were no estimated savings from reduced HUP releases as a result of the Grand Valley Water Management Project.

2. The 20,000 acre-feet target release would have been required in only six years (1975, 1978, 1979, 1980, 1985 and 1986) out of the 17 years in the 1975-1991 study period. If the release requirements were relaxed somewhat, a release could have been also required in two additional years, 1982 and 1991. Investigations herein indicate that 1978 was the only year in which the 20,000 acre-feet release would have been required and savings to the HUP as a result of the Grand Valley Water Management Project would have been available. The remaining four years in which estimated savings to the HUP would have occurred as a result of the Grand Valley Project (1977, 1981, 1988, and 1989) did not correspond with years in which a release could have been required.

3. Expected reasons for the absence of savings to HUP in other years during the study period and the relatively small estimated savings in 1977, 1978, 1981, 1988 and 1989 include:

    (a) Savings to HUP as a result of the Grand Valley Water Management Project can only occur in those years in which the Grand Valley Project water rights are calling and these rights do not call every year.

    (b) The Check Settlement (Stipulation and Agreement, Case No. 91CW247, Water Division 5) allows releases of surplus HUP water to be made to the Grand Valley Project Power Plant during the irrigation season thereby potentially releasing some or all of the HUP savings resulting from the Grand Valley Water Management Project. Releasing these HUP savings as surplus HUP storage to the Grand Valley Power Plant will obviously reduce the savings in the HUP available for release as the 20,000 acre-feet target release.

4. The U.S. Bureau of Reclamation (1998) studied use of HUP water in Green Mountain Reservoir for the years 1992, 1993 and 1994. Results of the Bureau's studies indicate the following volumes of water would have been available from the HUP as "surplus in excess of canal capacity":

    - 1992: 11,563 acre-feet,

- 1993: 0 acre-feet and
- 1994: 11,219 acre-feet.

These estimates of surplus in excess of canal capacity represent the savings in the HUP resulting from the Grand Valley Water Management Project which could be available for meeting the 20,000 acre-feet release target. Comparison of these estimates to those produced by StateMod and reported above indicates that the Bureau of Reclamation's estimates are larger. Possible reasons for this difference include:

- The data set estimating reductions in diversions for the study period, 1975-91, for the Grand Valley Project as a result of the Grand Valley Water Management Project (U.S. Bureau of Reclamation, 1996) was produced by the Bureau of Reclamation at the request of the CWCB for use in StateMod. This diversion data set was used by Brown and Caldwell as input to StateMod for estimating savings to the HUP as a result of the Grand Valley Project. The Bureau of Reclamation's Grand Valley Project diversion data set was produced in 1996 without benefit of the field measurements that contributed to later, and probably more accurate, Bureau of Reclamation estimates of reduced diversions by the Grand Valley Project as a result of the Grand Valley Water Management Project (U.S. Bureau of Reclamation, 1998). Communication with the Bureau of Reclamation suggests that this 1996 data set may underestimate reduced Grand Valley Project diversions resulting from the Grand Valley Water Management Project (Personal communication, Karen Fogelquist to Leo Eisel and Bruce Rindahl, March, 2001).

  For example, net reductions in Grand Valley Project diversions as a result of the Palisade Pipeline are not included in the Bureau of Reclamation's 1996 diversion data set because that feature was not part of the Grand Valley Water Management Project in 1996. The estimated annual average of 9,000 acre-feet of reduced Grand Valley Project diversions resulting from the Palisade Pipeline feature of the Grand Valley Water Management Project were, however, included in the Bureau of Reclamation's 1998 estimates of estimated savings to the HUP.

- The C1 dataset in StateMod uses a monthly time step. The Bureau of Reclamation's 1998 dataset used a daily time step. The differences could be significant especially in light of the spills through the Palisade pipeline. Preliminary Bureau of Reclamation modeling of the Grand Valley Water Management Program indicated spills through the proposed pipeline would vary daily from 0 to 120 cfs (Personal communication, Karen Fogelquist to Leo Eisel and Bruce Rindahl, March, 2001). An average of 3000 AF for August, September and October was used in the StateMod simulation equal to 50 cfs. Whether the StateMod calculated releases from HUP for the Grand Valley Project using a monthly time step and the G-1 data set are sufficiently realistic or not is not known with much certainty.

5. The 20,000 acre-feet target release would normally be made during late May and/or early June before Green Mountain Reservoir filled under its senior 1935 priority for

154,645 acre-feet. Replacement for this 20,000 acre-feet release would not be available from increased savings to the HUP pool until August through October. Therefore, in those years in which there was sufficient water availability, Green Mountain Reservoir would likely have replaced the 20,000 acre-feet target release under its 1935 refill right for 6,316 acre-feet and its proposed 1985 refill right for 154,645 acre-feet thereby reducing the usefulness of replacement water available from savings to the HUP. In those very dry years when Green Mountain was unable to fill (e.g., 1977), the 20,000 acre-feet target release would likely not have been required and, consequently, there would have been no need for replacement storage.

6. Carrying over HUP storage resulting from Grand Valley Water Management Project savings to the succeeding year would result in these carried over savings counting against the first fill right of Green Mountain Reservoir. Therefore, in those years in which the 20,000 acre-feet release is made and Green Mountain Reservoir fills, the replacement of the 20,000 acre-feet release would be done under the Green Mountain Reservoir refill rights and not from the 20,000 acre-feet of carry over storage. In those years when Green Mountain Reservoir does not fill, it is unlikely that the 20,000 acre-feet release would be required and, therefore, there would be no need for replacement.

7. In contrast to the relatively small estimated savings to the HUP as a result of the Grand Valley Water Management project, the increased water supply to the 15-Mile Reach during August through September is larger and more reliable. Based on the analysis herein, the average annual increase in flow at the head of the 15-Mile Reach for the three-month August through October period averages approximately 21,900 acre-feet which represents an average increase for this period of approximately 12 percent for the 1975 through 1991 study period. This estimated increase compares well with the Bureau of Reclamation's estimated average flow increase of approximately 19,600 acre-feet or 10 percent at the head of the 15-Mile Reach during August through October for 1992 through 1994 (U.S. Bureau of Reclamation, 1998).

The following conclusions and recommendations are based on the above results:

1. This alternative, Green Mountain Reservoir Preemptive Releases and Release of Water Carried Over in Green Mountain Reservoir, is not likely to be feasible because:

   a. It appears that this alternative would not produce sufficient volume of water supply for meeting the 20,000 acre-feet target release.
   b. This alternative would not produce a water supply with sufficient dependability for meeting the 20,000 acre-feet target release.
   c. Water supply from this alternative would not be produced in those years when it is needed to replace the 20,000 acre-feet target release.
   d. Water supply from this alternative would be available too late in the season to replace the target release of 20,000 acre-feet in all but those extremely dry years when Green Mountain Reservoir did not fill. Furthermore, it appears that the

required target release of 20,000 acre-feet would be extremely unlikely in these very dry years.

e. Savings to the HUP from the Grand Valley Water Management Project are likely to become surplus HUP water, which is already committed for release to the Government Power Plant in compliance with the settlement in the Check case (Case No. 91CW247).

2. Even if the flows available for meeting the 20,000 acre-feet target release from this alternative are more near the 11,000 acre-feet amounts estimated by the Bureau of Reclamation as compared to the 2,000 to 3,000 acre-feet amounts estimated herein, Brown and Caldwell believes that items 1b through 1e above are sufficient to produce an infeasible alternative. For all the above reasons and pending agreement by the Executive Committee, it is recommended that this alternative not be investigated further.

3. This investigation has focused on possible savings to the HUP from the Grand Valley Water Management Project during the descending limb of the annual hydrograph (i.e., August through October). Some consideration was given to the possibility of utilizing savings realized from the Grand Valley Water Management Project during the ascending limb of the annual hydrograph. Based on investigations by the Bureau of Reclamation (1998), expected reductions in Grand Valley Project diversions as a result of the Grand Valley Water Management Project would be much less than reductions during August through October. Furthermore, frequency and duration of the Grand Valley Project priority calls are normally less during the May-June period than during the August through October period. Therefore, no further consideration of possible HUP savings from the Grand Valley Water Management Project during the ascending limb of the annual hydrograph is recommended.

4. As indicated above, reduced diversion by the Grand Valley Water Users Association as a result of the Grand Valley Water Management Project is a good, dependable source of supply for providing water to meet Recovery Program target flows at the head of the 15-Mile Reach during the late summer and early fall. This is probably the best use of savings to the HUP from the Grand Valley Water Management Project.

5. As shown in Technical Memorandum No. 3 (CWCB, October 2001b) Green Mountain Reservoir will replace the 20,000 acre-feet pre-emptive release under its refill priority, consequently, there is little reason to explore sources of replacement water from the Grand Valley Water Management Project.

INTRODUCTION AND PURPOSE

Several options for revising Green Mountain Reservoir operations to produce flows contributing to the average annual 20,000 acre-feet target were developed in Phase 1 of this investigation. These alternatives include:

- Reduced winter power operations (see section 3.2.1.1 in *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River*.
- Green Mountain Reservoir conjunctive pool operations (section 3.2.1.2 in the Phase 1 Study).
- Green Mountain Reservoir preemptive releases (section 3.2.1.3 in the Phase 1 Study).
- Release of water carried over in Green Mountain Reservoir (section 3.2.1.4 in the Phase 1 study).

Analysis of the reduced winter power operations alternative was reported in Technical Memorandum No. 1.

The purpose of this Technical Memorandum is to present: (1) the methodology used to analyze Alternative 1a, Green Mountain Reservoir preemptive releases and release of water carried over in Green Mountain Reservoir and (2) the results of this analysis. After review by the CWCB and the Executive Committee, necessary changes will be made in the analysis methodology in response to comments and suggestions from the CWCB and the Executive Committee and the Green Mountain Reservoir winter power operations alternative will be reanalyzed accordingly. Subsequent to these analyses, the remaining alternative detailed above, Green Mountain Reservoir conjunctive pool operations, will be analyzed.

The Green Mountain Reservoir preemptive release alternative has the following components:

- A release of 20,000 acre-feet is made from Green Mountain Reservoir during a 10-day period surrounding the peak of the spring hydrograph in late May or early June.
- This 20,000 acre-feet is replaced in Green Mountain Reservoir during August, September and October using savings to the HUP which result from reduced releases from the HUP for augmenting downstream rights senior to 1977.
- The source of these reduced releases is the U.S. Bureau of Reclamation's Grand Valley Water Management Project which utilizes installation of gated check structures in the Grand Valley Project canals to reduce operational spills during the August through October period. By reducing operational spills, total required diversions by the Grand Valley Project are reduced with the subsequent effect of potentially reducing releases from the Green Mountain Reservoir HUP.

The release of carried over Green Mountain Reservoir water alternative is similar with the exception that the HUP savings would be carried over from one season to the next:

- HUP water not needed for release to maintain the Grand Valley Project water rights in priority during August, September and October would be carried over the winter in the HUP.
- This carried over water would be released during late May or early June in the following year to meet the 20,000 acre-feet per year target.

Specific concerns to be addressed in this engineering analysis of these alternatives include:

1. The frequency with which the 20,000 acre-feet per year target can be met in those years when the expected peak spring flow at the head of the 15-Mile reach is between 12,900 cfs and 26,600 cfs using these alternatives (Green Mountain Reservoir preemptive release alternative and release of carried over Green Mountain Reservoir water alternative) as the source of the 20,000 acre-feet.

2. The effect on Green Mountain Reservoir filling each year as a result of entering the fill season (approximately April 1) with additional water in storage or entering the fill season with reduced storage because the preemptive release was not replaced in Green Mountain Reservoir.

3. The effect on the operation and yield of other projects as a result of Green Mountain Reservoir entering the fill season with additional storage or with reduced storage because the preemptive release was not replaced in Green Mountain Reservoir. Analysis must look specifically at whether this alternative will increase Denver Water's risk of releasing water from Dillon Reservoir to assure a Green Mountain Reservoir fill under the Blue River Decree and subsequent agreements among Denver Water, Reclamation, NCWCD and the Colorado River Water Conservancy District.

4. The effect on hydropower generation at Green Mountain Reservoir, Shoshone Power Plant, and the Orchard Mesa Power Plant.

5. The effect on flooding in downstream reaches of the Blue and Colorado Rivers from releasing this additional 1,000 cfs on the peak of the spring runoff hydrograph.

6. The physical feasibility of releasing the 20,000 acre-feet at a rate of 1,000 cfs over a 10-day period from Green Mountain Reservoir.

Other legal/institutional concerns exist about Alternative 1a; these concerns are not addressed in this Technical Memorandum, but will be addressed by our legal team and discussed in the Phase 2 report or possibly in a separate legal memorandum. The ongoing controversy regarding Reclamation's authority to release water from Green Mountain Reservoir for piscatorial purposes is an example of these legal/institutional issues. The Federal Government asserts that Senate Document No. 80 and the Green Mountain Reservoir water rights give Reclamation the necessary authority to release water for endangered fish. The State of Colorado and various water users

submit that releases for piscatorial purposes are not allowed under the Green Mountain Reservoir water rights decree. Changes to the Green Mountain Reservoir water rights decree may be necessary.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following procedures and assumptions were employed in the analysis of: (1) Green Mountain Reservoir preemptive release alternative and (2) release of carried over Green Mountain Reservoir water alternative:

1. The StateMod surface water model and C1 data set were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 Scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).* These components of RIPRAP flows include:

   - 5,000 acre-feet per year from Ruedi Reservoir,
   - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
   - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
   - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
   - 6,000 acre-feet per year from Wolford Mountain Reservoir, and
   - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated in the C1 data set but not modeled.

3. Flow Targets: Releases of 20,000 acre-feet over a 10-day period were made from Green Mountain Reservoir when the expected spring peak flow at the head of the 15-Mile Reach was between 12,900 cfs and less than 26,600 cfs. If the 20,000 cfs was not released to enhance the spring peak flows, it was booked over to storage in the Historic Users Pool and no attempt was made to release this water in the late summer or early fall for purposes of augmenting low flows.

4. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee determine after their review and the consultant makes necessary changes that the methodology and calculations employed in

the analysis of Alternative 1a are acceptable, the necessary sensitivity analysis will be completed.

CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

5. Estimated Monthly Savings from Grand Valley Water Management project for the August 1974 through October 1991 were obtained from U.S. Bureau of Reclamation (1996) and used in StateMod with the C1 data set.

6. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

7. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

8. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,
   - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
   - A reservoir fill according to the criteria of the Blue River Decree.

   The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

   Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

   Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

9. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

    - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
    - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
    - Sufficient HUP Surplus water exists to make the release.

    Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. Releases of HUP Surplus water under the Municipal Recreational Agreement are not explicitly modeled by StateMod and the C1 data set and there is no demand specified at a node for the Municipal Recreational water.

USE OF STATEMOD

Green Mountain Reservoir is modeled in the C1 scenario using five separate pools including the Historic Users Pool (HUP), Colorado Big Thompson Pool (CBT), the contract pool, Silt Project Pool and the Inactive Pool. Details of the method of modeling Green Mountain Reservoir in the C1 scenario can be found in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).*

The C1 scenario was modified by adding full reservoir targets in Green Mountain Reservoir for the months of September and October. This prevented arbitrary releases to meet storage targets until after the irrigation season. All other releases, including releases to the Grand Valley Power Plant and HUP beneficiaries, remained in the C1 data set. In addition, monthly demands of 20,000 acre-feet were added to the head of the 15-mile reach (diversion ID #952001) corresponding to the projected 20,000 acre-feet releases to enhance the spring runoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1985 and 1986. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water in the stream when available. This modified C1 scenario was used as the baseline scenario for evaluating alternatives.

In the Baseline C1 scenario, a set of reduced demands, an average of approximately 19,400 acre-feet per year, for the Grand Valley Project (GVP) was already included in the model but the associated rights were simply turned off. For investigating this alternative, these reduced demands at the Grand Valley Project (model ID# 950009) were turned on and the historical demands at the same location were turned off. The 50 cfs by-pass flows at the Palisade pipeline for the months of August, September, and October, an average of approximately 9,000 acre-feet per year, were also turned on. The reduced demands were described in detail in U.S. Bureau of Reclamation (October 1996).

Several spreadsheets were then developed to allow side by side comparison of every aspect of the analysis in the two StateMod runs including reservoir storage, diversions, streamflows and operating releases.

RESULTS

WATER AVAILABILITY

Results of this analysis are presented in Figure 1 and Table 1 which indicate that the only years in which savings would accrue to the HUP as a result of the Grand Valley Water Management Project would be:

- 1977: 1,303 acre-feet,
- 1978: 641 acre-feet,
- 1981: 2,650 acre-feet,
- 1988: 3,031 acre-feet and
- 1989: 3,252 acre-feet

The U.S. Bureau of Reclamation studied use of HUP water in Green Mountain Reservoir for the years 1992, 1993 and 1994 Results from the Bureau of Reclamation's investigation indicate the following additional amounts of HUP water in the years indicated would have been available in the HUP as a result of the Grand Valley Water Management Project as "surplus in excess of canal capacity " (see Table 5 in U.S. Bureau of Reclamation, 1998):

- 1992: 11,563 acre-feet,
- 1993: 0 acre-feet and
- 1994: 11,219 acre-feet.

The "surplus in excess of canal capacity" represents the amount of HUP storage that would have been available for release toward the 20,000 acre-feet target. The Bureau of Reclamation's estimates were based on field measurements.

Figure 2 and Table 2 present flow at the head of the 15-Mile Reach. Hydrographs presented in Figure 2 indicate increased flows at the head of the 15-Mile Reach during the August-October period in every year as a result of the Grand Valley Water Management Project. The increased flow during the August-October period results from reduced diversions by the Grand Valley Project as a result of reduced operational spills. The increased flow at the head of the 15-Mile Reach for the August-October period averages approximately 21,900 acre-feet based on the estimated monthly savings calculated herein (see Table 2). Calculations by the Bureau of Reclamation indicate the expected increase in flow at the head of the 15-mile reach would average approximately 19,600 acre-feet for the August-October period as a result of the Grand Valley Water Management project (see Table 4 in U.S. Bureau of Reclamation, 1996). Therefore, it appears that the Grand Valley Water Management project is a good source of water supply for recovery of the endangered species during the late summer and fall period.

ANALYSIS OF RESULTS

HUP Savings and 20,000 Acre-Feet Release Occur in Different Years

Based on results reported in Technical Memorandum No. 1 (CWCB, October 2001a) the 20,000 acre-feet target release would have been required in only six years (1975, 1978, 1979, 1980, 1985 and 1986) out of the 17 years in the 1975-1991 study period. If the release requirements were relaxed somewhat, a release could have been also required in two additional years, 1982 and 1991. Investigations herein indicate that 1978 was the only year during the 1975-1991 study period in which: (a) the 20,000 acre-feet release would have been required and (2) savings to the HUP as a result of the Grand Valley Water Management Project would have occurred. Only 641 acre-feet of savings to the HUP from the Grand Valley Water Management Project would have been available in 1978. The remaining four years in which estimated savings to the HUP would have occurred as a result of the Grand Valley Project (1977, 1981, 1988, and 1989) were years in which the 20,000 acre-feet release was not required.

Small, Infrequent HUP Savings

Possible reasons for the infrequent and relatively low amounts of savings to the HUP from the Grand Valley Water Management Project were investigated.

Savings accrue to the HUP as a result of reduced HUP releases to keep water rights with priority dates senior to October 15, 1977 in priority. Reduced releases from the HUP occur as a result of the Grand Valley Water Management Project, which results in reduced diversions by the Grand Valley Project as a result of the conservation practices and projects implemented in the Grand Valley Water Management Project. Savings to the HUP as a result of the Grand Valley Water Management Project are limited to those periods when the Grand Valley Water Users Association's 730 cfs (priority date of 7/22/1912) water right is in priority and is issuing a priority call.

Available call records and diversion records were investigated to determine if the relatively small and infrequent volume of savings to the HUP estimated by the StateMod investigations detailed above and by the Bureau of Reclamation's 1998 investigation corresponded with the frequency and duration of historic priority calls by the Grand Valley Project's 1912 right. The results of the call record analysis are presented in Table 3 and the results of the diversion record analysis are presented in Figure 3 and Table 4.

Review of the call record analysis in Table 3 indicates that savings to the HUP were predicted only in those years during the 1975-1991 study period when the Grand Valley Project's 1912 right was historically calling. In some years, however, the Grand Valley Project's 1912 right was calling, but the StateMod analysis did not predict savings to HUP; these years include 1976, 1979, 1980, 1987 and 1990.

An additional explanation for the relatively small savings to the HUP as estimated by StateMod in some years when the Grand Valley Project's 1912 rights is calling involves the Stipulation and Agreement in Case No. 91CW247 (the "Check" Settlement). The Check Settlement allows releases of surplus HUP water to be made to the Grand Valley Project Power Plant during the

irrigation season thereby potentially providing for the release of all or a portion of the HUP savings resulting from the Grand Valley Water Management Project. The Check Settlement is modeled in StateMod.

Not all of the savings to the HUP resulting from the Grand Valley Water Management Project will be available for replacing the 20,000 acre-feet release. Savings to the HUP occurring during August through October are likely to: (1) contribute to the "Total HUP Draw Down Band" in Figure 1 of the Green Mountain Historic User Pool Operating Criteria developed as part of the Stipulation and Agreement in Case No. 91CW247 (the Check case) or (2) be surplus HUP water. As part of the Settlement in the Check case, the U.S. agreed not to exercise its power right against upstream junior rights during the irrigation season. Instead of calling for water to generate hydroelectric power, releases of surplus HUP water can be made. Consequently, if the HUP savings generated by the Grand Valley Water Management Project become surplus HUP water, this HUP surplus is already committed for release to the Government Power Plant and would be unavailable for replacing the 20,000 acre-feet target release if sufficient capacity exists in the OMID Power Canal. HUP storage which is "surplus in excess of canal capacity" could be made available for replacing the 20,000 acre-feet release.

Another explanation for the relatively small estimated HUP savings involves the data set containing estimated Grand Valley Project diversions with the Grand Valley Water Management Project in place and functioning. The dataset for the study period, 1975-91, was produced by the U.S. Bureau of Reclamation (1996) at the request of the CWCB for use in StateMod. This estimated dataset was produced without benefit of many of the field measurements that contributed to later, and probably more accurate, estimates of reduced diversions by the Grand Valley Project as a result of the Grand Valley Water Management Project (U.S. Bureau of Reclamation, 1998). Communication with the Bureau of Reclamation suggests that this 1996 data set may underestimate reduced Grand Valley Project Diversions resulting from the Grand Valley Water Management Project (Personal communication, Karen Fogelquist, U.S. Bureau of Reclamation, to Leo Eisel and Bruce Rindahl, March, 2001).

For example, net reductions in Grand Valley Project diversions as a result of the Palisade Pipeline are not included in the Bureau of Reclamation's 1996 diversion data set because that feature was not part of the Grand Valley Water Management Project in 1996. The estimated annual average of 9,000 acre-feet of reduced Grand Valley Project diversions resulting from the Palisade Pipeline feature of the Grand Valley Water Management Project were, however, included in the Bureau of Reclamation's 1998 estimates of estimated savings to the HUP.

The C1 dataset in StateMod uses a monthly time step. The Bureau of Reclamation's 1998 dataset used a daily time step. The differences could be significant especially in light of the spills through the Palisade pipeline. Preliminary Bureau of Reclamation modeling of the Grand Valley Water Management Program indicated spills through the proposed pipeline would vary daily from 0 to 120 cfs (Personal communication, Karen Fogelquist to Leo Eisel and Bruce Rindahl, March, 2001). An average of 3000 AF for August, September and October was used in the StateMod simulation equal to 50 cfs. Whether the StateMod calculated releases from HUP for the Grand Valley Project using a monthly time step and the G-1 data set are sufficiently realistic or not is unknown with much certainty.

Timing of HUP Savings

The 20,000 acre-feet target release would normally be made during late May and/or early June before Green Mountain Reservoir filled under its senior, 1935 priority for 154,645 acre-feet. Replacement water for this 20,000 acre-feet release under this alternative would not be available from increased savings to the HUP pool until August, September and/or October. Therefore, in those years in which a 20,000 acre-feet release had been made and there was sufficient water availability, Green Mountain Reservoir would likely have replaced the 20,000 acre-feet target release under its 1935 refill right for 6,316 acre-feet and its proposed 1985 refill right for 154,645 acre-feet thereby reducing the usefulness of replacement water available from savings to the HUP. In those very dry years when Green Mountain was unable to fill (e.g., 1977), the 20,000 acre-feet target release would not have been made and, consequently, there would be no need for water to replace a preemptive 20,000 acre-feet target release.

Carrying over HUP storage resulting from Grand Valley Water Management Project savings to the succeeding year would result in these carried over savings counting against the first refill right of Green Mountain Reservoir. In those years in which the 20,000 acre-feet release is made and Green Mountain Reservoir fills, the replacement of the 20,000 acre-feet release would be done under the Green Mountain Reservoir refill rights and not from the 20,000 acre-feet of carry over storage. In those years when Green Mountain Reservoir does not fill, it is unlikely that the 20,000 acre-feet release would be required and, therefore, there would be no need replacement of this 20,000 acre-feet.

CONCLUSIONS AND RECOMMENDATIONS

1. Based on the above analysis and results it was concluded that this alternative, Green Mountain Reservoir Preemptive Releases and Release of Water Carried Over in Green Mountain Reservoir, is not likely to be feasible because:

    - It appears that this alternative would not produce sufficient volume of water supply for meeting the 20,000 acre-feet target release.
    - This alternative would not produce a water supply with sufficient dependability for meeting the 20,000 acre-feet target release.
    - Water supply from this alternative would not be produced in those years when it is needed to make the 20,000 acre-feet target release.
    - Water supply from this alternative would be available too late in the season to replace the target release of 20,000 acre-feet in all but those extremely dry years when Green Mountain Reservoir did not fill. Furthermore, it appears that the required release of 20,000 acre-feet would be extremely unlikely in these very dry years.
    - Savings to the HUP from the Grand Valley Water Management Project are likely to become surplus HUP water, which is already committed for release to the Government Power Plant in compliance with the settlement in the Check case (Case No. 91CW247).

2. For all the above reasons and pending agreement by the Executive Committee, it is recommended that this alternative not be investigated further. Consequently, no further efforts have been made in the course of this investigation to analyze the impact of this alternative on: (1) existing projects' yields, (2) existing projects' operations and maintenance costs and (3) existing projects operational flexibility or reliability.

3. This investigation has focused on possible savings to the HUP from the Grand Valley Water Management Project during the descending limb of the annual hydrograph (i.e., August through October). Some consideration was given to the possibility of utilizing savings realized from the Grand Valley Water Management Project during the ascending limb of the annual hydrograph. Based on investigations by the Bureau of Reclamation (1998), expected reductions in Grand Valley Project diversions as a result of the Grand Valley Water Management Project would be much less than reductions during August through October. Furthermore, frequency and duration of the Grand Valley Project priority calls are normally less during the May-June period than during the August through October period. Therefore, no further consideration of possible HUP savings from the Grand Valley Water Management Project during the ascending limb of the annual hydrograph is recommended.

4. As indicated above, reduced diversion by the GVWUA as a result of the Grand Valley Water Management Project is a good, dependable source of supply for providing water to meet Recovery Program target flows at the head of the 15-Mile Reach during the late summer and early fall.

5. As shown in Technical Memorandum No. 3 (CWCB, October 2001b) Green Mountain Reservoir will replace the 20,000 acre-feet pre-emptive release under its refill priority, consequently, there is little reason to explore sources of replacement water from the Grand Valley Water Management Project.

REFERENCES

Colorado Water Conservation Board, October 2001a, *Technical Memorandum No. 1 Analysis of Alternative 1A, Expanded Coordination Reservoir Operations of Green Mountain Reservoir, Reduced Winter Power Operations.*

Colorado Water Conservation Board, October 2001b, *Technical Memorandum No. 3 Analysis of Alternative 1A, Expanded Coordination Reservoir Operations of Green Mountain Reservoir, Reduced Winter Power Operations.*

U.S. Bureau of Reclamation, October 1996, *Grand Valley Water Management Analysis of Potential Historical Savings 1974-1991*, Grand Junction, Colorado.

U.S. Bureau of Reclamation, September 1998, *Grand Valley Water Management Final Environmental Assessment,* Upper Colorado Region Western Colorado Area Office, Grand Junction, Colorado and Great Plains Region, Eastern Colorado Area Office, Loveland, Colorado.

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1

End of Month Storage - HUP

GREEN MOUNTAIN RESERVOIR

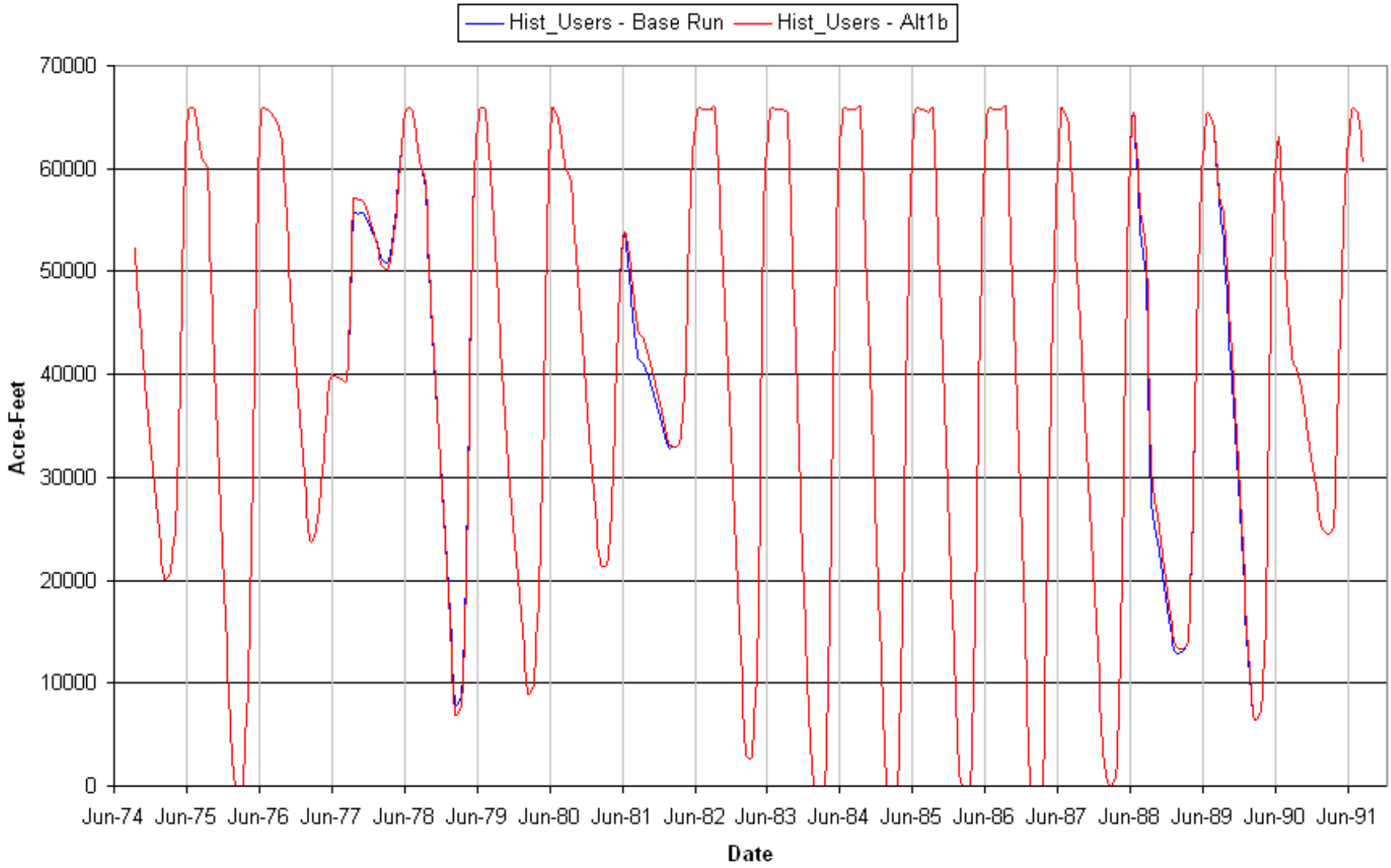

Figure 2

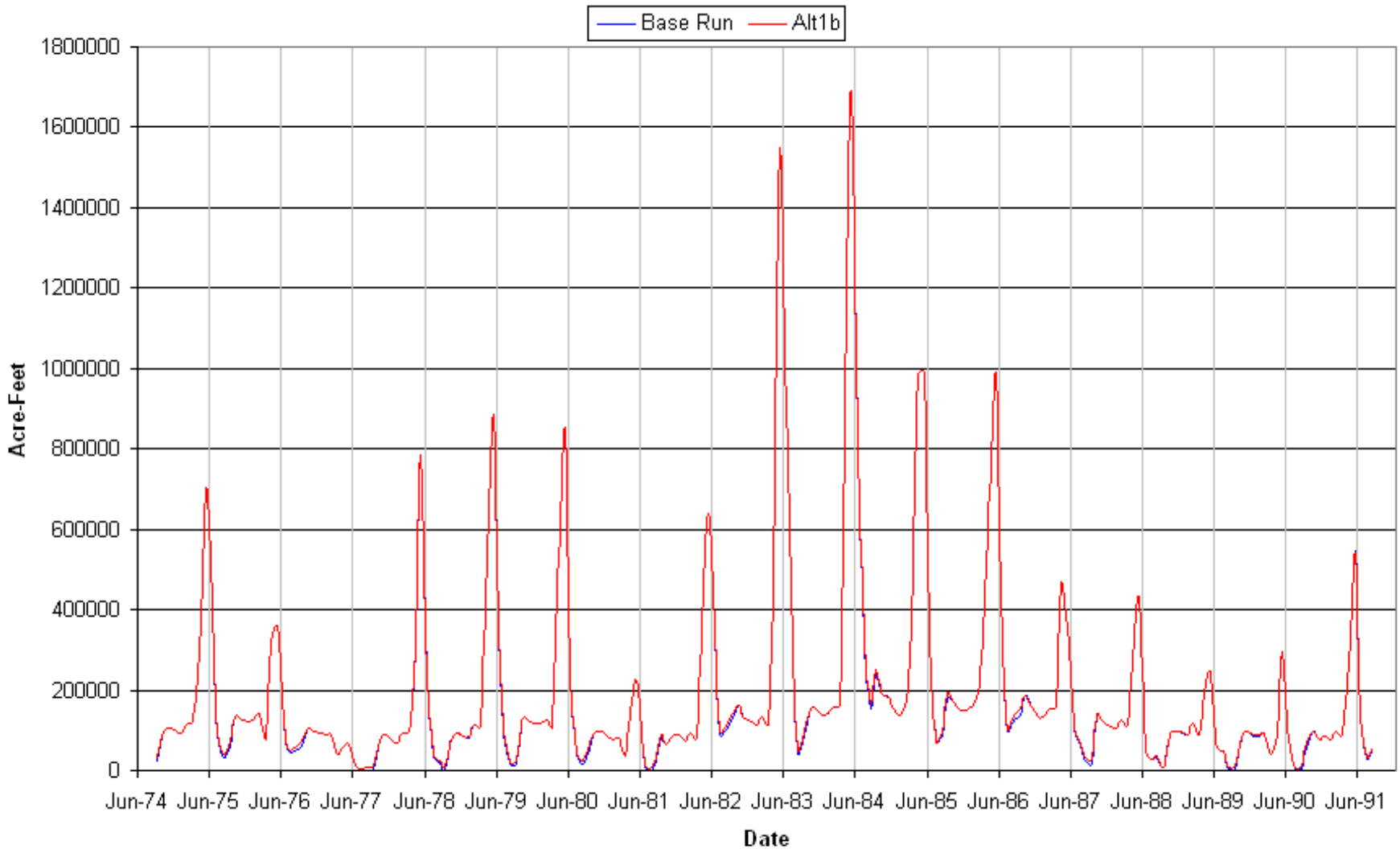
Inflow to 15-Mile Reach
Base Run
Alt1b
1800000
1600000
1400000
1200000
1000000
800000
600000
400000
200000
0
Acre-Feet
Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Figure 3
Grand Valley Project Diversions

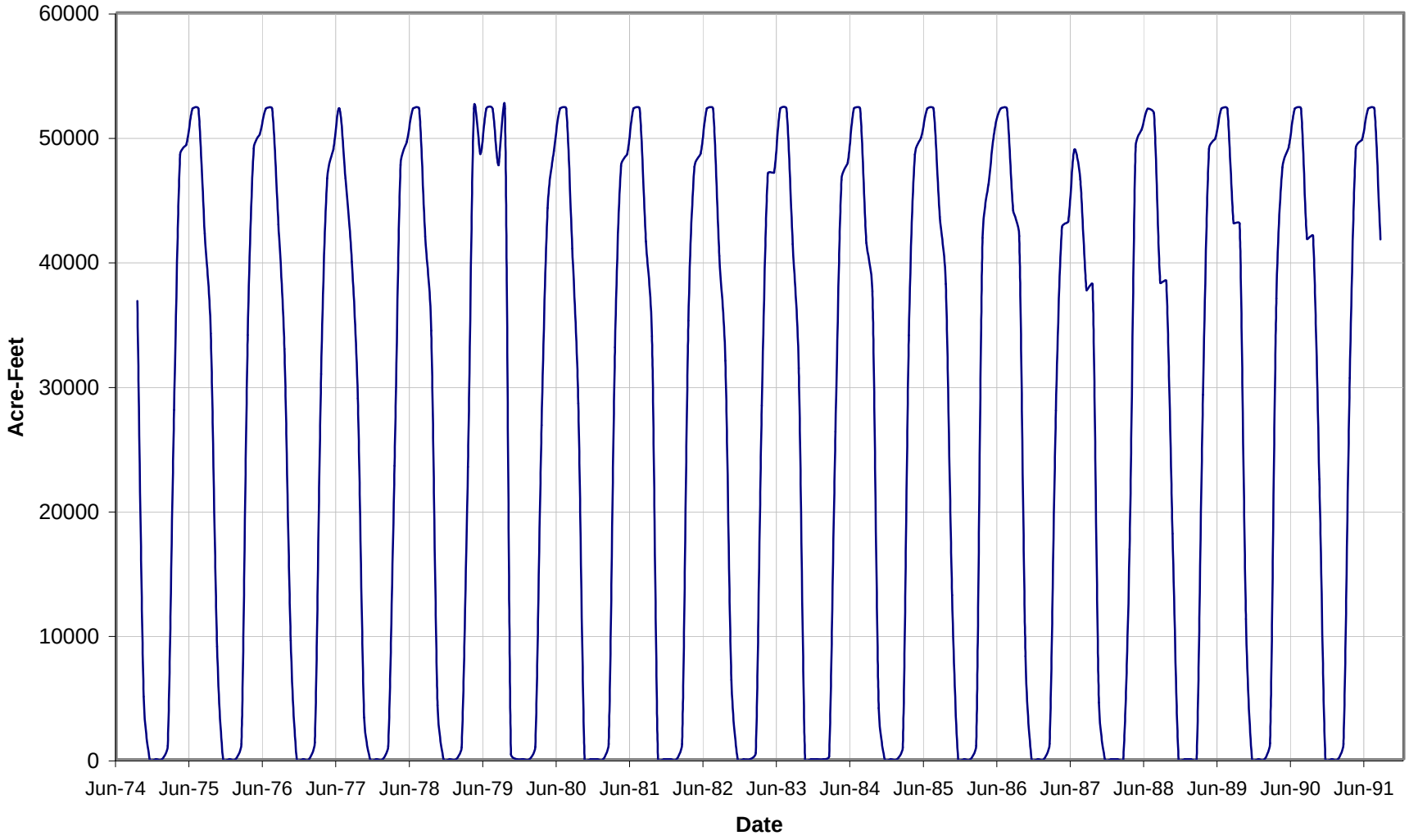

Table1
End of Month Storage: Green Mountain Reservoir

Year	Mo	Base Run EOM Content Hist_Users - Base Run	Alt1b EOM Content Hist_Users - Alt1b	Difference (Acre-Feet)
1974	OCT	52283	52283	0
1974	NOV	45527	45527	0
1974	DEC	37476	37476	0
1975	JAN	30906	30906	0
1975	FEB	24765	24765	0
1975	MAR	20133	20133	0
1975	APR	20721	20721	0
1975	MAY	29072	29072	0
1975	JUN	55536	55536	0
1975	JUL	65724	65724	0
1975	AUG	65761	65761	0
1975	SEP	61115	61115	0
1975	OCT	59916	59916	0
1975	NOV	44690	44690	0
1975	DEC	30100	30100	0
1976	JAN	15883	15883	0
1976	FEB	2299	2299	0
1976	MAR	0	0	0
1976	APR	53	53	0
1976	MAY	17673	17673	0
1976	JUN	50688	50688	0
1976	JUL	65721	65721	0
1976	AUG	65762	65762	0
1976	SEP	64994	64994	0
1976	OCT	63410	63410	0
1976	NOV	55045	55045	0
1976	DEC	46018	46018	0
1977	JAN	37739	37739	0
1977	FEB	30134	30134	0
1977	MAR	23877	23877	0
1977	APR	24582	24582	0
1977	MAY	30764	30764	0
1977	JUN	39364	39364	0
1977	JUL	39789	39789	0
1977	AUG	39600	39601	1
1977	SEP	39378	39383	5
1977	OCT	55660	56963	1303
1977	NOV	55631	56933	1302
1977	DEC	55631	56733	1102
1978	JAN	54160	54669	509
1978	FEB	52679	52597	-82
1978	MAR	51166	50492	-674
1978	APR	51035	50363	-672
1978	MAY	55289	54760	-529

Year	Mo	Base Run EOM Content Hist_Users - Base Run	Alt1b EOM Content Hist_Users - Alt1b	Difference (Acre-Feet)
1978	JUN	62453	62293	-160
1978	JUL	65721	65721	0
1978	AUG	65586	65586	0
1978	SEP	60785	60785	0
1978	OCT	58115	58756	641
1978	NOV	46708	47056	348
1978	DEC	36469	36524	55
1979	JAN	26612	26375	-237
1979	FEB	16593	16063	-530
1979	MAR	7799	6978	-821
1979	APR	8597	7790	-807
1979	MAY	28303	27747	-556
1979	JUN	54339	54170	-169
1979	JUL	65723	65723	0
1979	AUG	65761	65761	0
1979	SEP	57178	57178	0
1979	OCT	47177	47177	0
1979	NOV	38188	38188	0
1979	DEC	29022	29022	0
1980	JAN	22041	22041	0
1980	FEB	15076	15076	0
1980	MAR	8947	8947	0
1980	APR	9725	9725	0
1980	MAY	25249	25249	0
1980	JUN	53164	53164	0
1980	JUL	65721	65721	0
1980	AUG	65041	65041	0
1980	SEP	60290	60290	0
1980	OCT	58696	58696	0
1980	NOV	51663	51663	0
1980	DEC	43019	43019	0
1981	JAN	34198	34198	0
1981	FEB	26903	26903	0
1981	MAR	21555	21555	0
1981	APR	21473	21473	0
1981	MAY	30416	30416	0
1981	JUN	45546	45546	0
1981	JUL	53634	53634	0
1981	AUG	47406	50056	2650
1981	SEP	41795	44437	2642
1981	OCT	40913	43549	2636
1981	NOV	39693	41801	2108
1981	DEC	37446	39025	1579
1982	JAN	35316	36367	1051
1982	FEB	32985	33507	522
1982	MAR	32943	32987	44
1982	APR	33236	33261	25
1982	MAY	42008	42034	26

Year	Mo	Base Run EOM Content Hist_Users - Base Run	Alt1b EOM Content Hist_Users - Alt1b	Difference (Acre-Feet)
1982	JUN	58721	58722	1
1982	JUL	65724	65724	0
1982	AUG	65761	65761	0
1982	SEP	65797	65797	0
1982	OCT	65862	65862	0
1982	NOV	53179	53179	0
1982	DEC	40242	40242	0
1983	JAN	26017	26017	0
1983	FEB	13112	13112	0
1983	MAR	2915	2915	0
1983	APR	2898	2898	0
1983	MAY	18353	18353	0
1983	JUN	54912	54912	0
1983	JUL	65723	65723	0
1983	AUG	65763	65763	0
1983	SEP	65800	65800	0
1983	OCT	65329	65329	0
1983	NOV	47140	47140	0
1983	DEC	28228	28228	0
1984	JAN	9716	9716	0
1984	FEB	0	0	0
1984	MAR	0	0	0
1984	APR	0	0	0
1984	MAY	26516	26516	0
1984	JUN	52710	52710	0
1984	JUL	65723	65723	0
1984	AUG	65763	65763	0
1984	SEP	65800	65800	0
1984	OCT	65872	65872	0
1984	NOV	49313	49313	0
1984	DEC	31960	31960	0
1985	JAN	15006	15006	0
1985	FEB	0	0	0
1985	MAR	0	0	0
1985	APR	69	69	0
1985	MAY	26068	26068	0
1985	JUN	51763	51763	0
1985	JUL	65720	65720	0
1985	AUG	65762	65762	0
1985	SEP	65508	65508	0
1985	OCT	65873	65873	0
1985	NOV	49527	49527	0
1985	DEC	33031	33031	0
1986	JAN	16146	16146	0
1986	FEB	1089	1089	0
1986	MAR	0	0	0
1986	APR	70	70	0
1986	MAY	26069	26069	0

Year	Mo	Base Run EOM Content Hist_Users - Base Run	Alt1b EOM Content Hist_Users - Alt1b	Difference (Acre-Feet)
1986	JUN	51763	51763	0
1986	JUL	65723	65723	0
1986	AUG	65761	65763	2
1986	SEP	65799	65798	-1
1986	OCT	65873	65873	0
1986	NOV	49523	49523	0
1986	DEC	32449	32449	0
1987	JAN	15729	15729	0
1987	FEB	0	0	0
1987	MAR	0	0	0
1987	APR	69	69	0
1987	MAY	24917	24917	0
1987	JUN	50215	50215	0
1987	JUL	65721	65721	0
1987	AUG	64982	64982	0
1987	SEP	56059	56059	0
1987	OCT	47560	47560	0
1987	NOV	35725	35725	0
1987	DEC	24369	24369	0
1988	JAN	13418	13418	0
1988	FEB	3288	3288	0
1988	MAR	0	0	0
1988	APR	749	749	0
1988	MAY	20886	20886	0
1988	JUN	50265	50265	0
1988	JUL	65434	65435	1
1988	AUG	53973	55909	1936
1988	SEP	49006	51928	2922
1988	OCT	27564	30595	3031
1988	NOV	23930	26352	2422
1988	DEC	19447	21262	1815
1989	JAN	15442	16648	1206
1989	FEB	13033	13632	599
1989	MAR	13012	13332	320
1989	APR	13911	14036	125
1989	MAY	28169	28260	91
1989	JUN	53639	53668	29
1989	JUL	65363	65363	0
1989	AUG	64621	64620	-1
1989	SEP	57357	57357	0
1989	OCT	52415	55667	3252
1989	NOV	41767	44366	2599
1989	DEC	32028	33977	1949
1990	JAN	21676	22975	1299
1990	FEB	12506	13153	647
1990	MAR	6423	6420	-3
1990	APR	7351	7348	-3
1990	MAY	16612	16609	-3

Year	Mo	Base Run EOM Content Hist_Users - Base Run	Alt1b EOM Content Hist_Users - Alt1b	Difference (Acre-Feet)
1990	JUN	53771	53770	-1
1990	JUL	63137	63137	0
1990	AUG	50489	50489	0
1990	SEP	41660	41659	-1
1990	OCT	40679	40679	0
1990	NOV	37670	37670	0
1990	DEC	32913	32913	0
1991	JAN	29253	29253	0
1991	FEB	25418	25418	0
1991	MAR	24537	24536	-1
1991	APR	25059	25059	0
1991	MAY	39092	39092	0
1991	JUN	57227	57227	0
1991	JUL	65721	65721	0
1991	AUG	65372	65372	0
1991	SEP	60533	60533	0

Table 2
Inflow to 15-Mile Reach

Year	Month	Base Run River Inflow Base Run	Alt1b River Inflow Alt1b	INCREASES August	INCREASES September	INCREASES October	% INCREASES August	% INCREASES September	% INCREASES October
1974	OCT	24001	32909			8908			37%
1974	NOV	98948	98948						
1974	DEC	105714	105714						
1975	JAN	97701	97701						
1975	FEB	91272	91272						
1975	MAR	115949	115949						
1975	APR	120466	120466						
1975	MAY	300421	300421						
1975	JUN	701582	701582						
1975	JUL	540374	540374						
1975	AUG	88829	94382	5553			6%		
1975	SEP	32311	39721		7410			23%	
1975	OCT	61313	71482			10169			17%
1975	NOV	134778	134778						
1975	DEC	125121	125121						
1976	JAN	122077	122077						
1976	FEB	124685	124685						
1976	MAR	139784	139784						
1976	APR	85186	85186						
1976	MAY	317839	317839						
1976	JUN	357027	357027						
1976	JUL	114918	114918						
1976	AUG	46610	52536	5926			13%		
1976	SEP	48724	56984		8260			17%	
1976	OCT	60080	71415			11335			19%
1976	NOV	105185	105185						
1976	DEC	98025	98025						
1977	JAN	93318	93318						
1977	FEB	89222	89222						
1977	MAR	89292	89292						
1977	APR	39212	39212						
1977	MAY	62300	62300						
1977	JUN	64157	64157						
1977	JUL	13640	13640						
1977	AUG	182	2144	1962			1078%		
1977	SEP	925	6210		5285			571%	
1977	OCT	3298	13076			9778			296%
1977	NOV	72629	72769						
1977	DEC	88713	89013						
1978	JAN	78014	78679						
1978	FEB	67656	68303						
1978	MAR	91937	92569						
1978	APR	97599	97630						
1978	MAY	328853	330153						
1978	JUN	785809	785827						
1978	JUL	252992	251711						
1978	AUG	33190	38602	5412			16%		

Year	Month	Base Run River Inflow Base Run	Alt1b River Inflow Alt1b	INCREASES August	INCREASES September	INCREASES October	% INCREASES August	% INCREASES September	% INCREASES October
1978	SEP	18357	24699		6342			35%	
1978	OCT	956	8072			7116			744%
1978	NOV	77672	78005						
1978	DEC	94139	94458						
1979	JAN	84157	84470						
1979	FEB	82892	83200						
1979	MAR	112590	112895						
1979	APR	107599	107604						
1979	MAY	560848	560840						
1979	JUN	880644	880656						
1979	JUL	371925	371928						
1979	AUG	70478	75518	5040			7%		
1979	SEP	12048	15987		3939			33%	
1979	OCT	17763	25560			7797			44%
1979	NOV	129494	129875						
1979	DEC	120039	120269						
1980	JAN	115609	115778						
1980	FEB	119156	119278						
1980	MAR	126894	126986						
1980	APR	110521	110591						
1980	MAY	531592	531642						
1980	JUN	847946	847946						
1980	JUL	248995	249034						
1980	AUG	39924	46201	6277			16%		
1980	SEP	15670	22997		7327			47%	
1980	OCT	53179	63232			10053			19%
1980	NOV	93831	93833						
1980	DEC	98453	98454						
1981	JAN	86789	86790						
1981	FEB	76707	76708						
1981	MAR	80092	80093						
1981	APR	35285	35285						
1981	MAY	135538	135538						
1981	JUN	224447	224447						
1981	JUL	40817	40817						
1981	AUG	199	2999	2800			1407%		
1981	SEP	12562	20706		8144			65%	
1981	OCT	78960	89907			10947			14%
1981	NOV	65188	65856						
1981	DEC	85044	85672						
1982	JAN	88308	88911						
1982	FEB	72839	73425						
1982	MAR	93856	94375						
1982	APR	82800	82828						
1982	MAY	342481	342504						
1982	JUN	640511	640529						
1982	JUL	334329	334404						
1982	AUG	90842	97332	6490			7%		
1982	SEP	101103	110517		9414			9%	
1982	OCT	129488	142407			12919			10%
1982	NOV	160814	160814						

Year	Month	Base Run River Inflow Base Run	Alt1b River Inflow Alt1b	INCREASES August	INCREASES September	INCREASES October	% INCREASES August	% INCREASES September	% INCREASES October
1982	DEC	131406	131406						
1983	JAN	120992	120992						
1983	FEB	111387	111387						
1983	MAR	132680	132680						
1983	APR	116711	116711						
1983	MAY	459975	459975						
1983	JUN	1542286	1542286						
1983	JUL	894869	894866						
1983	AUG	296391	296391	0			0%		
1983	SEP	44062	53147		9085			21%	
1983	OCT	83422	95889			12467			15%
1983	NOV	153132	153132						
1983	DEC	153965	153965						
1984	JAN	136805	136805						
1984	FEB	142568	142568						
1984	MAR	156756	156756						
1984	APR	162611	162611						
1984	MAY	1178412	1178412						
1984	JUN	1688357	1688357						
1984	JUL	852131	852131						
1984	AUG	308518	316447	7929			3%		
1984	SEP	155248	164539		9291			6%	
1984	OCT	240661	250897			10236			4%
1984	NOV	191958	191958						
1984	DEC	182258	182258						
1985	JAN	152305	152305						
1985	FEB	137744	137744						
1985	MAR	172384	172384						
1985	APR	352222	352222						
1985	MAY	982858	982858						
1985	JUN	991996	991996						
1985	JUL	354978	354978						
1985	AUG	71460	71460	0			0%		
1985	SEP	85969	94921		8952			10%	
1985	OCT	175957	188242			12285			7%
1985	NOV	171726	171726						
1985	DEC	151327	151327						
1986	JAN	149813	149813						
1986	FEB	158955	158955						
1986	MAR	192920	192920						
1986	APR	322685	322685						
1986	MAY	691746	691746						
1986	JUN	986561	986560						
1986	JUL	434937	434937						
1986	AUG	100226	106640	6414			6%		
1986	SEP	125748	136841		11093			9%	
1986	OCT	138425	153454			15029			11%
1986	NOV	186309	186370						
1986	DEC	158664	158690						
1987	JAN	134684	134700						
1987	FEB	132818	132831						

Year	Month	Base Run River Inflow Base Run	Alt1b River Inflow Alt1b	INCREASES August	INCREASES September	INCREASES October	% INCREASES August	% INCREASES September	% INCREASES October
1987	MAR	155520	155529						
1987	APR	157317	157324						
1987	MAY	462868	462874						
1987	JUN	346264	348610						
1987	JUL	107493	107458						
1987	AUG	71085	76246	5161			7%		
1987	SEP	26019	34382		8363			32%	
1987	OCT	17142	28523			11381			66%
1987	NOV	135390	135642						
1987	DEC	120608	120860						
1988	JAN	109783	110035						
1988	FEB	103702	103954						
1988	MAR	126940	127192						
1988	APR	112595	112595						
1988	MAY	262936	262937						
1988	JUN	427901	427902						
1988	JUL	47066	47066						
1988	AUG	26947	29567	2620			10%		
1988	SEP	30974	35811		4837			16%	
1988	OCT	8785	8785			0			0%
1988	NOV	87904	88605						
1988	DEC	96678	97353						
1989	JAN	94728	95383						
1989	FEB	88880	89524						
1989	MAR	118507	118814						
1989	APR	91808	91888						
1989	MAY	222745	222760						
1989	JUN	240922	240937						
1989	JUL	58235	58248						
1989	AUG	46833	49806	2973			6%		
1989	SEP	4118	10029		5911			144%	
1989	OCT	5401	10192			4791			89%
1989	NOV	79034	79918						
1989	DEC	97040	97921						
1990	JAN	86143	87024						
1990	FEB	86890	87770						
1990	MAR	93808	94688						
1990	APR	40769	40769						
1990	MAY	89488	89488						
1990	JUN	295955	295981						
1990	JUL	79103	79103						
1990	AUG	4243	9454	5211			123%		
1990	SEP	3092	11362		8270			267%	
1990	OCT	58197	69603			11406			20%
1990	NOV	97623	97484						
1990	DEC	76518	76378						
1991	JAN	83413	83273						
1991	FEB	77496	77356						
1991	MAR	98880	98740						
1991	APR	89329	90500						
1991	MAY	270896	270897						

Year	Month	Base Run River Inflow Base Run	Alt1b River Inflow Alt1b	INCREASES August	INCREASES September	INCREASES October	% INCREASES August	% INCREASES September	% INCREASES October
1991	JUN	544755	543585						
1991	JUL	132956	132956						
1991	AUG	30875	36996	6121			20%		
1991	SEP	49254	57095		7841			16%	

Totals	August	75889					
	September		129764				
	October			166617			
Average	August	4464			6%		
	September		7633			17%	
	October			9801			14%

Table 3
Analysis of Call Records for Study Period

Year	HUP Savings (AF)	Date On	Date Off	Calling Structure	Dec. Amnt.(cfs)	Comments
1991	0					
		9/2/1991	9/13/1991	Grand Valley Canal	119.47	
		9/30/1991	10/25/1991	Grand Valley Canal	119.47	The Grand Valley Proj. rights are senior to this call and, consequently, no savings would be expect
1990	0					
		7/30/1990	10/22/1990	Grand Valley Canal	119.47	This absence of HUP savings in this year is probably explained
		8/9/1990	10/9/1990	GV Proj.	730	by paragraph 3a1 of the Check Settlement.
1989	3252					
		7/19/1989	10/31/1989	Grand Valley Canal	119.47	There was a GV Proj. call and there were HUP savings.
		8/28/1989	10/31/1989	Grand Valley Project	730	
1988	3031	7/19/1988	10/21/1988	GV Proj. (Power)	400	There was a GV Proj. call and there were HUP savings.
		8/16/1988	9/13/2008	GV Proj.	730	
1987	0					
		8/20/1987	8/22/1987	Grand Valley Canal (Cameo)		
		9/11/1987	10/1/2001	Grand Valley Canal (Cameo)		119.47 cfs GVIC was still on.The Gr. Valley Project (300cfs) was still on.
			10/23/1987			119.47 cfs GVIC off; Gr.Valley Proj. (300cfs) off.
						The lack of HUP savings may result from Sec. 3.a.(1) in the Check Settlement.
1986	0			No Cameo calls, only Shoshone		No GV Proj. call and no HUP savings in this year.
1985	0			No Cameo calls, only Shoshone		No GV Proj. call and no HUP savings in this year.
1984	0			Call records unavailable		
1983	0			Call records unavailable		
1982	0			Call records unavailable		
1981	2650			Call records unavailable		
1980	0	8/1/1980	10/31/1980	Cameo		The lack of HUP savings may result from Section 3.a.(1) in the Check Settlement
1979	0	9/1/1979	10/31/1979	Cameo		The lack of HUP savings may result from Section 3.a.(1) in the Check Settlement
1978	641	8/1/1978	10/31/1978	Cameo		There was a Cameo call and there were HUP savings.
1977	1303	7/1/1977	10/31/1977	Cameo		There was a Cameo call and there were HUP savings.
1976	0	7/1/1976	10/31/1976	Cameo		The lack of HUP savings may result from Section 3.a.(1) in the Check Settlement
1975	0			No Cameo call		No Cameo call, no HUP savings.

Table 4
Historic Grand Valley Project Diversions

Date	Diversions (Acre-Feet)	Diversions (cfs)
10/1/1974	36806	599
11/1/1974	5022	84
12/1/1974	0	0
1/1/1975	0	0
2/1/1975	0	0
3/1/1975	1071	17
4/1/1975	28050	471
5/1/1975	48549	790
6/1/1975	49377	830
7/1/1975	52265	850
8/1/1975	52265	850
9/1/1975	42240	710
10/1/1975	34209	556
11/1/1975	9040	152
12/1/1975	0	0
1/1/1976	0	0
2/1/1976	0	0
3/1/1976	1230	20
4/1/1976	34071	573
5/1/1976	49058	798
6/1/1976	50222	844
7/1/1976	52265	850
8/1/1976	52265	850
9/1/1976	42948	722
10/1/1976	32967	536
11/1/1976	9542	160
12/1/1976	0	0
1/1/1977	0	0
2/1/1977	0	0
3/1/1977	1357	22
4/1/1977	30945	520
5/1/1977	46663	759
6/1/1977	49022	824
7/1/1977	52265	850
8/1/1977	46651	759
9/1/1977	39966	672
10/1/1977	28970	471
11/1/1977	3348	56
12/1/1977	0	0
1/1/1978	0	0
2/1/1978	0	0
3/1/1978	1061	17
4/1/1978	23567	396
5/1/1978	47726	776
6/1/1978	49610	834
7/1/1978	52265	850

Date	Diversions (Acre-Feet)	Diversions (cfs)
8/1/1978	52265	850
9/1/1978	41984	706
10/1/1978	34439	560
11/1/1978	4345	73
12/1/1978	0	0
1/1/1979	0	0
2/1/1979	0	0
3/1/1979	950	15
4/1/1979	23488	395
5/1/1979	52265	850
6/1/1979	48611	817
7/1/1979	52265	850
8/1/1979	52265	850
9/1/1979	47701	802
10/1/1979	52265	850
11/1/1979	393	7
12/1/1979	0	0
1/1/1980	0	0
2/1/1980	0	0
3/1/1980	992	16
4/1/1980	26842	451
5/1/1980	44274	720
6/1/1980	48864	821
7/1/1980	52265	850
8/1/1980	52265	850
9/1/1980	41008	689
10/1/1980	28588	465
11/1/1980	0	0
12/1/1980	0	0
1/1/1981	0	0
2/1/1981	0	0
3/1/1981	1230	20
4/1/1981	33089	556
5/1/1981	47654	775
6/1/1981	48639	817
7/1/1981	52265	850
8/1/1981	52265	850
9/1/1981	41592	699
10/1/1981	33961	552
11/1/1981	0	0
12/1/1981	0	0
1/1/1982	0	0
2/1/1982	0	0
3/1/1982	1230	20
4/1/1982	35220	592
5/1/1982	47579	774
6/1/1982	48665	818
7/1/1982	52265	850
8/1/1982	52265	850
9/1/1982	40438	680

Date	Diversions (Acre-Feet)	Diversions (cfs)
10/1/1982	32005	521
11/1/1982	6378	107
12/1/1982	0	0
1/1/1983	0	0
2/1/1983	0	0
3/1/1983	501	8
4/1/1983	28404	477
5/1/1983	47028	765
6/1/1983	47128	792
7/1/1983	52265	850
8/1/1983	52265	850
9/1/1983	41372	695
10/1/1983	31390	511
11/1/1983	0	0
12/1/1983	0	0
1/1/1984	0	0
2/1/1984	0	0
3/1/1984	239	4
4/1/1984	26316	442
5/1/1984	46527	757
6/1/1984	47915	805
7/1/1984	52265	850
8/1/1984	52265	850
9/1/1984	41452	697
10/1/1984	37584	611
11/1/1984	4110	69
12/1/1984	0	0
1/1/1985	0	0
2/1/1985	0	0
3/1/1985	942	15
4/1/1985	34061	572
5/1/1985	48571	790
6/1/1985	49935	839
7/1/1985	52265	850
8/1/1985	52265	850
9/1/1985	43572	732
10/1/1985	38176	621
11/1/1985	13183	222
12/1/1985	0	0
1/1/1986	0	0
2/1/1986	0	0
3/1/1986	1089	18
4/1/1986	41879	704
5/1/1986	46167	751
6/1/1986	50545	849
7/1/1986	52265	850
8/1/1986	52265	850
9/1/1986	44069	741
10/1/1986	42034	684
11/1/1986	8265	139

Date	Diversions (Acre-Feet)	Diversions (cfs)
12/1/1986	0	0
1/1/1987	0	0
2/1/1987	0	0
3/1/1987	1242	20
4/1/1987	28002	471
5/1/1987	42729	695
6/1/1987	43183	726
7/1/1987	48945	796
8/1/1987	46568	757
9/1/1987	37679	633
10/1/1987	38125	620
11/1/1987	4543	76
12/1/1987	0	0
1/1/1988	0	0
2/1/1988	0	0
3/1/1988	0	0
4/1/1988	16867	283
5/1/1988	49174	800
6/1/1988	50579	850
7/1/1988	52265	850
8/1/1988	51881	844
9/1/1988	38273	643
10/1/1988	38414	625
11/1/1988	18110	304
12/1/1988	0	0
1/1/1989	0	0
2/1/1989	0	0
3/1/1989	0	0
4/1/1989	29271	492
5/1/1989	49022	797
6/1/1989	49851	838
7/1/1989	52265	850
8/1/1989	52265	850
9/1/1989	43049	723
10/1/1989	43025	700
11/1/1989	11252	189
12/1/1989	0	0
1/1/1990	0	0
2/1/1990	0	0
3/1/1990	1278	21
4/1/1990	37024	622
5/1/1990	47549	773
6/1/1990	49148	826
7/1/1990	52265	850
8/1/1990	52265	850
9/1/1990	41797	702
10/1/1990	42024	683
11/1/1990	22493	378
12/1/1990	0	0
1/1/1991	0	0

Date	Diversions (Acre-Feet)	Diversions (cfs)
2/1/1991	0	0
3/1/1991	1230	20
4/1/1991	30615	514
5/1/1991	49072	798
6/1/1991	49767	836
7/1/1991	52265	850
8/1/1991	52265	850
9/1/1991	41751	702

TECHNICAL MEMORANDUM NO. 3:
ANALYSIS OF ALTERNATIVE 1A,
EXPANDED COORDINATED RESERVOIR OPERATIONS OF GREEN MOUNTAIN RESERVOIR, CONJUNCTIVE POOL OPERATIONS

PRODUCED FOR:

Colorado Water Conservation Board

PRODUCED BY:

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TECHNICAL MEMORANDUM NO. 3:
ANALYSIS OF ALTERNATIVE 1A,
EXPANDED COORDINATED RESERVOIR OPERATIONS OF GREEN MOUNTAIN RESERVOIR, CONJUNCTIVE POOL OPERATIONS

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Figure 1. Green Mountain Reservoir EOM Content

Figure 2. Green Mountain Reservoir EOM Content – HUP Pool

Figure 3. Green Mountain Reservoir EOM Content – CBT Pool

Figure 4. Dillon Reservoir EOM Content

Figure 5. CBT Granby Reservoir EOM Content

Figure 6. Shoshone Power Plant Shortages

EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 3 is to present the results from investigating the Green Mountain Reservoir Conjunctive Pool Operations Alternative. The Green Mountain Reservoir Conjunctive Pool Operations Alternative has the following components:

- A release of 20,000 acre-feet is made from Green Mountain Reservoir during a 10-day period surrounding the spring peak hydrograph in late May or early June. Under the concept of this alternative as specified in the Phase 1 report (CWCB, September 2000) this release would be made from either the historic users pool (HUP) or the CBT pool depending on which pool had greater water availability. As this alternative has developed in the course of analysis for this Technical Memorandum, however, the 20,000 acre-feet would be released consistently from the HUP because the 20,000 acre-feet target release is not required in extremely dry years when greater physical availability of water would be expected in the CBT pool.
- This 20,000 acre-feet is replaced in Green Mountain Reservoir by diversions to storage in the HUP under the Green Mountain Reservoir 1935 refill right for 6,316 acre-feet and the 1985 refill right for 154,645 acre-feet.

This objective of this investigation is to determine the overall feasibility of this alternative and to analyze the impact of this alternative on: (1) existing projects' yields, (2) existing projects' operations and maintenance costs and (3) existing projects' operational flexibility or reliability. Overall feasibility and the effects on other existing projects from this proposed change in Green Mountain Reservoir operations was investigated using StateMod and the C1 data set for the 1975-91 study period.

Results of this investigation include:

1. **Simplification of Conjunctive Pool Operation Alternative.** As reported herein, there was sufficient supply in the HUP in all years in which the 20,000 acre-feet release was required to make the release from the HUP. It was not necessary to make the release from the CBT pool in any year during the study period because the 20,000 acre-feet release was not required to be made in any extremely dry year when insufficient storage to make the 20,000 acre-feet release could be expected in the HUP. As a result, the Conjunctive Operations Alternative became the following:

    - The 20,000 acre-feet preemptive release was made from the HUP in late May and/or early June in those six years in which the release was required during the 17-year study period.
    - The 20,000 acre-feet was replaced in Green Mountain Reservoir after the reservoir had attained a "paper-fill" in late June or early July under its first fill water rights. This replacement was accomplished by diverting from the Blue River to storage in Green Mountain Reservoir under the refill rights for Green Mountain Reservoir.

2. **Shoshone power production**. Shoshone power production was not affected by this alternative.

3. **Green Mountain power production.** Revenue from Green Mountain Reservoir power production was increased by a total of $171,500 over the 17-year study period.

4. **Green Mountain Reservoir storage.** Filling Green Mountain Reservoir was not affected by the new operating policy. The reservoir filled in every year it historically filled and in those years when it did not fill historically (1977 and 1981), the Conjunctive Pool Operations Policy Alternative 1a operating policy resulted in the same storage as occurred without the conjunctive pool operating policy.

5. **Dillon and Williams Fork Reservoirs.** Total storage in Dillon and Williams Fork Reservoirs was unaffected by implementation of the Conjunctive Pool Operations Alternative operating policy for the study period.

6. **Granby Reservoir**. Storage in Granby Reservoir was unaffected by imposition of the Conjunctive Pool Operations Alternative operating policy as compared to storage under the C1 Scenario for the study period.

7. **Orchard Mesa Power Plant.** The Conjunctive Pool Operations Alternative for Green Mountain Reservoir did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternative 1a operating policy.

8. **Check Case settlement.** Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternative 1a operations policy will make releases of the 20,000 acre-feet. Under the Conjunctive Pool Operations Alternative, there should be no decreased releases from Green Mountain Reservoir under this alternative unless the reservoir is unable to replace the preemptive 20,000 acre-feet release by diverting to storage under its refill rights. Analysis for the study period (1975-91) of the Conjunctive Pool Operations Alternative indicated that Green Mountain Reservoir would fill in every year that it had filled under the C1 data set. Therefore, implementation of the Conjunctive Pool Operations Alternative operations policy should not affect the Check Case settlement.

9. **Physical feasibility of Green Mountain Reservoir releases.** Results indicate that releases for the recovery program would be made in only six years (1975, 1978, 1979, 1980, 1985 and 1986) during the 1975-91 study period. In all other years, the spring peak flows at the head of the 15-Mile Reach were less than 12,900 cfs or greater than 26,600 cfs and a release would not be required. In these six years in which the 20,000 acre-feet release was required, it was possible to make the release at a rate of 1,000 cfs for a period of 10 days from Green Mountain Reservoir.

10. **Channel capacity constraints.** Restrictions on Blue River channel capacity or Colorado River channel capacity downstream from Green Mountain Reservoir would not have

limited the 1,000 cfs release in any of the six years in which the release was required for the 1975-91 study period.

Conclusions and Recommendations include:

1. The Conjunctive Operation Alternative appears feasible and further consideration of this alternative is warranted.

2. Feasibility of the Conjunctive Operation Alternative is dependent on Green Mountain Reservoir's ability to consistently replace the preemptive 20,000 acre-feet release by storing water under Green Mountain Reservoir's refill water rights. Based on the analysis described herein for the 1975-91 study period, Green Mountain Reservoir was able to consistently replace the 20,000 acre-feet preemptive release by storing under its refill rights. This feasibility of replacing the 20,000 acre-feet preemptive release should, however, be investigated under projected future conditions with an additional 60,000 to 120,000 acre-feet of depletions and with CROP in operation.

INTRODUCTION AND PURPOSE

Several options for revising Green Mountain Reservoir operations to produce flows contributing to the average annual 20,000 acre-feet target were developed in Phase 1 of this investigation. These alternatives include:

- Reduced winter power operations (see section 3.2.1.1 in *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River*.
- Green Mountain Reservoir conjunctive pool operations (section 3.2.1.2 in the Phase 1 Study).
- Green Mountain Reservoir preemptive releases (section 3.2.1.3 in the Phase 1 Study).
- Release of water carried over in Green Mountain Reservoir (section 3.2.1.4 in the Phase 1 study).

Analysis of the reduced winter power operations alternative was reported in Technical Memorandum No. 1 and analysis of Green Mountain Reservoir preemptive releases and release of water carried over was the subject of Technical Memorandum No. 2.

The purpose of this Technical Memorandum is to present: (1) the methodology used to analyze Alternative 1a, Green Mountain Reservoir Conjunctive Pool Operations and (2) the results of this analysis. After review by the CWCB and the Executive Committee, necessary changes will be made in the analysis methodology in response to comments and suggestions from the CWCB and the Executive Committee and the Green Mountain Reservoir Conjunctive Pool Operations Alternative will be reanalyzed accordingly.

The Green Mountain Reservoir Conjunctive Pool Operations Alternative, as presented in Phase 1, was developed to take advantage of the different water availability in the HUP and the CBT pools (CWCB, September 2000). Historically, demand for releases from the CBT pool has generally been lower in dry years and greater in average years. The reverse has generally been true for the HUP where demand for releases has been historically greater in dry years than in average years. Consequently, the conjunctive pool operation alternative was developed to determine the feasibility of releasing the 20,000 acre-feet target release from the pool which had the greater water availability.

The Green Mountain Reservoir Conjunctive Pool Operations Alternative has the following components:

- Release of 20,000 acre-feet is made from Green Mountain Reservoir during a 10-day period surrounding the spring peak hydrograph in late May or early June. Under the concept of this alternative as specified in the Phase 1 report, this release would be made from either the HUP or the CBT pool depending on which pool had greater water availability (CWCB, September 2000). As this alternative has developed in the course of analysis for this Technical Memorandum, however, the 20,000 acre-feet would be released consistently from the HUP because the 20,000 acre-feet target release is not required in

extremely dry years when greater physical availability of water would be expected in the CBT pool.

- This 20,000 acre-feet is replaced in Green Mountain Reservoir by diversions to storage in the HUP under the Green Mountain Reservoir 1935 refill right for 6316 acre-feet and the proposed 1985 refill right for 154,645 acre-feet (See Table 1).

Specific concerns to be addressed in this engineering analysis of the Green Mountain Reservoir Conjunctive Pool Operations Alternatives include:

1. The frequency with which the 20,000 acre-feet per year target can be met in those years when the expected peak spring flow at the head of the 15-Mile Reach is between 12,900 cfs and 26,600 cfs using this alternative (Green Mountain Reservoir Conjunctive Pool Operations) as the source of supply for the 20,000 acre-feet.

2. The frequency with which the 20,000 acre-feet release can be replaced in the Green Mountain Reservoir HUP. Filling Green Mountain Reservoir storage vacated by the 20,000 acre-feet release would be done under the Green Mountain Reservoir refill rights (see Table 1).

3. The effect on operation and yield of other projects as a result of this alternative. Analysis must look specifically at whether this alternative will increase Denver Water's risk of releasing water from Dillon Reservoir to assure a Green Mountain Reservoir fill under the Blue River Decree and subsequent agreements among Denver Water, Reclamation, NCWCD and the Colorado River Water Conservancy District.

4. The effect on hydropower generation at Green Mountain Reservoir, Shoshone Power Plant, and the Orchard Mesa Power Plant.

5. The effect on flooding in downstream reaches of the Blue and Colorado Rivers from releasing this additional 1,000 cfs on the peak of the spring runoff hydrograph.

6. The physical feasibility of releasing the 20,000 acre-feet at a rate of 1,000 cfs over a 10-day period from Green Mountain Reservoir.

Other legal/institutional concerns exist about this alternative; these concerns are not addressed in this Technical Memorandum, but will be addressed by our legal team and discussed in the Phase 2 report or possibly in a separate legal memorandum. These legal/institutional issues include the ongoing controversy regarding the Bureau of Reclamation's authority to release water from Green Mountain Reservoir for piscatorial purposes. The Federal Government asserts that Senate Document No. 80 and the Green Mountain Reservoir water rights give the Bureau of Reclamation the necessary authority to release water for endangered fish. The State of Colorado and various water users submit that releases for piscatorial purposes are not allowed under the Green Mountain Reservoir water rights decree. Changes to the Green Mountain Reservoir water rights decree may be necessary.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following procedures and assumptions were employed in the analysis of: Green Mountain Reservoir Conjunctive Pool Operations Alternative:

1. The StateMod surface water model with the C1 dataset were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).* These components of RIPRAP flows include:

   - 5,000 acre-feet per year from Ruedi Reservoir,
   - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
   - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
   - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
   - 6,000 acre-feet per year from Wolford Mountain Reservoir,
   - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project was included but not modeled.

3. As further discussed below, StateMod and the C1 dataset were modified to require necessary storage in the HUP on April 1 (the assumed start of the Green Mountain Reservoir fill season) to be transferred to the CBT pool in order to fill the CBT pool first. This modification was completed in order to make StateMod and the C1 data set more consistent with the actual operations for Green Mountain Reservoir. This modification is only important for analysis of the Green Mountain Reservoir Conjunctive Pool Operations Alternative. Consequently, there are no present plans to make this revision for Technical Memoranda Nos. 1 and 2.

4. Flow Targets: Releases of 20,000 acre-feet over a 10-day period were made from Green Mountain Reservoir when the expected spring peak flow at the head of the 15-Mile Reach was between 12,900 cfs and less than 26,600 cfs. If the 20,000 cfs was not released to enhance the spring peak flows, it was booked over to storage in the HUP and no attempt was made to release this water in the late summer or early fall for purposes of augmenting low flows.

5. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee determine after their review and the consultant makes necessary changes that the methodology and calculations employed in the analysis of this alternative are acceptable, the necessary sensitivity analysis will be completed.

   CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

6. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

7. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

8. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,
   - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
   - A reservoir fill according to the criteria of the Blue River Decree.

   The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

   Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

   Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations

of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

9. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
   - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
   - Sufficient HUP Surplus water exists to make the release.

   Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. Releases of HUP Surplus water under the Municipal Recreational Agreement are not explicitly modeled by StateMod and the C1 data set and there is no demand specified at a node for the Municipal Recreational water.

USE OF STATEMOD

Green Mountain Reservoir is modeled in the C1 scenario using five separate pools including the Historic Users Pool (HUP), Colorado Big Thompson Pool (CBT), the Contract Pool, Silt Project Pool and the Inactive Pool. Details of the method of modeling Green Mountain Reservoir in the C1 scenario can be found in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).*

The C1 scenario was modified by adding full reservoir targets in Green Mountain Reservoir for the months of September and October. This prevented surplus water hydropower releases until after the irrigation season. In addition, monthly demands of 20,000 acre-feet were added to the head of the 15-Mile Reach (Diversion ID #952001) corresponding to the projected 20,000 acre-feet releases to enhance the spring runoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1985 and 1986. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water in the stream when available. In addition, a new operating rule was created to transfer any HUP water into the CBT pool on April 1. This modified C1 scenario was used as the baseline scenario for evaluating alternatives.

For the Coordinated Pool Operations alternative, the baseline scenario was modified in only one way. The operating rule which allowed releases from the HUP account to the 15-Mile Reach fish requirement (Diversion ID# 952001) was turned on. These permitted a pre-emptive release of 20,000 acre-feet of water from the HUP account in those years when it would be required. The intent was to first identify those years where the HUP pool was depleted by the pre-emptive release and compare the contents of the CBT pool to see if this water could be used for HUP replacements. However, as discussed elsewhere in the memorandum, each pre-emptive release did not prevent Green Mountain Reservoir from filling under its decrees.

Several spreadsheets were then developed to allow side by side comparison of every aspect of the analysis in the two StateMod runs including reservoir storage, diversions, streamflows and operating releases.

RESULTS

WATER AVAILABILITY

As indicated in Technical Memorandum No. 1, the 20,000 acre-feet target release would have been required in only six years (1975, 1978, 1979, 1980, 1985 and 1986) out of the 17 years in the 1975-1991 study period (CWCB, October 2001). If the release requirements were relaxed somewhat, a release could have been also required in two additional years, 1982 and 1991.

The analysis of the Conjunctive Pool Operations alternative completed using StateMod and the C-1 dataset indicated that there was sufficient supply in the HUP in all years in which the 20,000 acre-feet release was required to make the release from the HUP. It was not necessary to make the release from the CBT pool in any year because the 20,000 acre-feet release was not required to be made in any extremely dry year when insufficient storage to make the 20,000 acre-feet release could be expected in the HUP.

Figure 1 presents end of month total storage content for Green Mountain Reservoir for: (1) base case and (2) with conjunctive operation and making the 20,000 acre-feet release in the six years required (1975, 1978, 1979, 1980, 1985, and 1986). As indicated in Figure 1, Green Mountain Reservoir filled every year in both the base case and with conjunctive operation except for 1977 when the reservoir did not fill under either the base case or with conjunctive operation. In those years when the 20,000 acre-feet release was made, replacement of this 20,000 acre-feet was done in priority under the Green Mountain Reservoir refill rights.

Figure 1 and the succeeding figures and Table 1 incorporate the change made to StateMod and the C-1 dataset in which the CBT pool was made to fill first by transferring necessary storage from the HUP to the CBT pool on April 1. As indicated above, the original C-1 dataset did not include this operating requirement and the change was made to more closely reflect present operating policy for the CBT pool and the HUP.

Figure 2 presents end of month storage in the HUP for the study period for: (1) base case and (2) with conjunctive operation and making the 20,000 acre-feet release in the six required years. As indicated in Figure 2, the HUP filled in every year in both the base case and with conjunctive operation except for 1977 when the HUP did not fill in either the base case or with conjunctive operation.

Figure 3 presents end of month storage in the CBT pool for the study period for: (1) base case and (2) with conjunctive operation and making the 20,000 acre-feet release in the six required years. As indicated in Figure 3, the CBT filled in every year in both the base case and with conjunctive operation with the exception of 1977 when the CBT pool did not fill in either the base case or with conjunctive operation.

The effects of the conjunctive operation alternative on Dillon Reservoir storage are presented in Figure 4 which indicates that there were no effects on Dillon Reservoir end of month storage as result of conjunctive operation.

The effects of the conjunctive operation alternative on end of month Granby Reservoir storage are presented in Figure 5 which indicates that there were no effects on Granby Reservoir storage resulting from conjunctive operation.

The effects of the conjunctive operation alternative Shoshone power generation are presented in Figure 6 which indicates that there were no effects on Shoshone power generation resulting from conjunctive operation.

Table 1 presents a comparison of Green Mountain Reservoir power generation revenues as a result of conjunctive operation. Results in this table indicate that with the base case, approximately $171,500 of additional power would have been generated at Green Mountain Reservoir as compared to the conjunctive operation scenario.

Results indicate that releases for the recovery program would be made in only six years (1975, 1978, 1979, 1980, 1985 and 1986) during the 1975-91 study period. In all other years, the spring peak flows at the head of the 15-Mile Reach were less than 12,900 cfs or greater than 26,600 cfs and a release would not be required.

In Revised Technical Memorandum No. 1 (CWCB, October 2001) the feasibility of making a 1,000 cfs release from Green Mountain Reservoir for a period of approximately 10 days during the spring peak runoff period was investigated. This analysis demonstrated that in these six years in which the 20,000 acre-feet release was required, it was possible to make the release at a rate of 1,000 cfs for a period of 10 days from Green Mountain Reservoir without increasing flood damages downstream on the Blue and/or Colorado Rivers. Under the Conjunctive Operation Alternative, the 1,000 cfs release would be made during the same years and at the same time. Consequently, the results of the Technical Memorandum 1 analysis apply to Conjunctive Operation Alternative.

ANALYSIS OF RESULTS

As reported above, there was sufficient supply in the HUP in all years in which the 20,000 acre-feet release was required to make the release from the HUP. It was not necessary to make the release from the CBT pool in any year because the 20,000 acre-feet release was not required to be made in any extremely dry year when insufficient storage to make the 20,000 acre-feet release could be expected in the HUP. As a result, the Conjunctive Operations Alternative collapsed into the following:

- The 20,000 acre-feet preemptive release was made from the HUP in late May and/or early June in those six years in which the release was required during the 17-year study period.
- The 20,000 acre-feet was replaced in Green Mountain Reservoir after the reservoir had attained a "paper-fill" in late June or early July under its first fill water rights. This replacement was accomplished by diverting from the Blue River to storage in Green Mountain Reservoir under the refill rights for Green Mountain Reservoir.

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. The Conjunctive Operation Alternative appears feasible and further consideration of this alternative is warranted.

2. Feasibility of the Conjunctive Operation Alternative is dependent on Green Mountain Reservoir's ability to consistently replace the preemptive 20,000 acre-feet release by storing water under Green Mountain Reservoir's refill water rights. Based on the analysis described herein for the 1975-91 study period, Green Mountain Reservoir was able to consistently replace the 20,000 acre-feet preemptive release by storing under its refill rights.

3. This feasibility of replacing the 20,000 acre-feet preemptive release should, however, be investigated under projected future conditions with an additional 60,000 to 120,000 acre-feet of depletions and with CROP in operation.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River.*

Colorado Water Conservation Board, October 2001, *Technical Memorandum No. 1 Concerning Analysis of Alternative 1A, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, reduced Winter Power Operations (Revised).*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Table 1
GREEN MOUNTAIN RESERVOIR
Power Revenues

			Base							Conjunctive Operations								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	11357	115846	7930.56	241.56	184.70	1501	58	0	0.03878
1974	NOV	Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	21320	104427	7923.83	234.83	358.29	3628	236	0	0.06502
1974	DEC	Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	19759	93370	7916.71	227.71	321.34	3015	318	0	0.10541
1975	JAN	Jan-75	18019	82713	7908.22	220.22	293.05	2409	313	18019	82713	7908.22	220.22	293.05	2409	313	0	0.13
1975	FEB	Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	17044	72644	7901.50	212.50	306.89	2130	138	0	0.065
1975	MAR	Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	15939	63730	7893.97	204.97	259.22	1533	69	0	0.045
1975	APR	Apr-75	12710	60889	7891.43	202.43	213.60	867	39	12710	60889	7891.43	202.43	213.60	867	39	0	0.045
1975	MAY	May-75	5289	75493	7903.76	214.76	0.00	0	0	5289	75493	7903.76	214.76	0.00	0	0	0	0.045
1975	JUN	Jun-75	10362	129047	7937.76	248.76	174.14	1475	80	22400	120205	7933.00	244.00	376.44	4170	226	146	0.05416
1975	JUL	Jul-75	84336	152997	7949.70	260.70	1371.57	18600	1149	75493	153011	7949.70	260.70	1227.76	17733	1095	-54	0.06176
1975	AUG	Aug-75	27765	150691	7948.60	259.60	451.55	5963	638	27779	150691	7948.60	259.60	451.78	5967	638	0	0.10693
1975	SEP	Sep-75	23444	143784	7945.26	256.26	393.98	4821	283	23444	143784	7945.26	256.26	393.98	4821	283	0	0.05866
1975	OCT	Oct-75	11432	141023	7943.89	254.89	185.92	1847	72	11432	141023	7943.89	254.89	185.92	1847	72	0	0.03878
1975	NOV	Nov-75	26434	124561	7935.37	246.37	444.23	5194	338	26434	124561	7935.37	246.37	444.23	5194	338	0	0.06502
1975	DEC	Dec-75	23514	108470	7926.28	237.28	382.41	4167	439	23514	108470	7926.28	237.28	382.41	4167	439	0	0.10541
1976	JAN	Jan-76	22347	92780	7916.31	227.31	363.43	3573	465	22347	92780	7916.31	227.31	363.43	3573	465	0	0.13
1976	FEB	Feb-76	22018	77676	7905.45	216.45	382.78	3244	211	22018	77676	7905.45	216.45	382.78	3244	211	0	0.065
1976	MAR	Mar-76	20867	64928	7895.03	206.03	339.36	2570	116	20867	64928	7895.03	206.03	339.36	2570	116	0	0.045
1976	APR	Apr-76	13611	62615	7892.97	203.97	228.74	1089	49	13611	62615	7892.97	203.97	228.74	1089	49	0	0.045
1976	MAY	May-76	5289	84324	7910.40	221.40	0.00	0	0	5289	84324	7910.40	221.40	0.00	0	0	0	0.045
1976	JUN	Jun-76	20309	129027	7937.75	248.75	341.30	3829	207	20309	129027	7937.75	248.75	341.30	3829	207	0	0.05416
1976	JUL	Jul-76	24273	150202	7948.37	259.37	394.76	5100	315	24273	150202	7948.37	259.37	394.76	5100	315	0	0.06176
1976	AUG	Aug-76	24579	149741	7948.15	259.15	399.73	5167	553	24579	149741	7948.15	259.15	399.73	5167	553	0	0.10693
1976	SEP	Sep-76	26715	142820	7944.78	255.78	448.95	5597	328	26715	142820	7944.78	255.78	448.95	5597	328	0	0.05866
1976	OCT	Oct-76	21293	136188	7941.46	252.46	346.29	4149	161	21293	136188	7941.46	252.46	346.29	4149	161	0	0.03878
1976	NOV	Nov-76	20049	124693	7935.44	246.44	336.93	3697	240	20049	124693	7935.44	246.44	336.93	3697	240	0	0.06502
1976	DEC	Dec-76	17772	113570	7929.26	240.26	289.03	2946	311	17772	113570	7929.26	240.26	289.03	2946	311	0	0.10541
1977	JAN	Jan-77	16388	102846	7922.85	233.85	266.52	2445	318	16388	102846	7922.85	233.85	266.52	2445	318	0	0.13
1977	FEB	Feb-77	15486	92706	7916.26	227.26	278.84	2190	142	15486	92706	7916.26	227.26	278.84	2190	142	0	0.065
1977	MAR	Mar-77	16143	83715	7909.95	220.95	262.54	2026	91	16143	83715	7909.95	220.95	262.54	2026	91	0	0.045
1977	APR	Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	25403	69475	7898.91	209.91	426.91	3687	166	0	0.045
1977	MAY	May-77	8191	76232	7904.33	215.33	133.21	186	8	8191	76232	7904.33	215.33	133.21	186	8	0	0.045
1977	JUN	Jun-77	9204	91191	7915.23	226.23	154.68	695	38	9204	91191	7915.23	226.23	154.68	695	38	0	0.05416
1977	JUL	Jul-77	19715	84169	7910.28	221.28	320.63	2807	173	19715	84169	7910.28	221.28	320.63	2807	173	0	0.06176
1977	AUG	Aug-77	24562	72947	7901.74	212.74	399.46	3558	380	24562	72947	7901.74	212.74	399.46	3558	380	0	0.10693
1977	SEP	Sep-77	13059	67022	7898.84	207.84	219.46	1075	63	13059	67022	7898.84	207.84	219.46	1075	63	0	0.05866
1977	OCT	Oct-77	13233	76527	7904.56	215.56	215.21	1258	49	13233	76527	7904.56	215.56	215.21	1258	49	0	0.03878
1977	NOV	Nov-77	13832	71278	7900.39	211.39	232.45	1326	86	13832	71278	7900.39	211.39	232.45	1326	86	0	0.06502
1977	DEC	Dec-77	13180	67062	7896.88	207.88	214.35	1047	110	13180	67062	7896.88	207.88	214.35	1047	110	0	0.10541
1978	JAN	Jan-78	11540	63609	7893.86	204.86	187.68	635	83	11540	63609	7893.86	204.86	187.68	635	83	0	0.13
1978	FEB	Feb-78	9468	61290	7891.83	202.83	170.48	336	22	9468	61290	7891.83	202.83	170.48	336	22	0	0.065
1978	MAR	Mar-78	9956	58454	7889.10	200.10	161.92	201	9	9956	58454	7889.10	200.10	161.92	201	9	0	0.045
1978	APR	Apr-78	6333	63350	7893.63	204.63	106.43	0	0	6333	63350	7893.63	204.63	106.43	0	0	0	0.045
1978	MAY	May-78	5289	81325	7908.20	219.20	0.00	0	0	5289	81325	7908.20	219.20	0.00	0	0	0	0.045
1978	JUN	Jun-78	15480	129034	7937.75	248.75	260.15	2686	145	22400	127246	7936.81	247.81	376.44	4294	233	87	0.05416
1978	JUL	Jul-78	41372	150202	7948.37	259.37	672.84	9285	573	41871	150204	7948.37	259.37	680.96	9407	581	8	0.06176
1978	AUG	Aug-78	31662	149026	7947.81	258.81	518.50	6940	742	32645	147404	7947.03	258.03	530.91	7094	759	17	0.10693
1978	SEP	Sep-78	26756	139955	7943.36	254.36	449.64	5556	326	26756	138336	7942.55	253.55	449.64	5527	324	-2	0.05866
1978	OCT	Oct-78	15652	133901	7940.29	251.29	254.55	2765	107	15652	132284	7939.45	250.45	254.55	2742	106	-1	0.03878
1978	NOV	Nov-78	22180	118865	7932.25	243.25	372.74	4095	266	21856	117572	7931.63	242.63	367.30	3996	260	-6	0.06502
1978	DEC	Dec-78	21471	104199	7923.69	234.69	349.19	3618	381	21147	103229	7923.09	234.09	343.92	3526	372	-10	0.10541
1979	JAN	Jan-79	21246	89932	7914.36	225.36	345.53	3268	425	20922	89286	7913.92	224.92	340.26	3183	414	-11	0.13
1979	FEB	Feb-79	19635	78253	7904.35	215.35	353.54	2756	179	19312	75929	7904.10	215.10	347.73	2680	174	-5	0.065
1979	MAR	Mar-79	19094	64928	7895.03	206.03	310.53	2208	99	18771	64928	7895.03	206.03	305.28	2142	96	-3	0.045
1979	APR	Apr-79	13825	61991	7892.45	203.45	232.33	1119	50	13825	61991	7892.45	203.45	232.33	1119	50	0	0.045
1979	MAY	May-79	5289	90705	7914.90	225.90	0.00	0	0	21596	74425	7902.92	213.92	351.22	2974	134	134	0.045
1979	JUN	Jun-79	47652	131409	7939.00	250.00	800.61	10366	561	32223	131445	7939.02	250.02	541.52	6700	383	-199	0.05416
1979	JUL	Jul-79	62920	152994	7949.70	260.70	1023.28	14643	904	63988	152994	7949.70	260.70	1040.65	14905	921	16	0.06176
1979	AUG	Aug-79	28239	150691	7948.60	259.60	459.26	6079	650	28239	150691	7948.60	259.60	459.26	6079	650	0	0.10693
1979	SEP	Sep-79	29407	136836	7941.79	252.79	494.19	6135	360	29407	136836	7941.79	252.79	494.19	6135	360	0	0.05866
1979	OCT	Oct-79	21480	125196	7935.71	246.71	349.33	4008	155	21480	125196	7935.71	246.71	349.33	4008	155	0	0.03878
1979	NOV	Nov-79	22123	111904	7928.30	239.30	371.78	3954	257	22123	111904	7928.30	239.30	371.78	3954	257	0	0.06502
1979	DEC	Dec-79	20742	98978	7920.40	231.40	337.33	3349	353	20742	98978	7920.40	231.40	337.33	3349	353	0	0.10541
1980	JAN	Jan-80	21081	86451	7911.92	222.92	342.84	3154	410	21081	86451	7911.92	222.92	342.84	3154	410	0	0.13
1980	FEB	Feb-80	20012	74512	7902.99	213.99	347.90	2745	178	20012	74512	7902.99	213.99	347.90	2745	178	0	0.065
1980	MAR	Mar-80	19707	63729	7893.97	204.97	320.50	2300	104	19707	63729	7893.97	204.97	320.50	2300	104	0	0.045
1980	APR	Apr-80	12046	61008	7891.55	202.55	202.44	737	33	12046	61008	7891.55	202.55	202.44	737	33	0	0.045
1980	MAY	May-80	5289	83658	7909.91	220.91	0.00	0	0	5289	83658	7909.91	220.91	0.00	0	0	0	0.045
1980	JUN	Jun-80	92514	129028	7937.75	248.75	1500.00	18000	975	92514	129028	7937.75	248.75	1500.00	18000	975	0	0.05416
1980	JUL	Jul-80	40746	150202	7948.37	259.37	662.66	9131	564	41765	150202	7948.37	259.37	679.20	9380	579	15	0.06176
1980	AUG	Aug-80	23454	146821	7946.74	257.74	381.44	4845	516	23454	146821	7946.74	257.74	381.44	4845	516	0	0.10693
1980	SEP	Sep-80	24812	137044	7941.89	252.89	413.61	4969	293	24812	137044	7941.89	252.89	413.61	4969	293	0	0.05866
1980	OCT	Oct-80	12204	133406	7940.03	251.03	198.48	1936	75	12204	133406	7940.03	251.03	198.48	1936	75	0	0.03878
1980	NOV	Nov-80	19891	122466	7934.23	245.23	334.27	3623	236	19891	122466	7934.23	245.23	334.27	3623	236	0	0.06502
1980	DEC	Dec-80	17896	111901	7928.30	239.30	291.05	2946	311	17896	111901	7928.30	239.30	291.05	2946	311	0	0.10541
1981	JAN	Jan-81	16154	101734	7922.15	233.15	262.72	2373	308	16154	101734	7922.15	233.15	262.72	2373	308	0	0.13
1981	FEB	Feb-81	15190	92151	7915.69	226.69	273.51	2115	137	15190	92151	7915.69	226.69	273.51	2115	137	0	0.065
1981	MAR	Mar-81	15583	83715	7909.95	220.95	253.43	1905	86	15583	83715	7909.95	220.95	253.43	1905	86	0	0.045
1981	APR	Apr-81	25807	69337	7898.80	209.80	433.69	3766	169	25807	69337	7898.80	209.80	433.69	3766	169	0	0.045
1981	MAY	May-81	5289	83356	7909.69	220.69	0.00	0	0	5289	83356	7909.69	220.69	0.00	0	0	0	0.045
1981	JUN	Jun-81	5970	110359	7927.39	238.39	100.33	228	12	5970	110359	7927.39	238.39	100.33	228	12	0	0.05416
1981	JUL	Jul-81	7258	122405	7934.20	245.20	118.04	631	39	7258	122405	7934.20	245.20	118.04	631	39	0	0.06176
1981	AUG	Aug-81	22273	109651	7926.98	237.98	362.23	3907	418	22273	109651	7926.98	237.98	362.23	3907	418	0	0.10693
1981	SEP	Sep-81	19446	98932	7920.37	231.37	326.80	3100	182	19446	98932	7920.37	231.37	326.80	3100	182	0	0.05866
1981	OCT	Oct-81	12966	92652	7916.23	227.23	210.87	1503	58	12966	92652	7916.23	227.23	210.87	1503	58	0	0.03878

			Base							Conjunctive Operations								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	NOV	Nov-81	14892	85879	7911.51	222.51	250.26	1845	120	14892	85879	7911.51	222.51	250.26	1845	120	0	0.06502
1981	DEC	Dec-81	13696	79459	7906.80	217.80	222.74	1415	149	13696	79459	7906.80	217.80	222.74	1415	149	0	0.10541
1982	JAN	Jan-82	13431	73439	7902.14	213.14	218.43	1237	161	13431	73439	7902.14	213.14	218.43	1237	161	0	0.13
1982	FEB	Feb-82	11351	68007	7897.68	208.68	204.38	851	55	11351	68007	7897.68	208.68	204.38	851	55	0	0.065
1982	MAR	Mar-82	10833	63969	7894.18	205.18	176.18	499	22	10833	63969	7894.18	205.18	176.18	499	22	0	0.045
1982	APR	Apr-82	14858	58835	7889.47	200.47	249.69	1248	56	14858	58835	7889.47	200.47	249.69	1248	56	0	0.045
1982	MAY	May-82	5289	79717	7907.00	218.00	0.00	0	0	5289	79717	7907.00	218.00	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	129037	7937.75	248.75	100.33	435	24	22400	116864	7931.13	242.13	376.44	4109	223	199	0.05416
1982	JUL	Jul-82	56634	152997	7949.70	260.70	921.05	13098	809	47755	150220	7948.38	259.38	776.65	10847	670	-139	0.06176
1982	AUG	Aug-82	34304	150691	7948.60	259.60	557.89	7565	809	31626	150694	7948.60	259.60	514.34	6909	739	-70	0.10693
1982	SEP	Sep-82	21382	148503	7947.55	258.55	359.33	4394	258	21388	148508	7947.56	258.56	359.43	4395	258	0	0.05866
1982	OCT	Oct-82	20961	142312	7944.53	255.53	340.89	4167	162	20964	142313	7944.53	255.53	340.94	4168	162	0	0.03878
1982	NOV	Nov-82	27691	123593	7934.85	245.85	465.36	5471	356	27692	123593	7934.85	245.85	465.37	5471	356	0	0.06502
1982	DEC	Dec-82	25936	105244	7924.33	235.33	421.80	4850	490	25936	105245	7924.33	235.33	421.80	4850	490	0	0.10541
1983	JAN	Jan-83	25060	87296	7912.52	223.52	407.56	4039	525	25060	87296	7912.52	223.52	407.56	4039	525	0	0.13
1983	FEB	Feb-83	24106	69934	7899.29	210.29	434.05	3535	230	24106	69934	7899.29	210.29	434.05	3535	230	0	0.065
1983	MAR	Mar-83	23807	54935	7885.66	196.66	387.18	2852	128	23807	54935	7885.66	196.66	387.18	2852	128	0	0.045
1983	APR	Apr-83	16472	46192	7876.32	187.32	276.82	1204	54	16472	46192	7876.32	187.32	276.82	1204	54	0	0.045
1983	MAY	May-83	5289	70791	7900.00	211.00	0.00	0	0	5289	70785	7899.99	210.99	0.00	0	0	0	0.045
1983	JUN	Jun-83	112817	131454	7939.02	250.02	1500.00	18000	975	112810	131454	7939.02	250.02	1500.00	18000	975	0	0.05416
1983	JUL	Jul-83	127497	152994	7949.70	260.70	1500.00	18600	1149	127497	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62879	153088	7949.74	260.74	1022.61	14635	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	25870	153173	7949.78	260.78	434.75	5567	327	25870	153173	7949.78	260.78	434.75	5567	327	0	0.05866
1983	OCT	Oct-83	17200	151135	7948.81	259.81	279.73	3382	131	17200	151135	7948.81	259.81	279.73	3382	131	0	0.03878
1983	NOV	Nov-83	30674	131848	7939.23	250.23	518.85	6387	415	30674	131848	7939.23	250.23	518.85	6387	415	0	0.06502
1983	DEC	Dec-83	31982	111436	7928.03	239.03	520.13	6168	650	31982	111436	7928.03	239.03	520.13	6168	650	0	0.10541
1984	JAN	Jan-84	29642	91423	7915.39	226.39	482.07	5146	669	29642	91423	7915.39	226.39	482.07	5146	669	0	0.13
1984	FEB	Feb-84	26794	71998	7900.98	211.98	465.81	4101	267	26794	71998	7900.98	211.98	465.81	4101	267	0	0.065
1984	MAR	Mar-84	20592	61032	7891.57	202.57	334.89	2405	108	20592	61032	7891.57	202.57	334.89	2405	108	0	0.045
1984	APR	Apr-84	17606	58043	7888.71	199.71	299.27	1817	82	17606	58043	7888.71	199.71	299.27	1817	82	0	0.045
1984	MAY	May-84	91645	94702	7917.60	228.60	1490.44	18600	837	91645	94702	7917.60	228.60	1490.44	18600	837	0	0.045
1984	JUN	Jun-84	155457	131401	7938.99	249.99	1500.00	18000	975	155457	131401	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	127128	152994	7949.70	260.70	1500.00	18600	1149	127128	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	81017	153088	7949.74	260.74	1317.60	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	35687	153173	7949.78	260.78	599.73	7980	468	35687	153173	7949.78	260.78	599.73	7980	468	0	0.05866
1984	OCT	Oct-84	23558	153342	7949.86	260.86	383.13	4975	193	23558	153342	7949.86	260.86	383.13	4975	193	0	0.03878
1984	NOV	Nov-84	32940	135612	7941.17	252.17	553.57	6957	452	32940	135612	7941.17	252.17	553.57	6957	452	0	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	33445	116759	7931.07	242.07	543.92	6630	699	0	0.10541
1985	JAN	Jan-85	30448	96306	7919.97	230.97	495.18	5502	715	30448	96306	7919.97	230.97	495.18	5502	715	0	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	28571	80438	7907.54	218.54	514.44	4760	309	0	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	25961	64927	7895.03	206.03	422.21	3611	163	0	0.045
1985	APR	Apr-85	26623	64819	7894.93	205.93	447.41	3798	171	26623	64819	7894.93	205.93	447.41	3798	171	0	0.045
1985	MAY	May-85	53155	98074	7919.82	230.82	864.47	10563	475	53155	98074	7919.82	230.82	864.47	10563	475	0	0.045
1985	JUN	Jun-85	100470	131394	7938.99	249.99	1500.00	18000	975	100470	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	47306	150196	7948.37	259.37	769.35	10737	663	49048	150196	7948.37	259.37	797.68	11163	689	26	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	20206	148184	7947.40	258.40	339.57	4102	241	0	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	8954	151947	7949.20	260.20	145.62	1370	53	0	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	30187	134497	7940.59	251.59	507.30	6276	408	0	0.06502
1985	DEC	Dec-85	28810	116555	7930.96	241.96	466.54	5552	585	28810	116555	7930.96	241.96	466.54	5552	585	0	0.10541
1986	JAN	Jan-86	28598	98170	7919.88	230.88	465.06	5085	661	28598	98170	7919.88	230.88	465.06	5085	661	0	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	26592	81570	7908.38	219.38	478.81	4366	284	0	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	27331	64926	7895.03	206.03	444.49	3891	175	0	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	16277	64819	7894.93	205.93	273.54	1684	76	0	0.045
1986	MAY	May-86	32194	98074	7919.82	230.82	523.58	5886	265	32194	98074	7919.82	230.82	523.58	5886	265	0	0.045
1986	JUN	Jun-86	103802	131394	7938.99	249.99	1500.00	18000	975	103802	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	54802	152994	7949.70	260.70	891.26	12648	781	58256	152994	7949.70	260.70	914.90	13005	803	22	0.06176
1986	AUG	Aug-86	19863	150691	7948.60	259.60	323.04	4028	431	19863	150691	7948.60	259.60	323.04	4028	431	0	0.10693
1986	SEP	Sep-86	13432	150697	7948.61	259.61	225.73	2480	145	13432	150697	7948.61	259.61	225.73	2480	145	0	0.05866
1986	OCT	Oct-86	9607	151945	7949.20	260.20	156.24	1530	59	9607	151945	7949.20	260.20	156.24	1530	59	0	0.03878
1986	NOV	Nov-86	29317	134496	7940.59	251.59	492.68	6068	395	29317	134496	7940.59	251.59	492.68	6068	395	0	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	27466	115922	7930.60	241.60	446.69	5228	551	0	0.10541
1987	JAN	Jan-87	25065	97747	7919.61	230.61	407.64	4288	557	25065	97747	7919.61	230.61	407.64	4288	557	0	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	24052	80159	7907.33	218.33	433.07	3787	246	0	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	23437	64927	7895.03	206.03	381.16	3095	139	0	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	12195	64819	7894.93	205.93	204.94	850	38	0	0.045
1987	MAY	May-87	8828	96476	7918.78	229.78	143.57	649	29	8828	96476	7918.78	229.78	143.57	649	29	0	0.045
1987	JUN	Jun-87	37857	129001	7937.74	248.74	636.20	7962	432	37857	129001	7937.74	248.74	636.20	7962	432	0	0.05416
1987	JUL	Jul-87	8541	150202	7948.37	259.37	138.90	1250	77	8541	150202	7948.37	259.37	138.90	1250	77	0	0.06176
1987	AUG	Aug-87	26795	146955	7946.81	257.81	435.77	5660	605	26795	146955	7946.81	257.81	435.77	5660	605	0	0.10693
1987	SEP	Sep-87	26443	134964	7940.83	251.83	444.38	5391	316	26443	134964	7940.83	251.83	444.38	5391	316	0	0.05866
1987	OCT	Oct-87	21345	124068	7935.11	246.11	347.14	3957	153	21345	124068	7935.11	246.11	347.14	3957	153	0	0.03878
1987	NOV	Nov-87	21731	111018	7927.78	238.78	365.20	3847	250	21731	111018	7927.78	238.78	365.20	3847	250	0	0.06502
1987	DEC	Dec-87	20232	98313	7919.97	230.97	329.04	3222	340	20232	98313	7919.97	230.97	329.04	3222	340	0	0.10541
1988	JAN	Jan-88	19936	86008	7911.61	222.61	324.22	2895	376	19936	86008	7911.61	222.61	324.22	2895	376	0	0.13
1988	FEB	Feb-88	18101	74291	7902.81	213.81	314.68	2337	152	18101	74291	7902.81	213.81	314.68	2337	152	0	0.065
1988	MAR	Mar-88	16898	64929	7895.03	206.03	274.82	1759	79	16898	64929	7895.03	206.03	274.82	1759	79	0	0.045
1988	APR	Apr-88	12593	64803	7894.92	205.92	211.63	931	42	12593	64803	7894.92	205.92	211.63	931	42	0	0.045
1988	MAY	May-88	5289	89574	7914.12	225.12	0.00	0	0	5289	89574	7914.12	225.12	0.00	0	0	0	0.045
1988	JUN	Jun-88	51027	129016	7937.74	248.74	857.52	11100	601	51027	129016	7937.74	248.74	857.52	11100	601	0	0.05416
1988	JUL	Jul-88	18685	149646	7948.20	259.20	303.88	3727	230	18685	149646	7948.20	259.20	303.88	3727	230	0	0.06176
1988	AUG	Aug-88	42120	130517	7938.53	249.53	685.01	8997	962	42120	130517	7938.53	249.53	685.01	8997	962	0	0.10693
1988	SEP	Sep-88	19530	122971	7934.51	245.51	328.21	3547	208	19530	122971	7934.51	245.51	328.21	3547	208	0	0.05866
1988	OCT	Oct-88	34701	98412	7920.04	231.04	564.35	6454	250	34701	98412	7920.04	231.04	564.35	6454	250	0	0.03878
1988	NOV	Nov-88	17806	90484	7914.75	225.75	299.27	2571	167	17806	90484	7914.75	225.75	299.27	2571	167	0	0.06502
1988	DEC	Dec-88	14659	82913	7909.37	220.37	238.40	1690	178	14659	82913	7909.37	220.37	238.40	1690	178	0	0.10541
1989	JAN	Jan-89	14066	75742	7903.95	214.95	228.76	1418	184	14066	75742	7903.95	214.95	228.76	1418	184	0	0.13
1989	FEB	Feb-89	13103	69158	7898.65	209.65	235.93	1236	80	13103	69158	7898.65	209.65	235.93	1236	80	0	0.065
1989	MAR	Mar-89	15213	63403	7893.68	204.68	247.41	1378	62	15213	63403	7893.68	204.68	247.41	1378	62	0	0.045
1989	APR	Apr-89	14954	63422	7893.70	204.70	251.31	1381	62	14954	63422	7893.70	204.70	251.31	1381	62	0	0.045

			Base							Conjunctive Operations								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1989	MAY	May-89	5289	86101	7911.67	222.67	0.00	0	0	5289	86101	7911.67	222.67	0.00	0	0	0	0.045
1989	JUN	Jun-89	20767	129023	7937.75	248.75	349.00	3937	213	20767	129023	7937.75	248.75	349.00	3937	213	0	0.05416
1989	JUL	Jul-89	23784	149684	7948.12	259.12	386.80	4972	307	23784	149684	7948.12	259.12	386.80	4972	307	0	0.06176
1989	AUG	Aug-89	33567	146237	7946.46	257.46	546.23	7300	781	33567	146237	7946.46	257.46	546.23	7300	781	0	0.10693
1989	SEP	Sep-89	26675	134301	7940.49	251.49	448.28	5434	319	26675	134301	7940.49	251.49	448.28	5434	319	0	0.05866
1989	OCT	Oct-89	18083	127198	7936.78	247.78	294.09	3241	126	18083	127198	7936.78	247.78	294.09	3241	126	0	0.03878
1989	NOV	Nov-89	22957	113504	7928.22	240.22	385.80	4176	272	22957	113504	7928.22	240.22	385.80	4176	272	0	0.06502
1989	DEC	Dec-89	21240	100178	7921.17	232.17	345.43	3485	367	21240	100178	7921.17	232.17	345.43	3485	367	0	0.10541
1990	JAN	Jan-90	19161	87252	7912.49	223.49	311.62	2754	358	19161	87252	7912.49	223.49	311.62	2754	358	0	0.13
1990	FEB	Feb-90	18046	74912	7903.30	214.30	324.93	2390	155	18046	74912	7903.30	214.30	324.93	2390	155	0	0.065
1990	MAR	Mar-90	18157	64539	7894.69	205.69	295.29	2006	90	18157	64539	7894.69	205.69	295.29	2006	90	0	0.045
1990	APR	Apr-90	21003	53220	7883.92	194.92	352.96	2304	104	21003	53220	7883.92	194.92	352.96	2304	104	0	0.045
1990	MAY	May-90	5289	66702	7896.57	207.57	0.00	0	0	5289	66702	7896.57	207.57	0.00	0	0	0	0.045
1990	JUN	Jun-90	16879	129067	7937.77	248.77	283.66	3018	163	16879	129067	7937.77	248.77	283.66	3018	163	0	0.05416
1990	JUL	Jul-90	21334	144634	7945.68	256.68	346.96	4294	265	21334	144634	7945.68	256.68	346.96	4294	265	0	0.06176
1990	AUG	Aug-90	46946	121496	7933.70	244.70	763.49	9893	1058	46946	121496	7933.70	244.70	763.49	9893	1058	0	0.10693
1990	SEP	Sep-90	32172	104467	7923.85	234.85	540.66	6083	357	32172	104467	7923.85	234.85	540.66	6083	357	0	0.05866
1990	OCT	Oct-90	21035	97667	7919.57	230.57	342.10	3388	131	21035	97667	7919.57	230.57	342.10	3388	131	0	0.03878
1990	NOV	Nov-90	19574	89906	7914.35	225.35	328.95	2946	192	19574	89906	7914.35	225.35	328.95	2946	192	0	0.06502
1990	DEC	Dec-90	17604	82479	7909.05	220.05	286.30	2315	244	17604	82479	7909.05	220.05	286.30	2315	244	0	0.10541
1991	JAN	Jan-91	15739	75452	7903.73	214.73	255.97	1765	229	15739	75452	7903.73	214.73	255.97	1765	229	0	-0.13
1991	FEB	Feb-91	13259	69014	7898.53	209.53	238.74	1265	82	13259	69014	7898.53	209.53	238.74	1265	82	0	0.065
1991	MAR	Mar-91	12625	63731	7893.97	204.97	205.32	859	39	12625	63731	7893.97	204.97	205.32	859	39	0	0.045
1991	APR	Apr-91	16156	56563	7887.27	198.27	271.51	1447	65	16156	56563	7887.27	198.27	271.51	1447	65	0	0.045
1991	MAY	May-91	5289	85280	7911.09	222.09	0.00	0	0	5289	85280	7911.09	222.09	0.00	0	0	0	0.045
1991	JUN	Jun-91	29376	129025	7937.75	248.75	493.67	5975	324	29376	129025	7937.75	248.75	493.67	5975	324	0	0.05416
1991	JUL	Jul-91	21099	150202	7948.37	259.37	343.14	4323	267	21099	150202	7948.37	259.37	343.14	4323	267	0	0.06176
1991	AUG	Aug-91	29152	147328	7946.99	257.99	474.10	6241	667	29152	147328	7946.99	257.99	474.10	6241	667	0	0.10693
1991	SEP	Sep-91	30325	135777	7941.25	252.25	0.00	0	0	30325	135777	7941.25	252.25	0.00	0	0	0	0.05866
						Totals			$61,987,748							$62,159,188		
						Difference										$171,440		
						Average Annual										$10,085		

Figure 1

GREEN MOUNTAIN RESERVOIR

EOM Content

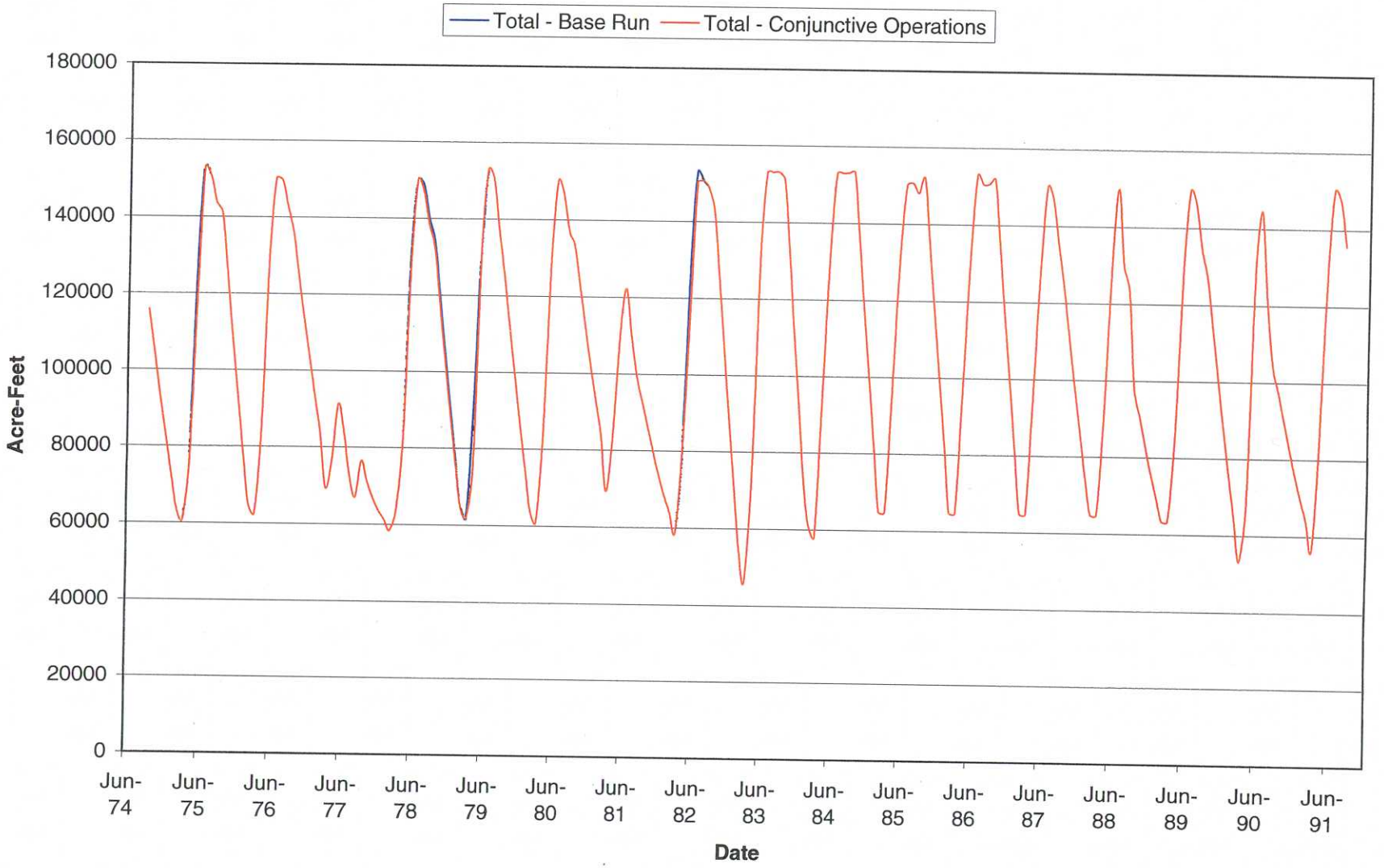

Figure 2

GREEN MOUNTAIN RESERVOIR

EOM Content

Figure 3

GREEN MOUNTAIN RESERVOIR

EOM Content

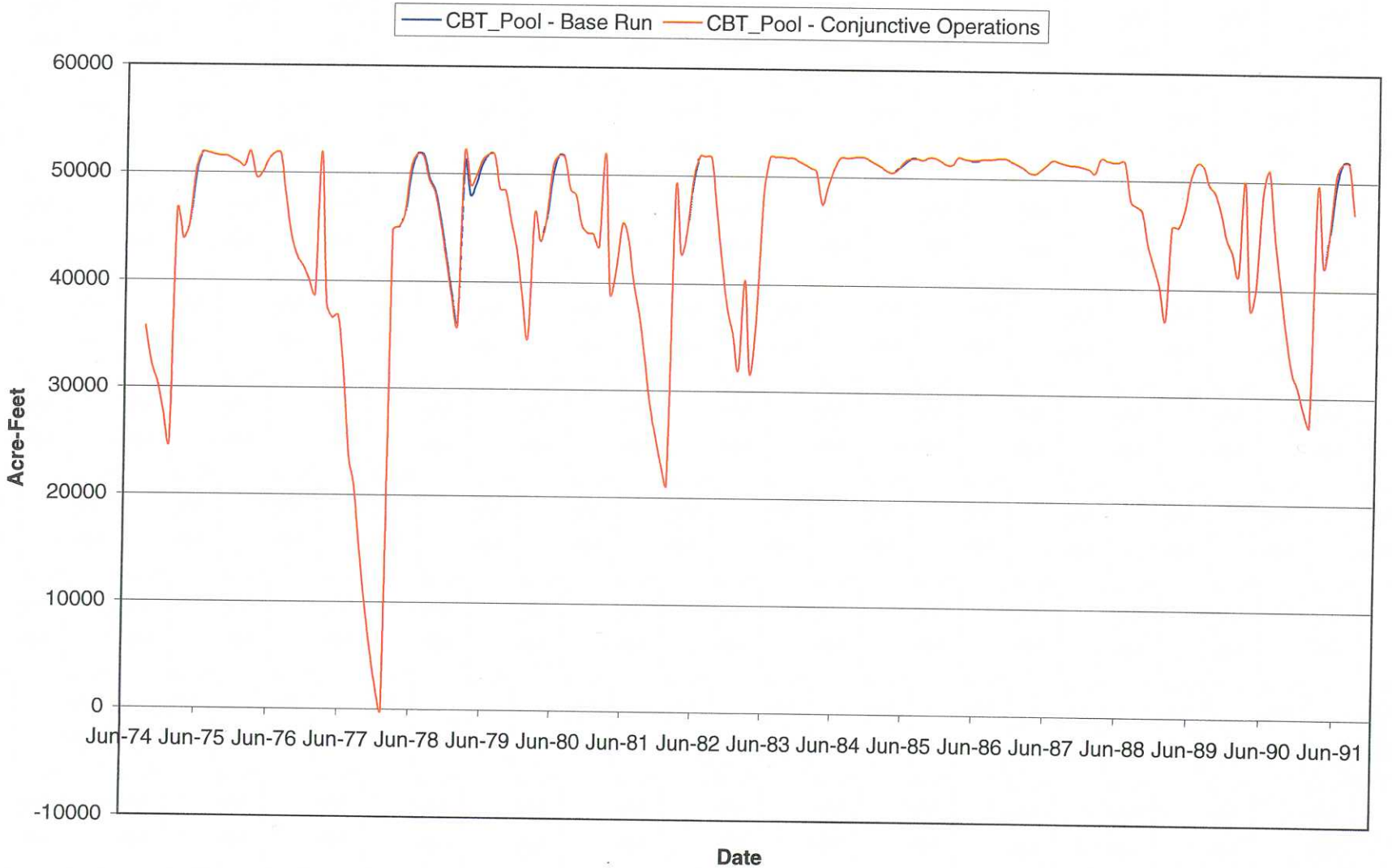

Figure 4

DILLON RESERVOIR

EOM Content

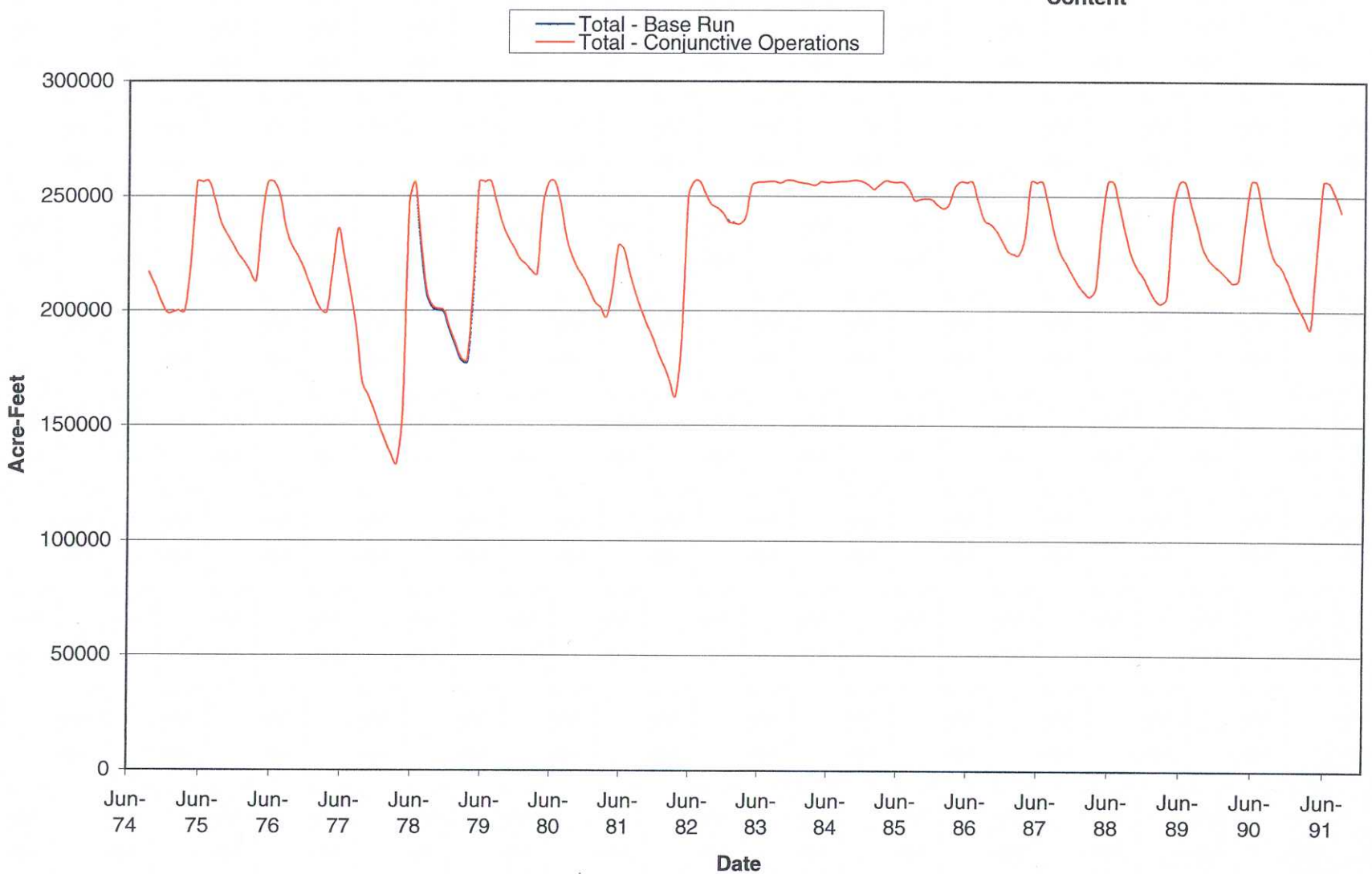

Figure 5

CBT GRANBY RESERVOIR

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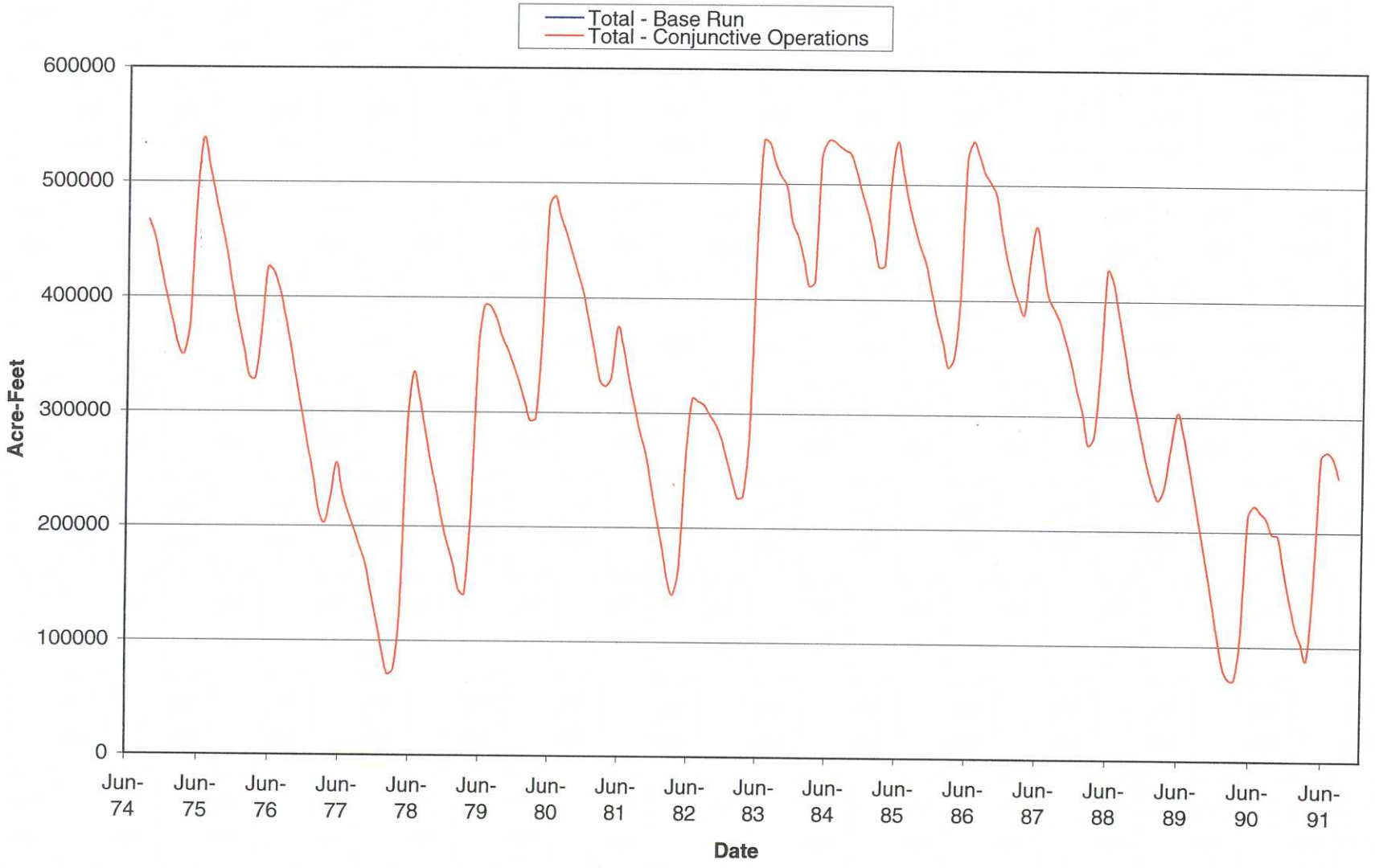
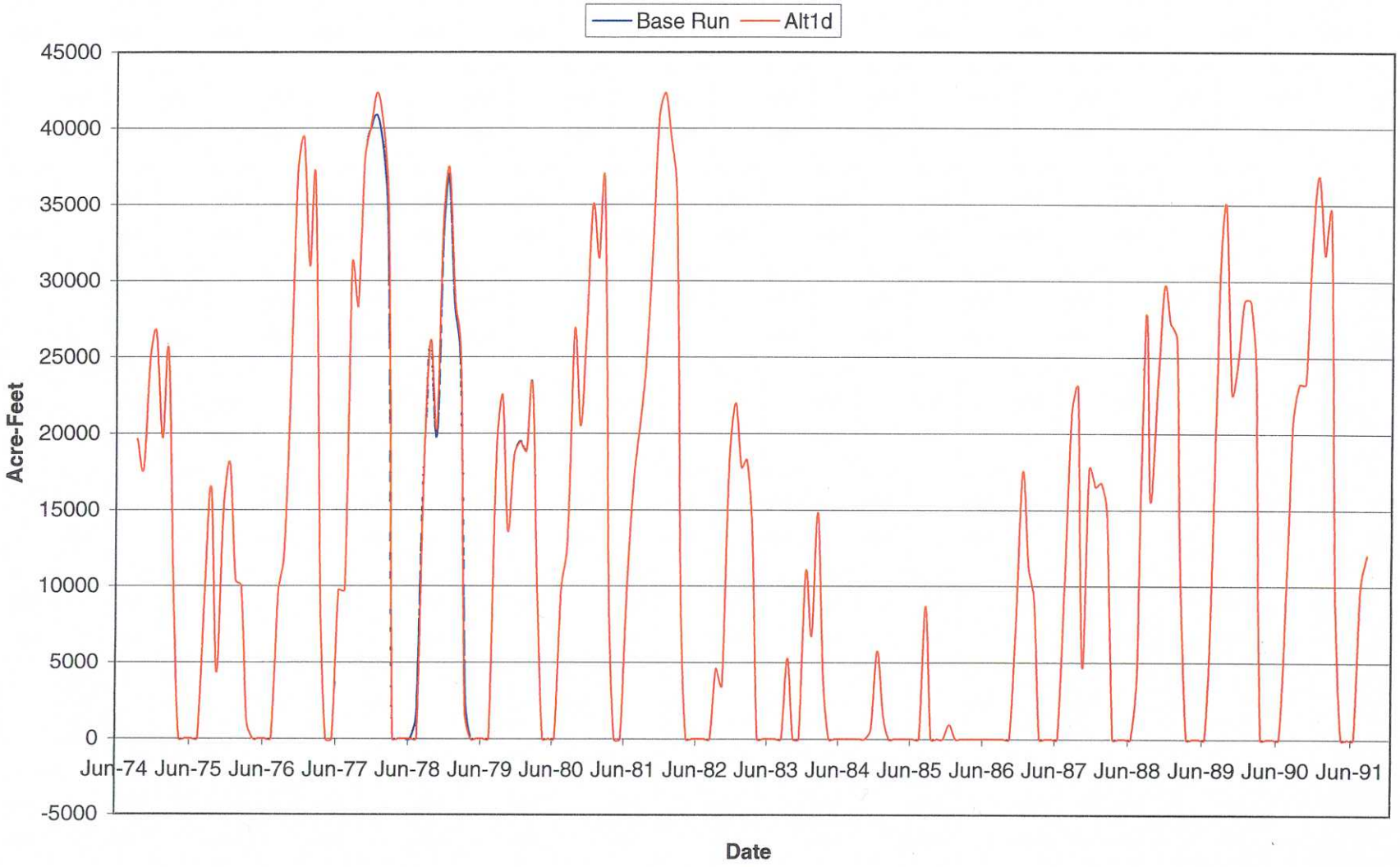


Figure 6

SHOSHONE POWER PLANT **Shortages**



TECHNICAL MEMORANDUM NO. 4:
ANALYSIS OF ALTERNATIVE 4,
NEW STORAGE FACILITIES
BELOW SHOSHONE

PRODUCED FOR:

Colorado Water Conservation Board

PRODUCED BY:

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March 2001
Revised October 2001

TECHNICAL MEMORANDUM NO. 4:
ANALYSIS OF ALTERNATIVE 4,
NEW STORAGE FACILITIES
BELOW SHOSHONE

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Figure 2. Right Abutment for Lower Dry Fork Dam, Roan Creek

Figure 3. Left Abutment for Lower Dry Fork Dam, Roan Creek

Figure 4. Right Abutment for Parachute Creek Dam

Figure 5. Left Abutment for Parachute Creek Dam

Figure 6. Parachute Creek Reservoir Site Looking Upstream from Dam Site

Figure 7. Webster Hill Reservoir Site, Colorado River, Looking South

EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 4 is to present the results from investigating the New Storage Facilities Below Shoshone Alternative. This investigation focuses on the following potential reservoir sites:

- Alternative 4f: Roan Creek Reservoir,
- Alternative 4k: Dry Hollow Reservoir,
- Alternative 4m: Mainstem Colorado River Reservoir (Webster Hill Site), and
- Alternative 4n: Parachute Creek Reservoir.

The location of these sites is shown in Figure 1. Two other potential reservoir sites were included in the alternatives recommended for further study in the Phase 1 report (CWCB, September 2000). Further investigation of these sites was not completed as part of this study for the reasons indicated:

- Alternative 4g: Mt. Logan Reservoir. This site is located on a tributary to Roan Creek and was investigated as an alternative to the mainstem Roan Creek site by the present owners of the Roan Creek site. Based on information and data received from the owner's representatives (personal communication Michael Franko, Texaco, Inc., and Gary Bishop, Chevron Shale Oil Company, to Leo Eisel and John Currier, February 16, 2001), it was determined that the mainstem Roan Creek (aka, Dry Fork) site appeared more likely to be feasible than the Mt. Logan site. Thus no further consideration was given to the Mt. Logan site.
- Alternative 4o: Starky Gulch Reservoir. The owner of this site plans to develop natural gas located beneath the site and the site is no longer available.

Individuals familiar with the Roan Creek, Parachute Creek, Dry Hollow Creek and mainstem Colorado River sites were contacted to obtain available reports and information concerning these sites. A field visit was made to the Roan Creek, Parachute Creek, and mainstem Colorado River sites. Based on available information, conferences with the owner's representatives, field investigations and cost calculations, the following results, conclusions and recommendations are presented:

1. Based on available information, the Roan Creek and Dry Hollow sites are likely feasible sites from an engineering perspective. Much less information was available for the Parachute Creek site, but based on a meeting with the owner's representatives, this site is also likely feasible from an engineering perspective. Very limited information was available concerning the engineering feasibility of the Webster Hill site on the mainstem of the Colorado River.
2. Cost data were available for the Roan Creek and Dry Hollow sites. Updating and analyzing these cost data indicate that both of these sites would be a relatively expensive source of water supply for making the 20,000 acre-feet releases for the fish. Based on the cost a yield data available, the estimated costs for a water supply from the Roan Creek site

would be $553/acre-foot/year and $533/acre-foot/year for water supply from the Dry Creek site.

3. Installation of pumped storage could reduce these costs by approximately $30-$40/acre-foot/year.

4. Based on these preliminary cost estimates, it appears doubtful that these tributary sites will prove to be a feasible source of water supply for making the 20,000 acre-feet release. Consequently, it was decided to discuss these findings for the tributary sites with the Executive Committee before doing more detailed feasibility studies.

5. The mainstem Webster Hill site is located in the upper portion of the Critical Habitat reach as designated for recovery of the Endangered Species. The U.S. Fish and Wildlife Service has previously indicated concern over the location of this site in the Critical Habitat. Before proceeding with further detailed feasibility studies of this site, it is desirable to obtain some indication from the Service concerning whether the location of this site represents a fatal flaw. If the Service indicates willingness to consider the Webster Hill site, we will proceed with a more detailed analysis.

INTRODUCTION AND PURPOSE

The Phase 1 investigation (CWCB, September 2000) recommended that six possible reservoir sites downstream from the Shoshone Power Plant be investigated for feasibility for supplying the 20,000 acre-feet release. These reservoir sites include:

- Alternative 4f, Roan Creek,
- Alternative 4g, Mt. Logan,
- Alternative 4k, Dry Hollow Creek,
- Alternative 4m, Colorado River Main Stem,
- Alternative 4n, Parachute Creek and
- Alternative 4o, Starky Gulch.

The purpose of this Technical Memorandum is to investigate the feasibility of these six sites as alternatives for providing necessary water supply for making the 20,000 acre-feet release.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following procedures and assumptions were employed in the analysis of the proposed reservoir sites:

- Data and information concerning the six sites were gathered and reviewed.
- Individuals knowledgeable concerning the sites were contacted and interviewed. Additional data, information and documents concerning the sites were obtained in the course of these interviews.
- Three of the sites were field inspected.
- Cost calculations were completed for capital and pumping costs at two of the sites where some cost information and data were available.

USE OF STATEMOD

StateMod was not employed in this investigation.

RESULTS

Two of the proposed sites were eliminated initially from further investigation:

- Alternative 4g, Mt. Logan Reservoir site. This site is located on a tributary to Roan Creek and near the Roan Creek site (Alternative 4f). An on-site meeting with representatives from Texaco and Chevron, together with review of documents provided by Texaco and Chevron, indicated that the Roan Creek site was more likely to be a feasible site for producing water supply for the 20,000 acre-feet release than the Mt. Logan site. Consequently, the remainder of this feasibility investigation focused on the Roan Creek site.
- Alternative 4o, Starky Gulch site. This site is located on a tributary to Parachute Creek and near the Parachute Creek site (Alternative 4n). An on-site meeting with representatives from Unocal indicated that Unocal no longer had any interest in the Starky Gulch site and that the present owners were planning on developing the site for natural gas production and were no longer interested in marketing this site for development of a reservoir. Consequently, this site was eliminated from further consideration in this feasibility investigation.

Figure 1 presents a map showing the location of the remaining four sites. Photographs of the sites are presented in Figures 2 through 7. Table 1 presents a summary of the four sites. A summary of the capital and operating and maintenance costs is presented in Table 2.

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. Based on available information, the Roan Creek and Dry Hollow sites are probably feasible sites from an engineering perspective. Much less information was available for the Parachute Creek site, but based on a meeting with the owner's representatives, this site is also probably feasible from an engineering perspective. Very limited information was available concerning the engineering feasibility of the Webster Hill site on the main stem of the Colorado River.

2. Cost data were available for the Roan Creek and Dry Hollow sites. Updating and analyzing these cost data indicate that both of these sites would be a relatively costly source of water supply for making the 20,000 acre-feet releases for the fish. Based on the cost and yield data available, the estimated costs for a water supply from the Roan Creek site would be $553/acre-foot/year and $533/acre-foot/year for water supply from the Dry Creek site.

3. Installation of pumped storage facilities could reduce these costs by approximately $30-$40/acre-foot/year.

4. Based on these cost estimates, it appears doubtful that these tributary sites will prove to be a feasible source of water supply for making the 20,000 acre-feet release. Consequently, it was decided to discuss these findings for the tributary sites with the Executive Committee before doing more detailed feasibility studies.

5. The main stem Webster Hill site is located in the upper portion of the Critical Habitat reach as designated for recovery of the Endangered Species. The U.S. Fish and Wildlife Service has previously indicated concern over the location of this site in the Critical Habitat. Before proceeding with further detailed feasibility studies of this site, it is desirable to obtain some indication from the Service concerning whether the location of this site represents a fatal flaw. If the Service indicates some willingness to consider this site, we will proceed with more detailed analysis

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 2. Right Abutment for Lower Dry Fork Dam, Roan Creek

Figure 3. Left Abutment for Lower Dry Fork Dam, Roan Creek

Figure 4. Right Abutment for Parachute Creek Dam

Figure 5. Left Abutment for Parachute Creek Dam

Figure 6. Parachute Creek Reservoir Site Looking Upstream from Dam Site

Figure 7. Webster Hill Reservoir Site, Colorado River, Looking South

TABLE 1
SUMMARY OF SITE CHARACTERISTICS

Site	Location	Approx. Tot. Stor. (AcFt)	Ave. Est. Static Ping Head (ft.)
Roan Creek	Roan Creek	125,000-175,000	310
Parachute Creek	Parachute Creek	33,000	655
Webster Hill	Mainstem Colo. River	24,000	No pumping
Dry Hollow	Dry Hollow Creek	23,400	540

TABLE 2
SUMMARY OF CAPITAL AND O&M COSTS

Site	Capital Costs ($)	Amortized Cap. Costs ($/yr)	Amortized Cap. (yr/AcFt)	O&M Costs ($/AcFt/yr)	Total Costs ($).AcFt yield/yr
Dry Hollow Creek	121,600,000	9,310,000	466	67	533
Roan Creek	200,000,000	15,300,000	510	43	553

NOTES:

1. Notes on Dry Hollow Creek Site Cost Calculations
   a. Capital costs were taken from: USBR, May 1982, Planning Report on the West Divide Project, Colorado and updated to 2001 costs based on 3%/year increase.
   b. The original USBR project included a high lift component to a canal above Dry Hollow Reservoir. Because this high lift component is not required, we have assumed that the pumping component to lift water into Dry Hollow Reservoir would be 2/3 of the total cost.
   c. The Dry Hollow Reservoir as configured by the USBR has a total capacity of 23,400 acre-feet, of which 18,800 is active capacity.
   d. Cost per acre-foot is based on 20,000 acre-feet pumped from Colorado River annually.
   e. Cost analysis assumes that Dry Hollow Creek yield is zero and that the entire 20,000 acre-feet is pumped from the Colorado River.
   f. An annual discount rate of 6.5 percent was used which is equivalent to the 2001 interest rate used for CWCB Construction loans for industrial and commercial projects.
   g. A 30 year amortization period was used.
   h. If pumped storage facilities were available, and based on an efficiency of 67 percent and assuming the power would be sold for the same as the purchase price, this would reduce the net cost of pumping to approximately $22/acre-foot, disregarding incremental capital costs for the pumped storage facilities.
   i. A total liftof 692 ft (including 80 feet for the Dry Hollow pumping plant) and $0.08/KWH were used.

2. Notes on Roan Creek Site Cost Calculations
   a. Estimated capital cost for the site is $200,000,000 (personal communication with Michael J. Franko, Texaco, Inc., February 16, 2001)

   This is for a capacity of 125,000 to 175,000 acre-feet.
   b. An average static pumping head of 310 ft. was used with $0.08/KWH. A wire to water efficiency of 60% was assumed.
   c. A discount rate of 6.5 percent was used together with a 30 year amortization rate. The 6.5 percent rate is the current interest rate used by the CWCB for industrial-commercial project loans from the Construction Loan Fund.
   d. Cost per acre-foot is based on 30,000 acre-feet yield with the yield in excess of 20,000 acre-feet per year going to other purposes.
   e. If pumped storage facilities were available, and based on an efficiency of 67 percent and assuming the power would be sold for the same as the purchase price, this would reduce the net cost of pumping to approximately $14/ acre-foot disregarding incremental capital costs for the pumped storage facilities.

TECHNICAL MEMORANDUM NO. 4A:
ANALYSIS OF ALTERNATIVE 4,
NEW STORAGE FACILITIY AT WEBSTER HILL SITE,
MAINSTEM COLORADO RIVER

PRODUCED FOR:

Colorado Water Conservation Board

PRODUCED BY:

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June 2001
Revised October 2001

TECHNICAL MEMORANDUM NO. 4A:
ANALYSIS OF ALTERNATIVE 4,
NEW STORAGE FACILITIY AT WEBSTER HILL SITE,
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EXECUTIVE SUMMARY

The purpose of Technical Memorandum 4A is to present the results from further investigating the Webster Hill reservoir site located on the mainstem of the Colorado River immediately downstream from Rifle, Colorado. This further investigation focuses primarily on water availability for diversion to storage under a junior storage right at the Webster Hill site and the potential economic feasibility of this site for development as a storage reservoir.

The following findings, conclusions and recommendations are based on this analysis:

1. Analysis of the recorded flow data for the Colorado River at the Cameo gaging station is presented in Table 1. These data indicate that an average of approximately 160,000 acre-feet/month are estimated to be available under a junior right for diversion at the Webster Hill Reservoir site on an average monthly basis.

2. Data in Table 1 further indicate that for those eight years of the 1975-1991 study period in which the 20,000 acre-feet release could be required (1975, 1978, 1979, 1980, 1985, 1986, 1982 and 1991): (a) there would be sufficient water available under a junior water right for diversion to storage in a 28,909 acre-feet reservoir at the Webster Hill site to allow the 20,000 acre-feet release for recovery of the endangered species during late May or early June and (b) it would be possible to refill the proposed reservoir during late June, July and August and to make another 20,000 acre-feet release in the late summer or early fall.

3. A 2,000 cfs flow would be available for run-of-the-river hydropower generation at the Webster Hill Reservoir site approximately 75 percent of the time.

4. A conceptual opinion of probable cost for the 28,909 acre-feet Webster Hill Reservoir is approximately $76.4 million. This total cost would equate to approximately $2,600 per acre-foot of storage or $146 per acre-foot of yield based on an expected yield of 40,000 acre-feet per year (two 20,000 acre-feet releases). This $76.4 million total cost estimate includes: (a) a 10 MW hydropower installation, (b) relocating the railroad, (c) I-70 vertical realignment, (d) gas well relocation, (e) 1,250 acres of real estate acquisition and (f) engineering and permitting.

5. An estimated average annual $5.3 million in revenue would be produced from the 10 MW hydropower installation.

6. Netting out this $5.3 million in hydropower revenue from the amortized project capital costs would result in an estimated cost of approximately $26 per acre-foot for releases to the 15-Mile Reach from the proposed reservoir. This estimated cost is based on the hydropower sales value (averaging $0.06839/KWhr) received from the Western Area Power Administration (WAPA) and used throughout these series of Technical Memoranda. In a review of the Draft Technical Memorandum 4a, (Colorado Water Conservation Board, June 2001) Northern Colorado Water Conservation District commented that a more appropriate value for hydropower produced from the Webster Hill facility would be

$0.04/KWhr. Based on the $0.04/KwHr value, the cost of a release from the Webster Hill Facility to the 15-Mile Reach would be approximately $134/acre-foot.

7. Analysis indicates that for those eight years in which the 20,000 acre-feet release would be made to the 15-Mile Reach in May and/or June, the Webster Hill Reservoir could be expected to refill by late Summer or early Fall, in time to make a second release of 20,000 acre-feet to the15-Mile Reach. Consequently, the cost of providing two, 20,000 acre-feet releases would be $12.85 per acre-foot based on the WAPA supplied hydropower sales values and approximately $67 per acre-foot based on the $0.04/KWhr estimated sales price.

8. It is concluded that the Webster Hill site with hydropower generation is a potential economically feasible alternative for supplying the 20,000 acre-feet releases required for the Recovery Program. Before concluding that this alternative is feasible from an engineering perspective, a detailed site investigation and materials availability investigation would be necessary. In addition the following areas would require additional investigation:
   - Right of way availability and estimated cost.
   - More detailed cost investigation for relocating the gas wells.
   - More detailed cost investigation concerning electrical transmission capacity available to the site and cost of providing necessary transmission capacity to the site.
   - More detailed cost investigation concerning railroad relation and highway relocation costs.
   - Necessary environmental investigations concerning the site.

9. Review of Draft Technical Memorandum No. 4A (Colorado Water Conservation Board, June 2001) by Northern Colorado Water Conservancy District produced an alternative for relocating the highway and the railroad. This alternative would involve building a containment dike, similar to that constructed at the Windy Gap Reservoir, on the north side of the Colorado River at the Windy Gap site. A sediment bypass channel could be constructed on the north side of the dike to allow the major portion of river sediment to pass downstream and also allowing possible mechanism for fish migration. The feasibility of this alternative would largely depend on the relative costs of moving the railroad and the highway as compared to building the containment dike. This alternative should be further analyzed to determine engineering and economic feasibility.

10. Before initiating additional feasibility investigations concerning this alternative, the U.S. Fish and Wildlife Service must determine the acceptability to the Service of constructing a reservoir at the Webster Hill site.

INTRODUCTION AND PURPOSE

The Phase 1 investigation (CWCB, September 2000) recommended that six possible reservoir sites downstream from the Shoshone Power Plant be investigated for feasibility for supplying the 20,000 acre-feet release. These reservoir sites include:

- Alternative 4f, Roan Creek,
- Alternative 4g, Mt. Logan,
- Alternative 4k, Dry Hollow Creek,
- Alternative 4m, Colorado River Main Stem,
- Alternative 4n, Parachute Creek and
- Alternative 4o, Starky Gulch.

These sites were analyzed in Technical Memorandum No. 4 (CWCB, March 2001). After review and discussion of these alternatives, the Executive Committee made the following findings and directions:

- The tributary sites (4f, 4g, 4k, 4n, and 4o) were found to be of questionable economic feasibility and were dismissed from further consideration.
- Further analysis of the economic feasibility of the mainstem site, Alternative 4m, was directed.

The purpose of Technical Memorandum No. 4A was to report on the findings of this additional economic analysis. Technical Memorandum No. 4A was produced in draft (Colorado Water Conservation Board, June 2001) and reviewed by the CWCB and the Executive Committee. The purpose of the Revised Technical Memorandum No. 4A is to incorporate the comments and revisions received.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The analysis consisted of two primary tasks:

- A water availability analysis was completed to determine the yield of a reservoir on the Colorado River mainstem at the Webster Hill site immediately downstream from Rifle, Colorado.
- More detailed opinions of probable cost were developed for a proposed reservoir at the Webster Hill site.
- A preliminary economic feasibility analysis was completed

The following procedures and assumptions were employed in the reservoir operations and yield analysis of the proposed reservoir sites:

- Daily historic streamflow data for the period October 1966 through September 1997 were obtained from HydroBase for several gages (DeBeque, Cameo, and Parachute Creek). Specifically the feasibility of making the following releases was investigated: (1) the 20,000 acre-feet release on the peak of the spring hydrograph in those years in which it is required for recovery of the endangered species and (2) a second 20,000 acre-feet release during the late summer or early fall for purposes of the recovery program.

- The Dwyer-Shepherd report (1976) based its hydropower calculations on daily flows equaling or exceeding 2,000 cfs approximately 75 percent of the time. This frequency of flows at the Webster Hill site equaling or exceeding 2,000 cfs was confirmed by a Cameo flow frequency calculation presented by Northern Colorado Water Conservancy District in their comments on Draft Technical Memorandum No. 4A (September 7, 2001 letter from Eric Wilkinson to Leo Eisel with attached July 24, 2001 memorandum).

For purposes of determining opinions of probable cost and the economic feasibility investigation, the calculations in the 1976 Dwyer-Shepherd study were updated to 2001. Preliminary cost estimates for the following components were made because costs for these components were not included in the Dwyer-Shepherd report:

(1) 10 MW hydropower component,
(2) railroad relocation,
(3) Interstate-70 vertical re-alignment,
(4) gas well relocation, and
(5) real-estate acquisition.

USE OF STATEMOD

StateMod was not employed in this investigation.

RESULTS

WATER AVAILABILITY

1. Analysis of the recorded flow data for the Colorado River at the Cameo gaging station is presented in Table 1. These data show that the average monthly amount of water available under a junior right for diversion at the Webster Hill Reservoir site is estimated to be approximately 160,000 acre-feet. This figure was based on flow at the Cameo gage in excess of 2,000 cfs during the irrigation season and in excess of 800 cfs during the winter months.

2. Data in Table 1 further indicate that for those eight years of the 1975-1991 study period in which the 20,000 acre-feet release could be required (1975, 1978, 1979, 1980, 1985, 1986, 1982 and 1991) there would have been sufficient water available under a junior water right for diversion to storage in a 28,909 acre-feet reservoir at the Webster Hill site. This available water for storage would permit the 20,000 acre-feet release for recovery of the endangered species during late May or early June as well as refill the reservoir during late June, July and August to allow another 20,000 acre-feet release in the late summer or early fall.

3. A 2,000 cfs flow would be available for run-of-the-river hydropower generation at the Webster Hill Reservoir site approximately 75 percent of the time.

OPINION OF PROBABLE COST AND ECONOMIC FEASIBILITY

1. A conceptual opinion of probable cost for the 28, 909 acre-feet Webster Hill Reservoir is approximately $76.4 million which would equate to approximately $2,600 per acre-foot of storage or $146 per acre-foot of yield based on 40,000 acre-feet per year (see Tables 2 and 3). This $76.4 million total cost estimate includes: (a) a 10 MW hydropower installation, (b) relocating the railroad, (c) I-70 vertical realignment, (d) gas well relocation, (e) 1,250 acres of real estate acquisition and (f) engineering and permitting.

2. An estimated $5.3 million in revenue would be produced annually from the 10 MW hydropower installation (see Table 4) based on the hydropower sales prices provided by WAPA and used throughout this series of Technical Memoranda (see footnotes in Table 4 herein). In their comments on the Draft Technical Memorandum No. 4A, Northern Colorado Water Conservancy District suggested that the WAPA hydropower sales prices might be too high and a sales price of $0.04/KwHr would be more appropriate. Using the $0.04/KwHr price would result in approximately $3.2 million in hydropower revenue produced annually.

3. Netting out this $5.3 million in hydropower revenue from the amortized project capital costs would result in the cost of releases from the proposed reservoir to the 15-Mile Reach being reduced to approximately $25.70 per acre-foot (see Table 4). This $25.70 per acre-

foot is based on the WAPA hydropower sales price. If the $0.04/KwHr sales price is used, the cost of a release to the15-Mile Reach increases to $134/acre-foot.

4. Analysis indicates that for those eight years in which the 20,000 acre-feet release would be made to the15-Mile Reach in May and/or June, the Webster Hill Reservoir could be expected to refill by late Summer or early Fall, in time to make a second release of 20,000 acre-feet to the 15-Mile Reach (see Table 1). Consequently, doubling the yield of the proposed reservoir will reduce the costs per acre-foot of yield by one-half. Consequently, the cost of providing two, 20,000 acre-feet releases would be $12.85 per acre-foot based on the WAPA supplied hydropower sales values and approximately $67 per acre-foot based on the $0.04/KwHr estimated sales price.

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. There appears to be sufficient legal and physical availability of water under a junior right for diversion to storage at the Webster Hill site to result in a yield of 40,000 acre-feet per year in those years in which the 20,000 acre-feet release for recovery of the endangered fish would be required. The 28,909 acre-feet reservoir could be expected to refill during late June, July and August under a junior refill right to permit a second release of 20,000 acre-feet release in late summer or early fall.

2. Hydropower revenues from the 10 MW installation would significantly reduce the cost of releases for the endangered species to approximately $26-$134 per acre-foot.

3. The opinions of probable cost developed herein are preliminary and would need additional refinement.

4. The Webster Hill site with a hydropower installation appears to be a potentially feasible reservoir site from an economic perspective. Before concluding that this is a feasible alternative for supplying stored water for making the 20,000 acre-feet releases to the 15-Mile Reach, it is necessary to complete additional investigations including:

    - Right of way availability and estimated cost.
    - More detailed cost investigation for relocating the gas wells.
    - More detailed cost investigation concerning electrical transmission capacity available to the site and cost of providing necessary transmission capacity to the site.
    - Necessary environmental investigations concerning the site.
    - More detailed cost investigation concerning railroad relation and highway relocation costs.
    - A detailed site investigation and materials availability investigation would be necessary to confirm engineering feasibility.
    - Investigation of the feasibility of avoiding railroad and highway relocation by constructing a confinement dike on the north side of the reservoir site.

5. Before doing additional analysis, the U.S. Fish and Wildlife Service should be asked for a determination of their possible acceptance and approval of constructing a 28,909 acre-feet reservoir at the Webster Hill site and the operation of this reservoir for making releases of stored water for recovery of the endangered species of fish.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River.*

Colorado Water Conservation Board, October 2001, *Technical Memorandum No. 4, Analysis of Alternative 4, New Storage Facilities Below Shoshone.*

Dwyer-Shepherd Engineers, February 1976, *Rifle Ski Corporation, Webster Hill Reservoir, Preliminary Engineering Evaluation.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
10/1/1966	335			yes
11/1/1966	50,895			yes
12/1/1966	42,130			yes
1/1/1967	41,291			yes
2/1/1967	34,146			yes
3/1/1967	62,450			yes
4/1/1967	23,909			yes
5/1/1967	220,982			yes
6/1/1967	433,157			yes
7/1/1967	171,176			yes
8/1/1967	19,014			yes
9/1/1967	11,272			yes
10/1/1967	407			yes
11/1/1967	62,274			yes
12/1/1967	56,383			yes
1/1/1968	45,382			yes
2/1/1968	47,011			yes
3/1/1968	51,480			yes
4/1/1968	21,243			yes
5/1/1968	229,082			yes
6/1/1968	662,352			yes
7/1/1968	140,085			yes
8/1/1968	110,832			yes
9/1/1968	11,655			yes
10/1/1968	12,952			yes
11/1/1968	72,051			yes
12/1/1968	60,100			yes
1/1/1969	62,357			yes
2/1/1969	46,549			yes
3/1/1969	53,426			yes
4/1/1969	144,607			yes
5/1/1969	464,657			yes
6/1/1969	410,237			yes
7/1/1969	241,336			yes
8/1/1969	34,799			yes
9/1/1969	19,968			yes
10/1/1969	62,345			yes
11/1/1969	91,380			yes
12/1/1969	78,705			yes
1/1/1970	62,411			yes
2/1/1970	56,859			yes
3/1/1970	74,401			yes
4/1/1970	44,621			yes
5/1/1970	768,567			yes
6/1/1970	743,860			yes
7/1/1970	247,543			yes

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
8/1/1970	50,341			yes
9/1/1970	75,752			yes
10/1/1970	58,938			yes
11/1/1970	115,253			yes
12/1/1970	97,539			yes
1/1/1971	95,627			yes
2/1/1971	72,620			yes
3/1/1971	109,428			yes
4/1/1971	194,163			yes
5/1/1971	429,461			yes
6/1/1971	793,953			yes
7/1/1971	334,521			yes
8/1/1971	61,492			yes
9/1/1971	59,979			yes
10/1/1971	36,951			yes
11/1/1971	98,179			yes
12/1/1971	87,835			yes
1/1/1972	84,555			yes
2/1/1972	79,173			yes
3/1/1972	109,678			yes
4/1/1972	64,573			yes
5/1/1972	282,448			yes
6/1/1972	552,805			yes
7/1/1972	100,780			yes
8/1/1972	23,627			yes
9/1/1972	36,812			yes
10/1/1972	49,159			yes
11/1/1972	111,225			yes
12/1/1972	84,446			yes
1/1/1973	73,096			yes
2/1/1973	65,214			yes
3/1/1973	82,563			yes
4/1/1973	16,398			yes
5/1/1973	526,306			yes
6/1/1973	782,778			yes
7/1/1973	456,086			yes
8/1/1973	92,050			yes
9/1/1973	30,889			yes
10/1/1973	34,801			yes
11/1/1973	101,069			yes
12/1/1973	83,934			yes
1/1/1974	79,568			yes
2/1/1974	68,935			yes
3/1/1974	112,266			yes
4/1/1974	80,524			yes
5/1/1974	611,166			yes
6/1/1974	545,568			yes

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
7/1/1974	168,419			yes
8/1/1974	42,338			yes
9/1/1974	13,375			yes
10/1/1974	18,589			yes
11/1/1974	85,265			yes
12/1/1974	71,174			yes
1/1/1975	63,781			yes
2/1/1975	58,021			yes
3/1/1975	80,611			yes
4/1/1975	46,352			yes
5/1/1975	299,923			yes
6/1/1975	663,425	yes	yes	yes
7/1/1975	452,662			yes
8/1/1975	81,970			yes
9/1/1975	29,076			yes
10/1/1975	25,405			yes
11/1/1975	91,709			yes
12/1/1975	76,853			yes
1/1/1976	71,466			yes
2/1/1976	73,641			yes
3/1/1976	95,309			yes
4/1/1976	50,663			yes
5/1/1976	296,511			yes
6/1/1976	341,354			yes
7/1/1976	94,532			yes
8/1/1976	30,476			yes
9/1/1976	21,654			yes
10/1/1976	21,499			yes
11/1/1976	73,649			yes
12/1/1976	65,265			yes
1/1/1977	59,447			yes
2/1/1977	44,672			yes
3/1/1977	34,434			yes
4/1/1977	5,393			yes
5/1/1977	35,062			yes
6/1/1977	60,413			yes
7/1/1977	3,332			yes
8/1/1977	422			yes
9/1/1977	48			yes
10/1/1977	230			yes
11/1/1977	37,504			yes
12/1/1977	40,120			yes
1/1/1978	33,341			yes
2/1/1978	31,472			yes
3/1/1978	51,045			yes
4/1/1978	64,452			yes
5/1/1978	332,066			yes

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
6/1/1978	748,085	yes	yes	yes
7/1/1978	241,933			yes
8/1/1978	17,491			yes
9/1/1978	549			yes
10/1/1978	635			yes
11/1/1978	68,704			yes
12/1/1978	47,146			yes
1/1/1979	36,611			yes
2/1/1979	42,802			yes
3/1/1979	68,603			yes
4/1/1979	68,766			yes
5/1/1979	515,347	yes	yes	yes
6/1/1979	821,744			yes
7/1/1979	407,397			yes
8/1/1979	61,280			yes
9/1/1979	10,905			yes
10/1/1979	16,086			yes
11/1/1979	85,279			yes
12/1/1979	77,382			yes
1/1/1980	67,082			yes
2/1/1980	70,995			yes
3/1/1980	81,776			yes
4/1/1980	86,132			yes
5/1/1980	549,007			yes
6/1/1980	808,399	yes	yes	yes
7/1/1980	216,922			yes
8/1/1980	28,612			yes
9/1/1980	9,172			yes
10/1/1980	4,015			yes
11/1/1980	65,753			yes
12/1/1980	57,644			yes
1/1/1981	39,765			yes
2/1/1981	25,119			yes
3/1/1981	28,501			yes
4/1/1981	19,932			yes
5/1/1981	88,069			yes
6/1/1981	212,223			yes
7/1/1981	29,528			yes
8/1/1981	12			yes
9/1/1981	3,394			yes
10/1/1981	3,455			yes
11/1/1981	54,352			yes
12/1/1981	43,032			yes
1/1/1982	48,975			yes
2/1/1982	35,394			yes
3/1/1982	53,285			yes
4/1/1982	38,407			yes

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
5/1/1982	331,651	yes	yes	yes
6/1/1982	604,952			yes
7/1/1982	300,738			yes
8/1/1982	94,133			yes
9/1/1982	70,049			yes
10/1/1982	61,334			yes
11/1/1982	108,158			yes
12/1/1982	74,752			yes
1/1/1983	61,853			yes
2/1/1983	55,877			yes
3/1/1983	70,250			yes
4/1/1983	30,649			yes
5/1/1983	429,945			yes
6/1/1983	1,337,633			yes
7/1/1983	923,795			yes
8/1/1983	299,165			yes
9/1/1983	56,754			yes
10/1/1983	32,375			yes
11/1/1983	103,122			yes
12/1/1983	97,945			yes
1/1/1984	87,909			yes
2/1/1984	80,181			yes
3/1/1984	117,403			yes
4/1/1984	127,837			yes
5/1/1984	1,099,791			yes
6/1/1984	1,417,806			yes
7/1/1984	826,921			yes
8/1/1984	281,062			yes
9/1/1984	135,136			yes
10/1/1984	106,474			yes
11/1/1984	145,966			yes
12/1/1984	135,414			yes
1/1/1985	111,949			yes
2/1/1985	93,066			yes
3/1/1985	125,060			yes
4/1/1985	260,473			yes
5/1/1985	883,183			yes
6/1/1985	898,956	yes	yes	yes
7/1/1985	319,145			yes
8/1/1985	95,644			yes
9/1/1985	32,192			yes
10/1/1985	84,190			yes
11/1/1985	134,640			yes
12/1/1985	106,240			yes
1/1/1986	103,422			yes
2/1/1986	115,900			yes
3/1/1986	165,005			yes

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Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
4/1/1986	316,614			yes
5/1/1986	702,177			yes
6/1/1986	941,423	yes	yes	yes
7/1/1986	409,325			yes
8/1/1986	104,390			yes
9/1/1986	87,998			yes
10/1/1986	103,541			yes
11/1/1986	142,671			yes
12/1/1986	112,191			yes
1/1/1987	89,609			yes
2/1/1987	85,921			yes
3/1/1987	105,941			yes
4/1/1987	130,249			yes
5/1/1987	438,072			yes
6/1/1987	366,832			yes
7/1/1987	74,050			yes
8/1/1987	38,210			yes
9/1/1987	15,259			yes
10/1/1987	10,800			yes
11/1/1987	84,400			yes
12/1/1987	67,268			yes
1/1/1988	57,779			yes
2/1/1988	55,062			yes
3/1/1988	74,550			yes
4/1/1988	76,404			yes
5/1/1988	281,957			yes
6/1/1988	351,748			yes
7/1/1988	66,745			yes
8/1/1988	13,030			yes
9/1/1988	10,429			yes
10/1/1988	125			yes
11/1/1988	60,241			yes
12/1/1988	50,202			yes
1/1/1989	46,412			yes
2/1/1989	42,094			yes
3/1/1989	71,567			yes
4/1/1989	85,120			yes
5/1/1989	211,497			yes
6/1/1989	203,751			yes
7/1/1989	53,029			yes
8/1/1989	26,392			yes
9/1/1989	2,604			yes
10/1/1989	2,329			yes
11/1/1989	49,897			yes
12/1/1989	38,055			yes
1/1/1990	28,261			yes
2/1/1990	30,373			yes

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
3/1/1990	37,534			yes
4/1/1990	4,969			yes
5/1/1990	75,357			yes
6/1/1990	275,724			yes
7/1/1990	62,808			yes
8/1/1990	5,363			yes
9/1/1990	4,120			yes
10/1/1990	3,126			yes
11/1/1990	52,864			yes
12/1/1990	30,435			yes
1/1/1991	38,956			yes
2/1/1991	31,976			yes
3/1/1991	40,380			yes
4/1/1991	14,819			yes
5/1/1991	295,109			yes
6/1/1991	478,984	yes	yes	yes
7/1/1991	124,131			yes
8/1/1991	29,649			yes
9/1/1991	27,372			yes
10/1/1991	7,226			yes
11/1/1991	76,494			yes
12/1/1991	51,309			yes
1/1/1992	39,932			yes
2/1/1992	40,918			yes
3/1/1992	57,660			yes
4/1/1992	50,387			yes
5/1/1992	263,560			yes
6/1/1992	172,648			yes
7/1/1992	59,900			yes
8/1/1992	34,297			yes
9/1/1992	20,579			yes
10/1/1992	2,676			yes
11/1/1992	77,894			yes
12/1/1992	48,382			yes
1/1/1993	41,780			yes
2/1/1993	37,966			yes
3/1/1993	75,651			yes
4/1/1993	82,061			yes
5/1/1993	752,871			yes
6/1/1993	870,054			yes
7/1/1993	378,119			yes
8/1/1993	86,971			yes
9/1/1993	45,121			yes
10/1/1993	37,859			yes
11/1/1993	87,746			yes
12/1/1993	73,058			yes
1/1/1994	70,404			yes

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
2/1/1994	58,720			yes
3/1/1994	86,026			yes
4/1/1994	63,494			yes
5/1/1994	282,677			yes
6/1/1994	259,130			yes
7/1/1994	27,622			yes
8/1/1994	21,386			yes
9/1/1994	15,630			yes
10/1/1994	9,679			yes
11/1/1994	57,533			yes
12/1/1994	54,390			yes
1/1/1995	49,532			yes
2/1/1995	47,675			yes
3/1/1995	77,376			yes
4/1/1995	33,511			yes
5/1/1995	272,033			yes
6/1/1995	1,131,706			yes
7/1/1995	972,336			yes
8/1/1995	234,297			yes
9/1/1995	77,263			yes
10/1/1995	59,449			yes
11/1/1995	115,793			yes
12/1/1995	96,186			yes
1/1/1996	83,273			yes
2/1/1996	95,529			yes
3/1/1996	129,947			yes
4/1/1996	229,368			yes
5/1/1996	685,900			yes
6/1/1996	713,550			yes
7/1/1996	223,084			yes
8/1/1996	35,405			yes
9/1/1996	30,030			yes
10/1/1996	38,395			yes
11/1/1996	97,876			yes
12/1/1996	80,417			yes
1/1/1997	82,000			yes
2/1/1997	67,110			yes
3/1/1997	129,529			yes
4/1/1997	143,605			yes
5/1/1997	784,690			yes
6/1/1997	1,235,601			yes
7/1/1997	320,097			yes
8/1/1997	198,058			yes
9/1/1997	107,732			yes
Total	59,685,846			

Table 1
Estimated Water Availability to a Junior Water Right Diverting from the Colorado River at the Webster Hill Reservoir Site

Date	Water Available (AF)	20,000 AF Release Required?	Is it possible to Refill in July & August?	Greater than 200 cfs?
Average	160,446			
Maximum	1,417,806			
Minimum	12			

Notes:

1. Source of data is: HydroBase, Division 5 Streamflow Records. Data in this table were estimated by:

a. Flow at the Webster Hill site was estimated as: Flow at the De Beque gage - Parachute Creek flow.

b. During the irrigation season, available flow for diversion under a junior right at the Webster Hill site was estimated by: Estimated flow at the Webster Hill site - 2000 cfs (the Cameo call).

c. During the non-irrigation season, available flow for diversion under a junior right at the Webster Hill site was estimated by: Estimated flow at the Webster Hill site - 800 cfs (the Grand Valley Power Project call)

Table 2 Updated Conceptual Cost Estimate for Webster Hill Dam and Reservoir

Feature	1976 Dwyer - Shepherd Dam Estimate	2001 Estimate of Other Required Components	2001 Cost
Webster Hill Dam and Reservoir	$ 8,480,000		$ 16,249,000
10 MW Hydropower Component		$13,000,000	$ 13,000,000
Railroad Relocation		$ 2,260,000	$ 2,260,000
Interstate 70 Vertical Re-alignment		$ 4,850,000	$4,850,000
Gas Well Re-location		$ 2,000,000	$ 2,000,000
Real Estate Acquisition (1250 acres)		$ 9,375,000	$ 9,375,000
Subtotal			**$ 47,734,000**
Engineering and Permitting - 30%			$ 14,320,000
Contingency - 30%			$ 14,320,000
Total			**$ 76,374,000**

Notes:

1) 3.0% = annual price index to adjust 1980 costs to 2001
2) The 1976 Dwyer - Sheperd cost does not include the cost of land acquisition, rights of way, reservoir basin clearing, relocations or modifications to transportation, relocation or modifications to gas wells or other facilities within the reservoir basin, nor does it include a hydropower component.
3) Reservoir Data:
   WSL: 5,250
   AF: 28,909
   Dam Height 68 ft. above stream bed.
4) 1976 Costs from *Rifle Ski Corporation, Webster Hill Reservoir, Preliminary Engineering Evaluation*, February 1976, Dwyer-Shepherd Engineers. Cost used above is for a concrete gravity dam, a maximum WSL of 5,250 and a reservoir capacity of 28,909 AF.
5) 2001 Costs for components not included in Dwyer-Shepherd estimate are conceptual estimates. These estimates should be refined based on pre-feasibility level design.
6) Acquisition and installation of the turbines is estimated to cost $1300/kw (personal communication from James Street, CRS Sirrine, Inc. to Jim Warford, Brown and Caldwell, Walnut Creek, CA, June 13, 2001. Therefore: $1300/kw x 10mw x 1000kw/mw = $13 million.

Table 3 Amortized Cost Based on CWCB Loan Criteria

Annual Rate	6.50%
Term (yrs)	30
Capital Recovery Factor	0.0766
Annual Payment	$ 5,849,000
Cost per AF for 20kaf of yield:	$ 292/AF of average annual yield
Cost per AF for 40kaf of yield:	$146/AF of average annual yield

Notes:

1) Annual Payment assumes payment at end of year.
2) Cost per AF based on 20,000 AF delivered to 15-Mile Reach annually.

Table 4 Estimated Power Revenue

	Case 1	Case 2
Annual Generation (KwHr) (from Dwyer and Sheperd)	78,000,000[1]	79,000,000[2]
Power Contract Rate ($/KwHr)	$ 0.0684[3]	$0.04[4]
Annual Power Revenue	$ 5,335,000	$3,160,000
Remaining Annual Cost After Deducting Power Revenue	-$514,000[5]	2,689,000[6]
Net Annual Cost After Deducting Power Revenue/AF for 20,000 AF of yield	$25.70/AF	$134/AF
Net Annual Cost After Deducting Power Revenue/AF for 40,000 AF of yield	$12.85/AF	$67/AF

Notes:

1) Annual Power Generation is from Dwyer-Shepherd for a 12MW plant operating as a run-of-the-river facility. This represents power generation for a period of approximately 271 days for 24 hours per day, a flow through the turbines of 200 cfs, a water to wire efficiency of 70 percent, and an average head of 50 feet.

2) The Dwyer-Shepherd estimate compares closely to an estimate based on the following:

   - 2,000 cfs approximately 70 percent of the time. This is based on a flow frequency diagram for Cameo (1974-1994) provided as an attachment to a memo (July 24, 2001 memo from Alan Berryman to Carl Brouwer) received from Eric Wilkinson (September 7, 2001).
   - Average head of 50 ft
   - Efficiency factor of 70 percent

   Therefore, using these values, we estimate about 79 KWhr.

3) The sales price of electric power used in this evaluation is $ 68.39/MWHr. These data were obtained from John Gierard, WAPA and were used in valuation of power generation foregone at Ruedi Reservoir. The $68.39 is the average sales price for the period of June 2000 through May 2001. See table below.

Actual and Projected Electric Power Prices ($/MWH)

Date	Purchase	Sale
June 2000	75.44	54.16 actual
July 2000	116.54	61.76
August 2000	115.89	106.93
September 2000	60.47	58.66
October 2000	65.48	38.78
November 2000	71.63	65.02
December 2000	113.19	105.41
January 2001	110.00	130.00 projected
February 2001	70.00	65.00
March 2001	50.00	45.00
April 2001	50.00	45.00
May 2001	50.00	45.00
Average	**79.05**	**68.39**

4) Carl Brouwer, NCWCD, suggests that $0.04/KWhr is a more appropriate power rate (July 24, 2001 memo from Carl Brouwer to Alan Berryman).

5) Remaining average annual cost after deducting power revenue: $5,849,000 - $5,335,000 = $514,000 The annual cost of $5,849,000 is from Table 3.

6) Remaining annual cost after deducting power revenue: $5,849,000 - $3,160,000 = $2,689,000

TECHNICAL MEMORANDUM NO. 5:
ANALYSIS OF ALTERNATIVE 1B,
EXPANDED COORDINATED RESERVOIR OPERATIONS
OF RUEDI RESERVOIR

PRODUCED FOR:

Colorado Water Conservation Board

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JUNE 2001
Revised October 2001

TECHNICAL MEMORANDUM NO. 5:
ANALYSIS OF ALTERNATIVE 1B,
EXPANDED COORDINATED RESERVOIR OPERATIONS
OF RUEDI RESERVOIR

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EXECUTIVE SUMMARY

A draft version of this Technical Memorandum was completed in June 2001 and presented to the Colorado Water Conservation Board (CWCB) and the Executive Committee for review. Comments were received from CWCB and the Executive Committee and have been incorporated into this revised version.

The purpose of Technical Memorandum No. 5 is to present the results from investigating Alternative 1b, Ruedi Reservoir Re-operations. As presented in the Phase 1 analysis (CWCB, September 2000), this alternative has the following components:

- A target release of 20,000 acre-feet is made from Ruedi Reservoir during a 10-day period surrounding the spring peak hydrograph in late May or early June. Under the concept of this alternative, this release would be made from the 26,000 acre-feet CWCB fish pool in Ruedi Reservoir.
- This 20,000 acre-feet release is replaced in Ruedi Reservoir by diversions to storage under the 101,280 acre-feet Ruedi Reservoir 1981 refill right.

The objective of this investigation is to determine the overall feasibility of this alternative and to analyze the impact of this alternative on: (1) Ruedi Reservoir's yield, operation and maintenance costs and operational flexibility and reliability (2) other existing west slope projects' yields, (3) existing west slope projects' operations and maintenance costs and (4) existing west slope projects' operational flexibility or reliability. Overall feasibility and the effects on other existing west slope projects from this proposed change in Ruedi Reservoir operations was investigated using StateMod and the C1 data set for the 1975-91 study period. Because StateMod and the C1 data set only cover the Colorado River basin in Colorado, it was not possible to investigate the effects of Alternative 1b on east slope facilities.

Results of this investigation include:

1. **20,000 acre-feet release frequency.** As reported in Technical Memorandum 1, it was not necessary to make the 20,000 acre-feet release in every year. The 20,000 acre-feet release would be required in only six years (1975, 1978, 1979, 1980, 1985, and 1986) and possibly in 1982 and 1991.

2. **Unfeasibility of making full 20,000 acre-feet release.** The 1,100 cfs channel constraint on the Frying Pan River near Basalt precludes releasing the full 20,000 acre-feet over a 10-day period at an average release rate of 1,000 cfs. Making the full 20,000 acre-feet release is further complicated by the inadequate physical availability of inflow to Ruedi Reservoir that can be diverted to storage under the 1981 Ruedi Reservoir refill right to replace the 20,000 acre-feet release.

3. **Maximum possible releases without violating channel flow constraint.** Calculations were performed to estimate the maximum release that could be made in specific years for the endangered fish. These calculations indicate the maximum release that could be made without violating the 1,100 cfs channel constraint varied from approximately 8,895 acre-

feet to approximately 17,445 acre-feet over a 10-day period for the 1975-1991 study period. The average maximum release for the eight years in which a release to the 15-Mile Reach could be required during the study period is 13,910 acre-feet.

4. **Ruedi Reservoir storage.** Further analysis indicates there would not be sufficient inflow to Ruedi Reservoir to allow replacement of these releases by diversion to storage under the Ruedi Reservoir refill right in all years. In 1978, 1980, and 1991, Ruedi inflows were insufficient to completely replace the release for the endangered species based on using the total available channel capacity. The CWCB fish pool would have been short an average of approximately 2,073 acre-feet in 1978, 1980 and 1991 as compared to the base case.

5. **Reduced releases.** Sensitivity analysis was completed to determine the effect on Ruedi Reservoir refilling if releases toward the 20,000 acre-feet target were reduced to a level below the maximum that would not violate the 1,100 cfs channel capacity constraint. Sensitivity analysis was completed using releases that were approximately one-half of the maximum possible releases that would not violate the channel capacity constraints.

6. **Sensitivity analysis.** Sensitivity analysis using the reduced releases (one-half of the available capacity in the constrained channel reach near Basalt) indicated: (a) Ruedi Reservoir would have refilled to the same level of storage as in the C1 baseline scenario in all but two years (1980 and 1991) and (b) the deficiency in refilling would have averaged approximately 351 acre-feet for those eight years when a release was made to the 15-Mile Reach. The sensitivity analysis further indicated that with the full releases (releasing from Ruedi Reservoir at a rate equivalent to the full available channel capacity near Basalt): (a) Ruedi Reservoir would have refilled to the same level as in the C1 baseline scenario in all but three years (1978, 1980 and 1991) and (b) the average annual deficiency in refilling for the eight years in which a release was made to the 15-Mile Reach would have averaged approximately 2,073 acre-feet.

7. **Ruedi Reservoir power production.** Revenue from Ruedi Reservoir power production was decreased for the scenario utilizing full channel capacity releases by a total of $309,500 over the 17-year study period for an average annual reduction of approximately $18,200 per year over the 17-year period. For the scenario utilizing half channel capacity releases, the revenue increased $70,600 over the 17-year study period or approximately $4,150 per year.

7. **Orchard Mesa Power Plant.** The Ruedi Reservoir Re-operations alternative did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the proposed operating policy for Ruedi Reservoir.

8. **Physical feasibility of making releases through existing Ruedi Reservoir outlet facilities.** In the six years in which the 20,000 acre-feet release was required and the two additional years in which the release might be required, it would be physically possible to

make the maximum release which would not violate the channel capacity through existing Ruedi Reservoir outlet facilities.

9. **Channel capacity constraints.** As reported above, restrictions on Frying Pan River channel capacity would have limited the 1,000 cfs for 10 days to lesser rates of release during all of the six years in which the release was required and the two years in which the release for the endangered species might have been required for the 1975-91 study period.

10. **Boustead Tunnel and Busk-Ivanhoe Tunnel Deliveries.** The C1 data set demand schedule for deliveries through the Boustead Tunnel was met under Alternative 1b for all months in the study period except May of 1979. The C1 data set deliveries through the Busk-Ivanhoe Tunnel were not shorted because of the partial releases from Ruedi Reservoir contributing toward the target 20,000 acre-feet releases to the 15-Mile Reach.

Conclusions and Recommendations include:

1. Because of the limited channel conveyance capacity on the Roaring Fork River near Basalt, it was not possible to make the total 20,000 acre-feet release to the 15-Mile Reach at a rate of 1,000 cfs for a period of 10 days. Making the full 20,000 acre-feet release is further complicated by the inadequate physical availability of inflow to Ruedi Reservoir that can be diverted to storage under the 1981 Ruedi Reservoir refill right to replace the 20,000 acre-feet release.

2. Other than the reduction in storage in Ruedi Reservoir as a result of making a portion of the 20,000 acre-feet release from this reservoir, storage in other west slope reservoirs was not affected by Alternative 1b.

3. Hydropower production at Ruedi Reservoir was reduced approximately $18,200 per year when full channel capacity releases were utilized, but increased approximately $4,150 per year when only half channel capacity releases were utilized.

4. If the Ruedi Reservoir release to the 15-Mile Reach during the years in which it is required is limited to approximately 7,000 acre-feet, this should significantly limit effects on Ruedi Reservoir storage.

5. Deliveries to the east slope via the Boustead and Busk-Ivanhoe Tunnels were not affected by Alternative 1b (except for a shortage in May of 1979 for the Boustead Tunnel). It was not possible to investigate other effects to east slope facilities and systems with StateMod and the C1 data set because this model and data set only cover the Colorado River basin in Colorado and do not extend to the east slope.

6. If releases to the 15-Mile Reach are limited to approximately 7,000 acre-feet from Ruedi Reservoir, there do not appear to be additional fatal flaws in Alternative 1b.

7. The Ruedi Reservoir Re-operations alternative appears feasible and further consideration of this alternative is warranted for providing an average of approximately 7,000 of the 20,000 acre-feet target release to the 15-Mile Reach.

8. The feasibility of replacing stored water releases toward the 20,000 acre-feet target release should be investigated under projected future conditions with an additional 60,000 to 120,000 acre-feet of depletions and with CROP in operation.

INTRODUCTION AND PURPOSE

Alternative 1b, revising Ruedi Reservoir operations to produce flows contributing to the average annual 20,000 acre-feet target, was recommended as a result of the Phase 1 investigation. As specified in the Phase 1 Report (CWCB, September 2000), the Ruedi Reservoir Re-operations alternative has the following components:

- A release of 20,000 acre-feet is made from Ruedi Reservoir at a rate of approximately 1,000 cfs during a 10-day period surrounding the spring peak hydrograph in late May or early June. This release would be made from the 26,000 acre-feet CWCB fish pool in Ruedi Reservoir.
- This 20,000 acre-feet release would be replaced in the CWCB fish pool by either: (1) refilling the pool under the 1981 Ruedi Reservoir refill right or (2) refilling the pool with water not released during the previous winter as a result of reduced Ruedi Reservoir bypass flows.

The purpose of this Technical Memorandum is to present: (1) the methodology used to analyze Alternative 1b, reoperation of Ruedi Reservoir and (2) the results of this analysis. Specific concerns to be addressed in this engineering analysis of the Ruedi Reservoir Re-operations alternative include:

1. The frequency with which the 20,000 acre-feet per year target release can be made in those years when the expected peak spring flow at the head of the 15-Mile Reach is between 12,900 cfs and 26,600 cfs using Alternative 1b (Ruedi Reservoir Re-operations) as the source of supply for the 20,000 acre-feet.

2. The frequency with which the 20,000 acre-feet release can be replaced in the CWCB fish pool in Ruedi Reservoir. Filling Ruedi Reservoir storage vacated by the 20,000 acre-feet release would be done under the Ruedi Reservoir refill right or with water saved by reducing the winter Ruedi Reservoir bypass flows.

3. The effect on deliveries to the east slope via the Boustead and Busk-Ivanhoe Tunnels. Investigation of the effects of Alternative 1a on other east slope facilities and systems is not possible because StateMod and the C1 data set only cover the Colorado River basin in Colorado and do not extend to the east slope.

4. The effect on operation and yield of Ruedi Reservoir and other west slope projects as a result of this alternative.

5. The effect on hydropower generation at Ruedi Reservoir and Orchard Mesa Power Plant.

6. The effect on flooding in downstream reaches of the Frying Pan River and the potential for exceeding the 1,100 cfs identified safe channel capacity near Basalt.

7. The physical feasibility of releasing the 20,000 acre-feet at a rate of 1,000 cfs over a 10-day period from Ruedi Reservoir through existing facilities.
8. Determining the acceptability of higher spring flows for a period of ten days in the Frying Pan and Roaring Fork Rivers.

Other legal/institutional concerns exist involving this alternative; these concerns are not addressed in this Technical Memorandum, but may be addressed by the legal team and discussed in the Phase 2 report or possibly in a separate legal memorandum. These legal/institutional issues include the ongoing controversy regarding the Bureau of Reclamation's authority to release water from Ruedi Reservoir for benefit of the endangered fishes. This may be an issue under: (1) Ruedi Reservoir water rights (which are held by the Colorado River Water Conservation District and SECWCD) and (2) the Frying Pan-Arkansas Project operating criteria and authorizing legislation. This second issue many not be of concern if water is released only from the regulatory pool. However, if water is released from the SECWCD replacement pool, this may become an issue of concern.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following procedures and assumptions were employed in the analysis of the Ruedi Reservoir Re-operations alternative:

1. The StateMod surface water model and C1 dataset were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 Scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the Programmatic Biological Opinion (U.S. Fish and Wildlife Service, December 1999). The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).* These components of RIPRAP flows include:

    - 5,000 acre-feet per year from Ruedi Reservoir
    - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir
    - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease
    - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs)
    - 6,000 acre-feet per year from Wolford Mountain Reservoir

5. StateMod and the C1 dataset were modified to include the actual Ruedi Reservoir refill priority date of January 22, 1981 for 101,280 acre-feet.

6. Flow Targets: In the initial phases of this investigation, releases of 20,000 acre-feet over a 10-day period were made from Ruedi Reservoir when the expected spring peak flow at the head of the 15-Mile Reach was between 12,900 cfs and less than 26,600 cfs. Results of this initial investigation indicated that 20,000 acre-feet released over the 10-day period would result in violation of the 1,100 cfs identified safe channel capacity of the Frying Pan River near Basalt. Consequently, the latter part of the study focused on determining the amount of water that could be released from Ruedi Reservoir without violating the downstream channel constraint.

7. CROP and the 60,000 and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee determine after their review and

Brown and Caldwell makes necessary changes that the methodology and calculations employed in the analysis of this alternative are acceptable, the necessary sensitivity analysis will be completed.

CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

8. Ruedi Reservoir has a first fill right with a priority date of July 29, 1957 for 102,368.7 acre-feet and a refill right for 101,280 acre-feet with priority date of January 22, 1981.

9. Ruedi Reservoir turbine capacity is 300 cfs but is limited to 260-270 cfs in practice (telephone conferences with Phil Harris, High Country Engineering, May 18, 2001 and Mark Fuller, Ruedi Water and Power Authority, May 16, 2001). Ruedi Reservoir outlet capacity bypassing the turbine is 1,000 cfs based on telephone conference with Mark Fuller. Mr. Fuller urged that this be confirmed with the Bureau of Reclamation; Brown and Caldwell was not able to confirm this with the Bureau.

10. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

11. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when these two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February.

The C1 dataset, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance. In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 baseline scenario's lack of simulation of the hydropower maintenance periods.

The effects of not specifically considering these maintenance periods are to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data set creates a significant bias in the results which would affect conclusions from this investigation.

A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 baseline scenario's lack of simulation of the hydropower maintenance periods

12. There are three categories of reservoir fill for Green Mountain Reservoir:

    - The physical fill,
    - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
    - A reservoir fill according to the criteria of the Blue River Decree.

    The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

    Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

    Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of

the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

13. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

    - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
    - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
    - Sufficient HUP Surplus water exists to make the release.

    Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. Releases of HUP Surplus water under the Municipal Recreational Agreement are not explicitly modeled by StateMod and the C1 data set and there is no demand specified at a node for the Municipal Recreational water.

USE OF STATEMOD

Ruedi Reservoir is modeled in the C1 scenario using six separate pools, including the Contract Pool, CWCB Fish Pool, the Unallocated/Dead Pool, Replacement Pool and two 5,000 acre-feet USFW Pools. Details of the method of modeling Ruedi Reservoir in the C1 scenario can be found in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000).*

A review of the Base C1 scenario releases from Ruedi Reservoir was made to compare existing releases to the available channel capacity at Basalt. The remaining available capacity was then compiled to estimate the maximum release to the 15-Mile Reach each year in the study period, which ranged from 9,000 to 17,500 acre-feet. Monthly demands of 5,000 to 9,000 acre-feet were added to the head of the 15-Mile Reach (Diversion ID #952001) corresponding to the projected 20,000 acre-feet releases to enhance the spring runoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1982, 1985, 1986 and 1991. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water in the stream when available.

For the Reudi Reservoir alternative, the baseline scenario was modified as follows:

- The operating rule that allowed releases from the CWCB account to the 15-Mile Reach fish requirement (Diversion ID# 952001) was turned on. These permitted a pre-emptive release of 5,000 to 9,000 acre-feet of water from the CWCB account in those years when it would be required.

- The Ruedi Reservoir refill right was incorrectly given a priority number of 99999.99 in the C1 run. The correct priority number of 47869 was used in the revised baseline run.

Several spreadsheets were then developed that allowed side by side comparison of every aspect of the analysis in the two StateMod runs, including reservoir storage, diversions, streamflows and operating releases.

RESULTS

Table 1 presents Ruedi Reservoir estimated inflows for the study period and indicates that there is limited water available in some years for filling the 101,280 acre-feet reservoir.

The portion of the 20,000 acre-feet release that could be made without violating the 1,100 cfs Frying Pan River channel constraint was determined for those years in which the release would be required (1975, 1978, 1979, 1980, 1985, 1986 and possibly 1982 and 1991). Table 2 and Figure 1A present the estimated releases from Ruedi Reservoir that could be made without violating the 1,100 cfs channel constraint. These estimated releases range from approximately 9,000 to 17,500 acre-feet during the 10-day period.

Figure 2A presents end of month storage in the 26,000 acre-feet CWCB fish pool in Ruedi Reservoir for: (1) the base case (no releases toward the 20,000 acre-feet release) and (2) the scenario in which releases toward the 20,000 acre-feet target release were made which would not violate the 1,100 cfs channel constraint in the Frying Pan River near Basalt. As indicated in Figure 2A, the 20,000 acre-feet Ruedi Reservoir CWCB fish pool would not refill every year that the releases for recovery of the endangered fish were made. Specifically, these results indicate that if the maximum estimated release is made that would not violate the 1,100 cfs channel constraint on the Frying Pan River near Basalt, Ruedi Reservoir would not have refilled in 1978, 1980 and 1991. As indicated in Table 3 (see Column 4), the average annual reduction in storage in Ruedi Reservoir as result of making the maximum estimated release that will not violate the 1,100 cfs channel constraint is approximately 2,073 acre-feet. The annual amounts of reduced storage ranged from 0 to approximately 8,422 acre-feet (see Column 4 in Table 3). Figure 3A presents total storage in Ruedi Reservoir and indicates the effect of making the maximum release toward the 20,000 acre-feet target without violating the 1,100 cfs channel constraint.

Sensitivity analysis was completed to determine the effect of smaller releases on refilling Ruedi Reservoir under its refill right. Releases toward the 20,000 acre-feet target were limited to approximately one-half of the available channel capacity (see Table 2 and Figure 1B). Results of this sensitivity analysis are presented on Figure 2B, which details end of month storage in the 20,000 acre-feet CWCB fish pool in Ruedi Reservoir with the reduced release. Table 3 (Column 5) summarizes these results and indicates that the average annual reduction in storage in the 20,000 acre-feet CWCB fish pool with the reduced releases is 351 acre-feet, as compared to the 2,073 acre-feet deficiency with the maximum releases that would not exceed channel capacity. Figure 3B presents total storage in Ruedi Reservoir and indicates the effect of making the reduced release.

The effects on power generation from making the maximum releases without violating the channel constraint is presented in Tables 4 and 5. Results in Table 4 indicate Ruedi Reservoir power revenues would be reduced by an average of $18,205 per year over the study period as a result of making the maximum releases toward the 20,000 acre-feet target without violating the channel constraint. Table 5 indicates that restricted releases at approximately half of the channel capacity would increase power revenues by approximately $4,150 per year over the study period.

The C1 data set demand schedule for deliveries through the Boustead Tunnel was met under Alternative 1b (restricted releases through Ruedi Reservoir) for all months in the study period except May of 1979 (see Table 6). The C1 data set deliveries through the Busk-Ivanhoe Tunnel were not shorted because of the partial releases from Ruedi Reservoir contributing toward the target 20,000 acre-feet releases to the 15-Mile Reach

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. The 1,100 cfs channel constraint on the Frying Pan River near Basalt would not allow the 20,000 cfs target release to be released at a rate of 1,000 cfs over a period of 10 days without violating the channel constraint in any of the eight years in which a release for the endangered species would have been required for the 1975-91 study period.

2. There is insufficient inflow to Ruedi Reservoir in three out of eight years during the 1975-91 study period in which the 20,000 acre-feet target release would be required to refill Ruedi Reservoir under its refill right to the same level as in the C1 baseline scenario. The average deficiency in storage for these eight years is 2,073 acre-feet and ranges from 0 to 8,422 acre-feet.

3. Sensitivity analysis indicates that the reservoir will refill to the same level as in the C1 baseline scenario under its junior refill priority if releases toward the 20,000 acre-feet are limited to approximately one-half of the available channel capacity at Basalt. By limiting releases from Ruedi Reservoir to an average of approximately 7,000 acre-feet, storage in Ruedi Reservoir will be approximately 525 acre-feet less with Alternative 1b than with the C1 baseline scenario in 1980 and 2,282b acre-feet less with Alternative 1b as compared to the C1 baseline scenario in 1991.

4. Refilling the pool with water not released during the previous winter as a result of reduced Ruedi Reservoir bypass flows was not further investigated because of: (1) expected opposition to reducing these bypass flows and (2) the apparent feasibility of replacing the stored water released for the 15-Mile Reach with diversions to storage under Ruedi Reservoir's refill right.

5. Deliveries to the east slope via the Boustead and Busk-Ivanhoe Tunnels were not affected by Alternative 1b (except for a shortage in May of 1979 for the Boustead Tunnel). It was not possible to investigate other effects to east slope facilities and systems with StateMod and the C1 data set because this model and data set only cover the Colorado River basin in Colorado and do not extend to the east slope.

6. Therefore, it appears that the Ruedi Reservoir Re-operations alternative is feasible and that further consideration of this alternative as a source of supply for a portion of the 20,000 acre-feet target is warranted. Based on the analysis herein, it appears that this alternative could be expected to provide a source of approximately 7,000 of the 20,000 acre-feet target release and still have a reasonable expectation of refilling the reservoir.

7. Feasibility of replacing the water released from Ruedi Reservoir toward the 20,000 acre-feet target release should be investigated under projected future conditions with an additional 60,000 to 120,000 acre-feet of depletions and with CROP in operation.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River.*

U.S. Fish and Wildlife Service, December 1999, *Final Programmatic Biological Opinion for Bureau of Reclamation's Operations and Depletions, Other Depletions and Funding and Implementation of Recovery Program Actions and Water Depletions in the Upper Colorado River Above the Confluence with the Gunnison River.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1A

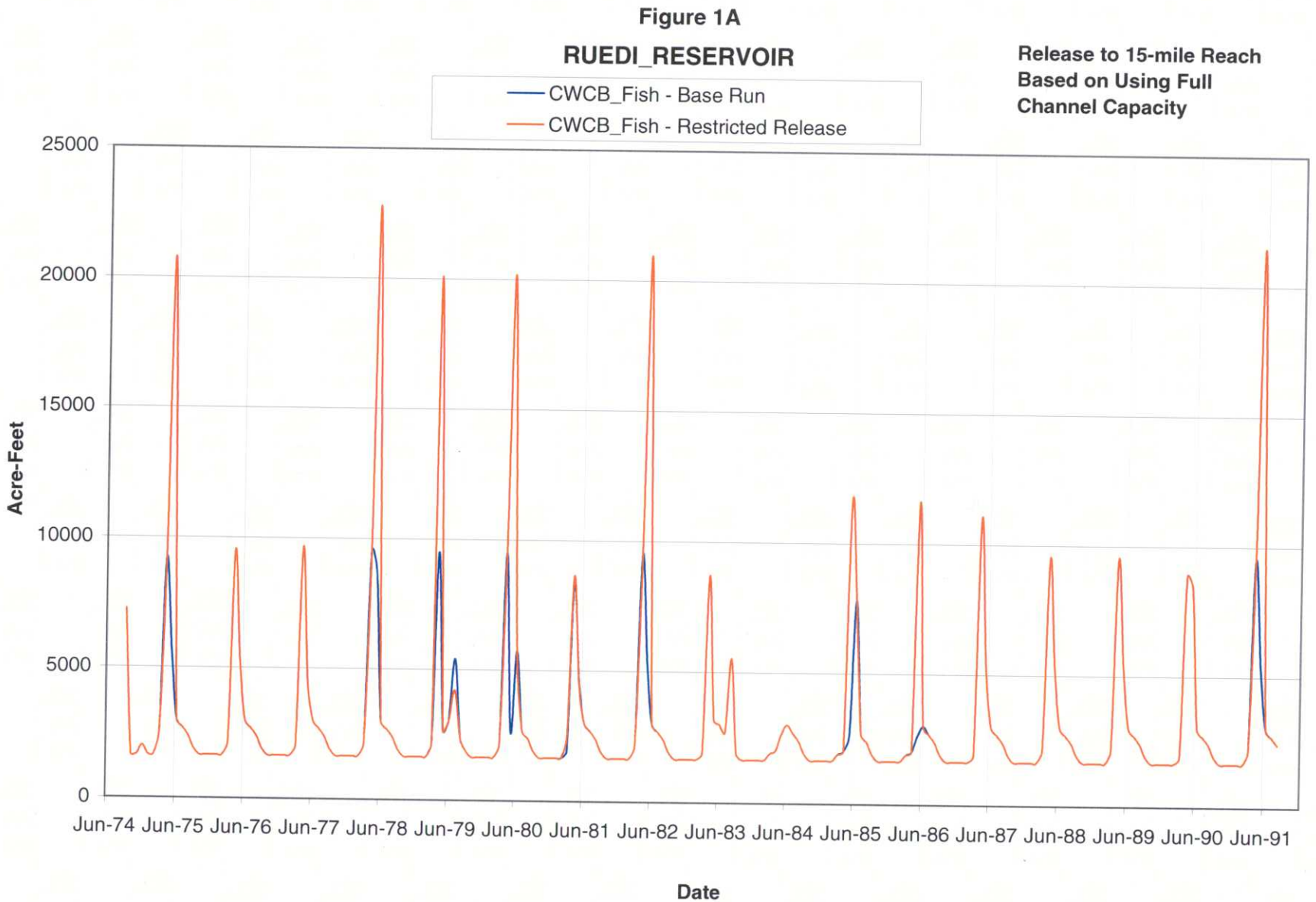
RUEDI_RESERVOIR
Release to 15-mile Reach Based on Using Full Channel Capacity
CWCB_Fish - Base Run
CWCB_Fish - Restricted Release
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Figure 1B

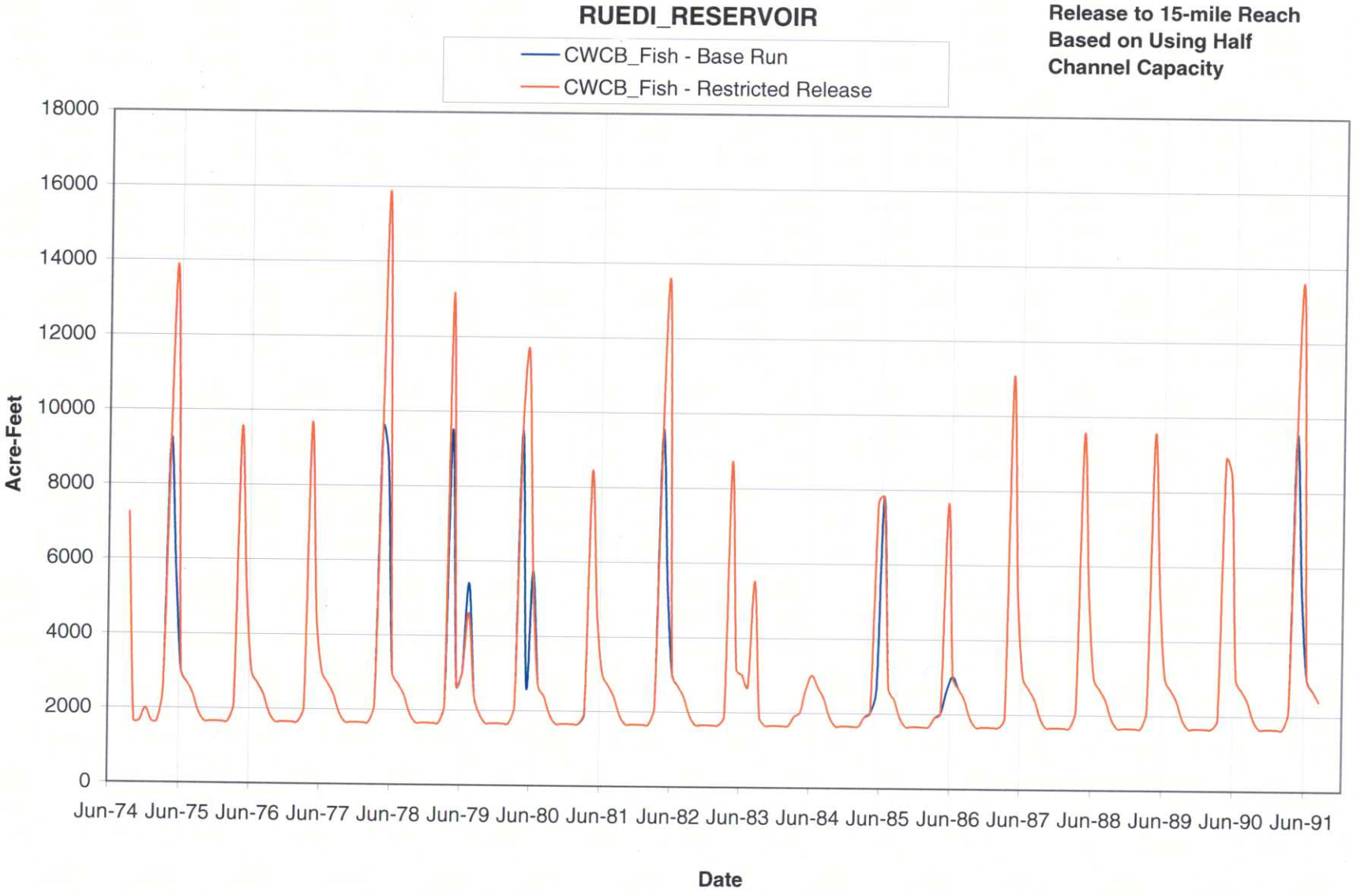
RUEDI_RESERVOIR
Release to 15-mile Reach Based on Using Half Channel Capacity
CWCB_Fish - Base Run
CWCB_Fish - Restricted Release
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Figure 2A

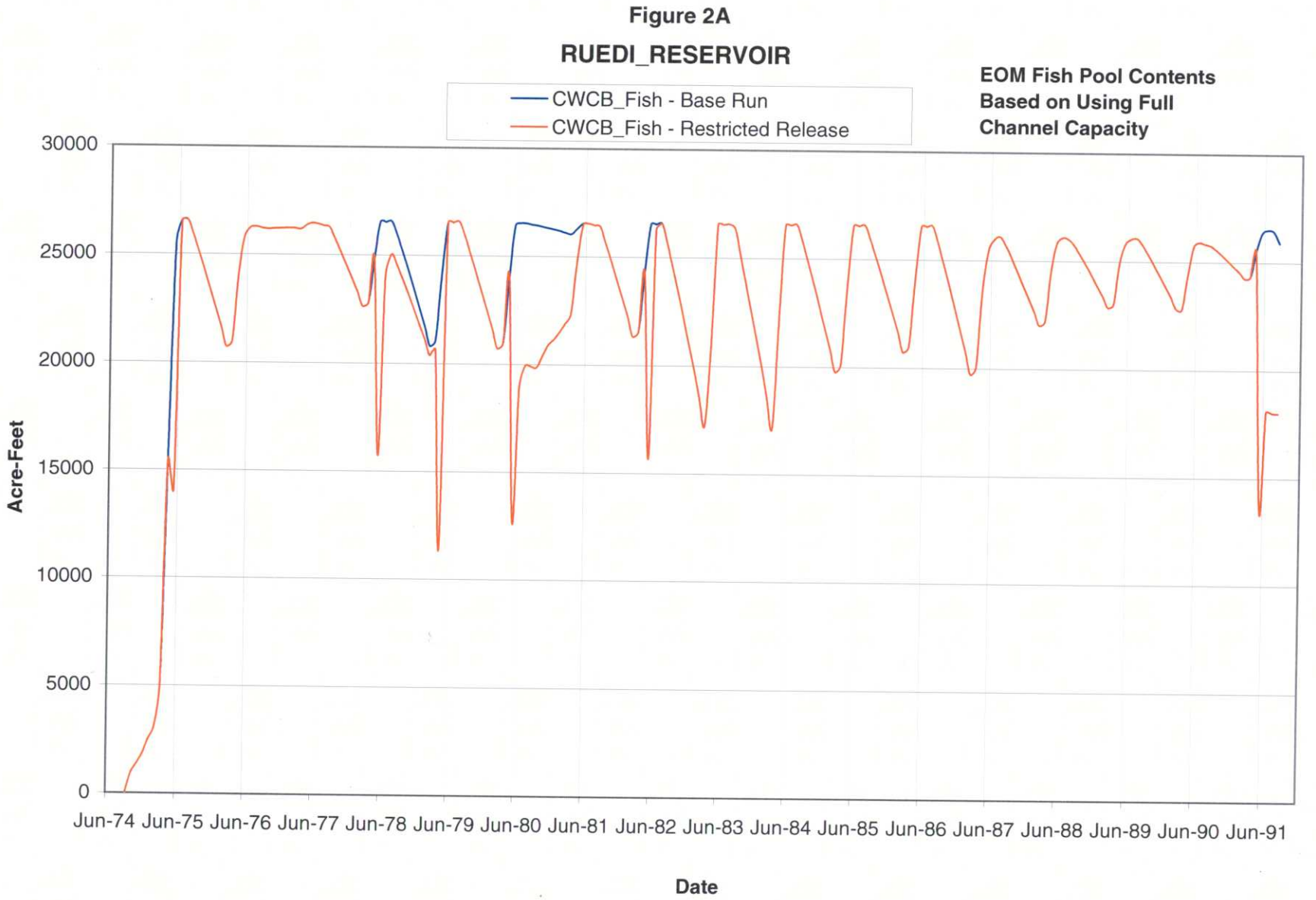
RUEDI_RESERVOIR
EOM Fish Pool Contents Based on Using Full Channel Capacity
CWCB_Fish - Base Run
CWCB_Fish - Restricted Release
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Figure 2B

RUEDI_RESERVOIR

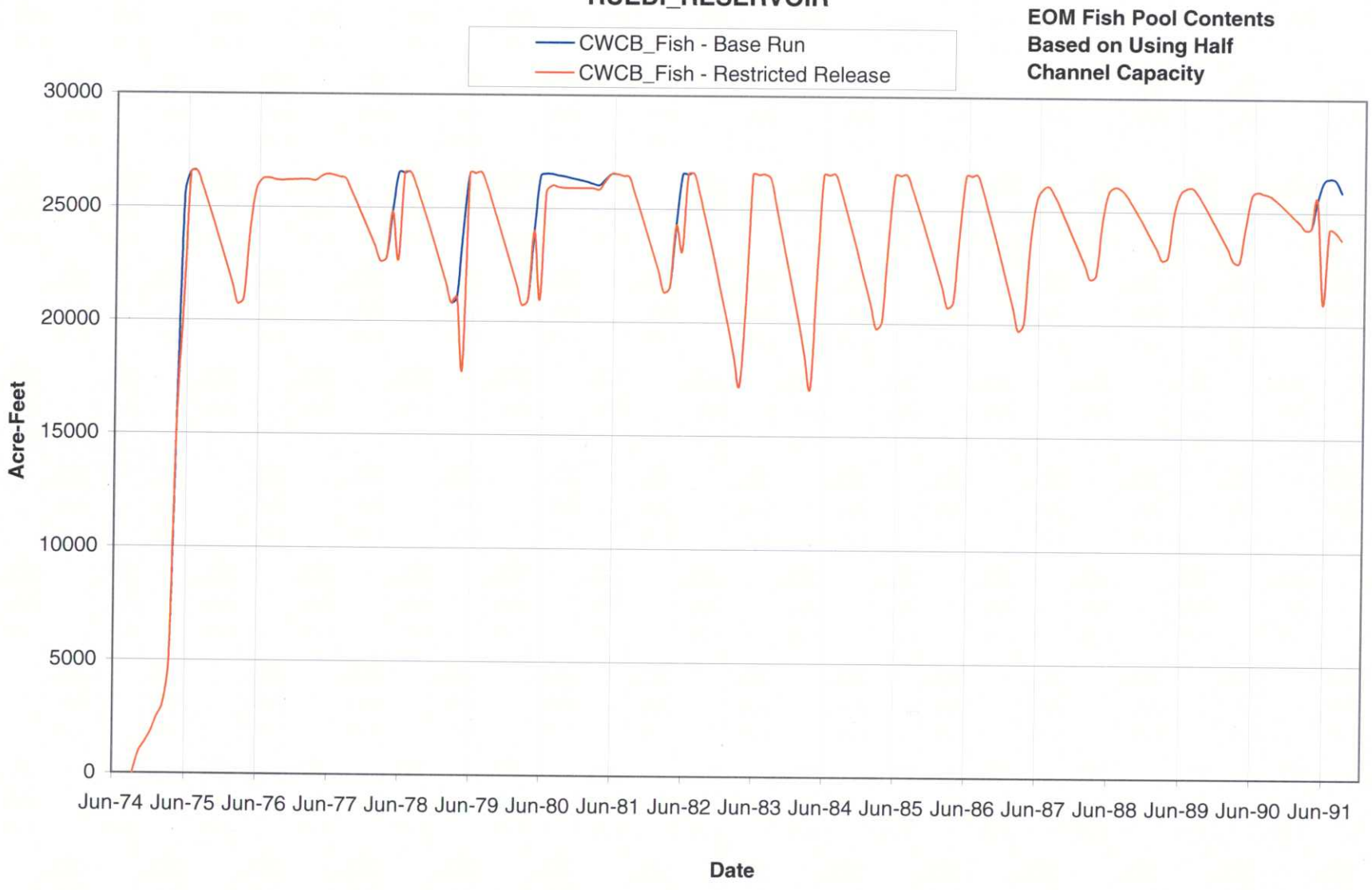

Figure 3A

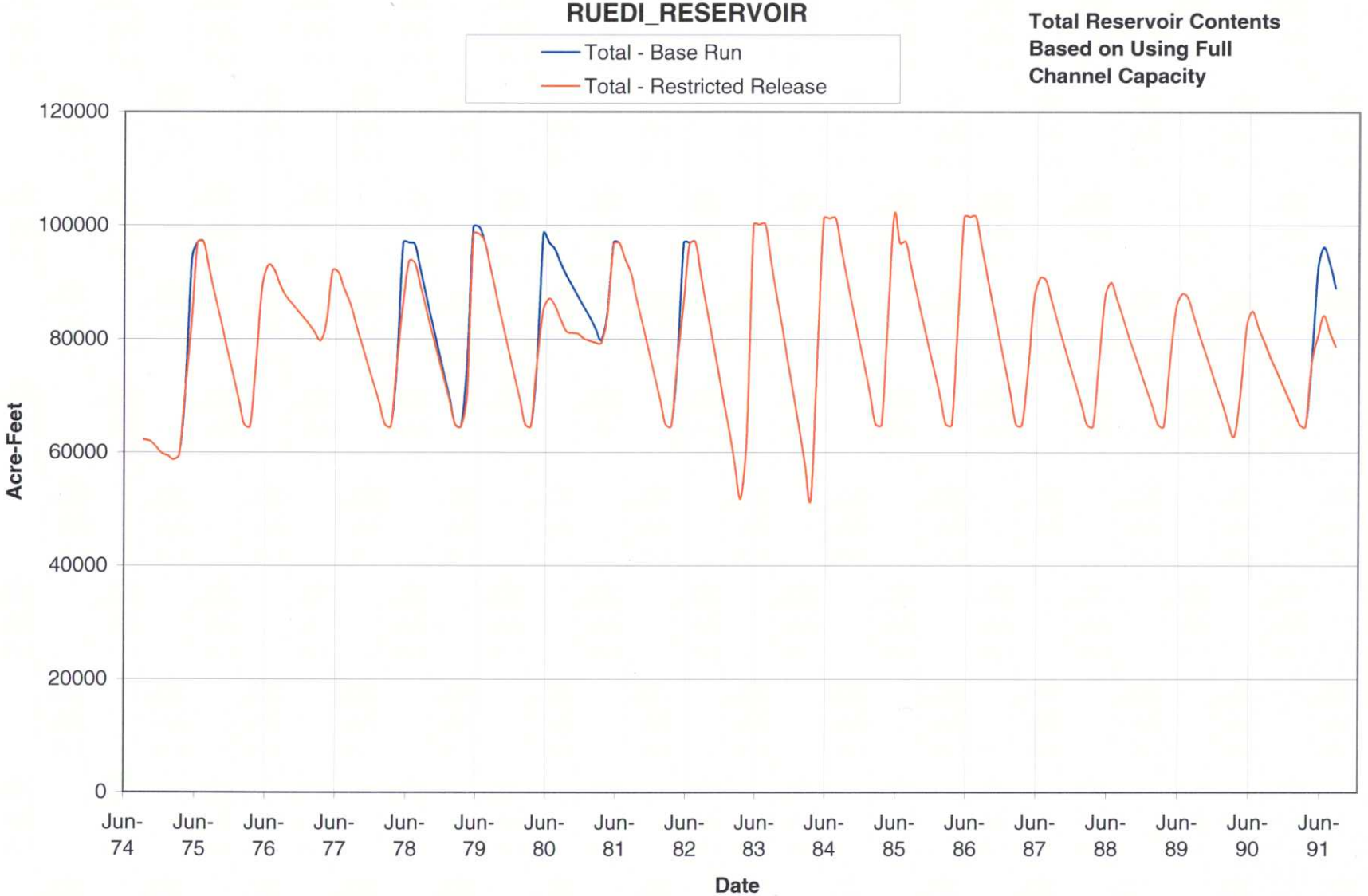
RUEDI_RESERVOIR
Total - Base Run
Total - Restricted Release
Total Reservoir Contents Based on Using Full Channel Capacity
120000
100000
80000
60000
40000
20000
0
Acre-Feet
Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Figure 3B

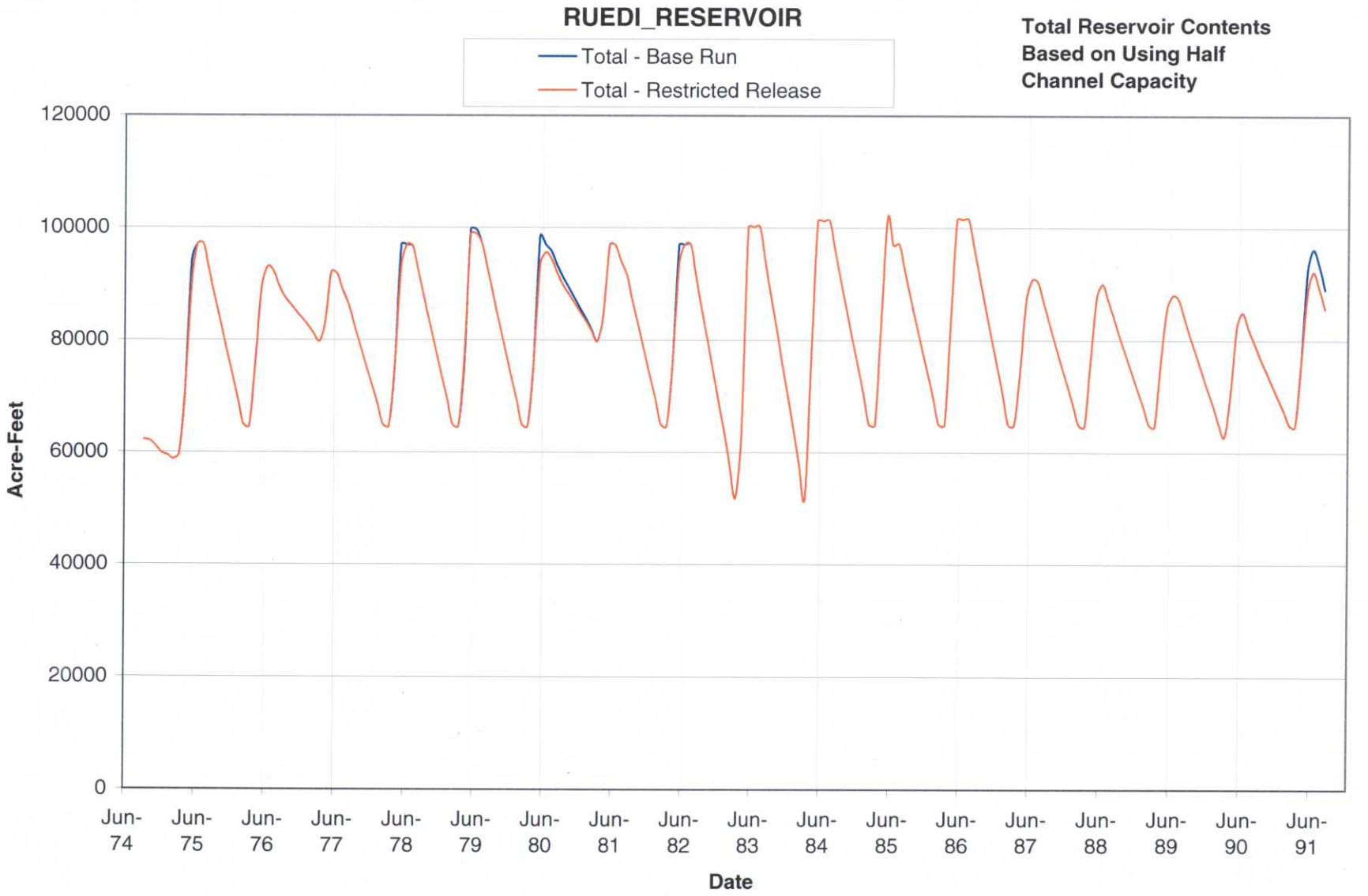
RUEDI_RESERVOIR
Total - Base Run
Total - Restricted Release
Total Reservoir Contents Based on Using Half Channel Capacity
120000
100000
80000
60000
40000
20000
0
Acre-Feet
Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Table 1
Ruedi Reservoir Inflows

		Inflow	Annual
Year	Month	(acre-feet)	Inflow (acre-feet)
1974	OCT	2,638	
1974	NOV	2,112	
1974	DEC	1,441	
1975	JAN	1,533	
1975	FEB	1,751	
1975	MAR	1,745	
1975	APR	3,967	
1975	MAY	20,959	
1975	JUN	32,915	
1975	JUL	27,198	
1975	AUG	7,497	
1975	SEP	4,674	108,430
1975	OCT	3,187	
1975	NOV	2,446	
1975	DEC	1,444	
1976	JAN	1,065	
1976	FEB	1,537	
1976	MAR	1,925	
1976	APR	5,855	
1976	MAY	20,901	
1976	JUN	22,873	
1976	JUL	11,090	
1976	AUG	6,352	
1976	SEP	4,132	82,807
1976	OCT	3,648	
1976	NOV	1,772	
1976	DEC	1,172	
1977	JAN	1,279	
1977	FEB	1,405	
1977	MAR	1,850	
1977	APR	5,192	
1977	MAY	13,360	
1977	JUN	17,716	
1977	JUL	6,840	
1977	AUG	3,629	
1977	SEP	2,773	60,636
1977	OCT	3,231	
1977	NOV	2,516	
1977	DEC	2,485	
1978	JAN	2,400	
1978	FEB	2,208	
1978	MAR	2,876	
1978	APR	8,282	
1978	MAY	20,901	
1978	JUN	33,476	
1978	JUL	14,691	
1978	AUG	6,710	
1978	SEP	4,078	103,854

Table 1
Ruedi Reservoir Inflows

		Inflow	Annual
Year	Month	(acre-feet)	Inflow (acre-feet)
1978	OCT	2,847	
1978	NOV	2,062	
1978	DEC	2,382	
1979	JAN	2,144	
1979	FEB	1,364	
1979	MAR	1,433	
1979	APR	5,386	
1979	MAY	20,901	
1979	JUN	36,097	
1979	JUL	13,390	
1979	AUG	8,190	
1979	SEP	4,241	105,175
1979	OCT	3,447	
1979	NOV	3,225	
1979	DEC	2,734	
1980	JAN	2,509	
1980	FEB	1,861	
1980	MAR	2,146	
1980	APR	5,470	
1980	MAY	20,901	
1980	JUN	29,731	
1980	JUL	11,996	
1980	AUG	5,839	
1980	SEP	3,797	93,656
1980	OCT	3,024	
1980	NOV	2,485	
1980	DEC	2,298	
1981	JAN	1,572	
1981	FEB	1,735	
1981	MAR	2,201	
1981	APR	7,089	
1981	MAY	14,565	
1981	JUN	21,460	
1981	JUL	10,812	
1981	AUG	5,404	
1981	SEP	4,196	76,841
1981	OCT	3,326	
1981	NOV	3,063	
1981	DEC	2,883	
1982	JAN	2,953	
1982	FEB	2,280	
1982	MAR	3,027	
1982	APR	6,779	
1982	MAY	20,901	
1982	JUN	31,593	
1982	JUL	17,681	
1982	AUG	8,976	
1982	SEP	7,770	111,232

Table 1
Ruedi Reservoir Inflows

		Inflow	Annual
Year	Month	(acre-feet)	Inflow (acre-feet)
1982	OCT	3,879	
1982	NOV	3,727	
1982	DEC	4,055	
1983	JAN	3,563	
1983	FEB	2,851	
1983	MAR	3,556	
1983	APR	4,048	
1983	MAY	19,782	
1983	JUN	46,633	
1983	JUL	29,847	
1983	AUG	25,067	
1983	SEP	7,575	154,583
1983	OCT	5,019	
1983	NOV	4,688	
1983	DEC	3,879	
1984	JAN	2,589	
1984	FEB	1,406	
1984	MAR	1,821	
1984	APR	6,381	
1984	MAY	35,021	
1984	JUN	63,365	
1984	JUL	56,573	
1984	AUG	23,803	
1984	SEP	9,941	214,486
1984	OCT	4,885	
1984	NOV	4,179	
1984	DEC	3,819	
1985	JAN	3,222	
1985	FEB	2,434	
1985	MAR	3,743	
1985	APR	10,797	
1985	MAY	27,667	
1985	JUN	38,209	
1985	JUL	14,728	
1985	AUG	8,652	
1985	SEP	6,242	128,577
1985	OCT	5,117	
1985	NOV	4,225	
1985	DEC	3,936	
1986	JAN	3,177	
1986	FEB	3,258	
1986	MAR	4,944	
1986	APR	13,095	
1986	MAY	28,613	
1986	JUN	37,712	
1986	JUL	15,712	
1986	AUG	8,726	
1986	SEP	6,674	135,189

Table 1
Ruedi Reservoir Inflows

		Inflow	Annual
Year	Month	(acre-feet)	Inflow (acre-feet)
1986	OCT	3,755	
1986	NOV	3,667	
1986	DEC	3,656	
1987	JAN	2,982	
1987	FEB	2,524	
1987	MAR	2,945	
1987	APR	9,274	
1987	MAY	20,774	
1987	JUN	22,277	
1987	JUL	10,735	
1987	AUG	6,674	
1987	SEP	4,311	93,574
1987	OCT	3,855	
1987	NOV	3,932	
1987	DEC	3,283	
1988	JAN	3,125	
1988	FEB	1,812	
1988	MAR	2,121	
1988	APR	8,232	
1988	MAY	20,901	
1988	JUN	21,516	
1988	JUL	9,489	
1988	AUG	5,825	
1988	SEP	3,773	87,864
1988	OCT	3,395	
1988	NOV	3,084	
1988	DEC	2,792	
1989	JAN	2,529	
1989	FEB	2,547	
1989	MAR	4,137	
1989	APR	9,518	
1989	MAY	20,901	
1989	JUN	19,365	
1989	JUL	9,602	
1989	AUG	6,396	
1989	SEP	3,640	87,906
1989	OCT	3,675	
1989	NOV	2,895	
1989	DEC	2,641	
1990	JAN	2,218	
1990	FEB	2,114	
1990	MAR	2,882	
1990	APR	6,935	
1990	MAY	16,693	
1990	JUN	22,122	
1990	JUL	9,605	
1990	AUG	5,036	
1990	SEP	4,162	80,978

Table 1
Ruedi Reservoir Inflows

		Inflow	Annual
Year	Month	(acre-feet)	Inflow (acre-feet)
1990	OCT	4,367	
1990	NOV	3,176	
1990	DEC	2,900	
1991	JAN	2,497	
1991	FEB	2,217	
1991	MAR	2,832	
1991	APR	6,068	
1991	MAY	20,901	
1991	JUN	26,457	
1991	JUL	10,821	
1991	AUG	6,628	
1991	SEP	5,277	94,141

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1974	OCT	9,888	166				
1974	NOV	2,321	39				
1974	DEC	2,398	40				
1975	JAN	2,741	46				
1975	FEB	2,166	36				
1975	MAR	2,398	40				
1975	APR	2,951	50				
1975	MAY	9,202	155				
1975	JUN	9,610	161	323	777	15,412	7,706
1975	JUL	23,906	402				
1975	AUG	7,097	119				
1975	SEP	9,259	156				
1975	OCT	7,734	130				
1975	NOV	6,969	117				
1975	DEC	5,963	100				
1976	JAN	5,584	94				
1976	FEB	6,056	102				
1976	MAR	6,443	108				
1976	APR	6,055	102				
1976	MAY	9,514	160				
1976	JUN	9,282	156				
1976	JUL	6,764	114				
1976	AUG	6,764	114				
1976	SEP	6,527	110				
1976	OCT	5,553	93				
1976	NOV	3,041	51				
1976	DEC	2,437	41				
1977	JAN	2,544	43				
1977	FEB	2,670	45				
1977	MAR	3,115	52				
1977	APR	6,549	110				
1977	MAY	9,662	162				

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1977	JUN	8,392	141				
1977	JUL	6,764	114				
1977	AUG	6,324	106				
1977	SEP	5,168	87				
1977	OCT	6,764	114				
1977	NOV	6,026	101				
1977	DEC	5,991	101				
1978	JAN	5,906	99				
1978	FEB	5,714	96				
1978	MAR	6,381	107				
1978	APR	8,483	143				
1978	MAY	9,514	160				
1978	JUN	11,861	199	399	701	13,911	6,956
1978	JUL	14,325	241				
1978	AUG	6,764	114				
1978	SEP	8,598	144				
1978	OCT	7,329	123				
1978	NOV	6,520	110				
1978	DEC	6,836	115				
1979	JAN	6,598	111				
1979	FEB	5,818	98				
1979	MAR	5,886	99				
1979	APR	5,586	94				
1979	MAY	9,514	160	320	780	15,476	7,738
1979	JUN	11,745	197				
1979	JUL	13,031	219				
1979	AUG	10,504	177				
1979	SEP	8,826	148				
1979	OCT	7,994	134				
1979	NOV	7,748	130				
1979	DEC	7,253	122				
1980	JAN	7,028	118				

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1980	FEB	6,380	107				
1980	MAR	6,664	112				
1980	APR	5,670	95				
1980	MAY	9,514	160				
1980	JUN	6,546	110	220	880	17,455	8,727
1980	JUL	13,198	222				
1980	AUG	6,764	114				
1980	SEP	6,192	104				
1980	OCT	4,929	83				
1980	NOV	4,338	73				
1980	DEC	4,147	70				
1981	JAN	3,421	57				
1981	FEB	3,584	60				
1981	MAR	4,050	68				
1981	APR	8,903	150				
1981	MAY	9,664	162				
1981	JUN	8,547	144				
1981	JUL	10,428	175				
1981	AUG	8,099	136				
1981	SEP	6,546	110				
1981	OCT	7,730	130				
1981	NOV	7,444	125				
1981	DEC	7,259	122				
1982	JAN	7,329	123				
1982	FEB	6,656	112				
1982	MAR	7,402	124				
1982	APR	6,979	117				
1982	MAY	9,514	160	320	780	15,476	7,738
1982	JUN	9,978	168				
1982	JUL	17,315	291				
1982	AUG	8,572	144				
1982	SEP	13,407	225				

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1982	OCT	9,483	159				
1982	NOV	9,312	156				
1982	DEC	9,637	162				
1983	JAN	9,145	154				
1983	FEB	8,433	142				
1983	MAR	9,138	154				
1983	APR	9,580	161				
1983	MAY	8,715	146				
1983	JUN	8,833	148				
1983	JUL	29,507	496				
1983	AUG	24,667	415				
1983	SEP	13,603	229				
1983	OCT	11,014	185				
1983	NOV	10,664	179				
1983	DEC	9,851	166				
1984	JAN	8,561	144				
1984	FEB	7,378	124				
1984	MAR	7,793	131				
1984	APR	12,302	207				
1984	MAY	9,778	164				
1984	JUN	38,640	649				
1984	JUL	56,215	945				
1984	AUG	23,404	393				
1984	SEP	15,127	254				
1984	OCT	10,031	169				
1984	NOV	9,302	156				
1984	DEC	8,937	150				
1985	JAN	8,340	140				
1985	FEB	7,552	127				
1985	MAR	8,860	149				
1985	APR	10,744	181				
1985	MAY	8,918	150				

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1985	JUN	19,386	326	652	448	8,895	4,447
1985	JUL	19,160	322				
1985	AUG	8,241	138				
1985	SEP	10,827	182				
1985	OCT	9,664	162				
1985	NOV	8,749	147				
1985	DEC	8,455	142				
1986	JAN	7,696	129				
1986	FEB	7,777	131				
1986	MAR	9,462	159				
1986	APR	13,041	219				
1986	MAY	9,864	166				
1986	JUN	19,191	323	645	455	9,025	4,512
1986	JUL	15,347	258				
1986	AUG	8,327	140				
1986	SEP	11,898	200				
1986	OCT	8,939	150				
1986	NOV	8,827	148				
1986	DEC	8,811	148				
1987	JAN	8,138	137				
1987	FEB	7,680	129				
1987	MAR	8,100	136				
1987	APR	9,221	155				
1987	MAY	11,041	186				
1987	JUN	9,168	154				
1987	JUL	6,764	114				
1987	AUG	6,764	114				
1987	SEP	7,933	133				
1987	OCT	7,440	125				
1987	NOV	7,495	126				
1987	DEC	6,841	115				
1988	JAN	6,683	112				

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1988	FEB	5,370	90				
1988	MAR	5,678	95				
1988	APR	8,433	142				
1988	MAY	9,514	160				
1988	JUN	9,282	156				
1988	JUL	6,764	114				
1988	AUG	8,520	143				
1988	SEP	6,919	116				
1988	OCT	6,506	109				
1988	NOV	6,173	104				
1988	DEC	5,877	99				
1989	JAN	5,614	94				
1989	FEB	5,632	95				
1989	MAR	7,221	121				
1989	APR	9,719	163				
1989	MAY	9,514	160				
1989	JUN	9,282	156				
1989	JUL	6,764	114				
1989	AUG	6,764	114				
1989	SEP	6,829	115				
1989	OCT	6,829	115				
1989	NOV	6,026	101				
1989	DEC	5,768	97				
1990	JAN	5,345	90				
1990	FEB	5,241	88				
1990	MAR	6,008	101				
1990	APR	8,840	149				
1990	MAY	8,866	149				
1990	JUN	9,798	165				
1990	JUL	6,764	114				
1990	AUG	7,731	130				
1990	SEP	6,593	111				

Table 2
Ruedi Reservoir Outflow

Year	Month	C1 Base Run Reservoir Release (AF)	C1 Base Run Reservoir Release (CFS)	Estimated Average Flow during 10-day peak (CFS)	Estimated Available Channel Capacity @ Basalt (CFS)	Estimated Available Channel Capacity @ Basalt (AF))	Half of Estimated Available Channel Capacity @ Basalt (AF)
1990	OCT	6,764	114				
1990	NOV	5,551	93				
1990	DEC	5,271	89				
1991	JAN	4,868	82				
1991	FEB	4,588	77				
1991	MAR	5,202	87				
1991	APR	6,269	105				
1991	MAY	9,514	160				
1991	JUN	9,282	156	312	788	15,631	7,815
1991	JUL	6,764	114				
1991	AUG	9,323	157				
1991	SEP	9,315	157				

Notes:

1. The Estimated Average Flow durin ghe 10-day peak was estimated by (average daily flow for the specific month) x 2.0
2. Estimated Available Channel Capacity at Basalt = 1,100 cfs -- (Estimated Average Flow during the 10-day peak in cfs)

Table 3
Comparison of Ruedi Reservoir Storage (acre-feet)

Column 1	Release Using		Ruedi Reservoir Storage Reduction	
	Column 2	Column 3	Column 4	Column 5
Release Date	Available Channel Capacity	One-half Available Channel Capacity	Available Channel Capacity	One-half Available Channel Capacity
Aug-75	15,412	7,732	0	0
Jun-78	13,911	6,988	1,510	0
Jun-79	15,476	7,866	0	0
Jun-80	17,455	8,745	6,648	525
Aug-82	15,476	7,866	0	0
Jun-85	8,895	4,501	0	0
Aug-86	9,025	4,565	0	0
Jul-91	15,631	7,841	8,422	2,282
Average	**13,910**	**7,013**	**2,073**	**351**

Note:
1. Available Channel Capacity is calculated in Table 2.

Table 4
Ruedi Reservoir Power Revenues

		Base							Restricted Releases								
		River	EOM			Turbine			River	EOM			Turbine				
		Outflow	Storage	Elevation	Head	Flow	Power	Power	Outflow	Storage	Elevation	Head	Flow	Power	Power	Difference	Power Cost
Year	Month	(AF)	(AF)	(ft)	(ft)	(cfs)	(MWhr)	($1000)	(AF)	(AF)	(ft)	(ft)	(cfs)	(MWhr)	($1000)	($1000)	$/KWhr
1974	OCT	9888	62221	222.49	222	161	2666	103	9888	62221	222.49	222	161	2666	103	0	0.03878
1974	NOV	2321	61998	222.16	222	39	2577	168	2321	61998	222.16	222	39	2577	168	0	0.06502
1974	DEC	2398	61041	220.75	221	39	2646	279	2398	61041	220.75	221	39	2646	279	0	0.10541
1975	JAN	2741	59833	218.98	219	45	2625	341	2741	59833	218.98	219	45	2625	341	0	0.13
1975	FEB	2166	59418	218.36	218	39	2364	154	2166	59418	218.36	218	39	2364	154	0	0.065
1975	MAR	2398	58716	217.33	217	39	2605	117	2398	58716	217.33	217	39	2605	117	0	0.045
1975	APR	2951	59612	218.65	219	50	2536	114	2951	59612	218.65	219	50	2536	114	0	0.045
1975	MAY	9202	71131	233.97	234	150	2803	126	9202	71131	233.97	234	150	2803	126	0	0.045
1975	JUN	9610	94081	260.68	261	161	3022	164	20709	82997	248.36	248	260	2879	156	-8	0.05416
1975	JUL	23906	96973	263.85	264	260	3160	195	12822	96988	263.87	264	209	3160	195	0	0.06176
1975	AUG	7097	97094	263.97	264	115	3162	338	7112	97094	263.97	264	116	3162	338	0	0.10693
1975	SEP	9259	92282	258.68	259	156	2998	176	9259	92282	258.68	259	156	2998	176	0	0.05866
1975	OCT	7734	87616	253.50	253	126	3037	118	7734	87616	253.50	253	126	3037	118	0	0.03878
1975	NOV	6969	83075	248.45	248	117	2880	187	6969	83075	248.45	248	117	2880	187	0	0.06502
1975	DEC	5963	78556	243.43	243	97	2916	307	5963	78556	243.43	243	97	2916	307	0	0.10541
1976	JAN	5584	74037	237.68	238	91	2848	370	5584	74037	237.68	238	91	2848	370	0	0.13
1976	FEB	6056	69518	231.92	232	105	2600	169	6056	69518	231.92	232	105	2600	169	0	0.065
1976	MAR	6443	64947	226.09	226	105	2709	122	6443	64947	226.09	226	105	2709	122	0	0.045
1976	APR	6055	64621	225.67	226	102	2617	118	6055	64621	225.67	226	102	2617	118	0	0.045
1976	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1976	JUN	9282	88993	255.03	255	156	2956	160	9282	88993	255.03	255	156	2956	160	0	0.05416
1976	JUL	6764	92932	259.40	259	110	3107	192	6764	92932	259.40	259	110	3107	192	0	0.06176
1976	AUG	6764	92249	258.64	259	110	3098	331	6764	92249	258.64	259	110	3098	331	0	0.10693
1976	SEP	6527	89633	255.74	256	110	2965	174	6527	89633	255.74	256	110	2965	174	0	0.05866
1976	OCT	5553	87610	253.49	253	90	3037	118	5553	87610	253.49	253	90	3037	118	0	0.03878
1976	NOV	3041	86325	252.06	252	51	2922	190	3041	86325	252.06	252	51	2922	190	0	0.06502
1976	DEC	2437	85060	250.66	251	40	3003	317	2437	85060	250.66	251	40	3003	317	0	0.10541
1977	JAN	2544	83795	249.25	249	41	2986	388	2544	83795	249.25	249	41	2986	388	0	0.13
1977	FEB	2670	82529	247.84	248	48	2682	174	2670	82529	247.84	248	48	2682	174	0	0.065
1977	MAR	3115	81204	246.37	246	51	2952	133	3115	81204	246.37	246	51	2952	133	0	0.045
1977	APR	6549	79702	244.70	245	110	2837	128	6549	79702	244.70	245	110	2837	128	0	0.045
1977	MAY	9662	83125	248.51	249	157	2977	134	9662	83125	248.51	249	157	2977	134	0	0.045
1977	JUN	8392	92080	258.46	258	141	2996	162	8392	92080	258.46	258	141	2996	162	0	0.05416
1977	JUL	6764	91766	258.11	258	110	3092	191	6764	91766	258.11	258	110	3092	191	0	0.06176
1977	AUG	6324	88805	254.82	255	103	3052	326	6324	88805	254.82	255	103	3052	326	0	0.10693
1977	SEP	5168	86194	251.92	252	87	2920	171	5168	86194	251.92	252	87	2920	171	0	0.05866
1977	OCT	6764	82548	247.86	248	110	2969	115	6764	82548	247.86	248	110	2969	115	0	0.03878
1977	NOV	6026	79021	243.95	244	101	2828	184	6026	79021	243.95	244	101	2828	184	0	0.06502
1977	DEC	5991	75516	239.56	240	97	2870	303	5991	75516	239.56	240	97	2870	303	0	0.10541
1978	JAN	5906	72010	235.09	235	96	2817	366	5906	72010	235.09	235	96	2817	366	0	0.13
1978	FEB	5714	68505	230.62	231	103	2496	162	5714	68505	230.62	231	103	2496	162	0	0.065
1978	MAR	6381	64948	226.09	226	104	2709	122	6381	64948	226.09	226	104	2709	122	0	0.045
1978	APR	8483	64621	225.67	226	143	2617	118	8483	64621	225.67	226	143	2617	118	0	0.045
1978	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1978	JUN	11861	97007	263.89	264	199	3058	166	22727	86156	251.87	252	260	2919	158	-8	0.05416
1978	JUL	14325	96969	263.85	264	233	3160	195	6764	93698	260.25	260	110	3117	193	-3	0.06176
1978	AUG	6764	96637	263.51	264	110	3156	337	6764	93372	259.89	260	110	3113	333	-5	0.10693
1978	SEP	8598	91891	258.25	258	144	2993	176	8131	89097	255.14	255	137	2958	173	-2	0.05866
1978	OCT	7329	87291	253.13	253	119	3032	118	6863	84964	250.55	251	112	3001	116	-1	0.03878
1978	NOV	6520	82816	248.16	248	110	2877	187	6055	80954	246.09	246	102	2853	186	-2	0.06502
1978	DEC	6836	78362	243.19	243	111	2914	307	6371	76966	241.41	241	104	2892	305	-2	0.10541
1979	JAN	6598	73907	237.51	238	107	2846	370	6133	72977	236.32	236	100	2832	368	-2	0.13
1979	FEB	5818	69453	231.83	232	105	2509	163	5353	68988	231.24	231	96	2503	163	0	0.065
1979	MAR	5886	64947	226.09	226	96	2709	122	5421	64947	226.09	226	88	2709	122	0	0.045
1979	APR	5586	64621	225.67	226	94	2617	118	5586	64621	225.67	226	94	2617	118	0	0.045
1979	MAY	9514	75758	239.87	240	155	2874	129	20090	69927	232.44	232	260	2785	125	-4	0.045
1979	JUN	11745	99741	266.68	267	197	3091	167	7137	98529	265.44	265	120	3077	167	-1	0.05416
1979	JUL	13031	99688	266.63	267	212	3193	197	13036	98474	265.38	265	212	3178	196	-1	0.06176
1979	AUG	10504	97091	263.97	264	171	3161	338	9291	97093	263.97	264	151	3162	338	0	0.10693
1979	SEP	8826	92279	258.68	259	148	2998	176	8826	92281	258.68	259	148	2998	176	0	0.05866
1979	OCT	7994	87614	253.49	253	130	3037	118	7994	87615	253.49	253	130	3037	118	0	0.03878
1979	NOV	7748	83074	248.45	248	130	2880	187	7748	83075	248.45	248	130	2880	187	0	0.06502
1979	DEC	7253	78555	243.43	243	118	2916	307	7253	78556	243.43	243	118	2916	307	0	0.10541
1980	JAN	7028	74036	237.67	238	114	2848	370	7028	74037	237.68	238	114	2848	370	0	0.13
1980	FEB	6380	69518	231.92	232	111	2600	169	6380	69518	231.92	232	111	2600	169	0	0.065
1980	MAR	6664	64947	226.09	226	108	2709	122	6664	64947	226.09	226	108	2709	122	0	0.045
1980	APR	5670	64621	225.67	226	95	2617	118	5670	64621	225.67	226	95	2617	118	0	0.045
1980	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1980	JUN	6546	98575	265.49	265	110	3077	167	20145	84995	250.58	251	260	2905	157	-9	0.05416
1980	JUL	13198	96967	263.84	264	215	3160	195	9489	87127	252.95	253	154	3030	187	-8	0.06176
1980	AUG	6764	95764	262.55	263	110	3145	336	6764	85944	251.64	252	110	3014	322	-14	0.10693
1980	SEP	6192	93142	259.64	260	104	3010	177	6192	83338	248.74	249	104	2884	169	-7	0.05866
1980	OCT	4929	91117	257.39	257	80	3083	120	4929	81321	246.50	247	80	2953	115	-5	0.03878
1980	NOV	4338	89246	255.31	255	73	2960	192	2705	81083	246.24	246	45	2855	186	-7	0.06502
1980	DEC	4147	87397	253.25	253	67	3034	320	2515	80866	246.00	246	41	2947	311	-9	0.10541
1981	JAN	3421	85547	251.20	251	56	3009	391	2398	80040	245.08	245	39	2936	382	-9	0.13
1981	FEB	3584	83698	249.14	249	65	2696	175	2166	79609	244.60	245	39	2647	172	-3	0.065

Table 4
Ruedi Reservoir Power Revenues

		Base							Restricted Releases								
		River	EOM			Turbine			River	EOM			Turbine				
		Outflow	Storage	Elevation	Head	Flow	Power	Power	Outflow	Storage	Elevation	Head	Flow	Power	Power	Difference	Power Cost
Year	Month	(AF)	(AF)	(ft)	(ft)	(cfs)	(MWhr)	($1000)	(AF)	(AF)	(ft)	(ft)	(cfs)	(MWhr)	($1000)	($1000)	$/KWhr
1981	MAR	4050	81788	247.02	247	66	2959	133	2398	79353	244.31	244	39	2927	132	-1	0.045
1981	APR	8903	79829	244.84	245	150	2839	128	6974	79325	244.28	244	117	2832	127	0	0.045
1981	MAY	9664	84454	249.98	250	157	2995	135	9656	83959	249.43	249	157	2988	134	0	0.045
1981	JUN	8547	96989	263.87	264	144	3058	166	8424	96619	263.49	263	142	3054	165	0	0.05416
1981	JUL	10428	96969	263.85	264	170	3160	195	10058	96969	263.85	264	164	3160	195	0	0.06176
1981	AUG	8099	93998	260.59	261	132	3121	334	8099	93998	260.59	261	132	3121	334	0	0.10693
1981	SEP	6546	91424	257.73	258	110	2988	175	6546	91424	257.73	258	110	2988	175	0	0.05866
1981	OCT	7730	86902	252.70	253	126	3027	117	7730	86902	252.70	253	126	3027	117	0	0.03878
1981	NOV	7444	82505	247.82	248	125	2873	187	7444	82505	247.82	248	125	2873	187	0	0.06502
1981	DEC	7259	78128	242.89	243	118	2910	307	7259	78128	242.89	243	118	2910	307	0	0.10541
1982	JAN	7329	73752	237.31	237	119	2843	370	7329	73752	237.31	237	119	2843	370	0	0.13
1982	FEB	6656	69375	231.73	232	120	2508	163	6656	69375	231.73	232	120	2508	163	0	0.065
1982	MAR	7402	64947	226.09	226	120	2709	122	7402	64947	226.09	226	120	2709	122	0	0.045
1982	APR	6979	64621	225.67	226	117	2617	118	6979	64621	225.67	226	117	2617	118	0	0.045
1982	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1982	JUN	9978	97007	263.89	264	168	3059	166	20882	86118	251.83	252	260	2919	158	-8	0.05416
1982	JUL	17315	96969	263.85	264	260	3160	195	6764	96646	263.52	264	110	3156	195	0	0.06176
1982	AUG	8572	97094	263.97	264	139	3162	338	8249	97094	263.97	264	134	3162	338	0	0.10693
1982	SEP	13407	91231	257.51	258	225	2985	175	13407	91231	257.51	258	225	2985	175	0	0.05866
1982	OCT	9483	85510	251.16	251	154	3009	117	9483	85510	251.16	251	154	3009	117	0	0.03878
1982	NOV	9312	79907	244.93	245	156	2840	185	9312	79907	244.93	245	156	2840	185	0	0.06502
1982	DEC	9637	74326	238.04	238	157	2852	301	9637	74326	238.04	238	157	2852	301	0	0.10541
1983	JAN	9145	68744	230.93	231	149	2767	360	9145	68744	230.93	231	149	2767	360	0	0.13
1983	FEB	8433	63162	223.81	224	152	2423	157	8433	63162	223.81	224	152	2423	157	0	0.065
1983	MAR	9138	57532	215.59	216	149	2584	116	9138	57532	215.59	216	149	2584	116	0	0.045
1983	APR	9580	51887	207.28	207	161	2404	108	9580	51887	207.28	207	161	2404	108	0	0.045
1983	MAY	8715	62734	223.24	223	142	2675	120	8715	62734	223.24	223	142	2675	120	0	0.045
1983	JUN	8833	100183	267.13	267	148	3096	168	8833	100183	267.13	267	148	3096	168	0	0.05416
1983	JUL	29507	100110	267.06	267	260	3198	198	29507	100110	267.06	267	260	3198	198	0	0.06176
1983	AUG	24667	100225	267.17	267	260	3199	342	24667	100225	267.17	267	260	3199	342	0	0.10693
1983	SEP	13603	93966	260.55	261	229	3020	177	13603	93966	260.55	261	229	3020	177	0	0.05866
1983	OCT	11014	87851	253.76	254	179	3040	118	11014	87851	253.76	254	179	3040	118	0	0.03878
1983	NOV	10664	81859	247.10	247	179	2865	186	10664	81859	247.10	247	179	2865	186	0	0.06502
1983	DEC	9851	75887	240.03	240	160	2876	303	9851	75887	240.03	240	160	2876	303	0	0.10541
1984	JAN	8561	69915	232.42	232	139	2785	362	8561	69915	232.42	232	139	2785	362	0	0.13
1984	FEB	7378	63943	224.81	225	128	2520	164	7378	63943	224.81	225	128	2520	164	0	0.065
1984	MAR	7793	57921	216.16	216	127	2591	117	7793	57921	216.16	216	127	2591	117	0	0.045
1984	APR	12302	51886	207.28	207	207	2404	108	12302	51886	207.28	207	207	2404	108	0	0.045
1984	MAY	9778	76893	241.32	241	159	2891	130	9778	76893	241.32	241	159	2891	130	0	0.045
1984	JUN	38640	101245	268.22	268	260	3108	168	38640	101245	268.22	268	260	3108	168	0	0.05416
1984	JUL	56215	101187	268.16	268	260	3211	198	56215	101187	268.16	268	260	3211	198	0	0.06176
1984	AUG	23404	101298	268.27	268	260	3213	344	23404	101298	268.27	268	260	3213	344	0	0.10693
1984	SEP	15127	95880	262.68	263	254	3044	179	15127	95880	262.68	263	254	3044	179	0	0.05866
1984	OCT	10031	90612	256.82	257	163	3076	119	10031	90612	256.82	257	163	3076	119	0	0.03878
1984	NOV	9302	85471	251.11	251	156	2911	189	9302	85471	251.11	251	156	2911	189	0	0.06502
1984	DEC	8937	80353	245.43	245	145	2940	310	8937	80353	245.43	245	145	2940	310	0	0.10541
1985	JAN	8340	75235	239.20	239	136	2866	373	8340	75235	239.20	239	136	2866	373	0	0.13
1985	FEB	7552	70117	232.68	233	136	2518	164	7552	70117	232.68	233	136	2518	164	0	0.065
1985	MAR	8860	64947	226.09	226	144	2709	122	8860	64947	226.09	226	144	2709	122	0	0.045
1985	APR	10744	64874	226.00	226	181	2621	118	10744	64874	226.00	226	181	2621	118	0	0.045
1985	MAY	8918	83365	248.77	249	145	2980	134	8918	83365	248.77	249	145	2980	134	0	0.045
1985	JUN	19386	101805	268.79	269	260	3115	169	19386	101805	268.79	269	260	3115	169	0	0.05416
1985	JUL	19160	96962	263.84	264	260	3160	195	19160	96962	263.84	264	260	3160	195	0	0.06176
1985	AUG	8241	97094	263.97	264	134	3162	338	8241	97094	263.97	264	134	3162	338	0	0.10693
1985	SEP	10827	92282	258.68	259	182	2998	176	10827	92282	258.68	259	182	2998	176	0	0.05866
1985	OCT	9664	87616	253.50	253	157	3036	118	9664	87616	253.50	253	157	3036	118	0	0.03878
1985	NOV	8749	83075	248.45	248	147	2880	187	8749	83075	248.45	248	147	2880	187	0	0.06502
1985	DEC	8455	78556	243.43	243	138	2916	307	8455	78556	243.43	243	138	2916	307	0	0.10541
1986	JAN	7696	74037	237.68	238	125	2848	370	7696	74037	237.68	238	125	2848	370	0	0.13
1986	FEB	7777	69518	231.92	232	140	2510	163	7777	69518	231.92	232	140	2510	163	0	0.065
1986	MAR	9462	64947	226.09	226	154	2709	122	9462	64947	226.09	226	154	2709	122	0	0.045
1986	APR	13041	64874	226.00	226	219	2621	118	13041	64874	226.00	226	219	2621	118	0	0.045
1986	MAY	9864	83365	248.77	249	160	2980	134	9864	83365	248.77	249	160	2980	134	0	0.045
1986	JUN	19191	101504	268.48	268	260	3111	169	19191	101504	268.48	268	260	3111	169	0	0.05416
1986	JUL	15347	101453	268.43	268	250	3214	199	15347	101453	268.43	268	250	3214	199	0	0.06176
1986	AUG	8327	101563	268.54	269	135	3216	344	8327	101563	268.54	269	135	3216	344	0	0.10693
1986	SEP	11898	96106	262.93	263	200	3047	179	11898	96106	262.93	263	200	3047	179	0	0.05866
1986	OCT	8939	90799	257.03	257	145	3079	119	8939	90799	257.03	257	145	3079	119	0	0.03878
1986	NOV	8827	85621	251.28	251	148	2913	189	8827	85621	251.28	251	148	2913	189	0	0.06502
1986	DEC	8811	80466	245.55	246	143	2942	310	8811	80466	245.55	246	143	2942	310	0	0.10541
1987	JAN	8138	75310	239.30	239	132	2867	373	8138	75310	239.30	239	132	2867	373	0	0.13
1987	FEB	7680	70155	232.73	233	138	2519	164	7680	70155	232.73	233	138	2519	164	0	0.065
1987	MAR	8100	64947	226.09	226	132	2709	122	8100	64947	226.09	226	132	2709	122	0	0.045
1987	APR	9221	64874	226.00	226	155	2621	118	9221	64874	226.00	226	155	2621	118	0	0.045
1987	MAY	11041	74359	238.09	238	180	2852	128	11041	74359	238.09	238	180	2852	128	0	0.045
1987	JUN	9168	87118	252.94	253	154	2932	159	9168	87118	252.94	253	154	2932	159	0	0.05416
1987	JUL	6764	90707	256.93	257	110	3078	190	6764	90707	256.93	257	110	3078	190	0	0.06176
1987	AUG	6764	90350	256.53	257	110	3073	329	6764	90350	256.53	257	110	3073	329	0	0.10693

Table 4
Ruedi Reservoir Power Revenues

		Base							Restricted Releases								
		River	EOM			Turbine			River	EOM			Turbine				
Year	Month	Outflow (AF)	Storage (AF)	Elevation (ft)	Head (ft)	Flow (cfs)	Power (MWhr)	Power ($1000)	Outflow (AF)	Storage (AF)	Elevation (ft)	Head (ft)	Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1987	SEP	7933	86512	252.27	252	133	2924	172	7933	86512	252.27	252	133	2924	172	0	0.05866
1987	OCT	7440	82812	248.16	248	121	2973	115	7440	82812	248.16	248	121	2973	115	0	0.03878
1987	NOV	7495	79233	244.18	244	126	2831	184	7495	79233	244.18	244	126	2831	184	0	0.06502
1987	DEC	6841	75674	239.76	240	111	2873	303	6841	75674	239.76	240	111	2873	303	0	0.10541
1988	JAN	6683	72116	235.23	235	109	2818	366	6683	72116	235.23	235	109	2818	366	0	0.13
1988	FEB	5370	68557	230.69	231	93	2586	168	5370	68557	230.69	231	93	2586	168	0	0.065
1988	MAR	5678	64948	226.09	226	92	2709	122	5678	64948	226.09	226	92	2709	122	0	0.045
1988	APR	8433	64621	225.67	226	142	2617	118	8433	64621	225.67	226	142	2617	118	0	0.045
1988	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1988	JUN	9282	87639	253.52	254	156	2939	159	9282	87639	253.52	254	156	2939	159	0	0.05416
1988	JUL	6764	89982	256.12	256	110	3068	189	6764	89982	256.12	256	110	3068	189	0	0.06176
1988	AUG	8520	87024	252.84	253	139	3029	324	8520	87024	252.84	253	139	3029	324	0	0.10693
1988	SEP	6919	83665	249.11	249	116	2888	169	6919	83665	249.11	249	116	2888	169	0	0.05866
1988	OCT	6506	80442	245.52	246	106	2941	114	6506	80442	245.52	246	106	2941	114	0	0.03878
1988	NOV	6173	77338	241.88	242	104	2805	182	6173	77338	241.88	242	104	2805	182	0	0.06502
1988	DEC	5877	74253	237.95	238	96	2851	301	5877	74253	237.95	238	96	2851	301	0	0.10541
1989	JAN	5614	71168	234.02	234	91	2804	365	5614	71168	234.02	234	91	2804	365	0	0.13
1989	FEB	5632	68084	230.09	230	101	2490	162	5632	68084	230.09	230	101	2490	162	0	0.065
1989	MAR	7221	64948	226.09	226	117	2709	122	7221	64948	226.09	226	117	2709	122	0	0.045
1989	APR	9719	64621	225.67	226	163	2617	118	9719	64621	225.67	226	163	2617	118	0	0.045
1989	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1989	JUN	9282	85491	251.13	251	156	2911	158	9282	85491	251.13	251	156	2911	158	0	0.05416
1989	JUL	6764	87953	253.87	254	110	3041	188	6764	87953	253.87	254	110	3041	188	0	0.06176
1989	AUG	6764	87324	253.17	253	110	3033	324	6764	87324	253.17	253	110	3033	324	0	0.10693
1989	SEP	6829	83922	249.39	249	115	2891	170	6829	83922	249.39	249	115	2891	170	0	0.05866
1989	OCT	6829	80656	245.76	246	111	2944	114	6829	80656	245.76	246	111	2944	114	0	0.03878
1989	NOV	6026	77508	242.10	242	101	2807	183	6026	77508	242.10	242	101	2807	183	0	0.06502
1989	DEC	5768	74381	238.11	238	94	2853	301	5768	74381	238.11	238	94	2853	301	0	0.10541
1990	JAN	5345	71254	234.13	234	87	2805	365	5345	71254	234.13	234	87	2805	365	0	0.13
1990	FEB	5241	68126	230.14	230	94	2491	162	5241	68126	230.14	230	94	2491	162	0	0.065
1990	MAR	6008	64948	226.09	226	98	2709	122	6008	64948	226.09	226	98	2709	122	0	0.045
1990	APR	8840	62918	223.50	224	149	2592	117	8840	62918	223.50	224	149	2592	117	0	0.045
1990	MAY	8866	70503	233.17	233	144	2794	126	8866	70503	233.17	233	144	2794	126	0	0.045
1990	JUN	9798	82489	247.80	248	165	2873	156	9798	82489	247.80	248	165	2873	156	0	0.05416
1990	JUL	6764	84962	250.55	251	110	3001	185	6764	84962	250.55	251	110	3001	185	0	0.06176
1990	AUG	7731	82014	247.27	247	126	2962	317	7731	82014	247.27	247	126	2962	317	0	0.10693
1990	SEP	6593	79379	244.34	244	111	2833	166	6593	79379	244.34	244	111	2833	166	0	0.05866
1990	OCT	6764	76874	241.29	241	110	2891	112	6764	76874	241.29	241	110	2891	112	0	0.03878
1990	NOV	5551	74483	238.24	238	93	2762	180	5551	74483	238.24	238	93	2762	180	0	0.06502
1990	DEC	5271	72112	235.22	235	86	2819	297	5271	72112	235.22	235	86	2819	297	0	0.10541
1991	JAN	4868	69741	232.20	232	79	2782	362	4868	69741	232.20	232	79	2782	362	0	0.13
1991	FEB	4588	67370	229.18	229	83	2481	161	4588	67370	229.18	229	83	2481	161	0	0.065
1991	MAR	5202	64948	226.09	226	85	2709	122	5202	64948	226.09	226	85	2709	122	0	0.045
1991	APR	6269	64621	225.67	226	105	2617	118	6269	64621	225.67	226	105	2617	118	0	0.045
1991	MAY	9514	75758	239.87	240	155	2874	129	9514	75758	239.87	240	155	2874	129	0	0.045
1991	JUN	9282	92572	259.00	259	156	3002	163	21382	80490	245.58	246	260	2847	154	-8	0.05416
1991	JUL	6764	96233	263.07	263	110	3151	195	6764	84183	249.68	250	110	2991	185	-10	0.06176
1991	AUG	9323	93263	259.77	260	152	3111	333	9323	81236	246.41	246	152	2952	316	-17	0.10693
1991	SEP	9315	89004	255.04	255	157	0	0	7597	78713	243.60	244	128	0	0	0	0.05866
							Totals	$40,171,746							$40,016,543		
							Difference								-$155,203		
							Average Annual								-$9,130		

Notes:

1. The monthly sales prices of electric power were obtained from John Gierard, WAPA, and were used in valuation of power generation:

Actual Projected Prices ($/MWH)

	Purchase	Sale			Purchase	Sale	
Jun-00	75.44	54.16	actual	Jan-01	110.00	130.00	projected
Jul-00	116.54	61.76	actual	Feb-01	70.00	65.00	projected
Aug-00	115.89	106.93	actual	Mar-01	50.00	45.00	projected
Sep-00	60.47	58.66	actual	Apr-01	50.00	45.00	projected
Oct-00	65.48	38.78	actual	May-01	50.00	45.00	projected
Nov-00	71.63	65.02	actual	Average	79.05	68.39	
Dec-00	113.19	105.41	actual				

2. Base River Outflow is from Table 2. Restricted Release River Outflow is from Table 2.
3. Maximum operational flow through the turbines is 260 cfs.

Table 5
Ruedi Reservoir
Foregone Power Revenues: Restricted Releases at Half Capacity

	Base						Restricted Relea								
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr	
1974 OCT	9888	62221	222	161	1567	61	9888	62221	222	161	1567	61	0	0.03878	3.770038
1974 NOV	2321	61998	222	39	193	13	2321	61998	222	39	193	13	0	0.06502	
1974 DEC	2398	61041	221	39	185	20	2398	61041	221	39	185	20	0	0.10541	
1975 JAN	2741	59833	219	45	230	30	2741	59833	219	45	230	30	0	0.13	
1975 FEB	2166	59418	218	39	146	9	2166	59418	218	39	146	9	0	0.065	
1975 MAR	2398	58716	217	39	151	7	2398	58716	217	39	151	7	0	0.045	
1975 APR	2951	59612	219	50	274	12	2951	59612	219	50	274	12	0	0.045	
1975 MAY	9202	71131	234	150	1553	70	9202	71131	234	150	1553	70	0	0.045	
1975 JUN	9610	94081	261	161	1880	102	13709	89988	256	230	2576	140	38	0.05416	
1975 JUL	23906	96973	264	260	3063	189	19813	96978	264	260	3063	189	0	0.06176	
1975 AUG	7097	97094	264	115	1464	157	7102	97094	264	116	1465	157	0	0.10693	
1975 SEP	9259	92282	259	156	1798	105	9259	92282	259	156	1798	105	0	0.05866	
1975 OCT	7734	87616	253	126	1477	57	7734	87616	253	126	1477	57	0	0.03878	
1975 NOV	6969	83075	248	117	1288	84	6969	83075	248	117	1288	84	0	0.06502	
1975 DEC	5963	78556	243	97	1058	112	5963	78556	243	97	1058	112	0	0.10541	
1976 JAN	5584	74037	238	91	933	121	5584	74037	238	91	933	121	0	0.13	
1976 FEB	6056	69518	232	105	971	63	6056	69518	232	105	971	63	0	0.065	
1976 MAR	6443	64947	226	105	975	44	6443	64947	226	105	975	44	0	0.045	
1976 APR	6055	64621	226	102	907	41	6055	64621	226	102	907	41	0	0.045	
1976 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045	
1976 JUN	9282	88993	255	156	1768	96	9282	88993	255	156	1768	96	0	0.05416	
1976 JUL	6764	92932	259	110	1360	84	6764	92932	259	110	1360	84	0	0.06176	
1976 AUG	6764	92249	259	110	1352	145	6764	92249	259	110	1352	145	0	0.10693	
1976 SEP	6527	89633	256	110	1278	75	6527	89633	256	110	1278	75	0	0.05866	
1976 OCT	5553	87610	253	90	1083	42	5553	87610	253	90	1083	42	0	0.03878	
1976 NOV	3041	86325	252	51	613	40	3041	86325	252	51	613	40	0	0.06502	
1976 DEC	2437	85060	251	40	492	52	2437	85060	251	40	492	52	0	0.10541	
1977 JAN	2544	83795	249	41	498	65	2544	83795	249	41	498	65	0	0.13	
1977 FEB	2670	82529	248	48	504	33	2670	82529	248	48	504	33	0	0.065	
1977 MAR	3115	81204	246	51	572	26	3115	81204	246	51	572	26	0	0.045	
1977 APR	6549	79702	245	110	1177	53	6549	79702	245	110	1177	53	0	0.045	
1977 MAY	9662	83125	249	157	1777	80	9662	83125	249	157	1777	80	0	0.045	
1977 JUN	8392	92080	258	141	1639	89	8392	92080	258	141	1639	89	0	0.05416	
1977 JUL	6764	91766	258	110	1347	83	6764	91766	258	110	1347	83	0	0.06176	
1977 AUG	6324	88805	255	103	1235	132	6324	88805	255	103	1235	132	0	0.10693	
1977 SEP	5168	86194	252	87	996	58	5168	86194	252	87	996	58	0	0.05866	
1977 OCT	6764	82548	248	110	1247	48	6764	82548	248	110	1247	48	0	0.03878	
1977 NOV	6026	79021	244	101	1075	70	6026	79021	244	101	1075	70	0	0.06502	
1977 DEC	5991	75516	240	97	1025	108	5991	75516	240	97	1025	108	0	0.10541	
1978 JAN	5906	72010	235	96	966	126	5906	72010	235	96	966	126	0	0.13	
1978 FEB	5714	68505	231	103	901	59	5714	68505	231	103	901	59	0	0.065	
1978 MAR	6381	64948	226	104	964	43	6381	64948	226	104	964	43	0	0.045	
1978 APR	8483	64621	226	143	1348	61	8483	64621	226	143	1348	61	0	0.045	
1978 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045	
1978 JUN	11861	97007	264	199	2314	125	15727	93147	260	260	2926	158	33	0.05416	
1978 JUL	14325	96969	264	233	2763	171	10465	96974	264	170	2069	128	-43	0.06176	
1978 AUG	6764	96637	264	110	1400	150	6764	96642	264	110	1400	150	0	0.10693	
1978 SEP	8598	91891	258	144	1675	98	8598	91895	258	144	1675	98	0	0.05866	
1978 OCT	7329	87291	253	119	1400	54	7330	87295	253	119	1400	54	0	0.03878	
1978 NOV	6520	82816	248	110	1204	78	6521	82819	248	110	1205	78	0	0.06502	
1978 DEC	6836	78362	243	111	1214	128	6837	78364	243	111	1214	128	0	0.10541	
1979 JAN	6598	73907	238	107	1115	145	6599	73909	238	107	1115	145	0	0.13	
1979 FEB	5818	69453	232	105	931	61	5819	69454	232	105	931	61	0	0.065	
1979 MAR	5886	64947	226	96	873	39	5887	64947	226	96	874	39	0	0.045	
1979 APR	5586	64621	226	94	821	37	5586	64621	226	94	821	37	0	0.045	
1979 MAY	9514	75758	240	155	1667	75	13172	76837	241	214	2342	105	30	0.045	
1979 JUN	11745	99741	267	197	2319	126	13637	98928	266	229	2652	144	18	0.05416	
1979 JUL	13031	99688	267	212	2557	158	13027	98880	266	212	2548	157	-1	0.06176	
1979 AUG	10504	97091	264	171	2077	222	9697	97092	264	158	1932	207	-16	0.10693	
1979 SEP	8826	92279	259	148	1720	101	8826	92280	259	148	1720	101	0	0.05866	
1979 OCT	7994	87614	253	130	1524	59	7994	87614	253	130	1524	59	0	0.03878	
1979 NOV	7748	83074	248	130	1429	93	7748	83074	248	130	1429	93	0	0.06502	
1979 DEC	7253	78555	243	118	1292	136	7253	78556	243	118	1292	136	0	0.10541	
1980 JAN	7028	74036	238	114	1195	155	7028	74037	238	114	1195	155	0	0.13	
1980 FEB	6380	69518	232	111	1029	67	6380	69518	232	111	1029	67	0	0.065	
1980 MAR	6664	64947	226	108	1015	46	6664	64947	226	108	1015	46	0	0.045	
1980 APR	5670	64621	226	95	837	38	5670	64621	226	95	837	38	0	0.045	
1980 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045	
1980 JUN	6546	98575	265	110	1373	74	11645	93483	260	196	2240	121	47	0.05416	
1980 JUL	13198	96967	264	215	2561	158	9490	95592	262	154	1879	116	-42	0.06176	
1980 AUG	6764	95764	263	110	1390	149	6764	94392	261	110	1375	147	-2	0.10693	
1980 SEP	6192	93142	260	104	1254	74	6192	91773	258	104	1240	73	-1	0.05866	
1980 OCT	4929	91117	257	80	1009	39	4929	89749	256	80	994	39	-1	0.03878	
1980 NOV	4338	89246	255	73	879	57	4110	88106	254	69	825	54	-3	0.06502	
1980 DEC	4147	87397	253	67	827	87	3919	86485	252	64	776	82	-5	0.10541	
1981 JAN	3421	85547	251	56	675	88	3193	84863	250	52	627	81	-6	0.13	
1981 FEB	3584	83698	249	65	681	44	3356	83242	249	60	635	41	-3	0.065	

Table 5
Ruedi Reservoir
Foregone Power Revenues: Restricted Releases at Half Capacity

	Base						Restricted Relea							
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981 MAR	4050	81788	247	66	747	34	3822	81560	247	62	704	32	-2	0.045
1981 APR	8903	79829	245	150	1604	72	8725	79779	245	147	1571	71	-1	0.045
1981 MAY	9664	84454	250	157	1791	81	9663	84405	250	157	1791	81	0	0.045
1981 JUN	8547	96989	264	144	1718	93	8534	96953	264	143	1715	93	0	0.05416
1981 JUL	10428	96969	264	170	2062	127	10392	96969	264	169	2056	127	0	0.06176
1981 AUG	8099	93998	261	132	1612	172	8099	93998	261	132	1612	172	0	0.10693
1981 SEP	6546	91424	258	110	1300	76	6546	91424	258	110	1300	76	0	0.05866
1981 OCT	7730	86902	253	126	1468	57	7730	86902	253	126	1468	57	0	0.03878
1981 NOV	7444	82505	248	125	1368	89	7444	82505	248	125	1368	89	0	0.06502
1981 DEC	7259	78128	243	118	1287	136	7259	78128	243	118	1287	136	0	0.10541
1982 JAN	7329	73752	237	119	1246	162	7329	73752	237	119	1246	162	0	0.13
1982 FEB	6656	69375	232	120	1082	70	6656	69375	232	120	1082	70	0	0.065
1982 MAR	7402	64947	226	120	1149	52	7402	64947	226	120	1149	52	0	0.045
1982 APR	6979	64621	226	117	1075	48	6979	64621	226	117	1075	48	0	0.045
1982 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1982 JUN	9978	97007	264	168	1976	107	13382	93608	260	225	2554	138	31	0.05416
1982 JUL	17315	96969	264	260	3062	189	13916	96973	264	226	2690	166	-23	0.06176
1982 AUG	8572	97094	264	139	1730	185	8576	97094	264	139	1730	185	0	0.10693
1982 SEP	13407	91231	258	225	2535	149	13407	91231	258	225	2535	149	0	0.05866
1982 OCT	9483	85510	251	154	1770	69	9483	85510	251	154	1770	69	0	0.03878
1982 NOV	9312	79907	245	156	1679	109	9312	79907	245	156	1679	109	0	0.06502
1982 DEC	9637	74326	238	157	1671	176	9637	74326	238	157	1671	176	0	0.10541
1983 JAN	9145	68744	231	149	1513	197	9145	68744	231	149	1513	197	0	0.13
1983 FEB	8433	63162	224	152	1336	87	8433	63162	224	152	1336	87	0	0.065
1983 MAR	9138	57532	216	149	1364	61	9138	57532	216	149	1364	61	0	0.045
1983 APR	9580	51887	207	161	1377	62	9580	51887	207	161	1377	62	0	0.045
1983 MAY	8715	62734	223	142	1361	61	8715	62734	223	142	1361	61	0	0.045
1983 JUN	8833	100183	267	148	1800	97	8833	100183	267	148	1800	97	0	0.05416
1983 JUL	29507	100110	267	260	3092	191	29507	100110	267	260	3092	191	0	0.06176
1983 AUG	24667	100225	267	260	3093	331	24667	100225	267	260	3093	331	0	0.10693
1983 SEP	13603	93966	261	229	2598	152	13603	93966	261	229	2598	152	0	0.05866
1983 OCT	11014	87851	254	179	2071	80	11014	87851	254	179	2071	80	0	0.03878
1983 NOV	10664	81859	247	179	1944	126	10664	81859	247	179	1944	126	0	0.06502
1983 DEC	9851	75887	240	160	1729	182	9851	75887	240	160	1729	182	0	0.10541
1984 JAN	8561	69915	232	139	1422	185	8561	69915	232	139	1422	185	0	0.13
1984 FEB	7378	63943	225	128	1146	74	7378	63943	225	128	1146	74	0	0.065
1984 MAR	7793	57921	216	127	1124	51	7793	57921	216	127	1124	51	0	0.045
1984 APR	12302	51886	207	207	1875	84	12302	51886	207	207	1875	84	0	0.045
1984 MAY	9778	76893	241	159	1728	78	9778	76893	241	159	1728	78	0	0.045
1984 JUN	38640	101245	268	260	3003	163	38640	101245	268	260	3003	163	0	0.05416
1984 JUL	56215	101187	268	260	3103	192	56215	101187	268	260	3103	192	0	0.06176
1984 AUG	23404	101298	268	260	3104	332	23404	101298	268	260	3104	332	0	0.10693
1984 SEP	15127	95880	263	254	2891	170	15127	95880	263	254	2891	170	0	0.05866
1984 OCT	10031	90612	257	163	1923	75	10031	90612	257	163	1923	75	0	0.03878
1984 NOV	9302	85471	251	156	1735	113	9302	85471	251	156	1735	113	0	0.06502
1984 DEC	8937	80353	245	145	1616	170	8937	80353	245	145	1616	170	0	0.10541
1985 JAN	8340	75235	239	136	1447	188	8340	75235	239	136	1447	188	0	0.13
1985 FEB	7552	70117	233	136	1253	81	7552	70117	233	136	1253	81	0	0.065
1985 MAR	8860	64947	226	144	1415	64	8860	64947	226	144	1415	64	0	0.045
1985 APR	10744	64874	226	181	1763	79	10744	64874	226	181	1763	79	0	0.045
1985 MAY	8918	83365	249	145	1645	74	8918	83365	249	145	1645	74	0	0.045
1985 JUN	19386	101805	269	260	3008	163	19386	101805	269	260	3008	163	0	0.05416
1985 JUL	19160	96962	264	260	3062	189	19160	96962	264	260	3062	189	0	0.06176
1985 AUG	8241	97094	264	134	1670	179	8241	97094	264	134	1670	179	0	0.10693
1985 SEP	10827	92282	259	182	2080	122	10827	92282	259	182	2080	122	0	0.05866
1985 OCT	9664	87616	253	157	1825	71	9664	87616	253	157	1825	71	0	0.03878
1985 NOV	8749	83075	248	147	1610	105	8749	83075	248	147	1610	105	0	0.06502
1985 DEC	8455	78556	243	138	1509	159	8455	78556	243	138	1509	159	0	0.10541
1986 JAN	7696	74037	238	125	1316	171	7696	74037	238	125	1316	171	0	0.13
1986 FEB	7777	69518	232	140	1288	84	7777	69518	232	140	1288	84	0	0.065
1986 MAR	9462	64947	226	154	1524	69	9462	64947	226	154	1524	69	0	0.045
1986 APR	13041	64874	226	219	2181	98	13041	64874	226	219	2181	98	0	0.045
1986 MAY	9864	83365	249	160	1816	82	9864	83365	249	160	1816	82	0	0.045
1986 JUN	19191	101504	268	260	3005	163	19191	101504	268	260	3005	163	0	0.05416
1986 JUL	15347	101453	268	250	2990	185	15347	101453	268	250	2990	185	0	0.06176
1986 AUG	8327	101563	269	135	1730	185	8327	101563	269	135	1730	185	0	0.10693
1986 SEP	11898	96106	263	200	2312	136	11898	96106	263	200	2312	136	0	0.05866
1986 OCT	8939	90799	257	145	1728	67	8939	90799	257	145	1728	67	0	0.03878
1986 NOV	8827	85621	251	148	1651	107	8827	85621	251	148	1651	107	0	0.06502
1986 DEC	8811	80466	246	143	1594	168	8811	80466	246	143	1594	168	0	0.10541
1987 JAN	8138	75310	239	132	1412	184	8138	75310	239	132	1412	184	0	0.13
1987 FEB	7680	70155	233	138	1277	83	7680	70155	233	138	1277	83	0	0.065
1987 MAR	8100	64947	226	132	1276	57	8100	64947	226	132	1276	57	0	0.045
1987 APR	9221	64874	226	155	1486	67	9221	64874	226	155	1486	67	0	0.045
1987 MAY	11041	74359	238	180	1926	87	11041	74359	238	180	1926	87	0	0.045
1987 JUN	9168	87118	253	154	1728	94	9168	87118	253	154	1728	94	0	0.05416
1987 JUL	6764	90707	257	110	1335	82	6764	90707	257	110	1335	82	0	0.06176
1987 AUG	6764	90350	257	110	1331	142	6764	90350	257	110	1331	142	0	0.10693

Table 5
Ruedi Reservoir
Foregone Power Revenues: Restricted Releases at Half Capacity

	Base						Restricted Relea							
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1987 SEP	7933	86512	252	133	1499	88	7933	86512	252	133	1499	88	0	0.05866
1987 OCT	7440	82812	248	121	1372	53	7440	82812	248	121	1372	53	0	0.03878
1987 NOV	7495	79233	244	126	1343	87	7495	79233	244	126	1343	87	0	0.06502
1987 DEC	6841	75674	240	111	1181	125	6841	75674	240	111	1181	125	0	0.10541
1988 JAN	6683	72116	235	109	1108	144	6683	72116	235	109	1108	144	0	0.13
1988 FEB	5370	68557	231	93	835	54	5370	68557	231	93	835	54	0	0.065
1988 MAR	5678	64948	226	92	836	38	5678	64948	226	92	836	38	0	0.045
1988 APR	8433	64621	226	142	1339	60	8433	64621	226	142	1339	60	0	0.045
1988 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1988 JUN	9282	87639	254	156	1754	95	9282	87639	254	156	1754	95	0	0.05416
1988 JUL	6764	89982	256	110	1327	82	6764	89982	256	110	1327	82	0	0.06176
1988 AUG	8520	87024	253	139	1612	172	8520	87024	253	139	1612	172	0	0.10693
1988 SEP	6919	83665	249	116	1286	75	6919	83665	249	116	1286	75	0	0.05866
1988 OCT	6506	80442	246	106	1177	46	6506	80442	246	106	1177	46	0	0.03878
1988 NOV	6173	77338	242	104	1082	70	6173	77338	242	104	1082	70	0	0.06502
1988 DEC	5877	74253	238	96	989	104	5877	74253	238	96	989	104	0	0.10541
1989 JAN	5614	71168	234	91	902	117	5614	71168	234	91	902	117	0	0.13
1989 FEB	5632	68084	230	101	882	57	5632	68084	230	101	882	57	0	0.065
1989 MAR	7221	64948	226	117	1116	50	7221	64948	226	117	1116	50	0	0.045
1989 APR	9719	64621	226	163	1573	71	9719	64621	226	163	1573	71	0	0.045
1989 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1989 JUN	9282	85491	251	156	1731	94	9282	85491	251	156	1731	94	0	0.05416
1989 JUL	6764	87953	254	110	1305	81	6764	87953	254	110	1305	81	0	0.06176
1989 AUG	6764	87324	253	110	1299	139	6764	87324	253	110	1299	139	0	0.10693
1989 SEP	6829	83922	249	115	1272	75	6829	83922	249	115	1272	75	0	0.05866
1989 OCT	6829	80656	246	111	1238	48	6829	80656	246	111	1238	48	0	0.03878
1989 NOV	6026	77508	242	101	1058	69	6026	77508	242	101	1058	69	0	0.06502
1989 DEC	5768	74381	238	94	970	102	5768	74381	238	94	970	102	0	0.10541
1990 JAN	5345	71254	234	87	854	111	5345	71254	234	87	854	111	0	0.13
1990 FEB	5241	68126	230	94	811	53	5241	68126	230	94	811	53	0	0.065
1990 MAR	6008	64948	226	98	896	40	6008	64948	226	98	896	40	0	0.045
1990 APR	8840	62918	224	149	1393	63	8840	62918	224	149	1393	63	0	0.045
1990 MAY	8866	70503	233	144	1484	67	8866	70503	233	144	1484	67	0	0.045
1990 JUN	9798	82489	248	165	1794	97	9798	82489	248	165	1794	97	0	0.05416
1990 JUL	6764	84962	251	110	1273	79	6764	84962	251	110	1273	79	0	0.06176
1990 AUG	7731	82014	247	126	1416	151	7731	82014	247	126	1416	151	0	0.10693
1990 SEP	6593	79379	244	111	1181	69	6593	79379	244	111	1181	69	0	0.05866
1990 OCT	6764	76874	241	110	1182	46	6764	76874	241	110	1182	46	0	0.03878
1990 NOV	5551	74483	238	93	935	61	5551	74483	238	93	935	61	0	0.06502
1990 DEC	5271	72112	235	86	852	90	5271	72112	235	86	852	90	0	0.10541
1991 JAN	4868	69741	232	79	749	97	4868	69741	232	79	749	97	0	0.13
1991 FEB	4588	67370	229	83	684	44	4588	67370	229	83	684	44	0	0.065
1991 MAR	5202	64948	226	85	749	34	5202	64948	226	85	749	34	0	0.045
1991 APR	6269	64621	226	105	946	43	6269	64621	226	105	946	43	0	0.045
1991 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1991 JUN	9282	92572	259	156	1805	98	13382	88479	254	225	2502	136	38	0.05416
1991 JUL	6764	96233	263	110	1396	86	6764	92150	259	110	1351	83	-3	0.06176
1991 AUG	9323	93263	260	152	1824	195	9323	89188	255	152	1780	190	-5	0.10693
1991 SEP	9315	89004	255	157	1774	104	8733	85518	251	147	1633	96	-8	0.05866
				Totals		$19,793,233						$19,863,842		
				Difference								$70,609		
				Average Annual								$4,153		

Notes:

1. The monthly sales prices of electric power were obtained from John Gierard, WAPA, and were used in valuation of power generation:

Actual Projected Prices ($/MWH)

	Purchase	Sale		Purchase	Sale
Jun-00	75.44	54.16	Jan-01	110.00	130.00 projected
Jul-00	116.54	61.76	Feb-01	70.00	65.00 projected
Aug-00	115.89	106.93	Mar-01	50.00	45.00 projected
Sep-00	60.47	58.66	Apr-01	50.00	45.00 projected
Oct-00	65.48	38.78	May-01	50.00	45.00 projected
Nov-00	71.63	65.02	Average	79.05	68.39
Dec-00	113.19	105.41			

2. Base River Outflow is from Table 2. Restricted Release River Outflow is from Table 2.
3. Maximum operational flow through the turbines is 260 cfs.

Table 6. Differences in Bousted Tunnel Supply Under Alternative 1B

Date	Base Run	Ruedi - Full Release	Difference	Base Run	Ruedi Restricted Release - Half Channel	Difference	Base Run	Ruedi Restricted Release - Full Channel	Difference
Oct-74	345	0	345	345	345	0	345	345	0
Nov-74	0	33	-33	0	0	0	0	0	0
Dec-74	0	0	0	0	0	0	0	0	0
Jan-75	0	0	0	0	0	0	0	0	0
Feb-75	0	0	0	0	0	0	0	0	0
Mar-75	0	0	0	0	0	0	0	0	0
Apr-75	0	0	0	0	0	0	0	0	0
May-75	4739	186	4553	4739	4739	0	4739	4739	0
Jun-75	31791	31791	0	31791	31791	0	31791	31791	0
Jul-75	18874	18874	0	18874	18874	0	18874	18874	0
Aug-75	1493	1493	0	1493	1493	0	1493	1493	0
Sep-75	0	0	0	0	0	0	0	0	0
Oct-75	101	101	0	101	101	0	101	101	0
Nov-75	0	0	0	0	0	0	0	0	0
Dec-75	0	0	0	0	0	0	0	0	0
Jan-76	0	0	0	0	0	0	0	0	0
Feb-76	0	0	0	0	0	0	0	0	0
Mar-76	0	0	0	0	0	0	0	0	0
Apr-76	0	0	0	0	0	0	0	0	0
May-76	12584	7972	4612	12584	12584	0	12584	12584	0
Jun-76	22343	22343	0	22343	22343	0	22343	22343	0
Jul-76	4889	4889	0	4889	4889	0	4889	4889	0
Aug-76	26	26	0	26	26	0	26	26	0
Sep-76	0	0	0	0	0	0	0	0	0
Oct-76	0	0	0	0	0	0	0	0	0
Nov-76	0	0	0	0	0	0	0	0	0
Dec-76	0	0	0	0	0	0	0	0	0
Jan-77	0	0	0	0	0	0	0	0	0
Feb-77	0	0	0	0	0	0	0	0	0
Mar-77	0	0	0	0	0	0	0	0	0
Apr-77	0	0	0	0	0	0	0	0	0
May-77	5156	494	4662	5156	5156	0	5156	5156	0
Jun-77	7582	7582	0	7582	7582	0	7582	7582	0
Jul-77	0	0	0	0	0	0	0	0	0
Aug-77	0	0	0	0	0	0	0	0	0
Sep-77	0	0	0	0	0	0	0	0	0
Oct-77	144	113	31	144	144	0	144	144	0
Nov-77	0	0	0	0	0	0	0	0	0
Dec-77	0	0	0	0	0	0	0	0	0
Jan-78	0	0	0	0	0	0	0	0	0
Feb-78	0	0	0	0	0	0	0	0	0
Mar-78	0	0	0	0	0	0	0	0	0
Apr-78	92	92	0	92	92	0	92	92	0
May-78	9085	4473	4612	9085	9085	0	9085	9085	0
Jun-78	56900	56900	0	56900	56900	0	56900	56900	0
Jul-78	20226	20226	0	20226	20226	0	20226	20226	0
Aug-78	1186	1186	0	1186	1186	0	1186	1186	0
Sep-78	0	0	0	0	0	0	0	0	0
Oct-78	0	0	0	0	0	0	0	0	0
Nov-78	0	0	0	0	0	0	0	0	0
Dec-78	0	0	0	0	0	0	0	0	0
Jan-79	0	0	0	0	0	0	0	0	0
Feb-79	0	0	0	0	0	0	0	0	0
Mar-79	0	0	0	0	0	0	0	0	0
Apr-79	0	0	0	0	0	0	0	0	0
May-79	16662	8614	8048	16662	11924	4738	16662	11924	4738
Jun-79	52245	52245	0	52245	52245	0	52245	52245	0
Jul-79	21606	21606	0	21606	21606	0	21606	21606	0
Aug-79	1893	1893	0	1893	1893	0	1893	1893	0
Sep-79	0	0	0	0	0	0	0	0	0
Oct-79	0	0	0	0	0	0	0	0	0
Nov-79	0	0	0	0	0	0	0	0	0
Dec-79	0	0	0	0	0	0	0	0	0
Jan-80	0	0	0	0	0	0	0	0	0
Feb-80	0	0	0	0	0	0	0	0	0
Mar-80	0	0	0	0	0	0	0	0	0
Apr-80	0	0	0	0	0	0	0	0	0
May-80	11171	6559	4612	11171	11171	0	11171	11171	0
Jun-80	48685	48685	0	48685	48685	0	48685	48685	0
Jul-80	10966	10966	0	10966	10966	0	10966	10966	0
Aug-80	0	0	0	0	0	0	0	0	0

Table 6. Differences in Bousted Tunnel Supply Under Alternative 1B

Date	Base Run	Ruedi - Full Release	Difference	Base Run	Ruedi Restricted Release - Half Channel	Difference	Base Run	Ruedi Restricted Release - Full Channel	Difference
Sep-80	0	0	0	0	0	0	0	0	0
Oct-80	0	0	0	0	0	0	0	0	0
Nov-80	0	0	0	0	0	0	0	0	0
Dec-80	0	0	0	0	0	0	0	0	0
Jan-81	0	0	0	0	0	0	0	0	0
Feb-81	0	0	0	0	0	0	0	0	0
Mar-81	0	0	0	0	0	0	0	0	0
Apr-81	0	0	0	0	0	0	0	0	0
May-81	8530	5074	3456	8530	8530	0	8530	8530	0
Jun-81	22544	22544	0	22544	22544	0	22544	22544	0
Jul-81	3512	3512	0	3512	3512	0	3512	3512	0
Aug-81	0	0	0	0	0	0	0	0	0
Sep-81	0	0	0	0	0	0	0	0	0
Oct-81	602	602	0	602	602	0	602	602	0
Nov-81	0	0	0	0	0	0	0	0	0
Dec-81	0	0	0	0	0	0	0	0	0
Jan-82	0	0	0	0	0	0	0	0	0
Feb-82	0	0	0	0	0	0	0	0	0
Mar-82	0	0	0	0	0	0	0	0	0
Apr-82	0	0	0	0	0	0	0	0	0
May-82	9285	4673	4612	9285	9285	0	9285	9285	0
Jun-82	38147	38147	0	38147	38147	0	38147	38147	0
Jul-82	19880	19880	0	19880	19880	0	19880	19880	0
Aug-82	4136	4136	0	4136	4136	0	4136	4136	0
Sep-82	1394	1394	0	1394	1394	0	1394	1394	0
Oct-82	2116	2116	0	2116	2116	0	2116	2116	0
Nov-82	723	723	0	723	723	0	723	723	0
Dec-82	0	0	0	0	0	0	0	0	0
Jan-83	0	0	0	0	0	0	0	0	0
Feb-83	0	0	0	0	0	0	0	0	0
Mar-83	0	0	0	0	0	0	0	0	0
Apr-83	0	0	0	0	0	0	0	0	0
May-83	4739	0	4739	4739	4739	0	4739	4739	0
Jun-83	54074	54074	0	54074	54074	0	54074	54074	0
Jul-83	32402	32402	0	32402	32402	0	32402	32402	0
Aug-83	0	0	0	0	0	0	0	0	0
Sep-83	0	0	0	0	0	0	0	0	0
Oct-83	1427	1427	0	1427	1427	0	1427	1427	0
Nov-83	809	809	0	809	809	0	809	809	0
Dec-83	383	383	0	383	383	0	383	383	0
Jan-84	0	0	0	0	0	0	0	0	0
Feb-84	0	0	0	0	0	0	0	0	0
Mar-84	0	0	0	0	0	0	0	0	0
Apr-84	0	0	0	0	0	0	0	0	0
May-84	42525	42525	0	42525	42525	0	42525	42525	0
Jun-84	48158	48158	0	48158	48158	0	48158	48158	0
Jul-84	0	0	0	0	0	0	0	0	0
Aug-84	0	0	0	0	0	0	0	0	0
Sep-84	0	0	0	0	0	0	0	0	0
Oct-84	3552	3552	0	3552	3552	0	3552	3552	0
Nov-84	1482	1482	0	1482	1482	0	1482	1482	0
Dec-84	649	649	0	649	649	0	649	649	0
Jan-85	65	65	0	65	65	0	65	65	0
Feb-85	0	0	0	0	0	0	0	0	0
Mar-85	0	0	0	0	0	0	0	0	0
Apr-85	1938	1938	0	1938	1938	0	1938	1938	0
May-85	25047	25047	0	25047	25047	0	25047	25047	0
Jun-85	43492	43492	0	43492	43492	0	43492	43492	0
Jul-85	13548	13548	0	13548	13548	0	13548	13548	0
Aug-85	785	785	0	785	785	0	785	785	0
Sep-85	0	0	0	0	0	0	0	0	0
Oct-85	2246	2246	0	2246	2246	0	2246	2246	0
Nov-85	707	707	0	707	707	0	707	707	0
Dec-85	0	0	0	0	0	0	0	0	0
Jan-86	0	0	0	0	0	0	0	0	0
Feb-86	0	0	0	0	0	0	0	0	0
Mar-86	1192	1192	0	1192	1192	0	1192	1192	0
Apr-86	1389	1389	0	1389	1389	0	1389	1389	0
May-86	18328	18328	0	18328	18328	0	18328	18328	0
Jun-86	44602	44602	0	44602	44602	0	44602	44602	0
Jul-86	15136	15136	0	15136	15136	0	15136	15136	0

Table 6. Differences in Bousted Tunnel Supply Under Alternative 1B

Date	Base Run	Ruedi - Full Release	Difference	Base Run	Ruedi Restricted Release - Half Channel	Difference	Base Run	Ruedi Restricted Release - Full Channel	Difference
Aug-86	1948	1948	0	1948	1948	0	1948	1948	0
Sep-86	1910	1910	0	1910	1910	0	1910	1910	0
Oct-86	2535	2535	0	2535	2535	0	2535	2535	0
Nov-86	907	907	0	907	907	0	907	907	0
Dec-86	17	17	0	17	17	0	17	17	0
Jan-87	0	0	0	0	0	0	0	0	0
Feb-87	0	0	0	0	0	0	0	0	0
Mar-87	0	0	0	0	0	0	0	0	0
Apr-87	1281	1281	0	1281	1281	0	1281	1281	0
May-87	21525	16786	4739	21525	21525	0	21525	21525	0
Jun-87	23532	23532	0	23532	23532	0	23532	23532	0
Jul-87	3258	3258	0	3258	3258	0	3258	3258	0
Aug-87	169	169	0	169	169	0	169	169	0
Sep-87	0	0	0	0	0	0	0	0	0
Oct-87	0	0	0	0	0	0	0	0	0
Nov-87	0	0	0	0	0	0	0	0	0
Dec-87	0	0	0	0	0	0	0	0	0
Jan-88	0	0	0	0	0	0	0	0	0
Feb-88	0	0	0	0	0	0	0	0	0
Mar-88	0	0	0	0	0	0	0	0	0
Apr-88	0	0	0	0	0	0	0	0	0
May-88	9803	5191	4612	9803	9803	0	9803	9803	0
Jun-88	27416	27416	0	27416	27416	0	27416	27416	0
Jul-88	2502	2502	0	2502	2502	0	2502	2502	0
Aug-88	0	0	0	0	0	0	0	0	0
Sep-88	0	0	0	0	0	0	0	0	0
Oct-88	0	0	0	0	0	0	0	0	0
Nov-88	0	0	0	0	0	0	0	0	0
Dec-88	0	0	0	0	0	0	0	0	0
Jan-89	0	0	0	0	0	0	0	0	0
Feb-89	0	0	0	0	0	0	0	0	0
Mar-89	0	0	0	0	0	0	0	0	0
Apr-89	3162	3162	0	3162	3162	0	3162	3162	0
May-89	12600	7988	4612	12600	12600	0	12600	12600	0
Jun-89	13659	13030	629	13659	13659	0	13659	13659	0
Jul-89	3503	3503	0	3503	3503	0	3503	3503	0
Aug-89	0	0	0	0	0	0	0	0	0
Sep-89	0	0	0	0	0	0	0	0	0
Oct-89	0	0	0	0	0	0	0	0	0
Nov-89	0	0	0	0	0	0	0	0	0
Dec-89	0	0	0	0	0	0	0	0	0
Jan-90	0	0	0	0	0	0	0	0	0
Feb-90	0	0	0	0	0	0	0	0	0
Mar-90	0	0	0	0	0	0	0	0	0
Apr-90	0	0	0	0	0	0	0	0	0
May-90	4739	0	4739	4739	4739	0	4739	4739	0
Jun-90	29205	26695	2510	29205	29205	0	29205	29205	0
Jul-90	5388	5388	0	5388	5388	0	5388	5388	0
Aug-90	0	0	0	0	0	0	0	0	0
Sep-90	0	0	0	0	0	0	0	0	0
Oct-90	1289	1556	-267	1289	1289	0	1289	1289	0
Nov-90	466	466	0	466	466	0	466	466	0
Dec-90	0	0	0	0	0	0	0	0	0
Jan-91	0	0	0	0	0	0	0	0	0
Feb-91	0	0	0	0	0	0	0	0	0
Mar-91	0	0	0	0	0	0	0	0	0
Apr-91	0	0	0	0	0	0	0	0	0
May-91	16009	11397	4612	16009	16009	0	16009	16009	0
Jun-91	33568	33568	0	33568	33568	0	33568	33568	0
Jul-91	8135	8135	0	8135	8135	0	8135	8135	0
Aug-91	505	505	0	505	505	0	505	505	0
Sep-91	0	0	0	0	0	0	0	0	0
Average			*345.2696078*			*23.2254902*			*23.2254902*

TECHNICAL MEMORANDUM NO. 6: ANALYSIS OF 2001 SPRING PEAK-FLOW CONDITIONS AND COMPARISON TO RESULTS OF STATEMOD MODELING FOR CFOPS ALTERNATIVES INVESTIGATIONS

PRODUCED FOR:

Colorado Water Conservation Board

PRODUCED BY:

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June 2001
Revised October 2001

TECHNICAL MEMORANDUM NO. 6:
ANALYSIS OF 2001 SPRING PEAK-FLOW CONDITIONS AND COMPARISON TO RESULTS OF STATEMOD MODELING FOR CFOPS ALTERNATIVES INVESTIGATIONS

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Table 1. Recorded Flow data at Cameo and Palisade Gages, 2001

EXECUTIVE SUMMARY

The purpose of Technical Memorandum 6 is to present results from investigating spring 2001 peak-flow conditions on the Colorado River and comparing these spring 2001 conditions to results of recent CFOPS alternatives modeling using StateMod.

The primary impetus for completing Technical Memorandum 6 arose out of key findings from the modeling results for the Green Mountain Reservoir Re-operation alternatives (see Technical Memorandum 1 [Colorado Water Conservation Board, October 2001a], Technical Memorandum 2 [Colorado Water Conservation Board, October 2001b], and Technical Memorandum 3 [Colorado Water Conservation Board, October 2001c]). This key finding involved the fact that:

- It was not necessary to make the 20,000 acre-feet target release in those years in which the spring peak flow at the head of the 15-Mile Reach was expected to be less than 12,900 cfs. Consequently, it was not necessary to make the release during dry years.

- It was possible to replace the stored water that had been released from Green Mountain Reservoir for the 20,000 acre-feet release under the Green Mountain Reservoir refill right in those six years that the 20,000 acre-feet release would have been required during the 1975-91 study period and the two years that the release might have been required.

The principal question to be investigated is whether the actual flow conditions during the relatively dry 2001 spring would support these key findings for the 1975-91 study period. Investigation of actual flow conditions in spring 2001 indicated that:

- The spring 2001 peak discharge at the head of the 15-Mile Reach (Palisade gage) was 7,610 cfs and occurred on June 3, 2001.

- CROP was not implemented.

- The 20,000 acre-feet target release would not have been required.

Consequently, it would not have been necessary to attempt to replace a 20,000 acre-feet Green Mountain Reservoir release under the Green Mountain Reservoir refill right in 2001 because there would have been no 20,000 acre-feet release.

Therefore, the flow conditions and events of the spring 2001 runoff season corroborate the findings from the StateMod and C1 data set modeling.

INTRODUCTION AND PURPOSE

The purpose of Technical Memorandum No. 6 is to present the results from investigating spring 2001 peak-flow conditions on the Colorado River and compare these conditions to results of recent modeling of CFOPs alternatives using StateMod.

ANALYSIS PROCEDURES AND ASSUMPTIONS

The analysis consisted of two primary tasks:

- Obtain data on Colorado River flow conditions at the Palisade and Cameo gages from the Colorado Department of Natural Resources' real-time database, SatMon.

- Analyze these data to determine if actual spring 2001 Colorado River flow conditions were in general agreement with the assumptions used in modeling for the CFOPs alternatives and the results of this modeling.

USE OF STATEMOD

StateMod was not employed in this investigation.

RESULTS

Analysis of the recorded flow data for the Colorado River at the Cameo and Palisade gages are presented in Table 1 and flow data for the Palisade gage are graphed in Figure 1. The spring 2001 peak discharge at the head of the 15-Mile Reach (Palisade gage) was 7,610 cfs and occurred on June 3, 2001. This peak flow was well below the 12,900 cfs minimum limit for requiring the 20,000 acre-feet release for recovery of the endangered fish.

CROP was not implemented in spring 2000.

Because a 20,000 acre-feet release would not have been required, it would not have been necessary to attempt to refill Green Mountain Reservoir under its junior refill right.

REFERENCES

Colorado Water Conservation Board, October 2001a, *Technical Memorandum No. 1: Concerning Analysis of Alternative 1A, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Reduced Winter Operations.*

Colorado Water Conservation Board, October 2001b, *Technical Memorandum No. 2: Analysis of Alternative 1A, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Including Green Mountain Reservoir Preemptive Release and Release of Water Carried Over in Green Mountain Reservoir.*

Colorado Water Conservation Board, October 2001c, *Technical Memorandum No. 3: Analysis of Alternative 1A, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Conjunctive Pool Operations.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1. Flows at 15-Mile Reach, 2001

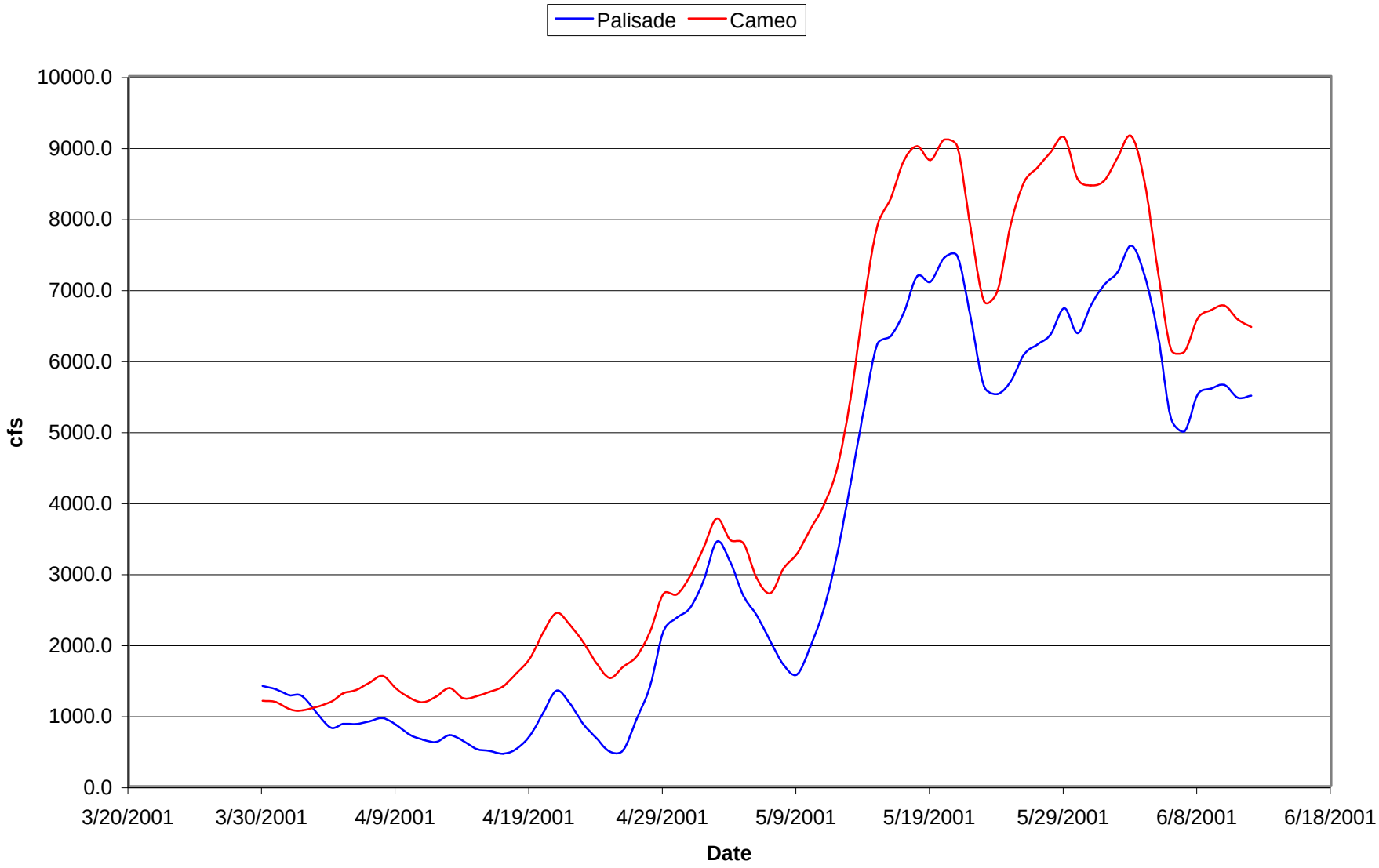

Table 1. Recorded Flow Data at Cameo and Palisade Gages, 2001

Date	Palisade	Cameo
3/30/2001	1411.3	1200.0
3/31/2001	1363.3	1182.7
4/1/2001	1278.5	1083.9
4/2/2001	1261.8	1068.6
4/4/2001	833.5	1176.7
4/5/2001	876.5	1303.8
4/6/2001	872.2	1353.8
4/7/2001	913.1	1456.3
4/8/2001	955.9	1552.5
4/9/2001	862.5	1374.6
4/10/2001	726.0	1242.1
4/11/2001	653.6	1180.8
4/12/2001	621.6	1262.5
4/13/2001	718.3	1383.3
4/14/2001	635.2	1237.0
4/15/2001	523.9	1266.5
4/16/2001	493.9	1330.0
4/17/2001	455.8	1402.5
4/18/2001	523.0	1585.0
4/19/2001	711.7	1798.5
4/20/2001	1030.5	2162.0
4/21/2001	1342.9	2439.2
4/22/2001	1166.4	2270.8
4/23/2001	873.0	2023.3
4/24/2001	672.8	1727.5
4/25/2001	484.9	1524.6
4/26/2001	509.6	1681.7
4/27/2001	944.3	1826.7
4/28/2001	1408.8	2176.7
4/29/2001	2179.1	2708.3
4/30/2001	2371.3	2701.3
5/1/2001	2509.7	2958.8
5/2/2001	2892.9	3357.1
5/3/2001	3442.5	3770.0
5/4/2001	3159.4	3465.0
5/5/2001	2676.8	3417.9
5/6/2001	2402.5	2925.8
5/7/2001	2039.0	2717.5
5/8/2001	1707.6	3067.1
5/9/2001	1570.7	3273.3
5/10/2001	1961.4	3613.8
5/11/2001	2493.4	3956.3
5/12/2001	3265.6	4476.7
5/13/2001	4249.4	5448.3
5/14/2001	5291.0	6777.5
5/15/2001	6215.6	7871.7
5/16/2001	6334.6	8273.3
5/17/2001	6671.9	8810.4
5/18/2001	7180.4	9010.4

Table 1. Recorded Flow Data at Cameo and Palisade Gages, 2001

Date	Palisade	Cameo
5/19/2001	7103.1	8817.5
5/20/2001	7437.4	9101.3
5/21/2001	7462.9	9003.9
5/22/2001	6595.4	7853.6
5/23/2001	5634.3	6829.2
5/24/2001	5518.4	6966.3
5/25/2001	5704.3	7913.8
5/26/2001	6080.0	8505.4
5/27/2001	6220.0	8710.0
5/28/2001	6364.1	8929.6
5/29/2001	6730.2	9135.0
5/30/2001	6376.8	8549.1
5/31/2001	6770.0	8459.6
6/1/2001	7060.5	8526.3
6/2/2001	7237.2	8849.6
6/3/2001	7610.3	9153.8
6/4/2001	7201.7	8522.5
6/5/2001	6378.2	7275.0
6/6/2001	5176.3	6148.8
6/7/2001	4998.1	6120.4
6/8/2001	5517.9	6591.3
6/9/2001	5597.2	6703.3
6/10/2001	5648.5	6768.3
6/11/2001	5471.3	6571.7
6/12/2001	5499.3	6467.1

TECHNICAL MEMORANDUM NO. 7: INVESTIGATION OF ALTERNATIVE 1F, BYPASS DIVERSIONS TO STORAGE, AND ALTERNATIVE 1G, REDUCE CONSTRAINTS ON CROP

DRAFT

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October 2001

TECHNICAL MEMORANDUM NO. 7:
INVESTIGATION OF ALTERNATIVE 1F, BYPASS DIVERSIONS TO STORAGE, AND ALTERNATIVE 1G, REDUCE CONSTRAINTS ON CROP

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EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 7 is to present the results from the investigation of Alternatives 1f, Bypass Diversions to Storage, and 1g, Reduce Constraints on Coordinated Reservoirs Operations Program (CROP), for Denver Water Systems Operations. As directed by the Executive Committee, these two alternatives have been investigated together because of their similarity.

Alternative 1f, Bypass Diversions to Storage, originally included all participating facilities ceasing diversion to in-basin storage, transmountain diversion and/or direct flow diversions during the 10-day period surrounding the estimated spring peak flow. This was subsequently modified in the Phase 1 Final Report (Colorado Water Conservation Board, September 2000) to include cessation of diversions to in-basin storage. Consequently, investigation of this alternative includes bypassing diversion to storage in the following reservoirs:

- Dillon,
- Granby,
- Green Mountain,
- Homestake,
- Ruedi,
- Williams Fork,
- Willow Creek,
- Wolford Mountain, and
- Vega.

For the investigation of Alternative 1g, Reduce Constraints on CROP, the following modifications of CROP constraints are considered.

- Alternative 1g recommended having additional projects participate in the CROP program on a consistent basis; consequently a scenario was developed to have more reservoirs participate in providing the 20,000 acre-feet release. The listed reservoirs above were assumed to participate in CROP on a consistent basis.
- In order to provide flows toward the 20,000 acre-feet target, the participating reservoirs could make releases from storage and/or bypass diversion to storage during the 10-day period surrounding the spring peak flow period.

To investigate Alternatives 1f and 1g, a portion of the 20,000 acre-feet target was assigned to each of the reservoirs listed above and assumed to be participating in the CROP program. For purposes of this analysis, the portion of the 20,000 acre-feet assigned to each reservoir was specified in three ways:

1. **Proportionate share based on reservoir inflow**. Each reservoir's bypass/release responsibility was based on the annual average annual inflow to that reservoir divided by the total annual average inflow to the nine reservoirs multiplied by 20,000 acre-feet
2. **Equal division among three reservoirs**. Responsibility for bypassing inflows or making a release was divided equally among Granby, Green Mountain and Williams Fork Reservoirs (i.e. 6,667 acre-feet for each reservoir).
3. **Total release from Granby Reservoir**. For comparison purposes, assigning all 20,000 acre-feet to each of the three reservoirs was also investigated. The scenarios in which all 20,000 acre-feet was the responsibility of Green Mountain or Williams Fork have already been investigated in Technical Memorandum No. 1 (Colorado Water Conservation Board, October 2001a), Technical Memorandum No. 2 (Colorado Water Conservation Board, October 2001b), Technical Memorandum No. 3 (Colorado Water Conservation Board, October 2001c) and Technical Memorandum No. 11 (Colorado Water Conservation Board, October 2001d). Therefore, only the remaining scenario of assigning responsibility to Granby Reservoir for bypassing and/or releasing the 20,000 acre-feet was investigated in this Technical Memorandum.

Results of the analysis using the proportionate share allocation of responsibility for the 20,000 acre-feet are presented in Table ES-1. As shown in this table, there was no effect on storage in Dillon and Vega Reservoirs from providing their proportionate shares of the 20,000 acre-feet target for the 15-Mile Reach. The average annual decrease in storage for the 1974-91 study period between the C1 base case and Alternatives 1f and 1g with proportionate sharing of responsibility for the 20,000 acre-feet release for the remaining seven reservoirs was:

- Granby Reservoir: an average of 1,007 acre-feet/year less storage over the 17-year study period.
- Green Mountain Reservoir: an average of 91 acre-feet/year less storage over the 17-year study period.
- Homestake Reservoir: an average of 1,598 acre-feet/year less storage over the 17-year study period. (As explained in the main body of the report, it is believed that StateMod is not correctly modeling Homestake Reservoir; consequently, this 1,598 acre-feet decrease should not be interpreted as an accurate estimate.)
- Ruedi Reservoir: an average of 10 acre-feet/year less storage over the 17-year study period.
- Williams Fork Reservoir: an average of 36 acre-feet/year less storage over the 17-year study period.
- Willow Creek Reservoir: an average of 281 acre-feet/year less storage over the 17-year study period.
- Wolford Mountain Reservoir: an average of 27 acre-feet/year less storage over the 17-year study period.

Table ES-1. Summary of Results for Proportionate Allocation of 20,00 acre-feet Bypass Among Nine Reservoirs

Reservoir	Ave. Annual Reduction in Storage[1] (acre-feet)
Dillon	0
Granby	1007
Green Mountain	91
Homestake[2]	1598
Ruedi	10
Williams Fork	36
Willow Creek	281
Wolford[2]	175
Vega	0

[1]average of differences between annual peak storage values, 1974-1991
[2]average of monthly storage, 1974-1991

Results of the analysis for bypassing/releasing the 20,000 acre-feet from just three reservoirs are presented in Table ES-2. Results in this table indicate that the effects on storage in Granby, Green Mountain and Williams Fork Reservoirs as a result of distributing responsibility for bypassing/releasing the 20,000 acre-feet from just these three reservoirs remained approximately the same as for the proportionate distribution scenario. Effects on the remaining reservoirs was substantially reduced or eliminated.

Table ES-2. Summary of Results for Equal Distribution of 20,00 acre-feet Bypass Among Granby, Green Mountain and Williams Fork Reservoir

Reservoir	Ave. Annual Reduction in Storage[1] (acre-feet)
Dillon	0
Granby	1439
Green Mountain	135
Homestake[2]	0
Ruedi	0
Williams Fork	350
Willow Creek	0
Wolford[2]	27
Vega	0

[1]average of differences between annual peak storage values, 1974-1991
[2]average of monthly storage, 1974-1991

Placing responsibility on Granby Reservoir for bypass/release of the entire 20,000 acre-feet for the eight years requiring the release during the study period resulted in an average annual reduction in Granby storage of approximately 16,000 acre-feet.

Specific results from the StateMod/C1 analysis of Alternatives 1f and 1g for the proportionate allocation include:

- **Dillon Reservoir (proportionate allocation).** Storage in Dillon Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In every year where a 3,700 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 scenario.

- **Granby Reservoir (proportionate allocation).** Storage in Granby Reservoir was only slightly affected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing among the nine reservoirs as compared to storage under the C1 Scenario for the study period. In every year where a 5,900 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario except in 1979-1982 where a deficit of approximately 3,000-4,000 acre-feet was not restored until the spring of 1983. The average annual reduction in storage over the 1974-91 study period with the proportionate sharing scenario as compared to the base C1 Scenario was approximately 1,000 acre-feet.

- **Green Mountain Reservoir (proportionate share).** Storage in Green Mountain Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In every year where a 4,300 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario. The total foregone power production for Green Mountain Reservoir was approximately $93,000, or approximately $5,500 per year, for the 1974-1991 study period with the proportionate share allocation of responsibility for meeting the 20,000 acre-feet release.

- **Homestake Reservoir (proportionate share).** Storage in Homestake Reservoir was significantly affected by imposition of the Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In every year where a 400 acre-feet release was made to the 15-Mile Reach, the reservoir failed to achieve the same level of storage as in the C1 Scenario. The proportional allocation version of Alternatives 1f and 1g resulted in a total deficit of approximately 2,700 acre-feet at the end of the study period. Review of estimated storage in Homestake Reservoir for the study period, however, indicates apparently erroneous behavior of Homestake Reservoir during the 1980s, a wetter than average period. Brown and Caldwell believes the Homestake Reservoir is not being modeled correctly by StateMod and the C1 data set and that this is the reason for this erroneous behavior of Homestake Reservoir. Additional analysis of the adequacy of how Homestake Reservoir is modeled by StateMod and the C1 data set is recommended.

- **Ruedi Reservoir (proportionate allocation).** Storage in Ruedi Reservoir was unaffected by imposition of the proportionate allocation version of Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In those years when a 1,600 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario. The proportionate allocation scenario resulted in a total decrease of approximately $14,000 in total power revenue over the 1974-91 study period or an average annual reduction of approximately $800.

- **Williams Fork Reservoir (proportionate allocation).** Storage in Williams Fork Reservoir was unaffected by imposition of the proportionate allocation version of Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In every

year when a 1,500 acre-feet release from Williams Fork Reservoir was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario.

- **Willow Creek Reservoir (proportionate allocation).** Storage in Willow Creek Reservoir was affected by implementation of the proportionate allocation version of Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In 1975, 1978, 1982 and 1991, a temporary deficit was modeled as a result of the 1,200 acre-feet release which continued until November of the same year when the storage levels again matched those of the C1 scenario. In 1991, a storage deficit occurred and it is anticipated, however, that this deficit would have been eliminated if the study period had been continued through November 1991. At no time did Willow Creek Reservoir empty due to this scenario.
- **Wolford Mountain Reservoir (proportionate allocation).** Storage in Wolford Mountain Reservoir was slightly affected by imposition of the proportionate allocation version of Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In 1978, 1982 and 1991 a temporary deficit was modeled from the spring 1,200 acre-feet release until the following spring where the storage levels matched the C1 Scenario. In 1991 the same deficit occurred and it is anticipated the deficit would have been eliminated if the study period had continued through spring 1992. At no time did Wolford Mountain Reservoir completely empty due to this scenario.
- **Vega Reservoir (proportionate allocation).** Storage in Vega Reservoir was unaffected by imposition of the proportional allocation version of Alternatives 1f and 1g operating rule as compared to storage under the C1 Scenario for the study period. In every year where a 200 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario.
- **Shoshone power production (proportionate allocation).** The value of Shoshone power production was increased under the proportionate allocation version of Alternatives 1f and 1g operating rule for the 1975-91 study period by approximately $63,000 or approximately $3,700 per year.
- **Shoshone priority calls (proportionate allocation).** The frequency and duration of Shoshone priority calls were not altered to any measurable degree by implementation of the Alternatives 1f and 1g operations policy for the 1975-91 study period.
- **Orchard Mesa power plant (proportionate allocation).** The Alternatives 1f and 1g operations policy did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternatives 1f and 1g operations policy.
- **Check Case settlement (proportionate allocation).** Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternatives 1f and 1g operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternatives 1f and 1g operations policy should not affect the Check Case settlement.
- **Channel Capacity Constraints (proportionate allocation).** Results produced herein indicate that the additional releases and/or bypasses of diversions to storage could be made from each of the reservoirs without violating channel flow constraints on: (1) the Blue River or Colorado

River downstream from Green Mountain Reservoir and (2) on the Frying Pan River downstream from Ruedi Reservoir.

- **Adams Tunnel Deliveries (proportionate allocation).** Deliveries through the Adams Tunnel were unchanged by the proportionate allocation scenario from deliveries under the C1 Scenario.
- **Boustead and Busk-Ivanhoe Tunnel Deliveries (proportionate allocation).** Deliveries through the Boustead and Busk-Ivanhoe tunnels were, for practical purposes, unchanged by the proportionate allocation scenario from deliveries under the C1 Scenario. The Boustead tunnel did show a decrease in total supply for two months during the study period, October of 1977 and May of 1979. These decreases in supply occurred because the prorated release from Ruedi Reservoir caused the junior fill right (1981-01-22) to be in priority, calling out the more junior (1982-12-31) Boustead tunnel diversion right.

Specific results of analysis of Alternatives 1f and 1g for the equal allocation of bypass/release of the 20,000 acre-feet among Granby, Green Mountain and Williams Fork Reservoirs include:

- **Granby Reservoir Storage (equal allocation).** Storage in Granby Reservoir was affected by imposition of the Alternatives 1f and 1g operating rule with equal allocation of responsibility for the 20,000 acre-feet release among three reservoirs as compared to storage under the C1 Scenario for the study period. In every year where a 6,667 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario except in 1979-1982 where a deficit of 2,900 - 4,700 acre-feet was not restored until the spring of 1983. There was little difference in effects on Granby Reservoir storage between the proportionate allocation scenario and the equal allocation scenario.
- **Green Mountain Reservoir Storage (equal allocation).** Storage in Green Mountain Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule with equal allocation of responsibility for the 20,000 acre-feet release as compared to storage under the C1 Scenario for the study period. In every year where a 6,667 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario. The total power generation revenue foregone at Green Mountain Reservoir for the 1975-1991 study period with equal allocation of responsibility for the 20,000 acre-feet release among the three reservoirs is approximately $101,000, or an average of approximately $5,900 per year.
- **Williams Fork Reservoir Storage (equal allocation).** Storage in Williams Fork Reservoir was more affected by imposition of the equal allocation version of Alternatives 1f and 1g operating rule as compared the proportionate allocation scenario. A shortage in storage of approximately 5,000 acre-feet that occurred in 1978 did not refill until 1979 under this scenario. At no time did the reservoir completely empty during the 1974-91 study period under this scenario.
- **Shoshone power production (equal allocation).** The impact on Shoshone power production by implementation of the Alternatives 1f and 1g operations policy with the equal allocation alternatives for the 1975-91 study period was a total reduction in power

revenue of approximately $117,000 for the study period or an average annual reduction of approximately $6,900.

- **Shoshone priority calls (equal allocation).** The frequency and duration of Shoshone priority calls were not altered to any measurable degree by implementation of the Alternatives 1f and 1g operations policy for the 1975-91 study period
- **Orchard Mesa power plant (equal allocation).** The Alternatives 1f and 1g operations policy with equal allocation of responsibility for the 20,000 acre-feet did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternatives 1f and 1g operations policy.
- **Check Case settlement (equal allocation).** Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternatives 1f and 1g operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternatives 1f and 1g operations policy should not affect the Check Case settlement.
- **Channel Capacity Constraints (equal allocation).** Results produced herein indicate that the additional releases and/or bypasses of diversions to storage could be made from each of the reservoirs without violating channel flow constraints on: (1) the Blue River or Colorado River downstream from Green Mountain Reservoir and (2) on the Frying Pan River downstream from Ruedi Reservoir.
- **Adams Tunnel Deliveries (equal allocation).** Adams tunnel deliveries were unaffected by the equal allocation scenario.

Placing responsibility on Granby Reservoir for bypassing and/or releasing the entire 20,000 acre-feet release to the 15-Mile Reach had the following effects:

- **Granby Reservoir Storage (total release from Granby Reservoir).** Releasing or bypassing the entire 20,000 acre-feet from Granby Reservoir decreased the average annual storage in Granby Reservoir by approximately 16,000 acre-feet as compared to the C1 base run scenario. At no time did the reservoir completely empty during the 1974-91 study period under this scenario.
- **Adams Tunnel Deliveries (total release from Granby Reservoir)**. Adams tunnel deliveries were unaffected by the total 20,000 acre-feet release from Granby Reservoir scenario.

The following conclusions and recommendations are based on the results of the analysis herein:

- Alternatives 1f, Bypass Diversions to Storage, and 1g, Reduce Constraints on CROP, can provide the 20,000 acre-feet to the 15-Mile Reach during the eight years in which this release would be required for the 1974-91 study period with any of the three alternatives scenarios.
- Effects of these alternatives on west slope facilities, operation of these facilities and flexibility of these facilities do not appear to constitute any fatal flaws from engineering

and economic perspectives. The Executive committee should evaluate these alternatives from legal and institutional perspectives

- The analysis of the effects of these alternatives and scenarios was limited to west slope facilities and systems because east slope facilities and systems are not included in the existing version of StateMod and the C1 data set. Consequently, further consideration of Alternatives 1f and 1g should include analysis of these alternatives by concerned east slope entities using their own models, data sets and calculation procedures.
- It is recommended that Alternatives 1f and 1g be given further consideration as a potential source of supply for the 20,000 acre-feet to the 15-Mile Reach.
- This further consideration should include sensitivity analysis of the performance of these alternatives with an additional 60,000 to 120,000 acre-feet of future depletions to the Colorado River.

INTRODUCTION AND PURPOSE

The Phase 1 investigation (CWCB, September 2000) recommended that Alternative 1f, Bypass Diversions to Storage, should be investigated together with Alternative 1g, Reduce Constraints on CROP. The purpose of this Technical Memorandum is to investigate the feasibility of Alternatives 1f and 1g for providing necessary water supply for making the 20,000 acre-feet release.

Alternative 1f, Bypass Diversions to Storage, originally included all participating facilities ceasing diversion to in-basin storage, transmountain diversion and/or direct flow diversions during the 10-day period surrounding the estimated spring peak flow. This was subsequently modified in the Phase 1 Final Report (Colorado Water Conservation Board, September 2000) to include cessation of diversions to in-basin storage. Consequently, investigation of this alternative includes bypassing diversion to storage in the following reservoirs:

- Dillon,
- Granby,
- Green Mountain,
- Homestake,
- Ruedi,
- Williams Fork,
- Willow Creek,
- Wolford Mountain and
- Vega.

For the investigation of Alternative 1g, Reduce Constraints on CROP, the following modifications of constraints are considered.

- The listed reservoirs above were assumed to participate in the CROP program on a consistent basis.
- In order to provide flows toward the 20,000 acre-feet target, the participating reservoirs could make releases from storage and/or bypass diversion to storage during the 10-day period surrounding the spring peak flow period.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following general procedures, tools, and assumptions were employed in the analysis of Alternatives 1f and 1g:

1. The StateMod surface water model and the C1 data set were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 Scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. StateMod and the C1 data set were modified to include the actual Ruedi Reservoir refill priority date of January 22, 1981 for 101,280 acre- feet. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000)*. These components of RIPRAP flows include:

    - 5,000 acre-feet per year from Ruedi Reservoir,
    - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
    - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
    - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
    - 6,000 acre-feet per year from Wolford Mountain Reservoir, and
    - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated on the C1 dataset but not modeled.

3. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee review the analysis and determine that the methodology and calculations employed in the analysis of Alternatives 1f and 1g are acceptable; the necessary sensitivity analysis will be completed.

   CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year,

including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

4. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

5. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

   The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

   A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the

alternative under investigation. Therefore these two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

6. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,
   - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
   - A reservoir fill according to the criteria of the Blue River Decree.

   The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

   Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

   Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

7. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
   - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
   - Sufficient HUP Surplus water exists to make the release.

Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. Releases of HUP Surplus water under the Municipal Recreational Agreement are not explicitly modeled by StateMod and the C1 data set and there is no demand specified at a node for the Municipal Recreational water.

SPECIFIC PROCEDURES

The following specific procedures were employed for modeling alternatives 1f and 1g.

1. Inflow data for each of the reservoirs to be included were obtained from the C1 data set and the average annual inflow to each reservoir for the study period was computed (see Table 1).
2. The following procedures were used for determining the allocation of responsibility for bypassing or releasing a total of 20,000 acre-feet among the reservoirs for meeting the 20,000 acre-feet target release:
   - **Proportionate share based on reservoir inflow**. Each reservoir's bypass/release responsibility for the 20,000 acre-feet release was based on the annual average annual inflow to that reservoir divided by the total annual average inflow to the nine reservoirs multiplied by 20,000 acre-feet (see Table 1).
   - **Equal division among three reservoirs**. Responsibility for bypassing inflows or making the 20,000 acre-feet release was divided equally among Granby, Green Mountain and Williams Fork Reservoirs. This resulted in each reservoir being responsible for 6,667 acre-feet of bypass and/or release.
   - **Total release from Granby**. Granby, Green Mountain and Williams Fork Reservoirs each have responsibility for bypassing or releasing the full 20,000 acre-feet to the 15-Mile Reach. This scenario has already been investigated for Green Mountain Reservoir (Colorado Water Conservation Board, 2001a, b and c) and for Williams Fork Reservoir (Colorado Water Conservation Board, 2001d). Consequently, this Technical Memorandum only includes analysis of Granby Reservoir releasing and/or bypassing the 20,000 acre-feet.
3. These bypass to storage and/or release from storage targets were then analyzed using StateMod and the C1 data set.

USE OF STATEMOD

The C1 scenario was modified by adding full reservoir targets in Green Mountain Reservoir for the months of September and October. This prevented surplus water hydropower releases until after the irrigation season. In addition, monthly demands of 20,000 acre-feet were added to diversion ID #952001 corresponding to the projected 20,000 acre-feet releases to enhance the spring runoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1982, 1985, 1986 and 1991. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water

in the stream when available. This was the basis for the baseline scenario for evaluating alternatives.

For Alternatives 1f and 1g, the baseline scenario was modified by adding nine additional diversion nodes in the river system immediately downstream of the head of the 15-mile reach. Each diversion point then had a demand added corresponding to each respective release from the nine identified reservoirs. A new operation rule was added to each of the modeled reservoirs to allow a release to their respective demand. These changes released additional 20,000 acre-feet of water in the appropriate ratio from each of the modeled reservoirs in those years when it would be required.

Several spreadsheets were then developed to allow side by side comparison of every aspect of the analysis in the two StateMod runs including reservoir storage, diversions, streamflows and operating releases.

RESULTS

EFFECTS ON RESERVOIR STORAGE

Dillon Reservoir

Storage in Dillon Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing among the nine reservoirs as compared to storage under the C1 Scenario for the study period (see Figure 1). In every year where a 3,700 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario.

For the equal allocation among three reservoirs, storage in Dillon Reservoir was likewise unaffected by imposition of the Alternatives 1f and 1g operating rule. During the eight years when a 6,667 acre-feet release was made from Williams Fork Reservoir to the 15-Mile Reach, Dillon Reservoir still achieved the same level of storage as in the C-1 Scenario.

Granby Reservoir

Storage in Granby Reservoir was only slightly affected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing among the nine reservoirs as compared to storage under the C1 Scenario for the study period (see Figure 2). In every year where a 5,900 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario except in 1979-1982 where a deficit of 3,000-4,000 acre-feet was not restored until the spring of 1983. The average annual reduction in storage over the 1974-91 study period with the proportionate sharing scenario as compared to the base C1 Scenario was approximately 1,000 acre-feet.

A similar result occurred with equal sharing among the three reservoirs. In every year where a 6,667 acre-feet release was made to the 15-Mile Reach, Granby Reservoir still achieved the same level of storage as in the C1 Scenario except in 1979-1982 where a deficit of 2,900-4,700 acre-feet was not restored until the spring of 1983 (see Figure 10). The average annual reduction in storage over the 1974-91 study period with the equal distribution scenario as compared to the base C1 Scenario was approximately 1,400 acre-feet.

For the scenario where Granby Reservoir had sole responsibility for making the 20,000 acre-feet release to the 15-Mile Reach, reservoir storage was lower for the following periods: June 1978 through June 1984, June 1986 through June 1987 and summer 1991 (see Figure 13). The average annual reduction in storage over the 1974-91 study period with Granby Reservoir having full responsibility for making the 20,000 acre-feet release/bypass as compared to the base C1 Scenario was approximately 16,000 acre-feet.

Green Mountain Reservoir

Storage in Green Mountain Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 3). In every year where a 4,300 acre-foot release was made to the 15-Mile Reach under the proportionate sharing scenario, the reservoir still achieved, for practical purposes, the same level of storage as in the C1 Scenario. The average annual reduction in storage over the 1974-91 study period with the proportionate sharing scenario as compared to the base C1 Scenario was approximately 90 acre-feet

A similar result occurred with equal sharing among the three reservoirs. In the eight years when a 6,667 acre-feet release or bypass was made from Green Mountain Reservoir to the 15-Mile Reach, the reservoir still achieved, for practical purposes, the same level of storage as in the C-1 scenario (see Figure 11). The average annual reduction in storage over the 1974-91 study period with the equal allocation scenario as compared to the base C1 Scenario was approximately 135 acre-feet

Homestake Reservoir

Storage in Homestake Reservoir was significantly affected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 4). In every year where a 400 acre-feet release was made to the 15-mile reach, the reservoir failed to achieve the same level of storage as in the C1 Scenario. The cumulative effect of this was to create a total deficit of 2,742 acre-feet of storage in Homestake Reservoir by the end of the study period. The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 1,600 acre-feet.

Analysis of Figure 4, Homestake Reservoir storage for the study period, indicates a general downward trend in storage for the 1974-1991 study period. This downward trend in storage continued through the very wet years in the early and mid-1980s. These results have led Brown and Caldwell to the preliminary conclusion that StateMod with the C1 data set is not correctly modeling Homestake Reservoir. Significant further investigation would be necessary to determine the cause of these apparent problems. At no time did the reservoir completely empty during the 1974-91 study period under this scenario.

For equal allocation of the 20,000 acre-feet bypass/release among three reservoirs (Granby, Green Mountain and Williams Fork) scenario, storage in Homestake Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule. During the eight years when a 20,000 acre-feet bypass/release was made from the three reservoirs to the 15-Mile Reach, Homestake Reservoir still achieved the same level of storage as in the C-1 Scenario. Again, interpretation of this result must be based on the fact that StateMod with the C-1 data set is apparently not modeling Homestake Reservoir correctly.

Ruedi Reservoir

Storage in Ruedi Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 5). In every year where a 1,600 acre-foot release was made to the 15-mile reach, the reservoir still achieved, for practical purposes, the same level of storage as in the C1 Scenario. The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 10 acre-feet.

For equal allocation of the 20,000 acre-feet bypass/release among three reservoirs, storage in Ruedi Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule. During the eight years when a 20,000 acre-feet bypass/release was made from the three reservoirs to the 15-Mile Reach, Ruedi Reservoir still achieved the same level of storage as in the C-1 Scenario

Williams Fork Reservoir

Storage in Williams Fork Reservoir was unaffected, for practical purposes, by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 6). In every year where a 1,600 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario. The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 1,600 acre-feet. The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 36 acre-feet.

For equal allocation of the 20,000 acre-feet bypass/release among three reservoirs (Granby, Green Mountain and Williams Fork Reservoirs), storage in Williams Fork Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule except in 1978. In this year approximately 5,000 acre-feet deficiency occurred which was not replaced until 1979 (see Figure 12). The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 350 acre-feet for the equal allocation scenario.

Willow Creek Reservoir

Storage in Willow Creek Reservoir was only slightly affected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 7). In 1975, 1978, 1982 and 1991 a temporary deficit was modeled from the spring 1,200 acre-feet release until approximately November of each year when the storage levels matched the C1 Scenario. In 1991 the same deficit occurred and it is anticipated the deficit would be eliminated if the study period were continued until November 1991. The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 280 acre-feet for the equal allocation scenario. At no time did Willow Creek Reservoir completely empty due to this scenario.

Storage in Willow Creek Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule for the equal allocation of the 20,000 acre-feet bypass/release among three reservoirs Granby, Green Mountain and Williams Fork) scenario. During the eight years when a 20,000 acre-feet bypass/release was made from the three reservoirs to the 15-Mile Reach, Willow Creek Reservoir still achieved the same level of storage as in the C-1 Scenario.

Wolford Mountain Reservoir

Storage in Wolford Mountain Reservoir was only slightly affected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 8). In 1978 and 1982 temporary deficits in storage of approximately 1,000-2,000 acre-feet were modeled as a result of the spring 1,200 acre-feet release to the 15-Mile Reach. This storage deficit existed until the following spring in 1979 and 1983 when the storage levels matched the levels modeled in the C1 Scenario. In 1991, a similar deficit occurred and it is anticipated the deficit would have been eliminated if the study period were continued till spring 1992. The average annual decrease in storage between the C1 base run scenario and the proportionate sharing scenario over the study period was approximately 175 acre-feet for the equal allocation scenario. At no time did Wolford Mountain Reservoir completely empty due to this scenario.

For equal allocation of the 20,000 acre-feet bypass/release among three reservoirs, storage in Wolford Mountain Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule. During the eight years when a 20,000 acre-feet bypass/release was made from the three reservoirs (Granby, Green Mountain and Williams Fork Reservoirs) to the 15-Mile Reach, Wolford Mountain Reservoir still achieved the same level of storage as in the C-1 Scenario.

Vega Reservoir

Storage in Vega Reservoir was unaffected by imposition of the Alternatives 1f and 1g operating rule with proportionate sharing as compared to storage under the C1 Scenario for the study period (see Figure 9). In every year where a 200 acre-feet release was made to the 15-Mile Reach, the reservoir still achieved the same level of storage as in the C1 Scenario.

For equal allocation of the 20,000 acre-feet bypass/release among three reservoirs, storage in Vega Reservoir was likewise unaffected by imposition of the Alternatives 1f and 1g operating rule. During the eight years when a 20,000 acre-feet bypass/release was made from the three reservoirs to the 15-Mile Reach, Vega Reservoir still achieved the same level of storage as in the C-1 Scenario.

EFFECTS ON POWER GENERATION

Green Mountain Reservoir Power Plant

As indicated in Table 2, Green Mountain Reservoir Power Plant would produce slightly more power with the Alternatives 1f and 1g operations policy and proportionate sharing of the 20,000 acre-feet bypass/release during the 1975-91 study period. A total of approximately $93,000 of power would have been produced over the study period or an average of approximately $5,450 per year.

Table 5 indicates that with equal allocation of the 20,000 acre-feet among three reservoirs, Green Mountain Reservoir would produce $101,000 of increased power over the 1974-91 study period ($6,000 annually) as compared to the base case C1 Scenario.

Shoshone Power Plant

Table 3 indicates the total foregone power revenue from Shoshone Power Plant for the 1975-91 study period for Alternatives 1f and 1g operations policy with proportional allocation of the 20,000 acre-feet among nine reservoirs is approximately $62,500 or approximately $3,700 per year.

Table 6 indicates the total foregone power revenue from Shoshone Power Plant for the 1975-91 study period for Alternatives 1f and 1g operations policy with equal allocation of the 20,000 acre-feet bypass/release among three reservoirs is approximately $117,000 or an average annual reduction of approximately $6,900.

Ruedi Reservoir Power Plant

Table 4 indicates that approximately $14,400 of additional power would have been generated at Ruedi Reservoir Power Plant with the Alternatives 1f and 1g operations policy with proportional allocation of the 20,000 acre-feet release among the nine reservoirs during the 1975-91 study period or approximately $845 per year.

The alternatives 1f and 1g operations policy with equal sharing of the 20,000 acre-feet bypass/release among Granby, Green Mountain and Williams Fork Reservoirs would not affect power production at Ruedi Reservoir.

Orchard Mesa Power Plant

The Alternatives 1f and 1g operations policy did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternatives 1f and 1g operations policy.

OTHER EFFECTS

Shoshone Priority Calls

The frequency and duration of Shoshone priority calls were not altered to any measurable degree by implementation of the Alternatives 1f and 1g operations policy for the 1975-91 study period.

Check Case Settlement

Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternatives 1f and 1g operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternatives 1f and 1g operations policy should not affect the Check Case settlement.

Channel Capacity Constraints

Results produced herein, together with the results from previous investigations of alternatives with respect to channel capacity constraints (Colorado Water Conservation Board, 2001a, b, c, and d) indicate that the additional releases and/or bypasses of diversions to storage could be made from each of the reservoirs without violating channel flow constraints on: (1) the Blue River or Colorado River downstream from Green Mountain Reservoir and (2) on the Frying Pan River downstream from Ruedi Reservoir.

Adams Tunnel Deliveries

The effects of Alternatives 1f and 1g for the proportionate allocation, three reservoirs equal allocation and total release from Granby Reservoir scenarios on deliveries of water through the Adams tunnel are presented in Figures 14, 15 and 16. These figures compare deliveries under each of the three scenarios with deliveries under the base case C1 scenario. The figures indicate that there were no effects of alternatives 1f and 1g on deliveries through the Adams Tunnel under any of the three scenarios, except for March 1978. In this year there was approximately 8,500 acre-feet more water delivered through the Adams Tunnel under all three scenarios of Alternatives 1f and 1g than there was delivered under the C1 base run scenario.

The reasons for StateMod estimating this additional Adams Tunnel delivery in only March 1978 is not completely understood. StateMod estimates an increase in deliveries through the Adams tunnel in March 1978 for every scenario. This is due to an increase in the exchange from Green Mountain Reservoir to Granby Reservoir from Dec 1977 to March 1978. This, in turn, allows an increase in the exchange from Granby Reservoir to the Adams Tunnel in March 1978. It is unclear at this time why StateMod (or the priority system) allows this but this does not appear to have any impact on the overall objective of evaluating the impact of various alternatives for providing the 20,000 acre-foot release for the 15- Mile Reach. Consequently, we have concluded that StateMod with the C1 data set is providing a reasonable estimate of Adams Tunnel deliveries for the various

alternatives and scenarios in all months other than March 1978. This unexplained increase in Adams Tunnel Deliveries in March 1978 does not bias the overall findings from these model runs concerning the feasibility of Alternatives 1f and 1g for the three scenarios.

Boustead and Busk-Ivanhoe Tunnel Deliveries

Deliveries through the Boustead and Busk-Ivanhoe tunnels were, for practical purposes, unchanged by the proportionate allocation scenario from deliveries under the C1 Scenario. The Boustead tunnel did show a decrease in total supply for two months during the study period, October of 1977 and May of 1979. These decreases in supply occurred because the prorated release from Ruedi Reservoir caused the junior fill right (1981-01-22) to be in priority, calling out the more junior (1982-12-31) Boustead tunnel diversion right.

Roberts Tunnel Deliveries

There is no expected effect on Roberts Tunnel deliveries from Alternatives 1f and 1g because storage in Dillon reservoir was not affected by the proportionate allocation scenario and no release toward the 20,000 acre-feet target was required from Dillon Reservoir in the equal allocation scenario.

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CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. Alternatives 1f, Bypass Diversions to Storage, and 1g, Reduce Constraints on CROP, were investigated for three different scenarios of responsibility for providing the 20,000 acre-feet for the 15-Mile Reach: (1) proportionate sharing among nine reservoirs for the 20,000 acre-feet release to the 15-Mile Reach, (2) equally sharing responsibility for the 20,000 among three reservoirs (Granby, Green Mountain and Williams Fork Reservoirs) and (3) sole responsibility for providing the 20,000 acre-feet to Granby, Green Mountain or Williams Fork Reservoirs. Results of the investigations and calculations completed for this technical memorandum together with earlier work completed (Colorado Water Conservation Board, 2021a, b, c and e) indicate that alternatives 1f and 1g with any of the three responsibility scenarios can supply the 20,000 acre-feet to the 15-Mile Reach in the eight years of the study period when it is required.

2. Investigation of effects on existing projects' yields, existing projects' operations and maintenance costs, and existing projects' operational flexibility and/or reliability has been limited to west slope projects because StateMod and the C1 data set do not presently extend to the east slope. The only partial exception to this is that estimated deliveries through the Adams, Boustead and Busk-Ivanhoe Tunnels for Alternatives 1f and 1g have been calculated. Therefore, in order to determine the effects of Alternatives 1f and 1g on east slope systems, it will be necessary for concerned east slope entities to review the results detailed in this and other technical memoranda and determine, perhaps through calculations and their own modeling, what the likely effects of Alternatives 1f and 1g on the performance of east slope reservoirs and other structures is likely to be.

3. The scenario calling for proportionate sharing of responsibility for providing the 20,000 acre-feet among nine reservoirs provides an opportunity for "spreading the pain" among a wide group of water users. The effects of this scenario include temporary reductions in storage in some reservoirs. This would be a temporary reduction extending for a maximum of four years before it was replaced or the reservoir filled. In no case would a reservoir go completely dry as a result of the proportionate sharing scenario. Other effects include an increase in power revenues from Green Mountain Reservoir, a relatively small decrease in power revenue from Shoshone Power Plant and a smaller decrease in power revenue from Ruedi Reservoir. Other effects on Orchard Mesa hydropower generation, Shoshone priority calls, channel capacity constraints, and Adams Tunnel deliveries are relatively small.

4. It is concluded that Alternatives 1f and 1g with proportionate sharing of responsibility among the nine reservoirs should be further considered as a potential source for producing the 20,000 acre-feet for the 15-Mile Reach.

5. The scenario involving equal sharing of responsibility for the 20,000 acre-feet bypass/release among Granby, Green Mountain and Williams Fork Reservoirs appears to eliminate effects on the other reservoirs while not substantially increasing effects on

Granby, Green Mountain and Williams Fork Reservoirs as compared to the proportionate sharing scenario. Therefore, based on the results detailed above, it is concluded that the equal sharing scenario for Alternatives 1f and 1g should be further considered as a source of supply for the 20,000 acre-feet for the 15-Mile Reach.

6. The scenario placing sole responsibility for providing the 20,000 acre-feet on a single reservoir was investigated for Green Mountain Reservoir in Technical Memoranda Nos. 1, 2 and 3 (CWCB, 2001a, b, and c) and for Williams Fork Reservoir in Technical Memorandum No. 11 (CWCB, 2001d). These Technical Memoranda concluded that these reservoirs were capable of providing the 20,000 acre-feet individually and the effects on west slope structures did not appear to constitute fatal flaws from engineering and economic perspectives. The scenario placing full responsibility on Granby Reservoir for providing the 20,000 acre-feet was investigated in this Technical Memorandum and found to be capable of providing the 20,000 acre-feet without significantly increased effects on west slope structures. Therefore, it is recommended that there be further consideration of this scenario.

7. It is recommended that the Executive Committee further analyze the institutional and legal feasibility of Alternatives 1f and 1g.

8. It is further recommended that Alternatives 1f and 1g be further investigated to determine performance of these alternatives with an additional 60,000 to 120,000 acre-feet of future depletions.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River.*

Colorado Water Conservation Board, October 2001a (Revised), *Technical Memorandum No. 1 Concerning Analysis of Alternative 1a, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Reduced Winter Power Operations.*

Colorado Water Conservation Board, October 2001b, *Technical Memorandum No. 2, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Including Green Mountain Reservoir Preemptive Release and Release of Water Carried over in Green Mountain Reservoir.*

Colorado Water Conservation Board, October 2001c, *Technical Memorandum No. 3, Analysis of Alternative 1a Expanded Coordinated Reservoir operations of Green Mountain Reservoir, Conjunctive Pool Operations.*

Colorado Water Conservation Board, September 2001d, Technical Memorandum No. 11, *Investigation of Alternative 1e, Expanded Coordinated Reservoir Operations, Denver Water System Operations.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1

DILLON RESERVOIR

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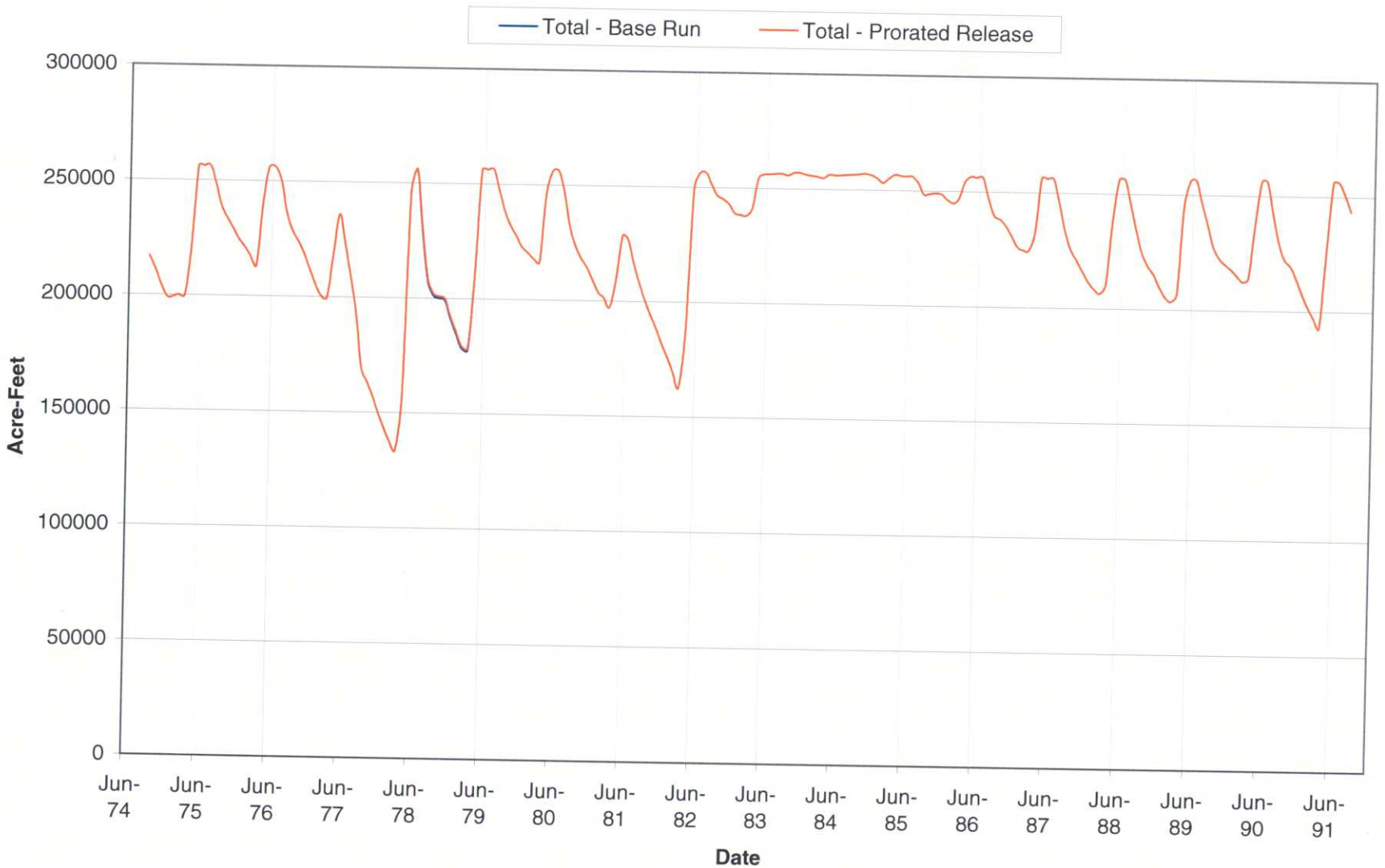

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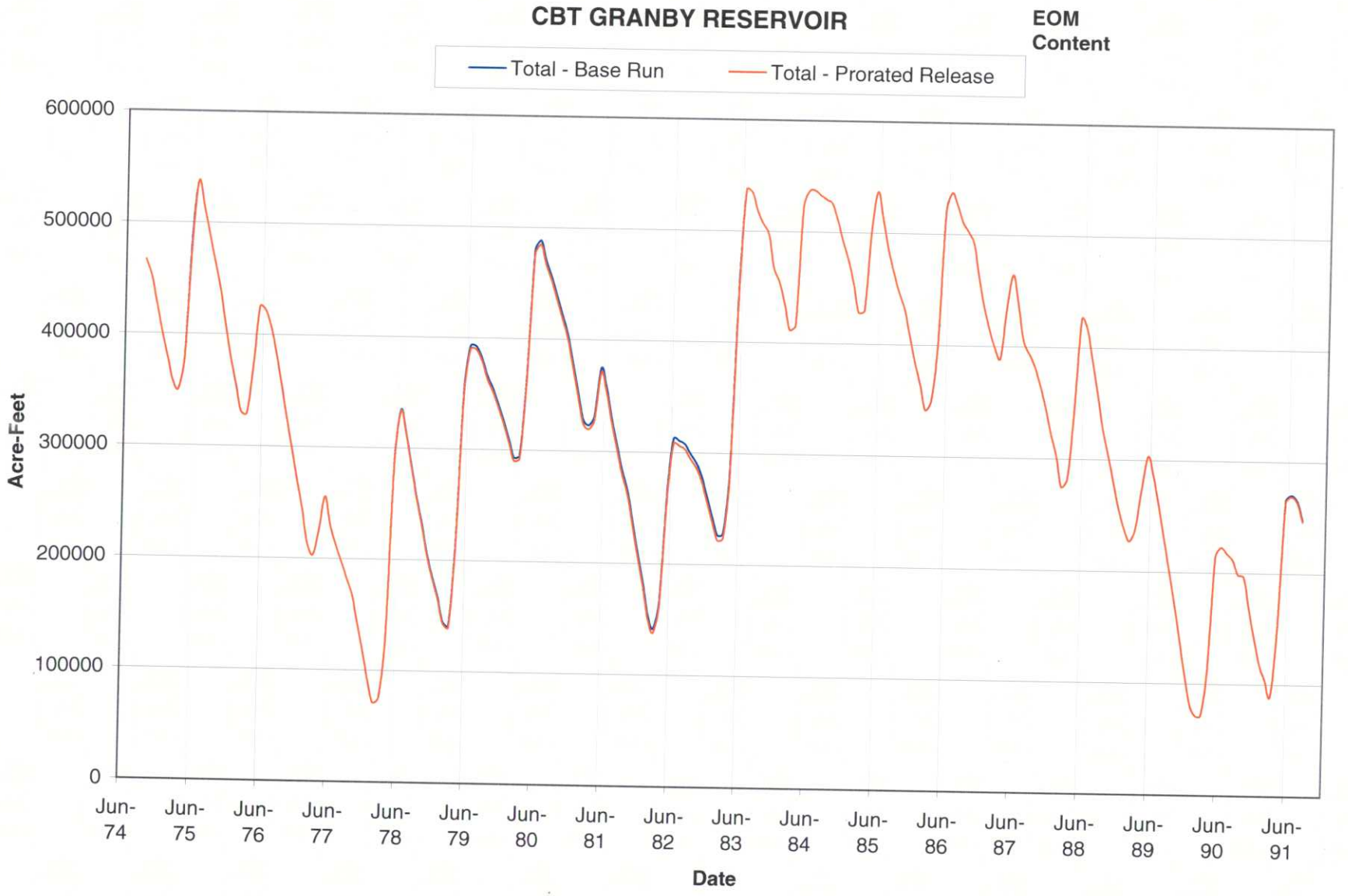
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Figure 3

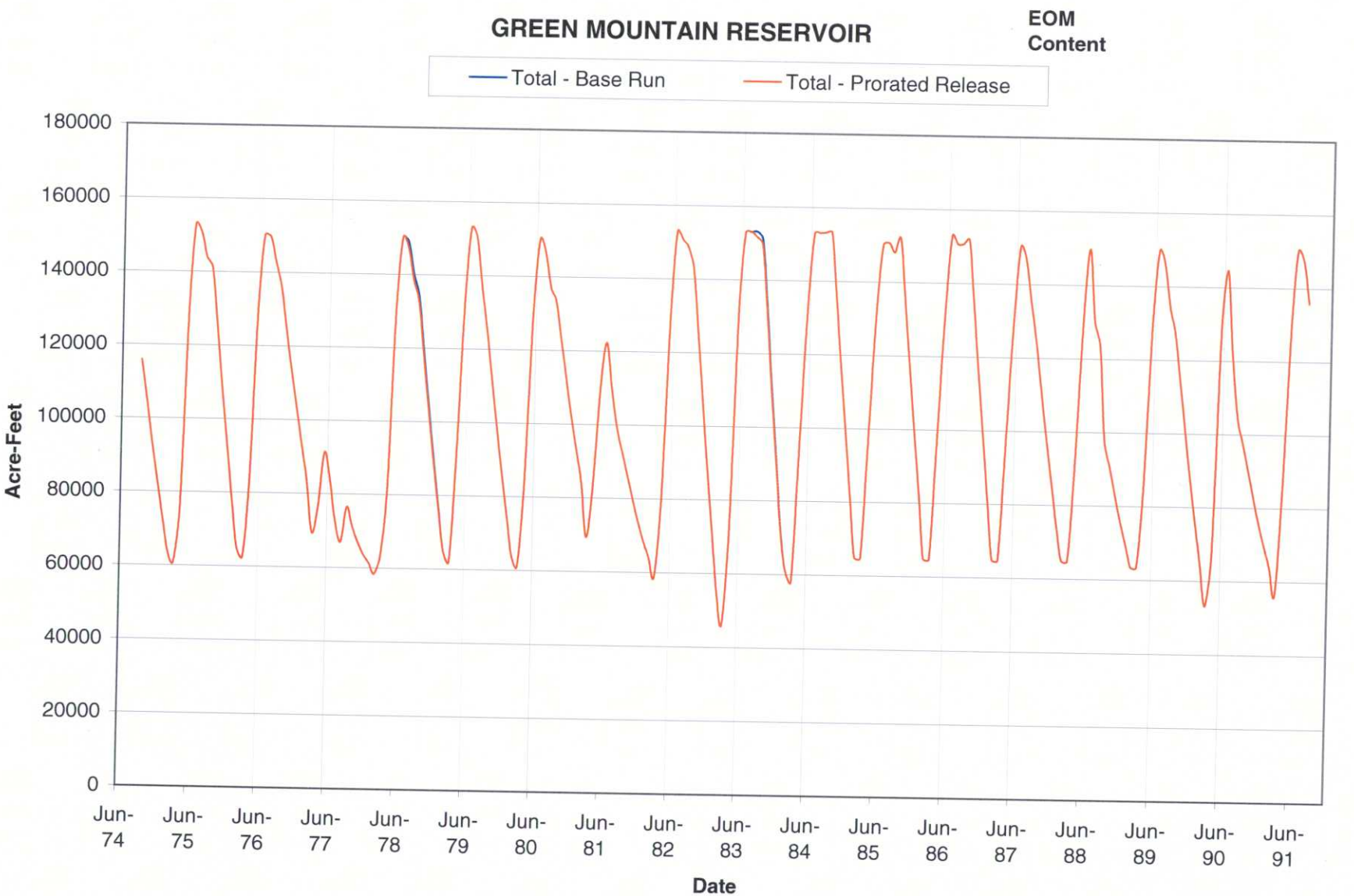
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Figure 4

HOMESTAKE PROJ RESERVOIR **EOM Content**

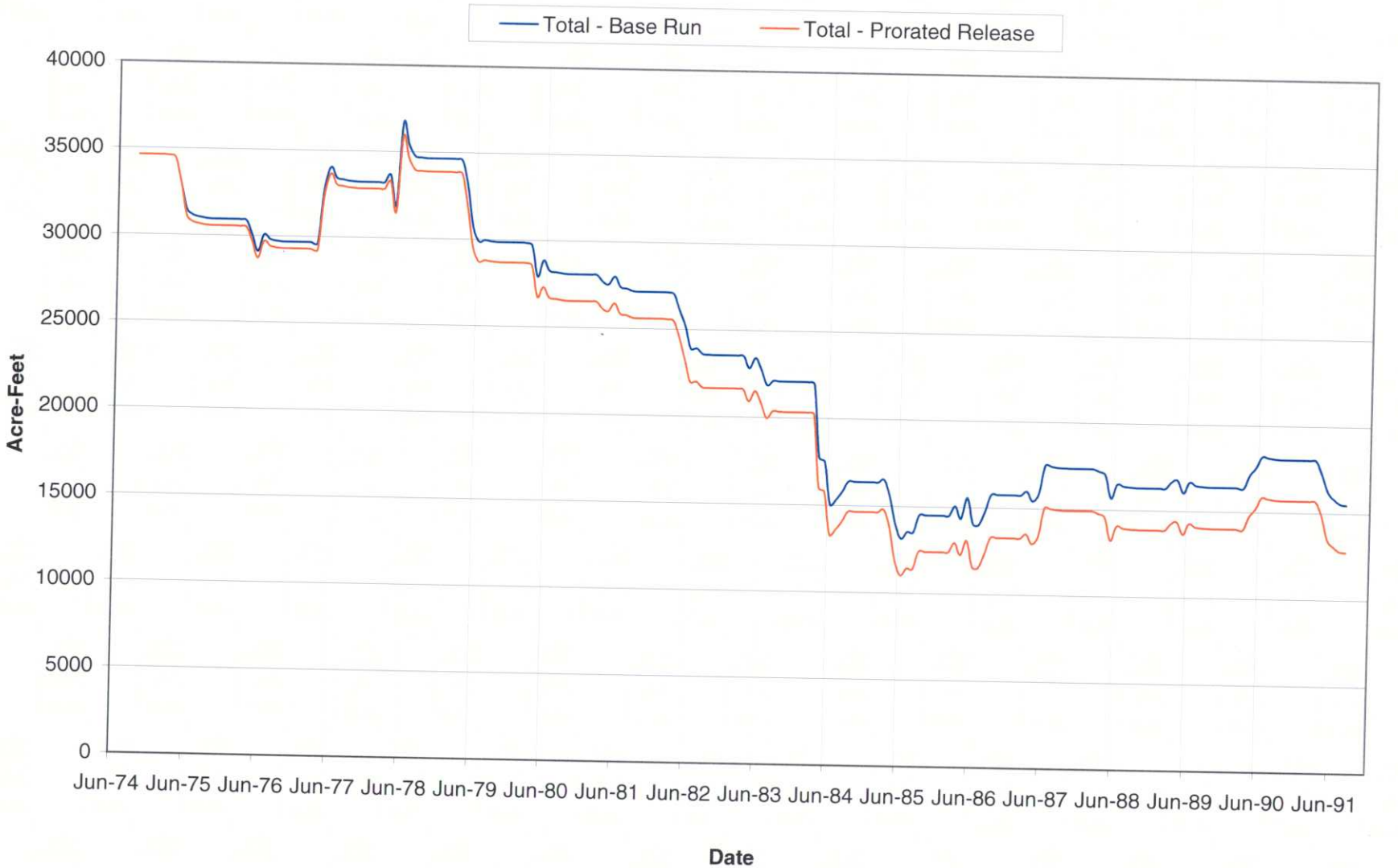

Figure 5

RUEDI_RESERVOIR

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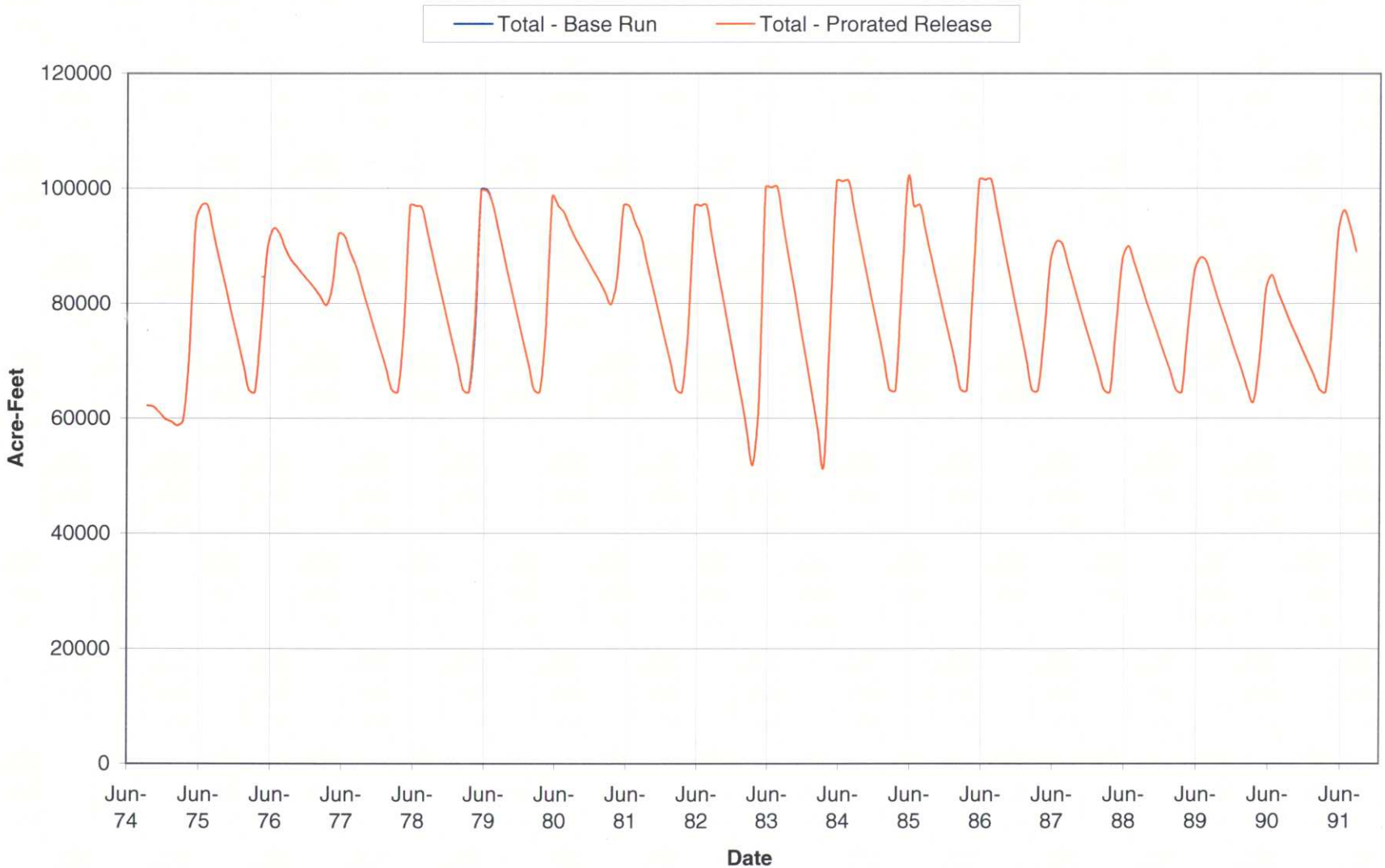

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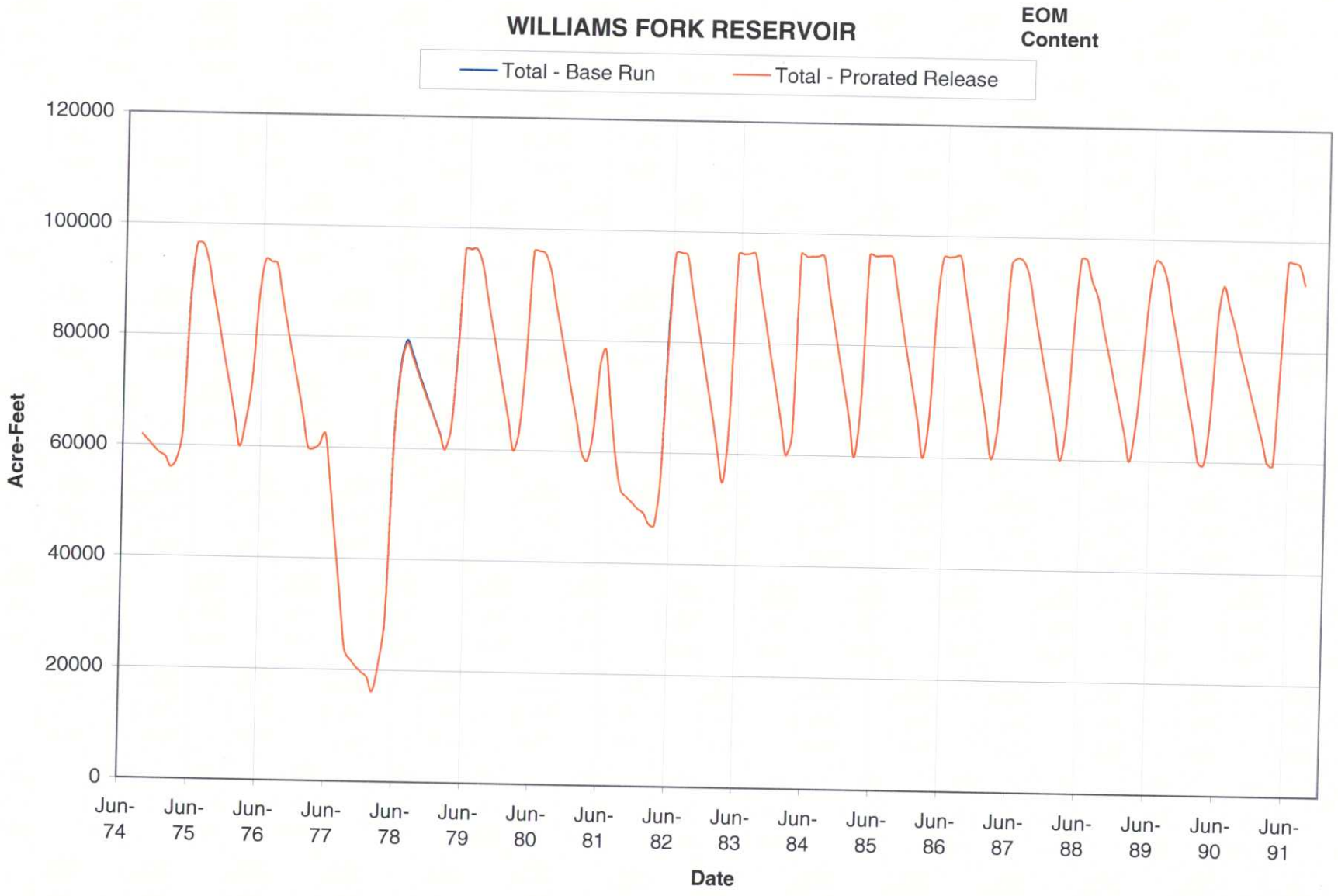
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Figure 7

CBT WILLOW CREEK RES

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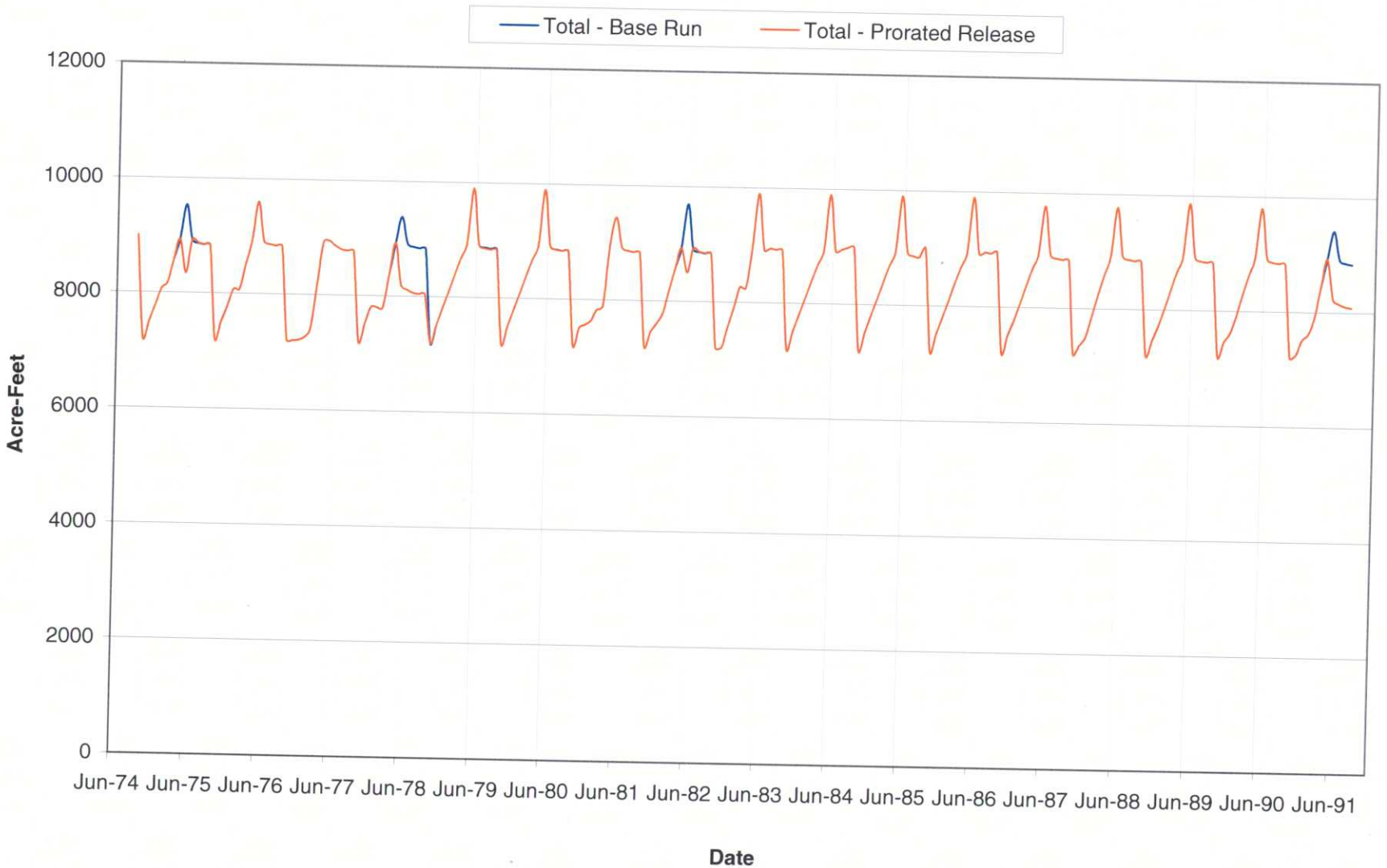

Figure 8

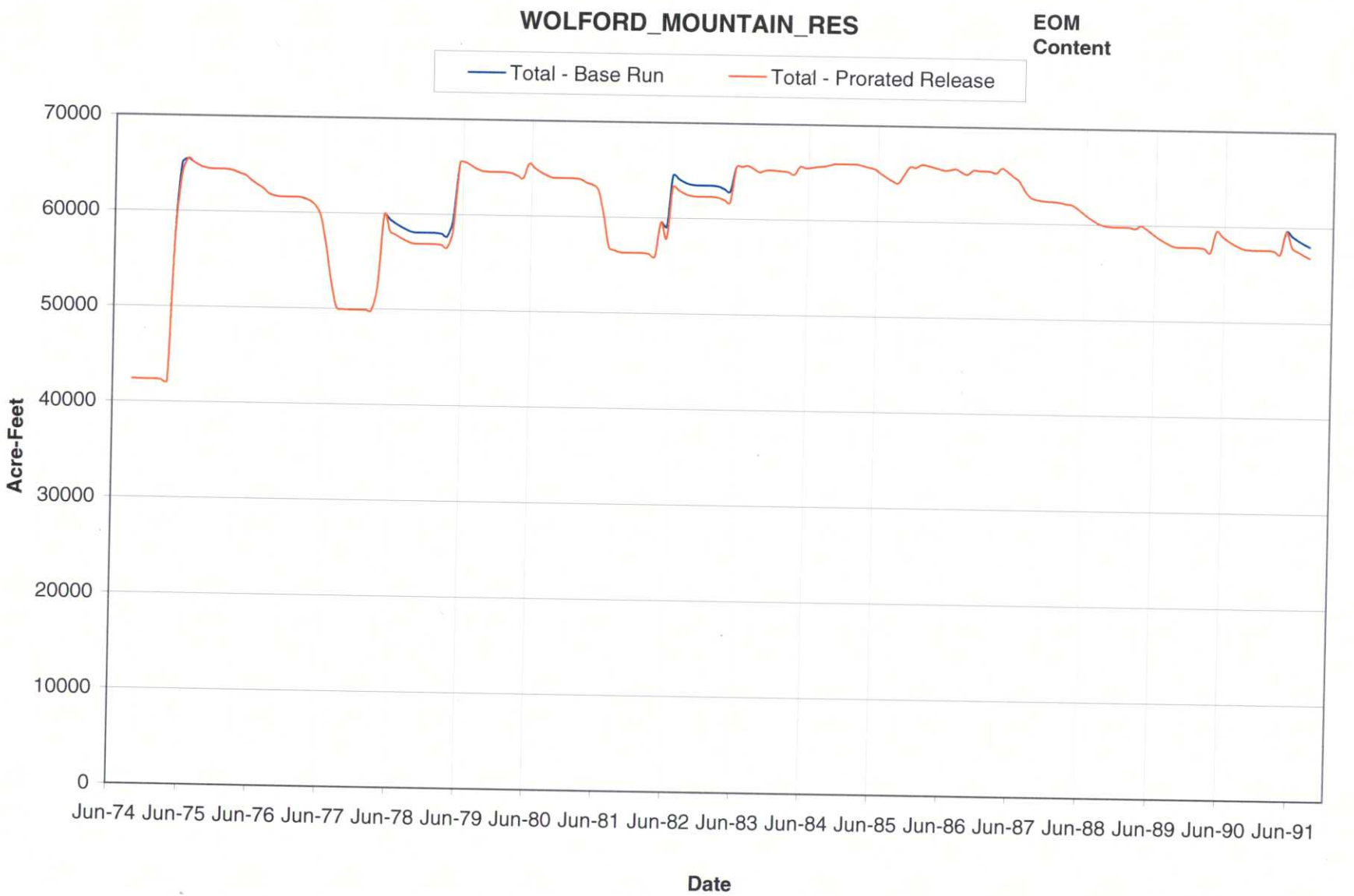
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Figure 9

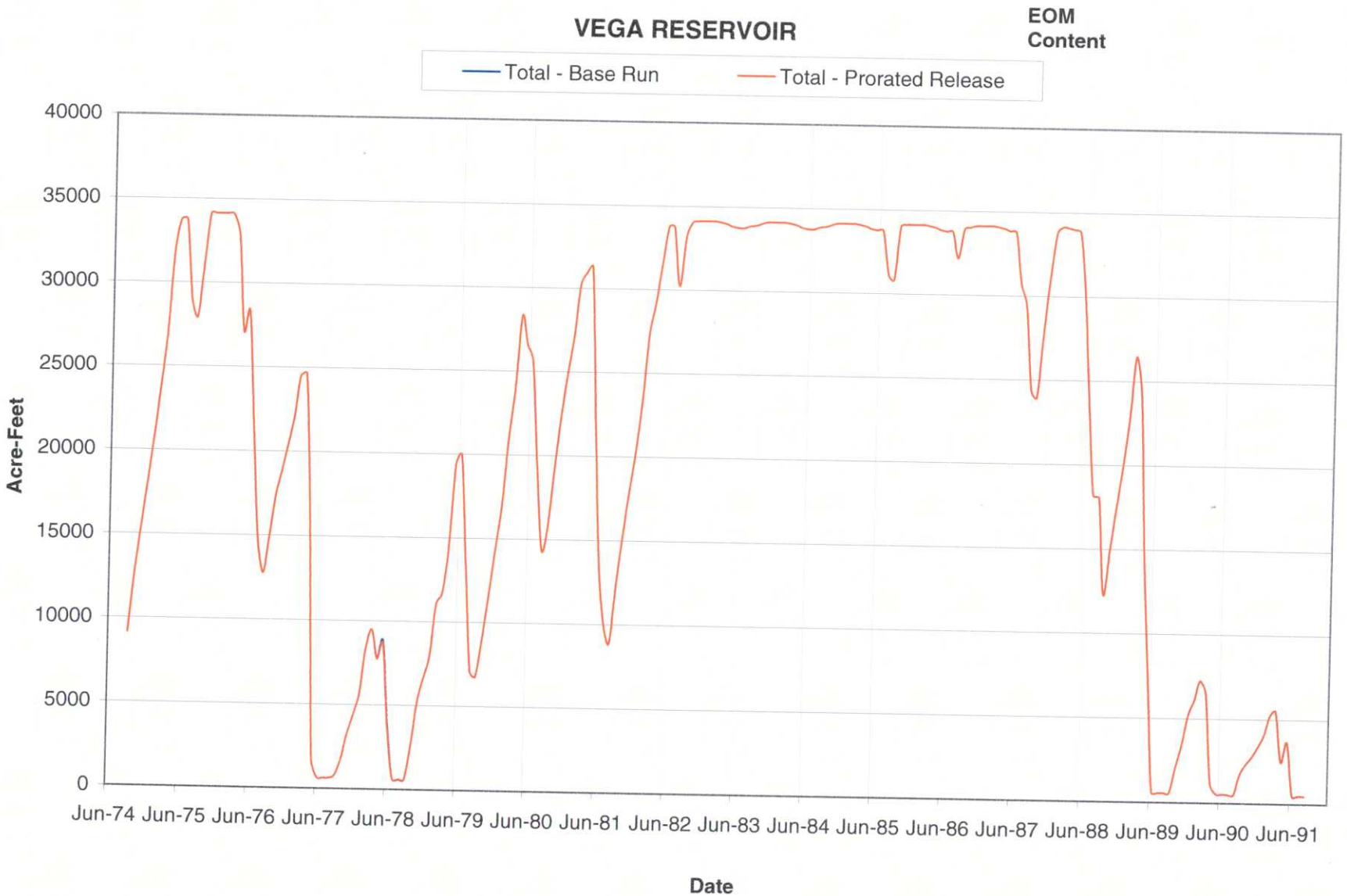
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Figure 10

CBT GRANBY RESERVOIR

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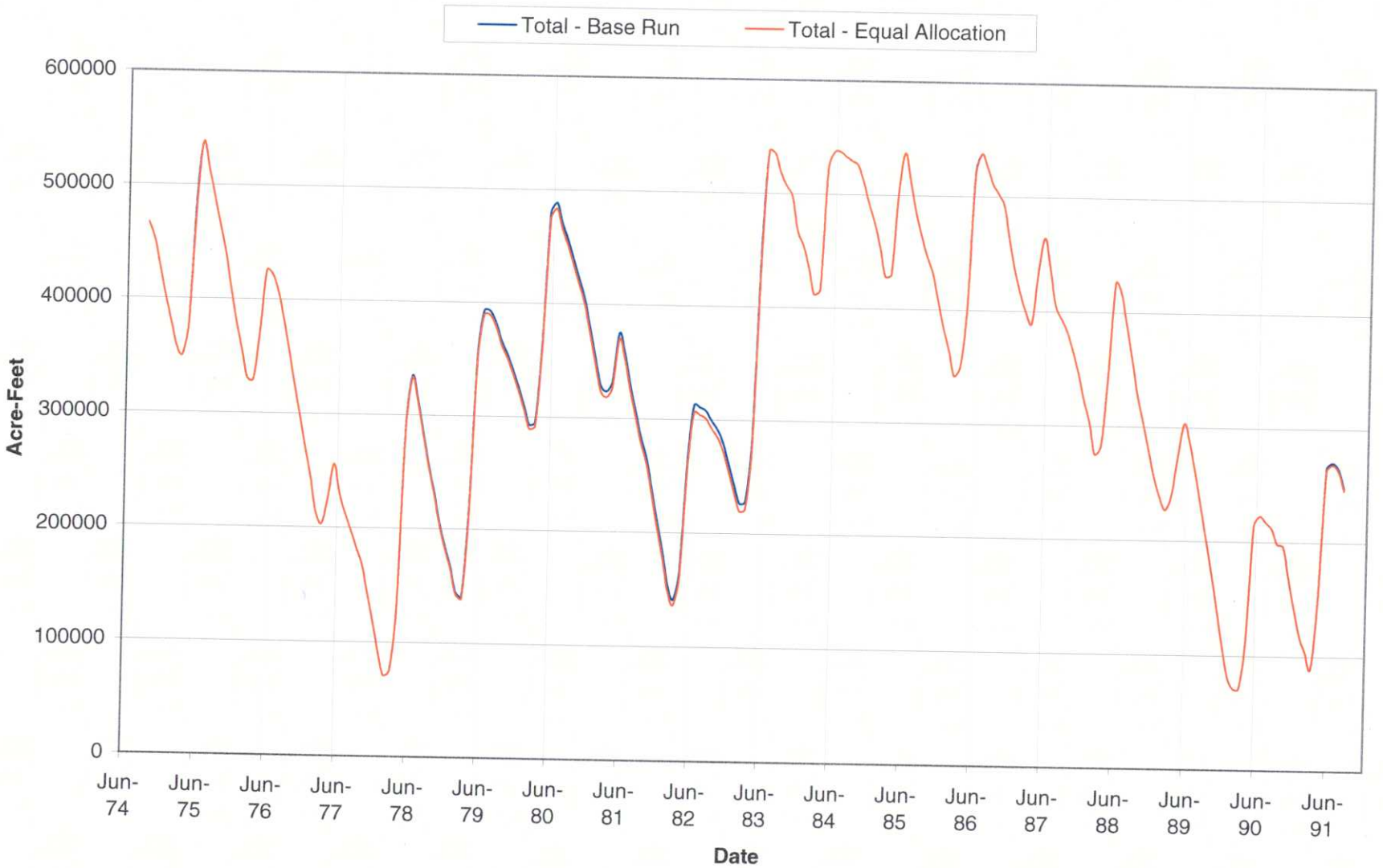

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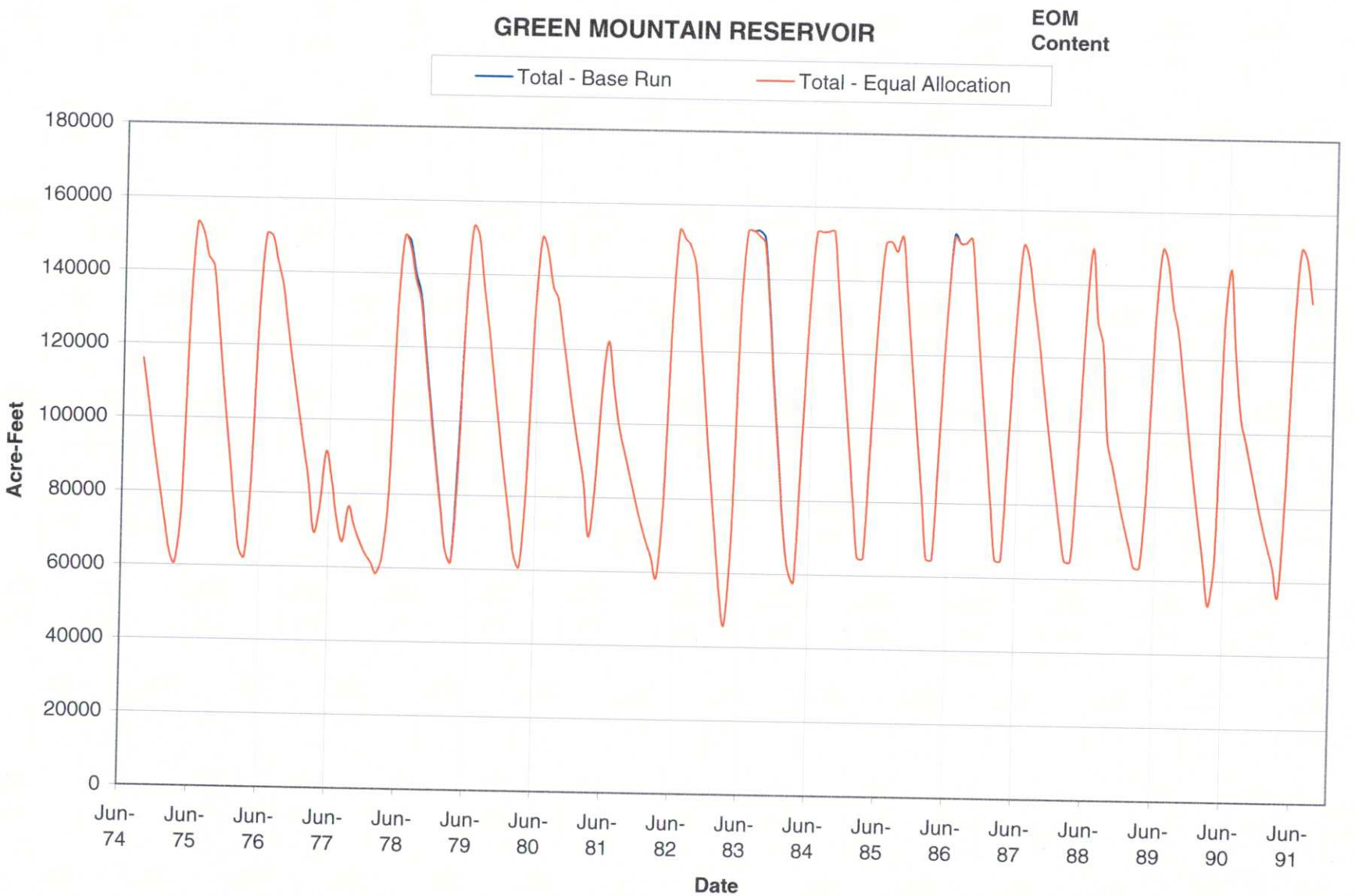
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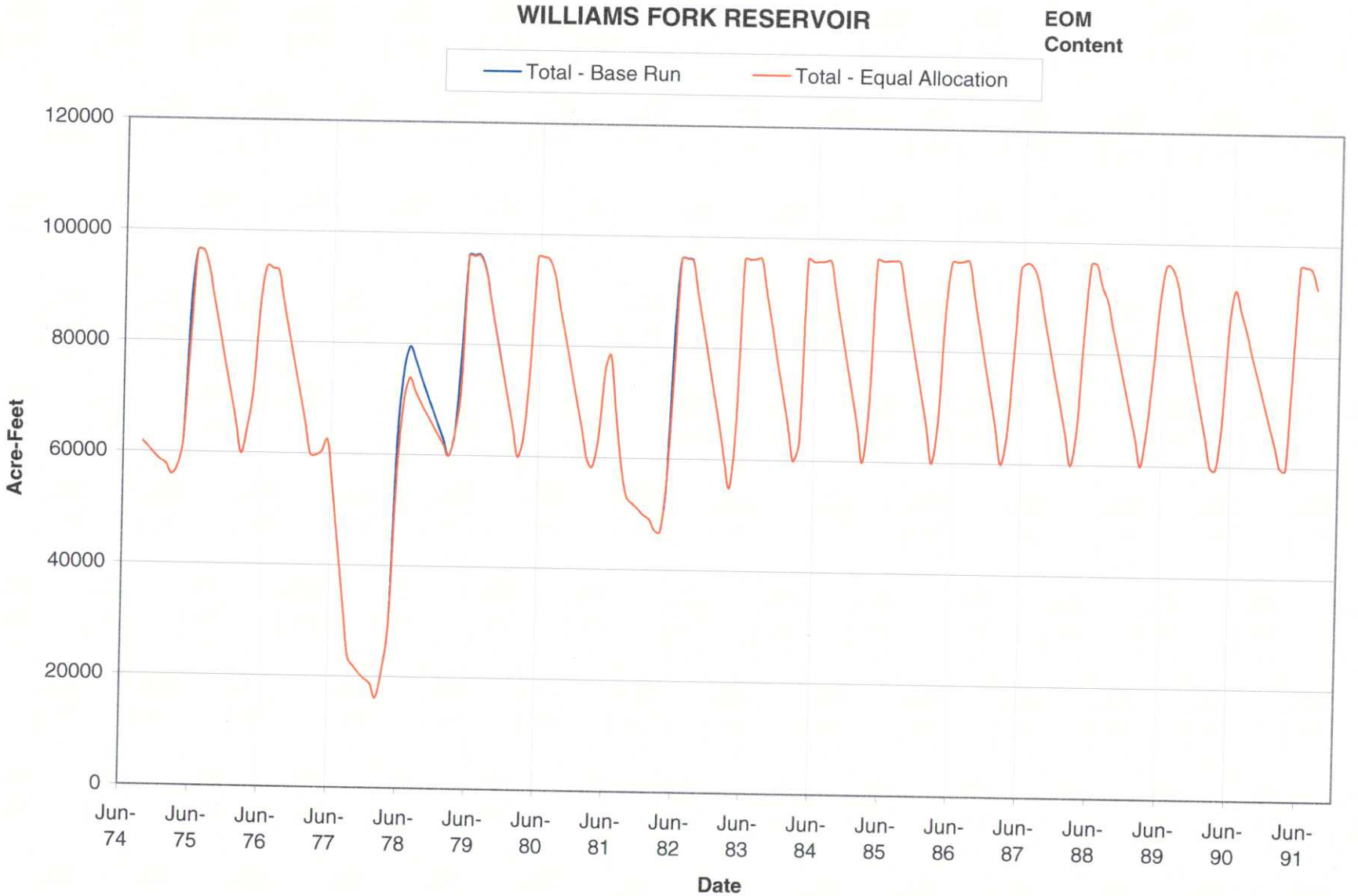
Figure 12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Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Figure 13

CBT GRANBY RESERVOIR

EOM Content

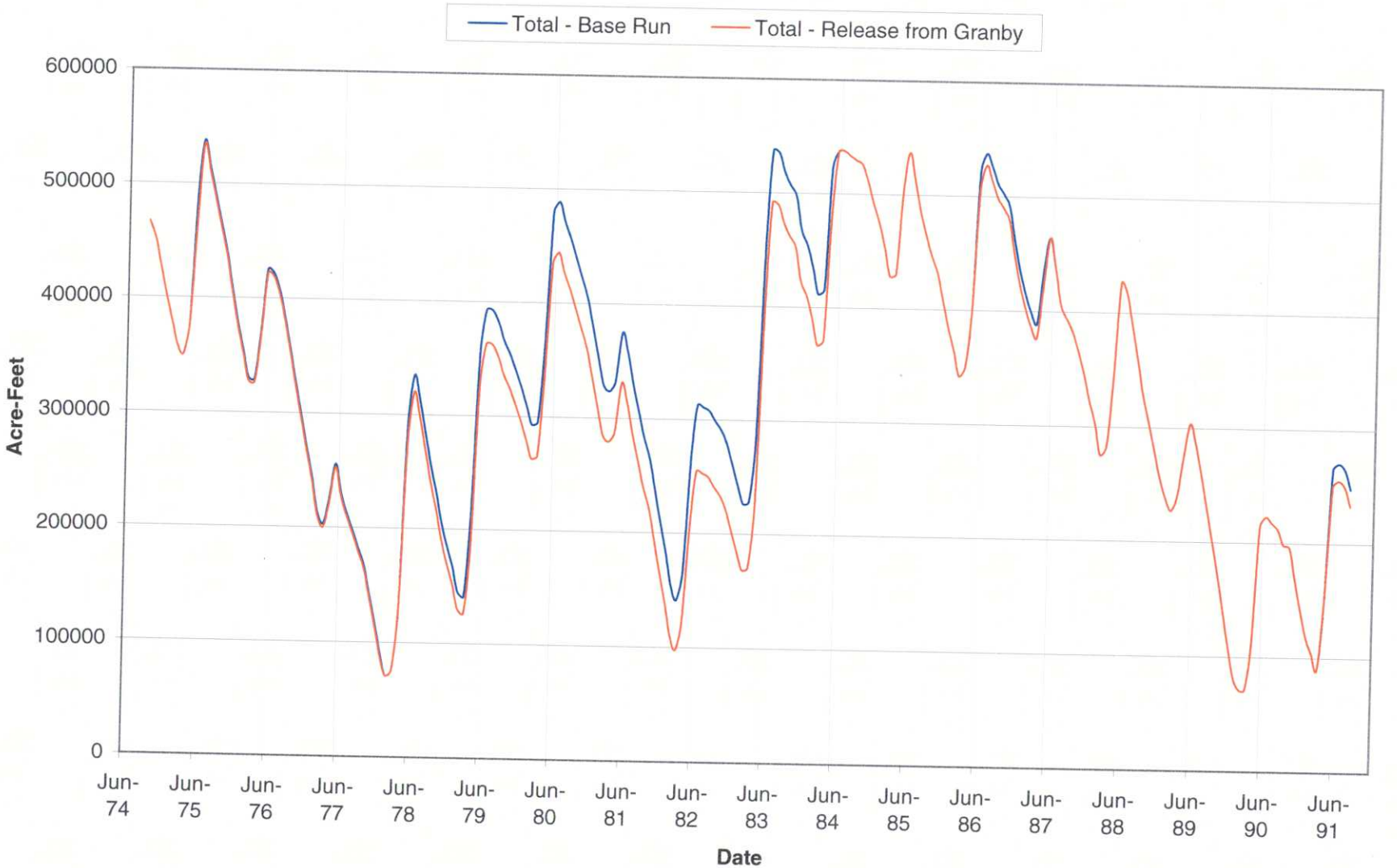

Figure 14

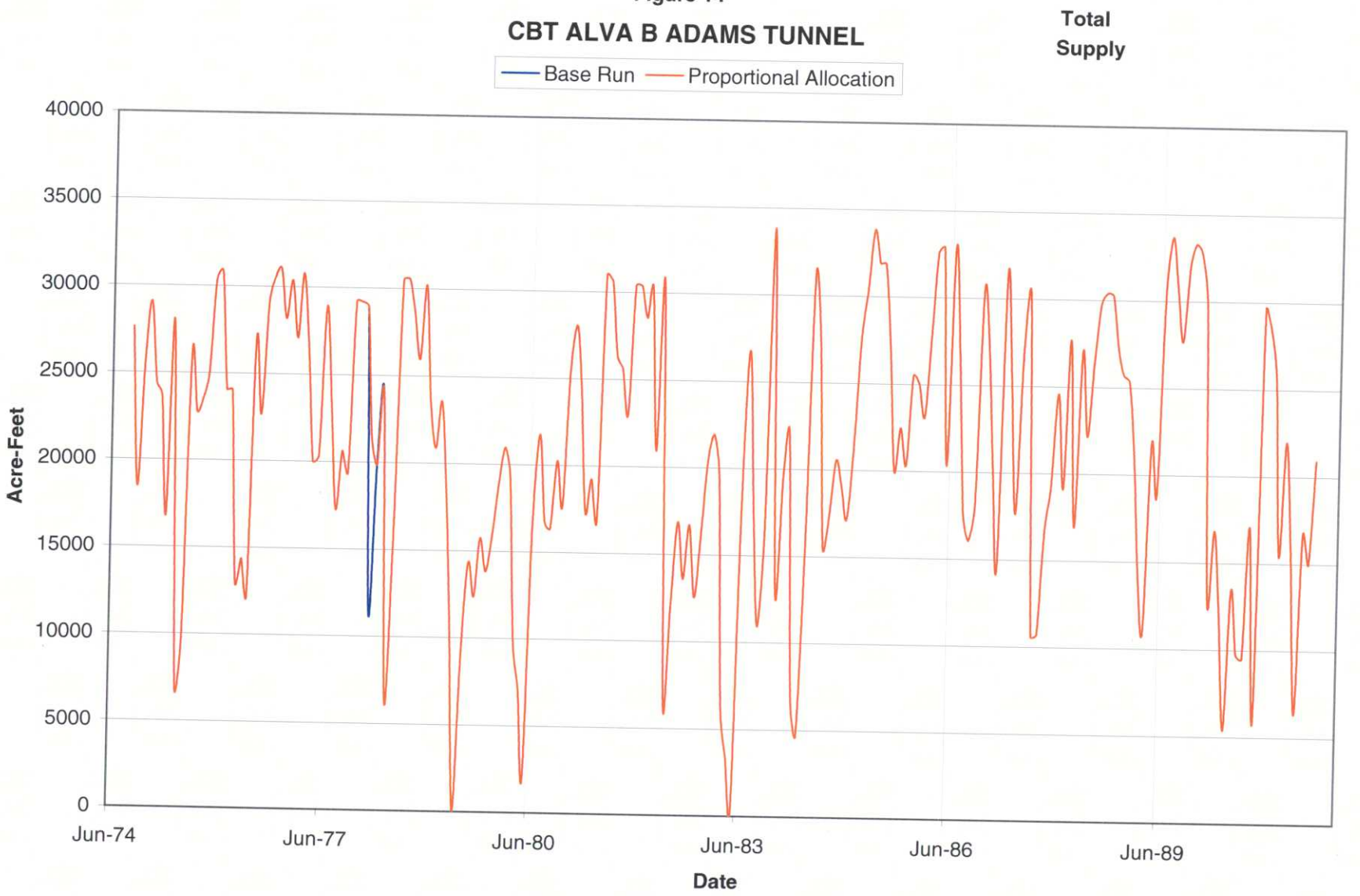
CBT ALVA B ADAMS TUNNEL
Total Supply
Base Run
Proportional Allocation
40000
35000
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74
Jun-77
Jun-80
Jun-83
Jun-86
Jun-89
Date

Figure 15

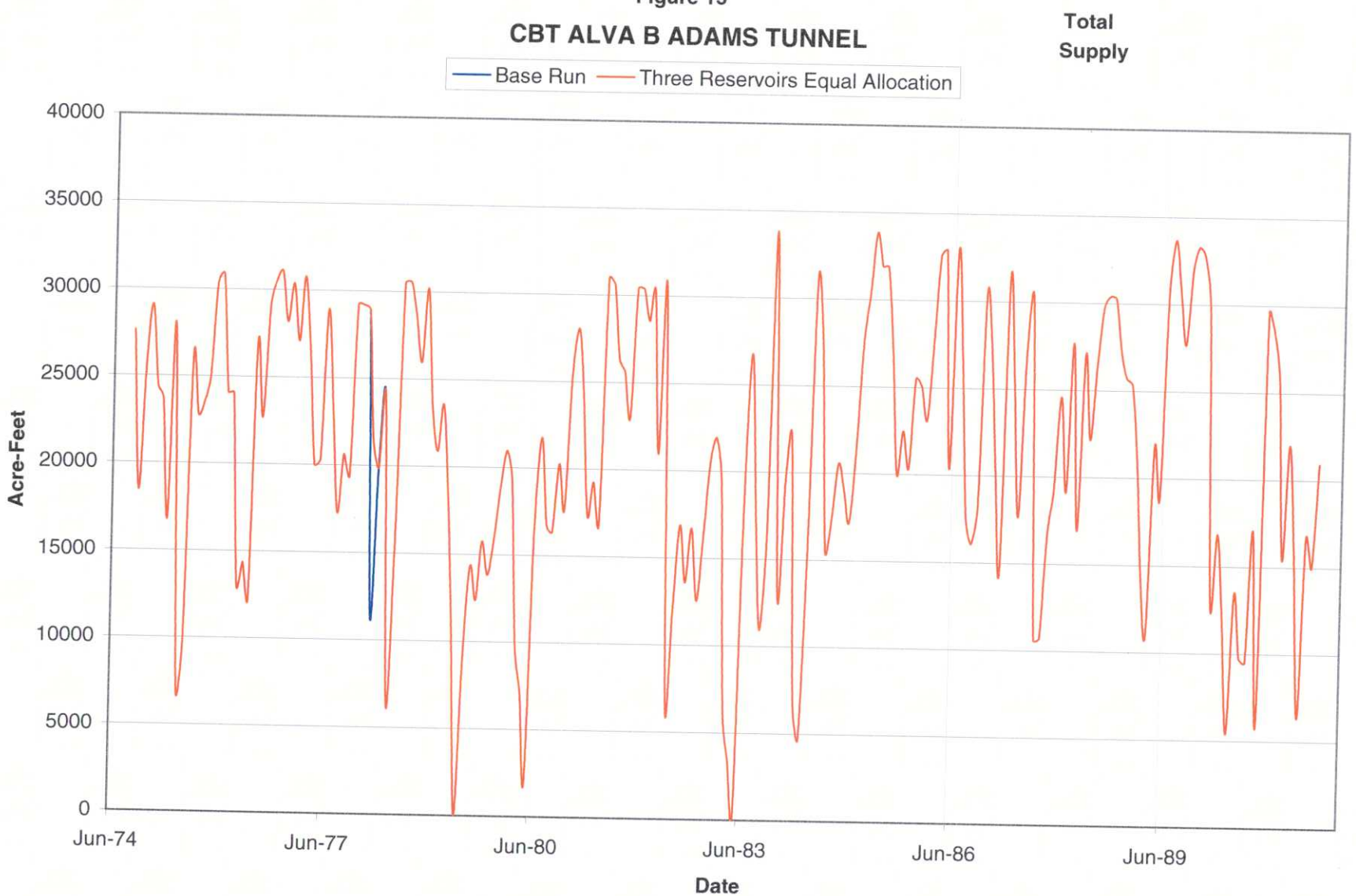
CBT ALVA B ADAMS TUNNEL
Total Supply
Base Run
Three Reservoirs Equal Allocation
40000
35000
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74
Jun-77
Jun-80
Jun-83
Jun-86
Jun-89
Date

Figure 16

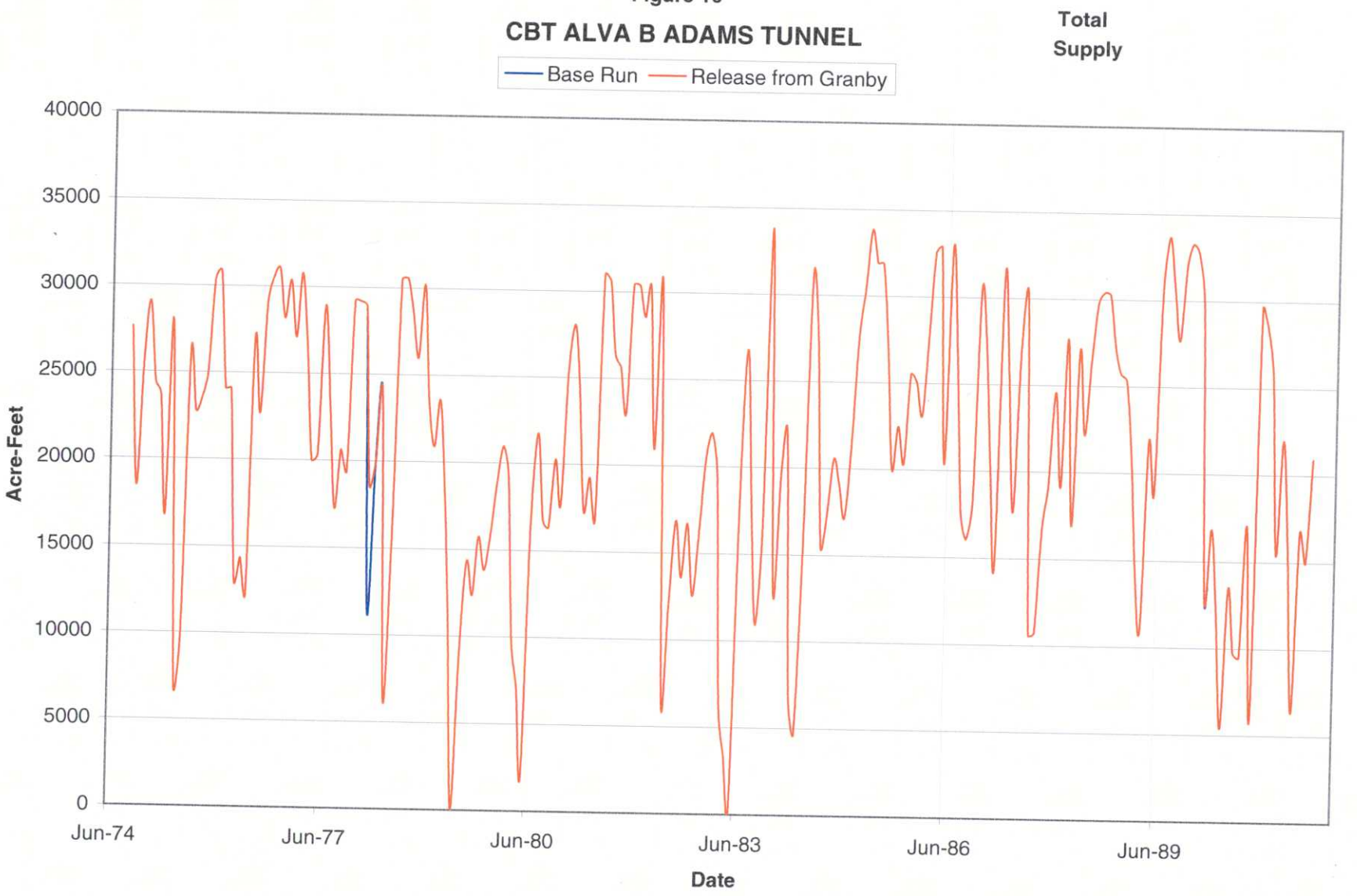
CBT ALVA B ADAMS TUNNEL
Total Supply
Base Run
Release from Granby
40000
35000
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74
Jun-77
Jun-80
Jun-83
Jun-86
Jun-89
Date

Table 1
Monthly Inflows During 20,000 Required Releases

Year	Mo	Date	Grandby	Dillon	Green Mt.	Williams Fk.	Homestake	Wolford Mt.	Ruedi	Vega	Willow Ck.	Ave Daily Inflow
1975	JUN	Jun-75	128158	64714	64468	25923	7402	20802	32915	4860	24116	12445
1978	JUN	Jun-78	169901	101328	63755	33317	12599	31394	33476	3985	32373	16071
1979	MAY	May-79	92514	35639	31957	15191	4468	28330	20901	2792	30424	8459
1980	JUN	Jun-80	124093	96258	138655	28599	10473	19804	29731	4583	17425	15654
1982	JUN	Jun-82	112048	73425	55852	31114	9262	32394	31593	4610	22427	12424
1985	JUN	Jun-85	65004	74885	134396	34803	7140	17250	38209	4546	14043	13009
1986	JUN	Jun-86	126569	86044	137728	41140	10603	21972	37712	5033	30768	16586
1991	JUN	Jun-91	127237	63411	73696	37823	8176	22099	26457	3080	17956	12665
Average Daily Inflow			3940	2482	2919	1033	292	809	1046	140	790	13414
Percent of Total Inflow			29%	19%	22%	8%	2%	6%	8%	1%	6%	
Proportionate Share			5873.97	3700.7	4351.8274	1540.11527	435.63189	1205.48452	1559.274	208.047	1177.448	
Modeled Release			5900	3700	4300	1500	400	1200	1600	200	1200	

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Proportional Allocation

			Base							Proportional Allocation								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	11357	115846	7930.56	241.56	184.70	1501	58	0	0.03878
1974	NOV	Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	21320	104427	7923.83	234.83	358.29	3628	236	0	0.06502
1974	DEC	Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	19759	93370	7916.71	227.71	321.34	3015	318	0	0.10541
1975	JAN	Jan-75	18019	82713	7909.22	220.22	293.05	2409	313	18019	82713	7909.22	220.22	293.05	2409	313	0	0.13
1975	FEB	Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	17044	72644	7901.50	212.50	306.89	2130	138	0	0.065
1975	MAR	Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	15939	63730	7893.97	204.97	259.22	1533	69	0	0.045
1975	APR	Apr-75	12710	60889	7891.43	202.43	213.60	867	39	12710	60889	7891.43	202.43	213.60	867	39	0	0.045
1975	MAY	May-75	5289	75493	7903.76	214.76	0.00	0	0	5289	75493	7903.76	214.76	0.00	0	0	0	0.045
1975	JUN	Jun-75	10362	129047	7937.76	248.76	174.14	1475	80	10362	129047	7937.76	248.76	174.14	1475	80	0	0.05416
1975	JUL	Jul-75	84336	152997	7949.70	260.70	1371.57	18600	1149	84336	152997	7949.70	260.70	1371.57	18600	1149	0	0.06176
1975	AUG	Aug-75	27765	150691	7948.60	259.60	451.55	5963	638	27765	150691	7948.60	259.60	451.55	5963	638	0	0.10693
1975	SEP	Sep-75	23444	143784	7945.26	256.26	393.98	4821	283	23444	143784	7945.26	256.26	393.98	4821	283	0	0.05866
1975	OCT	Oct-75	11432	141023	7943.89	254.89	185.92	1847	72	11432	141023	7943.89	254.89	185.92	1847	72	0	0.03878
1975	NOV	Nov-75	26434	124561	7935.37	246.37	444.23	5194	338	26434	124561	7935.37	246.37	444.23	5194	338	0	0.06502
1975	DEC	Dec-75	23514	108470	7926.28	237.28	382.41	4167	439	23514	108470	7926.28	237.28	382.41	4167	439	0	0.10541
1976	JAN	Jan-76	22347	92780	7916.31	227.31	363.43	3573	465	22347	92780	7916.31	227.31	363.43	3573	465	0	0.13
1976	FEB	Feb-76	22018	77676	7905.45	216.45	382.78	3244	211	22018	77676	7905.45	216.45	382.78	3244	211	0	0.065
1976	MAR	Mar-76	20867	64928	7895.03	206.03	339.36	2570	116	20867	64928	7895.03	206.03	339.36	2570	116	0	0.045
1976	APR	Apr-76	13611	62615	7892.97	203.97	228.74	1089	49	13611	62615	7892.97	203.97	228.74	1089	49	0	0.045
1976	MAY	May-76	5289	84324	7910.40	221.40	0.00	0	0	5289	84324	7910.40	221.40	0.00	0	0	0	0.045
1976	JUN	Jun-76	20309	129027	7937.75	248.75	341.30	3829	207	20309	129027	7937.75	248.75	341.30	3829	207	0	0.05416
1976	JUL	Jul-76	24273	150202	7948.37	259.37	394.76	5100	315	24273	150202	7948.37	259.37	394.76	5100	315	0	0.06176
1976	AUG	Aug-76	24579	149741	7948.15	259.15	399.73	5167	553	24579	149741	7948.15	259.15	399.73	5167	553	0	0.10693
1976	SEP	Sep-76	26715	142820	7944.78	255.78	448.95	5597	328	26715	142820	7944.78	255.78	448.95	5597	328	0	0.05866
1976	OCT	Oct-76	21293	136188	7941.46	252.46	346.29	4149	161	21293	136188	7941.46	252.46	346.29	4149	161	0	0.03878
1976	NOV	Nov-76	20049	124693	7935.44	246.44	336.93	3697	240	20049	124693	7935.44	246.44	336.93	3697	240	0	0.06502
1976	DEC	Dec-76	17772	113570	7929.26	240.26	289.03	2946	311	17772	113570	7929.26	240.26	289.03	2946	311	0	0.10541
1977	JAN	Jan-77	16388	102846	7922.85	233.85	266.52	2445	318	16388	102846	7922.85	233.85	266.52	2445	318	0	0.13
1977	FEB	Feb-77	15486	92708	7916.26	227.26	278.84	2190	142	15486	92708	7916.26	227.26	278.84	2190	142	0	0.065
1977	MAR	Mar-77	16143	83715	7909.95	220.95	262.54	2026	91	16143	83715	7909.95	220.95	262.54	2026	91	0	0.045
1977	APR	Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	25403	69475	7898.91	209.91	426.91	3687	166	0	0.045
1977	MAY	May-77	8191	76232	7904.33	215.33	133.21	186	8	8191	76232	7904.33	215.33	133.21	186	8	0	0.045
1977	JUN	Jun-77	9204	91191	7915.23	226.23	154.68	695	38	9204	91191	7915.23	226.23	154.68	695	38	0	0.05416
1977	JUL	Jul-77	19715	84169	7910.28	221.28	320.63	2807	173	19715	84169	7910.28	221.28	320.63	2807	173	0	0.06176
1977	AUG	Aug-77	24562	72947	7901.74	212.74	399.46	3558	380	24562	72947	7901.74	212.74	399.46	3558	380	0	0.10693
1977	SEP	Sep-77	13059	67022	7896.84	207.84	219.46	1075	63	13059	67022	7896.84	207.84	219.46	1075	63	0	0.05866
1977	OCT	Oct-77	13233	76527	7904.56	215.56	215.21	1258	49	13233	76527	7904.56	215.56	215.21	1258	49	0	0.03878
1977	NOV	Nov-77	13832	71278	7900.39	211.39	232.45	1326	86	13832	71278	7900.39	211.39	232.45	1326	86	0	0.06502
1977	DEC	Dec-77	13180	67062	7896.88	207.88	214.35	1047	110	13180	67062	7896.88	207.88	214.35	1047	110	0	0.10541
1978	JAN	Jan-78	11540	63609	7893.86	204.86	187.68	635	83	11540	63609	7893.86	204.86	187.68	635	83	0	0.13
1978	FEB	Feb-78	9468	61290	7891.83	202.83	170.48	336	22	9468	61290	7891.83	202.83	170.48	336	22	0	0.065
1978	MAR	Mar-78	9956	58454	7889.10	200.10	161.92	201	9	9956	58454	7889.10	200.10	161.92	201	9	0	0.045
1978	APR	Apr-78	6333	63350	7893.63	204.63	106.43	0	0	6333	63350	7893.63	204.63	106.43	0	0	0	0.045
1978	MAY	May-78	5289	81325	7908.20	219.20	0.00	0	0	5289	81325	7908.20	219.20	0.00	0	0	0	0.045
1978	JUN	Jun-78	15480	129034	7937.75	248.75	260.15	2686	145	15480	129034	7937.75	248.75	260.15	2686	145	0	0.05416
1978	JUL	Jul-78	41372	150202	7948.37	259.37	672.84	9285	573	43659	150202	7948.37	259.37	710.04	9844	608	35	0.06176
1978	AUG	Aug-78	31882	149026	7947.81	258.81	518.50	6940	742	32645	147402	7947.02	258.02	530.91	7094	759	17	0.10693
1978	SEP	Sep-78	26756	139955	7943.36	254.36	449.64	5556	326	26756	138334	7942.55	253.55	449.64	5527	324	-2	0.05866
1978	OCT	Oct-78	15652	133901	7940.29	251.29	254.55	2765	107	15656	132278	7939.45	250.45	254.62	2743	106	-1	0.03878
1978	NOV	Nov-78	22180	118865	7932.25	243.25	372.74	4095	266	21855	117567	7931.53	242.53	367.28	3996	260	-6	0.06502
1978	DEC	Dec-78	21471	104199	7923.69	234.69	349.19	3618	381	21146	103225	7923.09	234.09	343.90	3525	372	-10	0.10541
1979	JAN	Jan-79	21246	89932	7914.36	225.36	345.53	3268	425	20921	89283	7913.91	224.91	340.24	3183	414	-11	0.13
1979	FEB	Feb-79	19635	76253	7904.35	215.35	353.54	2756	179	19310	75928	7904.10	215.10	347.69	2680	174	-5	0.065
1979	MAR	Mar-79	19094	64928	7895.03	206.03	310.53	2208	99	18770	64928	7895.03	206.03	305.26	2142	96	-3	0.045
1979	APR	Apr-79	13825	61991	7892.45	203.45	232.33	1119	50	13825	61991	7892.45	203.45	232.33	1119	50	0	0.045
1979	MAY	May-79	5289	90705	7914.90	225.90	0.00	0	0	5896	90725	7914.91	225.91	0.00	0	0	0	0.045
1979	JUN	Jun-79	47652	131409	7939.00	250.00	800.81	10366	561	47898	131409	7939.00	250.00	804.94	10424	565	3	0.05416
1979	JUL	Jul-79	62920	152994	7949.70	260.70	1023.28	14643	904	63953	152994	7949.70	260.70	1040.08	14896	920	16	0.06176
1979	AUG	Aug-79	28239	150691	7948.60	259.60	459.26	6079	650	28239	150691	7948.60	259.60	459.26	6079	650	0	0.10693
1979	SEP	Sep-79	29407	136836	7941.79	252.79	494.19	6135	360	29407	136836	7941.79	252.79	494.19	6135	360	0	0.05866
1979	OCT	Oct-79	21480	125196	7935.71	246.71	349.33	4008	155	21480	125196	7935.71	246.71	349.33	4008	155	0	0.03878
1979	NOV	Nov-79	22123	111904	7928.30	239.30	371.78	3954	257	22123	111904	7928.30	239.30	371.78	3954	257	0	0.06502
1979	DEC	Dec-79	20742	98978	7920.40	231.40	337.33	3349	353	20742	98978	7920.40	231.40	337.33	3349	353	0	0.10541
1980	JAN	Jan-80	21081	86451	7911.92	222.92	342.84	3154	410	21081	86451	7911.92	222.92	342.84	3154	410	0	0.13
1980	FEB	Feb-80	20012	74512	7902.99	213.99	347.90	2745	178	20012	74512	7902.99	213.99	347.90	2745	178	0	0.065
1980	MAR	Mar-80	19707	63729	7893.97	204.97	320.50	2300	104	19707	63729	7893.97	204.97	320.50	2300	104	0	0.045
1980	APR	Apr-80	12046	61008	7891.55	202.55	202.44	737	33	12046	61008	7891.55	202.55	202.44	737	33	0	0.045
1980	MAY	May-80	5289	83658	7909.91	220.91	0.00	0	0	5289	83658	7909.91	220.91	0.00	0	0	0	0.045
1980	JUN	Jun-80	92514	129028	7937.75	248.75	1500.00	18000	975	92513	129028	7937.75	248.75	1500.00	18000	975	0	0.05416
1980	JUL	Jul-80	40746	150202	7948.37	259.37	662.66	9131	564	41763	150202	7948.37	259.37	679.20	9380	579	15	0.06176
1980	AUG	Aug-80	23454	146821	7946.74	257.74	381.44	4845	518	23535	146821	7946.74	257.74	382.75	4864	520	2	0.10693
1980	SEP	Sep-80	24612	137044	7941.89	252.89	413.61	4989	293	24612	137044	7941.89	252.89	413.61	4989	293	0	0.05866
1980	OCT	Oct-80	12204	133406	7940.03	251.03	198.48	1936	75	12204	133406	7940.03	251.03	198.48	1936	75	0	0.03878
1980	NOV	Nov-80	19891	122468	7934.23	245.23	334.27	3623	236	19891	122468	7934.23	245.23	334.27	3623	236	0	0.06502
1980	DEC	Dec-80	17897	111901	7928.30	239.30	291.06	2946	311	17896	111901	7928.30	239.30	291.05	2946	311	0	0.10541
1981	JAN	Jan-81	16154	101734	7922.15	233.15	262.72	2373	308	16154	101734	7922.15	233.15	262.72	2373	308	0	0.13
1981	FEB	Feb-81	15190	92151	7915.89	226.89	273.51	2115	137	15190	92151	7915.89	226.89	273.51	2115	137	0	0.065
1981	MAR	Mar-81	15583	83715	7909.95	220.95	253.43	1905	86	15583	83715	7909.95	220.95	253.43	1905	86	0	0.045
1981	APR	Apr-81	25807	69337	7898.80	209.80	433.69	3766	169	25804	69340	7898.80	209.80	433.64	3766	169	0	0.045
1981	MAY	May-81	5289	83356	7909.69	220.69	0.00	0	0	5289	83359	7909.69	220.69	0.00	0	0	0	0.045
1981	JUN	Jun-81	5970	110359	7927.39	238.39	100.33	228	12	5970	110362	7927.40	238.40	100.33	228	12	0	0.05416
1981	JUL	Jul-81	7258	122405	7934.20	245.20	118.04	631	39	7258	122400	7934.20	245.20	118.04	631	39	0	0.06176
1981	AUG	Aug-81	22273	109651	7926.98	237.98	362.23	3907	418	22270	109649	7926.98	237.98	362.18	3907	418	0	0.10693

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Proportional Allocation

			Base							Proportional Allocation								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	SEP	Sep-81	19446	98932	7920.37	231.37	326.80	3100	182	19445	98930	7920.37	231.37	326.78	3100	182	0	0.05866
1981	OCT	Oct-81	12966	92652	7916.23	227.23	210.87	1503	58	12966	92650	7916.22	227.22	210.87	1503	58	0	0.03878
1981	NOV	Nov-81	14892	85879	7911.51	222.51	250.26	1845	120	14892	85877	7911.51	222.51	250.26	1845	120	0	0.06502
1981	DEC	Dec-81	13696	79459	7906.80	217.80	222.74	1415	149	13695	79458	7906.80	217.80	222.72	1415	149	0	0.10541
1982	JAN	Jan-82	13431	73439	7902.14	213.14	218.43	1237	161	13431	73438	7902.14	213.14	218.43	1237	161	0	0.13
1982	FEB	Feb-82	11351	68007	7897.68	208.68	204.38	851	55	11351	68007	7897.68	208.68	204.38	851	55	0	0.065
1982	MAR	Mar-82	10833	63969	7894.18	205.18	176.18	499	22	10831	63969	7894.18	205.18	176.15	499	22	0	0.045
1982	APR	Apr-82	14858	58835	7889.47	200.47	249.69	1248	56	14858	58836	7889.47	200.47	249.69	1248	56	0	0.045
1982	MAY	May-82	5289	79717	7907.00	218.00	0.00	0	0	5289	79718	7907.00	218.00	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	129037	7937.75	248.75	100.33	435	24	6700	129037	7937.75	248.75	112.60	608	33	9	0.05416
1982	JUL	Jul-82	56634	152997	7949.70	260.70	921.05	13098	809	56646	152997	7949.70	260.70	921.25	13101	809	0	0.06176
1982	AUG	Aug-82	34304	150691	7948.60	259.60	557.89	7565	809	34304	150691	7948.60	259.60	557.89	7565	809	0	0.10693
1982	SEP	Sep-82	21382	148503	7947.55	258.55	359.33	4394	258	21382	148503	7947.55	258.55	359.33	4394	258	0	0.05866
1982	OCT	Oct-82	20961	142312	7944.53	255.53	340.89	4167	162	20961	142312	7944.53	255.53	340.89	4167	162	0	0.03878
1982	NOV	Nov-82	27691	123593	7934.85	245.85	465.36	5471	356	27691	123593	7934.85	245.85	465.36	5471	356	0	0.06502
1982	DEC	Dec-82	25936	105244	7924.33	235.33	421.80	4650	490	25936	105244	7924.33	235.33	421.80	4650	490	0	0.10541
1983	JAN	Jan-83	25060	87296	7912.52	223.52	407.56	4039	525	25060	87296	7912.52	223.52	407.56	4039	525	0	0.13
1983	FEB	Feb-83	24106	69934	7899.29	210.29	434.05	3535	230	24106	69934	7899.29	210.29	434.05	3535	230	0	0.065
1983	MAR	Mar-83	23807	54935	7885.66	196.66	387.18	2852	128	23807	54935	7885.66	196.66	387.18	2852	128	0	0.045
1983	APR	Apr-83	16472	46192	7876.32	187.32	276.82	1204	54	16472	46192	7876.32	187.32	276.82	1204	54	0	0.045
1983	MAY	May-83	5289	70791	7900.00	211.00	0.00	0	0	5289	70791	7900.00	211.00	0.00	0	0	0	0.045
1983	JUN	Jun-83	112817	131454	7939.02	250.02	1500.00	18000	975	112817	131454	7939.02	250.02	1500.00	18000	975	0	0.05416
1983	JUL	Jul-83	127497	152994	7949.70	260.70	1500.00	18600	1149	127497	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62879	153088	7949.74	260.74	1022.61	14635	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	25870	153173	7949.78	260.78	434.75	5567	327	27365	151679	7949.07	260.07	459.88	5909	347	20	0.05866
1983	OCT	Oct-83	17200	151135	7948.81	259.81	279.73	3382	131	17200	149643	7948.10	259.10	279.73	3361	130	-1	0.03878
1983	NOV	Nov-83	30874	131848	7939.23	250.23	518.85	6387	415	30575	130655	7938.60	249.60	513.82	6292	409	-6	0.06502
1983	DEC	Dec-83	31982	111436	7928.03	239.03	520.13	6168	650	31684	110541	7927.50	238.50	515.28	6079	641	-9	0.10541
1984	JAN	Jan-84	29642	91423	7915.39	226.39	482.07	5146	669	29344	90827	7914.98	225.98	477.23	5065	658	-11	0.13
1984	FEB	Feb-84	26794	71998	7900.98	211.98	465.81	4101	267	26496	71700	7900.74	211.74	460.63	4030	262	-5	0.065
1984	MAR	Mar-84	20592	61032	7891.57	202.57	334.89	2405	108	20296	61030	7891.57	202.57	330.08	2345	106	-3	0.045
1984	APR	Apr-84	17808	58043	7888.71	199.71	299.27	1817	82	17808	58040	7888.71	199.71	299.27	1817	82	0	0.045
1984	MAY	May-84	91645	94702	7917.60	228.60	1490.44	18600	837	91643	94701	7917.60	228.60	1490.41	18600	837	0	0.045
1984	JUN	Jun-84	155457	131401	7938.99	249.99	1500.00	18000	975	155456	131401	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	127128	152994	7949.70	260.70	1500.00	18600	1149	127128	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	81017	153088	7949.74	260.74	1317.60	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	35687	153173	7949.78	260.78	599.73	7980	468	35687	153173	7949.78	260.78	599.73	7980	468	0	0.05866
1984	OCT	Oct-84	23558	153342	7949.86	260.86	383.13	4975	193	23558	153342	7949.86	260.86	383.13	4975	193	0	0.03878
1984	NOV	Nov-84	32940	135612	7941.17	252.17	553.57	6957	452	32940	135612	7941.17	252.17	553.57	6957	452	0	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	33445	116759	7931.07	242.07	543.92	6630	699	0	0.10541
1985	JAN	Jan-85	30448	98306	7919.97	230.97	495.18	5502	715	30448	98306	7919.97	230.97	495.18	5502	715	0	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	28571	80438	7907.54	218.54	514.44	4760	309	0	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	25961	64927	7895.03	206.03	422.21	3611	163	0	0.045
1985	APR	Apr-85	26623	64819	7894.93	205.93	447.41	3798	171	26623	64819	7894.93	205.93	447.41	3798	171	0	0.045
1985	MAY	May-85	53155	98074	7919.82	230.82	864.47	10563	475	53155	98074	7919.82	230.82	864.47	10563	475	0	0.045
1985	JUN	Jun-85	100470	131394	7938.99	249.99	1500.00	18000	975	100470	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	47306	150198	7948.37	259.37	769.35	10737	663	49048	150198	7948.37	259.37	797.68	11163	689	26	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	20206	148184	7947.40	258.40	339.57	4102	241	0	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	8954	151947	7949.20	260.20	145.62	1370	53	0	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	30187	134497	7940.59	251.59	507.30	6276	408	0	0.06502
1985	DEC	Dec-85	28810	116555	7930.96	241.96	468.54	5552	585	28810	116555	7930.96	241.96	468.54	5552	585	0	0.10541
1986	JAN	Jan-86	28596	98170	7919.88	230.88	465.06	5085	661	28596	98170	7919.88	230.88	465.06	5085	661	0	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	26592	81570	7908.38	219.38	478.81	4366	284	0	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	27331	64926	7895.03	206.03	444.49	3891	175	0	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	16277	64819	7894.93	205.93	273.54	1684	76	0	0.045
1986	MAY	May-86	32194	98074	7919.82	230.82	523.58	5886	265	32194	98074	7919.82	230.82	523.58	5886	265	0	0.045
1986	JUN	Jun-86	103802	131394	7938.99	249.99	1500.00	18000	975	103802	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	54802	152994	7949.70	260.70	891.26	12648	781	56297	152953	7949.68	260.68	915.57	13014	804	23	0.06176
1986	AUG	Aug-86	19863	150691	7948.60	259.60	323.04	4028	431	19822	150691	7948.60	259.60	322.37	4018	430	-1	0.10693
1986	SEP	Sep-86	13432	150697	7948.61	259.61	225.73	2480	145	13432	150697	7948.61	259.61	225.73	2480	145	0	0.05866
1986	OCT	Oct-86	9607	151945	7949.20	260.20	156.24	1530	59	9607	151945	7949.20	260.20	156.24	1530	59	0	0.03878
1986	NOV	Nov-86	29317	134496	7940.59	251.59	492.68	6068	395	29317	134496	7940.59	251.59	492.68	6068	395	0	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	27466	115922	7930.60	241.60	446.69	5228	551	0	0.10541
1987	JAN	Jan-87	25065	97747	7919.61	230.61	407.64	4288	557	25065	97747	7919.61	230.61	407.64	4288	557	0	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	24052	80159	7907.33	218.33	433.07	3787	246	0	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	23437	64927	7895.03	206.03	381.16	3095	139	0	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	12195	64819	7894.93	205.93	204.94	850	38	0	0.045
1987	MAY	May-87	8828	96476	7918.78	229.78	143.57	649	29	8828	96476	7918.78	229.78	143.57	649	29	0	0.045
1987	JUN	Jun-87	37857	129001	7937.74	248.74	636.20	7982	432	37857	129001	7937.74	248.74	636.20	7982	432	0	0.05416
1987	JUL	Jul-87	8541	150202	7948.37	259.37	138.90	1250	77	8541	150202	7948.37	259.37	138.90	1250	77	0	0.06176
1987	AUG	Aug-87	26795	146955	7946.81	257.81	435.77	5660	605	26795	146955	7946.81	257.81	435.77	5660	605	0	0.10693
1987	SEP	Sep-87	26443	134964	7940.83	251.83	444.38	5391	316	26443	134964	7940.83	251.83	444.38	5391	316	0	0.05866
1987	OCT	Oct-87	21345	124088	7935.11	246.11	347.14	3957	153	21345	124088	7935.11	246.11	347.14	3957	153	0	0.03878
1987	NOV	Nov-87	21731	111018	7927.78	238.78	365.20	3847	250	21731	111018	7927.78	238.78	365.20	3847	250	0	0.06502
1987	DEC	Dec-87	20232	98313	7919.97	230.97	329.04	3222	340	20232	98313	7919.97	230.97	329.04	3222	340	0	0.10541
1988	JAN	Jan-88	19936	86008	7911.61	222.61	324.22	2895	376	19936	86008	7911.61	222.61	324.22	2895	376	0	0.13
1988	FEB	Feb-88	18101	74291	7902.81	213.81	314.68	2337	152	18101	74291	7902.81	213.81	314.68	2337	152	0	0.065
1988	MAR	Mar-88	16898	64929	7895.03	206.03	274.82	1759	79	16898	64929	7895.03	206.03	274.82	1759	79	0	0.045
1988	APR	Apr-88	12593	64803	7894.92	205.92	211.63	931	42	12593	64803	7894.92	205.92	211.63	931	42	0	0.045
1988	MAY	May-88	5289	89574	7914.12	225.12	0.00	0	0	5289	89574	7914.12	225.12	0.00	0	0	0	0.045
1988	JUN	Jun-88	51027	129016	7937.74	248.74	857.52	11100	601	51027	129016	7937.74	248.74	857.52	11100	601	0	0.05416
1988	JUL	Jul-88	18685	149846	7948.20	259.20	303.88	3727	230	18685	149846	7948.20	259.20	303.88	3727	230	0	0.06176
1988	AUG	Aug-88	42120	130517	7938.53	249.53	685.01	8997	962	42120	130517	7938.53	249.53	685.01	8997	962	0	0.10693

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Proportional Allocation

			Base							Proportional Allocation								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1988	SEP	Sep-88	19530	122971	7934.51	245.51	328.21	3547	208	19530	122971	7934.51	245.51	328.21	3547	208	0	0.05866
1988	OCT	Oct-88	34701	98412	7920.04	231.04	564.35	6454	250	34701	98412	7920.04	231.04	564.35	6454	250	0	0.03878
1988	NOV	Nov-88	17808	90484	7914.75	225.75	299.27	2571	167	17808	90484	7914.75	225.75	299.27	2571	167	0	0.06502
1988	DEC	Dec-88	14659	82913	7909.37	220.37	238.40	1690	178	14659	82913	7909.37	220.37	238.40	1690	178	0	0.10541
1989	JAN	Jan-89	14066	75742	7903.95	214.95	228.76	1418	184	14066	75742	7903.95	214.95	228.76	1418	184	0	0.13
1989	FEB	Feb-89	13103	69158	7898.65	209.65	235.93	1236	80	13103	69158	7898.65	209.65	235.93	1236	80	0	0.065
1989	MAR	Mar-89	15213	63403	7893.68	204.68	247.41	1378	62	15213	63403	7893.68	204.68	247.41	1378	62	0	0.045
1989	APR	Apr-89	14954	63422	7893.70	204.70	251.31	1381	62	14954	63422	7893.70	204.70	251.31	1381	62	0	0.045
1989	MAY	May-89	5289	86101	7911.67	222.67	0.00	0	0	5289	86101	7911.67	222.67	0.00	0	0	0	0.045
1989	JUN	Jun-89	20767	129023	7937.75	248.75	349.00	3937	213	20767	129023	7937.75	248.75	349.00	3937	213	0	0.05416
1989	JUL	Jul-89	23784	149684	7948.12	259.12	386.80	4972	307	23784	149684	7948.12	259.12	386.80	4972	307	0	0.06176
1989	AUG	Aug-89	33587	146237	7946.46	257.46	546.23	7300	781	33587	146237	7946.46	257.46	546.23	7300	781	0	0.10693
1989	SEP	Sep-89	26675	134301	7940.49	251.49	448.28	5434	319	26675	134301	7940.49	251.49	448.28	5434	319	0	0.05866
1989	OCT	Oct-89	18083	127198	7936.78	247.78	294.09	3241	126	18083	127198	7936.78	247.78	294.09	3241	126	0	0.03878
1989	NOV	Nov-89	22957	113504	7929.22	240.22	385.80	4176	272	22957	113504	7929.22	240.22	385.80	4176	272	0	0.06502
1989	DEC	Dec-89	21240	100178	7921.17	232.17	345.43	3485	367	21240	100178	7921.17	232.17	345.43	3485	367	0	0.10541
1990	JAN	Jan-90	19161	87252	7912.49	223.49	311.62	2754	358	19161	87252	7912.49	223.49	311.62	2754	358	0	0.13
1990	FEB	Feb-90	18046	74912	7903.30	214.30	324.93	2390	155	18046	74912	7903.30	214.30	324.93	2390	155	0	0.065
1990	MAR	Mar-90	18157	64539	7894.69	205.69	295.29	2006	90	18157	64539	7894.69	205.69	295.29	2006	90	0	0.045
1990	APR	Apr-90	21003	53220	7883.92	194.92	352.96	2304	104	21003	53220	7883.92	194.92	352.96	2304	104	0	0.045
1990	MAY	May-90	5289	66702	7896.57	207.57	0.00	0	0	5289	66702	7896.57	207.57	0.00	0	0	0	0.045
1990	JUN	Jun-90	16879	129067	7937.77	248.77	283.66	3018	163	16879	129067	7937.77	248.77	283.66	3018	163	0	0.05416
1990	JUL	Jul-90	21334	144634	7945.68	256.68	346.96	4294	265	21334	144634	7945.68	256.68	346.96	4294	265	0	0.06176
1990	AUG	Aug-90	46946	121496	7933.70	244.70	763.49	9893	1058	46946	121496	7933.70	244.70	763.49	9893	1058	0	0.10693
1990	SEP	Sep-90	32172	104467	7923.85	234.85	540.66	6083	357	32172	104467	7923.85	234.85	540.66	6083	357	0	0.05866
1990	OCT	Oct-90	21035	97687	7919.57	230.57	342.10	3388	131	21035	97687	7919.57	230.57	342.10	3388	131	0	0.03878
1990	NOV	Nov-90	19574	89906	7914.35	225.35	328.95	2946	192	19574	89906	7914.35	225.35	328.95	2946	192	0	0.06502
1990	DEC	Dec-90	17604	82479	7909.05	220.05	286.30	2315	244	17604	82479	7909.05	220.05	286.30	2315	244	0	0.10541
1991	JAN	Jan-91	15739	75452	7903.73	214.73	255.97	1765	229	15739	75452	7903.73	214.73	255.97	1765	229	0	0.13
1991	FEB	Feb-91	13259	69014	7898.53	209.53	238.74	1265	82	13259	69014	7898.53	209.53	238.74	1265	82	0	0.065
1991	MAR	Mar-91	12625	63731	7893.97	204.97	205.32	859	39	12625	63731	7893.97	204.97	205.32	859	39	0	0.045
1991	APR	Apr-91	16156	56563	7887.27	198.27	271.51	1447	65	16156	56563	7887.27	198.27	271.51	1447	65	0	0.045
1991	MAY	May-91	5289	85280	7911.09	222.09	0.00	0	0	5289	85280	7911.09	222.09	0.00	0	0	0	0.045
1991	JUN	Jun-91	29376	129025	7937.75	248.75	493.67	5975	324	29375	129025	7937.75	248.75	493.66	5975	324	0	0.05416
1991	JUL	Jul-91	21099	150202	7948.37	259.37	343.14	4323	267	21099	150202	7948.37	259.37	343.14	4323	267	0	0.06176
1991	AUG	Aug-91	29152	147328	7946.99	257.99	474.10	6241	667	29152	147328	7946.99	257.99	474.10	6241	667	0	0.10693
1991	SEP	Sep-91	30325	135777	7941.25	252.25	0.00	0	0	30325	135777	7941.25	252.25	0.00	0	0	0	0.05866

Totals	$61,987,748	$62,080,397
Difference		$92,649
Average Annual		$5,450

Table 3
SHOSHONE
Foregone Power Revenues: Proportional Allocation

			Base				Proportional Allocation					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	66970	1089	9208	357	0	0.04
1974	NOV	Nov-74	66071	1110	9085	591	66071	1110	9085	591	0	0.07
1974	DEC	Dec-74	61830	1006	8502	896	61830	1006	8502	896	0	0.11
1975	JAN	Jan-75	59899	974	8236	1071	59899	974	8236	1071	0	0.13
1975	FEB	Feb-75	58476	1053	8040	523	58476	1053	8040	523	0	0.07
1975	MAR	Mar-75	61181	995	8412	379	61181	995	8412	379	0	0.05
1975	APR	Apr-75	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1975	OCT	Oct-75	70098	1140	9638	374	70097	1140	9638	374	0	0.04
1975	NOV	Nov-75	79448	1335	10924	710	79452	1335	10924	710	0	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	71742	1167	9864	1040	0	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	68496	1114	9418	1224	0	0.13
1976	FEB	Feb-76	70614	1228	9709	631	70613	1228	9709	631	0	0.07
1976	MAR	Mar-76	76631	1246	10537	474	76630	1246	10536	474	0	0.05
1976	APR	Apr-76	82638	1389	11363	511	82638	1389	11363	511	0	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1976	SEP	Sep-76	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1976	OCT	Oct-76	74383	1210	10228	397	74383	1210	10228	397	0	0.04
1976	NOV	Nov-76	59697	1003	8208	534	59697	1003	8208	534	0	0.07
1976	DEC	Dec-76	49447	804	6799	717	49447	804	6799	717	0	0.11
1977	JAN	Jan-77	47151	767	6483	843	47151	767	6483	843	0	0.13
1977	FEB	Feb-77	47230	850	6494	422	47230	850	6494	422	0	0.07
1977	MAR	Mar-77	49872	811	6857	309	49872	811	6857	309	0	0.05
1977	APR	Apr-77	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1977	MAY	May-77	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1977	JUN	Jun-77	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1977	JUL	Jul-77	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1977	SEP	Sep-77	52714	886	7248	425	52714	886	7248	425	0	0.06
1977	OCT	Oct-77	58234	947	8007	311	58234	947	8007	311	0	0.04
1977	NOV	Nov-77	45851	771	6304	410	45851	771	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	46458	756	6388	673	0	0.11
1978	JAN	Jan-78	45729	744	6288	817	44236	719	6082	791	-27	0.13
1978	FEB	Feb-78	39553	712	5438	353	38061	685	5233	340	-13	0.07
1978	MAR	Mar-78	53027	862	7291	328	51543	838	7087	319	-9	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	86576	1408	11904	1273	25	0.11
1978	SEP	Sep-78	65053	1093	8945	525	65053	1093	8945	525	0	0.06
1978	OCT	Oct-78	60476	984	8315	322	60393	982	8304	322	0	0.04
1978	NOV	Nov-78	63938	1074	8791	572	63334	1064	8708	566	-5	0.07
1978	DEC	Dec-78	53625	872	7373	777	53021	862	7290	768	-9	0.11
1979	JAN	Jan-79	49664	808	6829	888	49060	798	6746	877	-11	0.13
1979	FEB	Feb-79	50049	901	6882	447	49444	890	6798	442	-5	0.07
1979	MAR	Mar-79	61728	1004	8487	382	61123	994	8404	378	-4	0.05
1979	APR	Apr-79	80714	1356	11098	499	81913	1377	11263	507	7	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	64845	1090	8916	523	0	0.06
1979	OCT	Oct-79	64083	1042	8811	342	64074	1042	8810	342	0	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70137	1179	9644	627	0	0.07
1979	DEC	Dec-79	67970	1105	9346	985	67976	1106	9347	985	0	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67132	1092	9231	1200	0	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62095	1080	8538	555	0	0.07
1980	MAR	Mar-80	63444	1032	8723	393	63450	1032	8724	393	0	0.05
1980	APR	Apr-80	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1980	JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980	AUG	Aug-80	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1980	SEP	Sep-80	70872	1191	9745	572	70816	1190	9737	571	0	0.06

Table 3
SHOSHONE
Foregone Power Revenues: Proportional Allocation

			Base				Proportional Allocation					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1980	OCT	Oct-80	59823	973	8226	319	59786	972	8220	319	0	0.04
1980	NOV	Nov-80	63271	1063	8700	566	63245	1063	8696	565	0	0.07
1980	DEC	Dec-80	59613	969	8197	864	59593	969	8194	864	0	0.11
1981	JAN	Jan-81	51581	839	7092	922	51566	839	7090	922	0	0.13
1981	FEB	Feb-81	46680	841	6418	417	46669	840	6417	417	0	0.07
1981	MAR	Mar-81	50048	814	6881	310	50038	814	6880	310	0	0.05
1981	APR	Apr-81	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1981	MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981	JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981	JUL	Jul-81	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1981	AUG	Aug-81	69790	1135	9596	1026	69794	1135	9597	1026	0	0.11
1981	SEP	Sep-81	63221	1062	8693	510	63221	1062	8693	510	0	0.06
1981	OCT	Oct-81	61933	1007	8516	330	61933	1007	8516	330	0	0.04
1981	NOV	Nov-81	51751	870	7116	463	51751	870	7116	463	0	0.07
1981	DEC	Dec-81	45812	745	6299	664	45812	745	6299	664	0	0.11
1982	JAN	Jan-82	44243	720	6083	791	44243	720	6083	791	0	0.13
1982	FEB	Feb-82	38976	702	5359	348	38976	702	5359	348	0	0.07
1982	MAR	Mar-82	50770	826	6981	314	50770	826	6981	314	0	0.05
1982	APR	Apr-82	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1982	MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982	JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982	JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982	AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982	SEP	Sep-82	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1982	OCT	Oct-82	82000	1334	11275	437	81996	1334	11274	437	0	0.04
1982	NOV	Nov-82	80279	1349	11038	718	80281	1349	11038	718	0	0.07
1982	DEC	Dec-82	68395	1112	9404	991	68391	1112	9404	991	0	0.11
1983	JAN	Jan-83	64588	1050	8881	1154	64585	1050	8880	1154	0	0.13
1983	FEB	Feb-83	60401	1088	8305	540	60398	1088	8305	540	0	0.07
1983	MAR	Mar-83	68328	1111	9395	423	68324	1111	9394	423	0	0.05
1983	APR	Apr-83	70275	1181	9663	435	70275	1181	9663	435	0	0.05
1983	MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983	JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983	JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983	AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983	SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983	OCT	Oct-83	81342	1323	11184	434	81341	1323	11184	434	0	0.04
1983	NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983	DEC	Dec-83	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1984	JAN	Jan-84	75666	1231	10404	1353	75368	1226	10363	1347	-5	0.13
1984	FEB	Feb-84	74251	1291	10209	664	73952	1286	10168	661	-3	0.07
1984	MAR	Mar-84	71770	1167	9868	444	71473	1162	9827	442	-2	0.05
1984	APR	Apr-84	79696	1339	10958	493	79696	1339	10958	493	0	0.05
1984	MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984	JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984	JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984	AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984	SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984	OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984	NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984	DEC	Dec-84	85925	1397	11815	1245	85925	1397	11815	1245	0	0.11
1985	JAN	Jan-85	80865	1315	11119	1445	80865	1315	11119	1445	0	0.13
1985	FEB	Feb-85	76628	1380	10536	685	76628	1380	10536	685	0	0.07
1985	MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985	APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985	MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985	JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985	JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985	AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985	SEP	Sep-85	75129	1263	10330	606	75129	1263	10330	606	0	0.06
1985	OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985	NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985	DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986	JAN	Jan-86	85651	1393	11777	1531	85651	1393	11777	1531	0	0.13
1986	FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986	MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986	APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986	MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986	JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986	JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1986	AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986	SEP	Sep-86	83783	1408	11520	676	83783	1408	11520	676	0	0.06

Table 3
SHOSHONE
Foregone Power Revenues: Proportional Allocation

			Base				Proportional Allocation					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1986	OCT	Oct-86	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1986	NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986	DEC	Dec-86	78786	1281	10833	1142	78786	1281	10833	1142	0	0.11
1987	JAN	Jan-87	69058	1123	9495	1234	69058	1123	9495	1234	0	0.13
1987	FEB	Feb-87	66954	1206	9206	598	66954	1206	9206	598	0	0.07
1987	MAR	Mar-87	77469	1260	10652	479	77469	1260	10652	479	0	0.05
1987	APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987	MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987	JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987	JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987	AUG	Aug-87	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1987	SEP	Sep-87	62419	1049	8582	503	62419	1049	8582	503	0	0.06
1987	OCT	Oct-87	63624	1035	8748	339	63624	1035	8748	339	0	0.04
1987	NOV	Nov-87	79093	1329	10875	707	79093	1329	10875	707	0	0.07
1987	DEC	Dec-87	68906	1121	9474	999	68906	1121	9474	999	0	0.11
1988	JAN	Jan-88	70055	1139	9632	1252	70055	1139	9632	1252	0	0.13
1988	FEB	Feb-88	64279	1117	8838	574	64279	1117	8838	574	0	0.07
1988	MAR	Mar-88	71897	1169	9886	445	71897	1169	9886	445	0	0.05
1988	APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988	MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988	JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988	JUL	Jul-88	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1988	AUG	Aug-88	81837	1331	11252	1203	81837	1331	11252	1203	0	0.11
1988	SEP	Sep-88	56113	943	7715	453	56113	943	7715	453	0	0.06
1988	OCT	Oct-88	71010	1155	9764	379	71010	1155	9764	379	0	0.04
1988	NOV	Nov-88	60510	1017	8320	541	60510	1017	8320	541	0	0.07
1988	DEC	Dec-88	56962	926	7832	826	56962	926	7832	826	0	0.11
1989	JAN	Jan-89	59364	965	8162	1061	59364	965	8162	1061	0	0.13
1989	FEB	Feb-89	52009	936	7151	465	52009	936	7151	465	0	0.07
1989	MAR	Mar-89	76345	1242	10497	472	76345	1242	10497	472	0	0.05
1989	APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989	MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989	JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989	JUL	Jul-89	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1989	AUG	Aug-89	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1989	SEP	Sep-89	54165	910	7448	437	54165	910	7448	437	0	0.06
1989	OCT	Oct-89	51573	839	7091	275	51573	839	7091	275	0	0.04
1989	NOV	Nov-89	61037	1026	8392	546	61037	1026	8392	546	0	0.07
1989	DEC	Dec-89	61907	1007	8512	897	61907	1007	8512	897	0	0.11
1990	JAN	Jan-90	57901	942	7961	1035	57901	942	7961	1035	0	0.13
1990	FEB	Feb-90	49568	893	6816	443	49568	893	6816	443	0	0.07
1990	MAR	Mar-90	62558	1017	8602	387	62558	1017	8602	387	0	0.05
1990	APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990	MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990	JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990	JUL	Jul-90	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1990	AUG	Aug-90	78519	1277	10796	1154	78519	1277	10796	1154	0	0.11
1990	SEP	Sep-90	62931	1058	8653	508	62931	1058	8653	508	0	0.06
1990	OCT	Oct-90	63305	1030	8704	338	63305	1030	8704	338	0	0.04
1990	NOV	Nov-90	60470	1016	8315	541	60469	1016	8314	541	0	0.07
1990	DEC	Dec-90	53934	877	7416	782	53933	877	7416	782	0	0.11
1991	JAN	Jan-91	49706	808	6834	888	49705	808	6834	888	0	0.13
1991	FEB	Feb-91	46476	837	6390	415	46475	837	6390	415	0	0.07
1991	MAR	Mar-91	52128	848	7167	323	52128	848	7167	323	0	0.05
1991	APR	Apr-91	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1991	MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991	JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991	JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991	AUG	Aug-91	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1991	SEP	9/1	71767	1206	9868	579	71767	1206	9868	579	0	0.06
		Totals				$ 137,670,795				$ 137,608,278		
		Difference								-$62,517		
		Average Annual								-$3,677		

Table 4
RUEDI RESERVOIR
Foregone Power Revenues: Proportional Allocation

	Base						Proportional Allocation							
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974 OCT	9888	62221	222	161	1567	61	9888	62221	222	161	1567	61	0	0.03878
1974 NOV	2321	61998	222	39	193	13	2321	61998	222	39	193	13	0	0.06502
1974 DEC	2398	61041	221	39	185	20	2398	61041	221	39	185	20	0	0.10541
1975 JAN	2741	59833	219	45	230	30	2741	59833	219	45	230	30	0	0.13
1975 FEB	2166	59418	218	39	146	9	2166	59418	218	39	146	9	0	0.065
1975 MAR	2398	58716	217	39	151	7	2398	58716	217	39	151	7	0	0.045
1975 APR	2951	59612	219	50	274	12	2951	59612	219	50	274	12	0	0.045
1975 MAY	9202	71131	234	150	1553	70	9202	71131	234	150	1553	70	0	0.045
1975 JUN	9610	94081	261	161	1880	102	9610	94081	261	161	1880	102	0	0.05416
1975 JUL	23906	96973	264	260	3063	189	23906	96973	264	260	3063	189	0	0.06176
1975 AUG	7097	97094	264	115	1464	157	7097	97094	264	115	1464	157	0	0.10693
1975 SEP	9259	92282	259	156	1798	105	9259	92282	259	156	1798	105	0	0.05866
1975 OCT	7734	87616	253	126	1477	57	7734	87616	253	126	1477	57	0	0.03878
1975 NOV	6969	83075	248	117	1288	84	6969	83075	248	117	1288	84	0	0.06502
1975 DEC	5963	78556	243	97	1058	112	5963	78556	243	97	1058	112	0	0.10541
1976 JAN	5584	74037	238	91	933	121	5584	74037	238	91	933	121	0	0.13
1976 FEB	6056	69518	232	105	971	63	6056	69518	232	105	971	63	0	0.065
1976 MAR	6443	64947	226	105	975	44	6443	64947	226	105	975	44	0	0.045
1976 APR	6055	64621	226	102	907	41	6055	64621	226	102	907	41	0	0.045
1976 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1976 JUN	9282	88993	255	156	1768	96	9282	88993	255	156	1768	96	0	0.05416
1976 JUL	6764	92932	259	110	1360	84	6764	92932	259	110	1360	84	0	0.06176
1976 AUG	6764	92249	259	110	1352	145	6764	92249	259	110	1352	145	0	0.10693
1976 SEP	6527	89633	256	110	1278	75	6527	89633	256	110	1278	75	0	0.05866
1976 OCT	5553	87610	253	90	1083	42	5553	87610	253	90	1083	42	0	0.03878
1976 NOV	3041	86325	252	51	613	40	3041	86325	252	51	613	40	0	0.06502
1976 DEC	2437	85060	251	40	492	52	2437	85060	251	40	492	52	0	0.10541
1977 JAN	2544	83795	249	41	498	65	2544	83795	249	41	498	65	0	0.13
1977 FEB	2670	82529	248	48	504	33	2670	82529	248	48	504	33	0	0.065
1977 MAR	3115	81204	246	51	572	26	3115	81204	246	51	572	26	0	0.045
1977 APR	6549	79702	245	110	1177	53	6549	79702	245	110	1177	53	0	0.045
1977 MAY	9662	83125	249	157	1777	80	9662	83125	249	157	1777	80	0	0.045
1977 JUN	8392	92080	258	141	1639	89	8392	92080	258	141	1639	89	0	0.05416
1977 JUL	6764	91766	258	110	1347	83	6764	91766	258	110	1347	83	0	0.06176
1977 AUG	6324	88805	255	103	1235	132	6324	88805	255	103	1235	132	0	0.10693
1977 SEP	5168	86194	252	87	996	58	5168	86194	252	87	996	58	0	0.05866
1977 OCT	6764	82548	248	110	1247	48	6764	82548	248	110	1247	48	0	0.03878
1977 NOV	6026	79021	244	101	1075	70	6026	79021	244	101	1075	70	0	0.06502
1977 DEC	5991	75516	240	97	1025	108	5991	75516	240	97	1025	108	0	0.10541
1978 JAN	5906	72010	235	96	966	126	5906	72010	235	96	966	126	0	0.13
1978 FEB	5714	68505	231	103	901	59	5714	68505	231	103	901	59	0	0.065
1978 MAR	6381	64948	226	104	964	43	6381	64948	226	104	964	43	0	0.045
1978 APR	8483	64621	226	143	1348	61	8483	64621	226	143	1348	61	0	0.045
1978 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1978 JUN	11861	97007	264	199	2314	125	11861	97007	264	199	2314	125	0	0.05416
1978 JUL	14325	96969	264	233	2763	171	14325	96969	264	233	2763	171	0	0.06176
1978 AUG	6764	96637	264	110	1400	150	6764	96637	264	110	1400	150	0	0.10693
1978 SEP	8598	91891	258	144	1675	98	8598	91891	258	144	1675	98	0	0.05866
1978 OCT	7329	87291	253	119	1400	54	7329	87291	253	119	1400	54	0	0.03878
1978 NOV	6520	82816	248	110	1204	78	6520	82816	248	110	1204	78	0	0.06502
1978 DEC	6836	78362	243	111	1214	128	6836	78362	243	111	1214	128	0	0.10541
1979 JAN	6598	73907	238	107	1115	145	6598	73907	238	107	1115	145	0	0.13
1979 FEB	5818	69453	232	105	931	61	5818	69453	232	105	931	61	0	0.065
1979 MAR	5886	64947	226	96	873	39	5886	64947	226	96	873	39	0	0.045
1979 APR	5586	64621	226	94	821	37	5586	64621	226	94	821	37	0	0.045
1979 MAY	9514	75758	240	155	1667	75	9690	77181	242	158	1716	77	2	0.045
1979 JUN	11745	99741	267	197	2319	126	13331	99576	267	224	2603	141	15	0.05416
1979 JUL	13031	99688	267	212	2557	158	13028	99526	266	212	2555	158	0	0.06176
1979 AUG	10504	97091	264	171	2077	222	10343	97092	264	168	2048	219	-3	0.10693
1979 SEP	8826	92279	259	148	1720	101	8826	92280	259	148	1720	101	0	0.05866
1979 OCT	7994	87614	253	130	1524	59	7994	87614	253	130	1524	59	0	0.03878
1979 NOV	7748	83074	248	130	1429	93	7748	83074	248	130	1429	93	0	0.06502
1979 DEC	7253	78555	243	118	1292	136	7253	78556	243	118	1292	136	0	0.10541
1980 JAN	7028	74036	238	114	1195	155	7028	74037	238	114	1195	155	0	0.13
1980 FEB	6380	69518	232	111	1029	67	6380	69518	232	111	1029	67	0	0.065
1980 MAR	6664	64947	226	108	1015	46	6664	64947	226	108	1015	46	0	0.045
1980 APR	5670	64621	226	95	837	38	5670	64621	226	95	837	38	0	0.045
1980 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1980 JUN	6546	98575	265	110	1373	74	6546	98575	265	110	1373	74	0	0.05416
1980 JUL	13198	96967	264	215	2561	158	13198	96967	264	215	2561	158	0	0.06176
1980 AUG	6764	95764	263	110	1390	149	6764	95764	263	110	1390	149	0	0.10693
1980 SEP	6192	93142	260	104	1254	74	6192	93142	260	104	1254	74	0	0.05866

Table 4
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	Base						Proportional Allocation							
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1980 OCT	4929	91117	257	80	1009	39	4929	91117	257	80	1009	39	0	0.03878
1980 NOV	4338	89246	255	73	879	57	4338	89246	255	73	879	57	0	0.06502
1980 DEC	4147	87397	253	67	827	87	4147	87397	253	67	827	87	0	0.10541
1981 JAN	3421	85547	251	56	675	88	3421	85547	251	56	675	88	0	0.13
1981 FEB	3584	83698	249	65	681	44	3584	83698	249	65	681	44	0	0.065
1981 MAR	4050	81788	247	66	747	34	4050	81788	247	66	747	34	0	0.045
1981 APR	8903	79829	245	150	1604	72	8903	79829	245	150	1604	72	0	0.045
1981 MAY	9664	84454	250	157	1791	81	9664	84454	250	157	1791	81	0	0.045
1981 JUN	8547	96989	264	144	1718	93	8547	96989	264	144	1718	93	0	0.05416
1981 JUL	10428	96969	264	170	2062	127	10428	96969	264	170	2062	127	0	0.06176
1981 AUG	8099	93998	261	132	1612	172	8099	93998	261	132	1612	172	0	0.10693
1981 SEP	6546	91424	258	110	1300	76	6546	91424	258	110	1300	76	0	0.05866
1981 OCT	7730	86902	253	126	1468	57	7730	86902	253	126	1468	57	0	0.03878
1981 NOV	7444	82505	248	125	1368	89	7444	82505	248	125	1368	89	0	0.06502
1981 DEC	7259	78128	243	118	1287	136	7259	78128	243	118	1287	136	0	0.10541
1982 JAN	7329	73752	237	119	1246	162	7329	73752	237	119	1246	162	0	0.13
1982 FEB	6656	69375	232	120	1082	70	6656	69375	232	120	1082	70	0	0.065
1982 MAR	7402	64947	226	120	1149	52	7402	64947	226	120	1149	52	0	0.045
1982 APR	6979	64621	226	117	1075	48	6979	64621	226	117	1075	48	0	0.045
1982 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1982 JUN	9978	97007	264	168	1976	107	9978	97007	264	168	1976	107	0	0.05416
1982 JUL	17315	96969	264	260	3062	189	17315	96969	264	260	3062	189	0	0.06176
1982 AUG	8572	97094	264	139	1730	185	8572	97094	264	139	1730	185	0	0.10693
1982 SEP	13407	91231	258	225	2535	149	13407	91231	258	225	2535	149	0	0.05866
1982 OCT	9483	85510	251	154	1770	69	9483	85510	251	154	1770	69	0	0.03878
1982 NOV	9312	79907	245	156	1679	109	9312	79907	245	156	1679	109	0	0.06502
1982 DEC	9637	74326	238	157	1671	176	9637	74326	238	157	1671	176	0	0.10541
1983 JAN	9145	68744	231	149	1513	197	9145	68744	231	149	1513	197	0	0.13
1983 FEB	8433	63162	224	152	1336	87	8433	63162	224	152	1336	87	0	0.065
1983 MAR	9138	57532	216	149	1364	61	9138	57532	216	149	1364	61	0	0.045
1983 APR	9580	51887	207	161	1377	62	9580	51887	207	161	1377	62	0	0.045
1983 MAY	8715	62734	223	142	1361	61	8715	62734	223	142	1361	61	0	0.045
1983 JUN	8833	100183	267	148	1800	97	8833	100183	267	148	1800	97	0	0.05416
1983 JUL	29507	100110	267	260	3092	191	29507	100110	267	260	3092	191	0	0.06176
1983 AUG	24667	100225	267	260	3093	331	24667	100225	267	260	3093	331	0	0.10693
1983 SEP	13603	93966	261	229	2598	152	13603	93966	261	229	2598	152	0	0.05866
1983 OCT	11014	87851	254	179	2071	80	11014	87851	254	179	2071	80	0	0.03878
1983 NOV	10664	81859	247	179	1944	126	10664	81859	247	179	1944	126	0	0.06502
1983 DEC	9851	75887	240	160	1729	182	9851	75887	240	160	1729	182	0	0.10541
1984 JAN	8561	69915	232	139	1422	185	8561	69915	232	139	1422	185	0	0.13
1984 FEB	7378	63943	225	128	1146	74	7378	63943	225	128	1146	74	0	0.065
1984 MAR	7793	57921	216	127	1124	51	7793	57921	216	127	1124	51	0	0.045
1984 APR	12302	51886	207	207	1875	84	12302	51886	207	207	1875	84	0	0.045
1984 MAY	9778	76893	241	159	1728	78	9778	76893	241	159	1728	78	0	0.045
1984 JUN	38640	101245	268	260	3003	163	38640	101245	268	260	3003	163	0	0.05416
1984 JUL	56215	101187	268	260	3103	192	56215	101187	268	260	3103	192	0	0.06176
1984 AUG	23404	101298	268	260	3104	332	23404	101298	268	260	3104	332	0	0.10693
1984 SEP	15127	95880	263	254	2891	170	15127	95880	263	254	2891	170	0	0.05866
1984 OCT	10031	90612	257	163	1923	75	10031	90612	257	163	1923	75	0	0.03878
1984 NOV	9302	85471	251	156	1735	113	9302	85471	251	156	1735	113	0	0.06502
1984 DEC	8937	80353	245	145	1616	170	8937	80353	245	145	1616	170	0	0.10541
1985 JAN	8340	75235	239	136	1447	188	8340	75235	239	136	1447	188	0	0.13
1985 FEB	7552	70117	233	136	1253	81	7552	70117	233	136	1253	81	0	0.065
1985 MAR	8860	64947	226	144	1415	64	8860	64947	226	144	1415	64	0	0.045
1985 APR	10744	64874	226	181	1763	79	10744	64874	226	181	1763	79	0	0.045
1985 MAY	8918	83365	249	145	1645	74	8918	83365	249	145	1645	74	0	0.045
1985 JUN	19386	101805	269	260	3008	163	19386	101805	269	260	3008	163	0	0.05416
1985 JUL	19160	96962	264	260	3062	189	19160	96962	264	260	3062	189	0	0.06176
1985 AUG	8241	97094	264	134	1670	179	8241	97094	264	134	1670	179	0	0.10693
1985 SEP	10827	92282	259	182	2080	122	10827	92282	259	182	2080	122	0	0.05866
1985 OCT	9664	87616	253	157	1825	71	9664	87616	253	157	1825	71	0	0.03878
1985 NOV	8749	83075	248	147	1610	105	8749	83075	248	147	1610	105	0	0.06502
1985 DEC	8455	78556	243	138	1509	159	8455	78556	243	138	1509	159	0	0.10541
1986 JAN	7696	74037	238	125	1316	171	7696	74037	238	125	1316	171	0	0.13
1986 FEB	7777	69518	232	140	1288	84	7777	69518	232	140	1288	84	0	0.065
1986 MAR	9462	64947	226	154	1524	69	9462	64947	226	154	1524	69	0	0.045
1986 APR	13041	64874	226	219	2181	98	13041	64874	226	219	2181	98	0	0.045
1986 MAY	9864	83365	249	160	1816	82	9864	83365	249	160	1816	82	0	0.045
1986 JUN	19191	101504	268	260	3005	163	19191	101504	268	260	3005	163	0	0.05416
1986 JUL	15347	101453	268	250	2990	185	15347	101453	268	250	2990	185	0	0.06176
1986 AUG	8327	101563	269	135	1730	185	8327	101563	269	135	1730	185	0	0.10693
1986 SEP	11898	96106	263	200	2312	136	11898	96106	263	200	2312	136	0	0.05866

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Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1986 OCT	8939	90799	257	145	1728	67	8939	90799	257	145	1728	67	0	0.03878
1986 NOV	8827	85621	251	148	1651	107	8827	85621	251	148	1651	107	0	0.06502
1986 DEC	8811	80466	246	143	1594	168	8811	80466	246	143	1594	168	0	0.10541
1987 JAN	8138	75310	239	132	1412	184	8138	75310	239	132	1412	184	0	0.13
1987 FEB	7680	70155	233	138	1277	83	7680	70155	233	138	1277	83	0	0.065
1987 MAR	8100	64947	226	132	1276	57	8100	64947	226	132	1276	57	0	0.045
1987 APR	9221	64874	226	155	1486	67	9221	64874	226	155	1486	67	0	0.045
1987 MAY	11041	74359	238	180	1926	87	11041	74359	238	180	1926	87	0	0.045
1987 JUN	9168	87118	253	154	1728	94	9168	87118	253	154	1728	94	0	0.05416
1987 JUL	6764	90707	257	110	1335	82	6764	90707	257	110	1335	82	0	0.06176
1987 AUG	6764	90350	257	110	1331	142	6764	90350	257	110	1331	142	0	0.10693
1987 SEP	7933	86512	252	133	1499	88	7933	86512	252	133	1499	88	0	0.05866
1987 OCT	7440	82812	248	121	1372	53	7440	82812	248	121	1372	53	0	0.03878
1987 NOV	7495	79233	244	126	1343	87	7495	79233	244	126	1343	87	0	0.06502
1987 DEC	6841	75674	240	111	1181	125	6841	75674	240	111	1181	125	0	0.10541
1988 JAN	6683	72116	235	109	1108	144	6683	72116	235	109	1108	144	0	0.13
1988 FEB	5370	68557	231	93	835	54	5370	68557	231	93	835	54	0	0.065
1988 MAR	5678	64948	226	92	836	38	5678	64948	226	92	836	38	0	0.045
1988 APR	8433	64621	226	142	1339	60	8433	64621	226	142	1339	60	0	0.045
1988 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1988 JUN	9282	87639	254	156	1754	95	9282	87639	254	156	1754	95	0	0.05416
1988 JUL	6764	89982	256	110	1327	82	6764	89982	256	110	1327	82	0	0.06176
1988 AUG	8520	87024	253	139	1612	172	8520	87024	253	139	1612	172	0	0.10693
1988 SEP	6919	83665	249	116	1286	75	6919	83665	249	116	1286	75	0	0.05866
1988 OCT	6506	80442	246	106	1177	46	6506	80442	246	106	1177	46	0	0.03878
1988 NOV	6173	77338	242	104	1082	70	6173	77338	242	104	1082	70	0	0.06502
1988 DEC	5877	74253	238	96	989	104	5877	74253	238	96	989	104	0	0.10541
1989 JAN	5614	71168	234	91	902	117	5614	71168	234	91	902	117	0	0.13
1989 FEB	5632	68084	230	101	882	57	5632	68084	230	101	882	57	0	0.065
1989 MAR	7221	64948	226	117	1116	50	7221	64948	226	117	1116	50	0	0.045
1989 APR	9719	64621	226	163	1573	71	9719	64621	226	163	1573	71	0	0.045
1989 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1989 JUN	9282	85491	251	156	1731	94	9282	85491	251	156	1731	94	0	0.05416
1989 JUL	6764	87953	254	110	1305	81	6764	87953	254	110	1305	81	0	0.06176
1989 AUG	6764	87324	253	110	1299	139	6764	87324	253	110	1299	139	0	0.10693
1989 SEP	6829	83922	249	115	1272	75	6829	83922	249	115	1272	75	0	0.05866
1989 OCT	6829	80656	246	111	1238	48	6829	80656	246	111	1238	48	0	0.03878
1989 NOV	6026	77508	242	101	1058	69	6026	77508	242	101	1058	69	0	0.06502
1989 DEC	5768	74381	238	94	970	102	5768	74381	238	94	970	102	0	0.10541
1990 JAN	5345	71254	234	87	854	111	5345	71254	234	87	854	111	0	0.13
1990 FEB	5241	68126	230	94	811	53	5241	68126	230	94	811	53	0	0.065
1990 MAR	6008	64948	226	98	896	40	6008	64948	226	98	896	40	0	0.045
1990 APR	8840	62918	224	149	1393	63	8840	62918	224	149	1393	63	0	0.045
1990 MAY	8866	70503	233	144	1484	67	8866	70503	233	144	1484	67	0	0.045
1990 JUN	9798	82489	248	165	1794	97	9798	82489	248	165	1794	97	0	0.05416
1990 JUL	6764	84962	251	110	1273	79	6764	84962	251	110	1273	79	0	0.06176
1990 AUG	7731	82014	247	126	1416	151	7731	82014	247	126	1416	151	0	0.10693
1990 SEP	6593	79379	244	111	1181	69	6593	79379	244	111	1181	69	0	0.05866
1990 OCT	6764	76874	241	110	1182	46	6764	76874	241	110	1182	46	0	0.03878
1990 NOV	5551	74483	238	93	935	61	5551	74483	238	93	935	61	0	0.06502
1990 DEC	5271	72112	235	86	852	90	5271	72112	235	86	852	90	0	0.10541
1991 JAN	4868	69741	232	79	749	97	4868	69741	232	79	749	97	0	0.13
1991 FEB	4588	67370	229	83	684	44	4588	67370	229	83	684	44	0	0.065
1991 MAR	5202	64948	226	85	749	34	5202	64948	226	85	749	34	0	0.045
1991 APR	6269	64621	226	105	946	43	6269	64621	226	105	946	43	0	0.045
1991 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1991 JUN	9282	92572	259	156	1805	98	9282	92572	259	156	1805	98	0	0.05416
1991 JUL	6764	96233	263	110	1396	86	6764	96233	263	110	1396	86	0	0.06176
1991 AUG	9323	93263	260	152	1824	195	9323	93263	260	152	1824	195	0	0.10693
1991 SEP	9315	89004	255	157	1774	104	9315	89004	255	157	1774	104	0	0.05866
	Totals					$19,793,233						$19,807,590		
	Difference											$14,357		
	Average Annual											$845		

Table 5
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Three Reservoirs Equal Allocation

			Base							Equal Allocation								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	11357	115846	7930.56	241.56	184.70	1501	58	0	0.03878
1974	NOV	Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	21320	104427	7923.83	234.83	358.29	3628	236	0	0.06502
1974	DEC	Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	19759	93370	7916.71	227.71	321.34	3015	318	0	0.10541
1975	JAN	Jan-75	18019	82713	7909.22	220.22	293.05	2409	313	18019	82713	7909.22	220.22	293.05	2409	313	0	0.13
1975	FEB	Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	17044	72644	7901.50	212.50	306.89	2130	138	0	0.065
1975	MAR	Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	15939	63730	7893.97	204.97	259.22	1533	69	0	0.045
1975	APR	Apr-75	12710	60889	7891.43	202.43	213.60	867	39	12710	60889	7891.43	202.43	213.60	867	39	0	0.045
1975	MAY	May-75	5289	75493	7903.76	214.76	0.00	0	0	5289	75493	7903.76	214.76	0.00	0	0	0	0.045
1975	JUN	Jun-75	10362	129047	7937.76	248.76	174.14	1475	80	10362	129047	7937.76	248.76	174.14	1475	80	0	0.05416
1975	JUL	Jul-75	84336	152997	7949.70	260.70	1371.57	18600	1149	84336	152997	7949.70	260.70	1371.57	18600	1149	0	0.06176
1975	AUG	Aug-75	27765	150691	7948.60	259.60	451.55	5963	638	27765	150691	7948.60	259.60	451.55	5963	638	0	0.10693
1975	SEP	Sep-75	23444	143784	7945.26	256.26	393.98	4821	283	23444	143784	7945.26	256.26	393.98	4821	283	0	0.05866
1975	OCT	Oct-75	11432	141023	7943.89	254.89	185.92	1847	72	11432	141023	7943.89	254.89	185.92	1847	72	0	0.03878
1975	NOV	Nov-75	26434	124561	7935.37	246.37	444.23	5194	338	26434	124561	7935.37	246.37	444.23	5194	338	0	0.06502
1975	DEC	Dec-75	23514	108470	7926.28	237.28	382.41	4167	439	23514	108470	7926.28	237.28	382.41	4167	439	0	0.10541
1976	JAN	Jan-76	22347	92780	7916.31	227.31	363.43	3573	465	22347	92780	7916.31	227.31	363.43	3573	465	0	0.13
1976	FEB	Feb-76	22018	77676	7905.45	216.45	382.78	3244	211	22018	77676	7905.45	216.45	382.78	3244	211	0	0.065
1976	MAR	Mar-76	20867	64928	7895.03	206.03	339.36	2570	116	20867	64928	7895.03	206.03	339.36	2570	116	0	0.045
1976	APR	Apr-76	13611	62615	7892.97	203.97	228.74	1089	49	13611	62615	7892.97	203.97	228.74	1089	49	0	0.045
1976	MAY	May-76	5289	84324	7910.40	221.40	0.00	0	0	5289	84324	7910.40	221.40	0.00	0	0	0	0.045
1976	JUN	Jun-76	20309	129027	7937.75	248.75	341.30	3829	207	20309	129027	7937.75	248.75	341.30	3829	207	0	0.05416
1976	JUL	Jul-76	24273	150202	7948.37	259.37	394.76	5100	315	24273	150202	7948.37	259.37	394.76	5100	315	0	0.06176
1976	AUG	Aug-76	24579	149741	7948.15	259.15	399.73	5167	553	24579	149741	7948.15	259.15	399.73	5167	553	0	0.10693
1976	SEP	Sep-76	26715	142820	7944.78	255.78	448.95	5597	328	26715	142820	7944.78	255.78	448.95	5597	328	0	0.05866
1976	OCT	Oct-76	21293	136188	7941.46	252.46	346.29	4149	161	21293	136188	7941.46	252.46	346.29	4149	161	0	0.03878
1976	NOV	Nov-76	20049	124693	7935.44	246.44	336.93	3697	240	20049	124693	7935.44	246.44	336.93	3697	240	0	0.06502
1976	DEC	Dec-76	17772	113570	7929.26	240.26	289.03	2946	311	17772	113570	7929.26	240.26	289.03	2946	311	0	0.10541
1977	JAN	Jan-77	16388	102846	7922.85	233.85	266.52	2445	318	16388	102846	7922.85	233.85	266.52	2445	318	0	0.13
1977	FEB	Feb-77	15486	92708	7916.26	227.26	278.84	2190	142	15486	92708	7916.26	227.26	278.84	2190	142	0	0.065
1977	MAR	Mar-77	16143	83715	7909.95	220.95	262.54	2026	91	16143	83715	7909.95	220.95	262.54	2026	91	0	0.045
1977	APR	Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	25403	69475	7898.91	209.91	426.91	3687	166	0	0.045
1977	MAY	May-77	8191	76232	7904.33	215.33	133.21	186	8	8191	76232	7904.33	215.33	133.21	186	8	0	0.045
1977	JUN	Jun-77	9204	91191	7915.23	226.23	154.68	695	38	9204	91191	7915.23	226.23	154.68	695	38	0	0.05416
1977	JUL	Jul-77	19715	84169	7910.28	221.28	320.63	2807	173	19715	84169	7910.28	221.28	320.63	2807	173	0	0.06176
1977	AUG	Aug-77	24562	72947	7901.74	212.74	399.46	3558	380	24562	72947	7901.74	212.74	399.46	3558	380	0	0.10693
1977	SEP	Sep-77	13059	67022	7896.84	207.84	219.46	1075	63	13059	67022	7896.84	207.84	219.46	1075	63	0	0.05866
1977	OCT	Oct-77	13233	76527	7904.56	215.56	215.21	1258	49	13233	76527	7904.56	215.56	215.21	1258	49	0	0.03878
1977	NOV	Nov-77	13832	71278	7900.39	211.39	232.45	1326	86	13832	71278	7900.39	211.39	232.45	1326	86	0	0.06502
1977	DEC	Dec-77	13180	67062	7896.88	207.88	214.35	1047	110	13180	67062	7896.88	207.88	214.35	1047	110	0	0.10541
1978	JAN	Jan-78	11540	63609	7893.86	204.86	187.68	635	83	11540	63609	7893.86	204.86	187.68	635	83	0	0.13
1978	FEB	Feb-78	9468	61290	7891.83	202.83	170.48	336	22	9468	61290	7891.83	202.83	170.48	336	22	0	0.065
1978	MAR	Mar-78	9956	58454	7889.10	200.10	161.92	201	9	9956	58454	7889.10	200.10	161.92	201	9	0	0.045
1978	APR	Apr-78	6333	63350	7893.63	204.63	106.43	0	0	6333	63350	7893.63	204.63	106.43	0	0	0	0.045
1978	MAY	May-78	5289	81325	7908.20	219.20	0.00	0	0	5289	81325	7908.20	219.20	0.00	0	0	0	0.045
1978	JUN	Jun-78	15480	129034	7937.75	248.75	260.15	2686	145	15480	129034	7937.75	248.75	260.15	2686	145	0	0.05416
1978	JUL	Jul-78	41372	150202	7948.37	259.37	672.84	9285	573	43659	150202	7948.37	259.37	710.04	9844	608	35	0.06176
1978	AUG	Aug-78	31882	149026	7947.81	258.81	518.50	6940	742	32645	147402	7947.02	258.02	530.91	7094	759	17	0.10693
1978	SEP	Sep-78	26756	139955	7943.36	254.36	449.64	5556	326	26756	138334	7942.55	253.55	449.64	5527	324	-2	0.05866
1978	OCT	Oct-78	15652	133901	7940.29	251.29	254.55	2765	107	15652	132282	7939.45	250.45	254.55	2742	106	-1	0.03878
1978	NOV	Nov-78	22180	118865	7932.25	243.25	372.74	4095	266	21856	117571	7931.53	242.53	367.30	3996	260	-6	0.06502
1978	DEC	Dec-78	21471	104199	7923.69	234.69	349.19	3618	381	21147	103228	7923.09	234.09	343.92	3526	372	-10	0.10541
1979	JAN	Jan-79	21246	89932	7914.36	225.36	345.53	3268	425	20922	89285	7913.92	224.92	340.26	3183	414	-11	0.13
1979	FEB	Feb-79	19635	76253	7904.35	215.35	353.54	2756	179	19311	75929	7904.10	215.10	347.71	2680	174	-5	0.065
1979	MAR	Mar-79	19094	64928	7895.03	206.03	310.53	2208	99	18771	64928	7895.03	206.03	305.28	2142	96	-3	0.045
1979	APR	Apr-79	13825	61991	7892.45	203.45	232.33	1119	50	13825	61991	7892.45	203.45	232.33	1119	50	0	0.045
1979	MAY	May-79	5289	90705	7914.90	225.90	0.00	0	0	8263	87736	7912.83	223.83	134.38	391	18	18	0.045
1979	JUN	Jun-79	47652	131409	7939.00	250.00	800.81	10366	561	45533	131416	7939.00	250.00	765.20	9862	534	-27	0.05416
1979	JUL	Jul-79	62920	152994	7949.70	260.70	1023.28	14643	904	63959	152994	7949.70	260.70	1040.18	14898	920	16	0.06176
1979	AUG	Aug-79	28239	150691	7948.60	259.60	459.26	6079	650	28239	150691	7948.60	259.60	459.26	6079	650	0	0.10693
1979	SEP	Sep-79	29407	136836	7941.79	252.79	494.19	6135	360	29407	136836	7941.79	252.79	494.19	6135	360	0	0.05866
1979	OCT	Oct-79	21480	125196	7935.71	246.71	349.33	4008	155	21480	125196	7935.71	246.71	349.33	4008	155	0	0.03878
1979	NOV	Nov-79	22123	111904	7928.30	239.30	371.78	3954	257	22123	111904	7928.30	239.30	371.78	3954	257	0	0.06502
1979	DEC	Dec-79	20742	98978	7920.40	231.40	337.33	3349	353	20742	98978	7920.40	231.40	337.33	3349	353	0	0.10541
1980	JAN	Jan-80	21081	86451	7911.92	222.92	342.84	3154	410	21081	86451	7911.92	222.92	342.84	3154	410	0	0.13
1980	FEB	Feb-80	20012	74512	7902.99	213.99	347.90	2745	178	20012	74512	7902.99	213.99	347.90	2745	178	0	0.065
1980	MAR	Mar-80	19707	63729	7893.97	204.97	320.50	2300	104	19707	63729	7893.97	204.97	320.50	2300	104	0	0.045
1980	APR	Apr-80	12046	61008	7891.55	202.55	202.44	737	33	12046	61008	7891.55	202.55	202.44	737	33	0	0.045
1980	MAY	May-80	5289	83658	7909.91	220.91	0.00	0	0	5289	83658	7909.91	220.91	0.00	0	0	0	0.045
1980	JUN	Jun-80	92514	129028	7937.75	248.75	1500.00	18000	975	92514	129028	7937.75	248.75	1500.00	18000	975	0	0.05416
1980	JUL	Jul-80	40746	150202	7948.37	259.37	662.66	9131	564	41763	150202	7948.37	259.37	679.20	9380	579	15	0.06176
1980	AUG	Aug-80	23454	146821	7946.74	257.74	381.44	4845	518	23537	146821	7946.74	257.74	382.79	4865	520	2	0.10693
1980	SEP	Sep-80	24612	137044	7941.89	252.89	413.61	4989	293	24612	137044	7941.89	252.89	413.61	4989	293	0	0.05866
1980	OCT	Oct-80	12204	133406	7940.03	251.03	198.48	1936	75	12204	133406	7940.03	251.03	198.48	1936	75	0	0.03878
1980	NOV	Nov-80	19891	122468	7934.23	245.23	334.27	3623	236	19891	122468	7934.23	245.23	334.27	3623	236	0	0.06502
1980	DEC	Dec-80	17897	111901	7928.30	239.30	291.06	2946	311	17896	111901	7928.30	239.30	291.05	2946	311	0	0.10541
1981	JAN	Jan-81	16154	101734	7922.15	233.15	262.72	2373	308	16154	101734	7922.15	233.15	262.72	2373	308	0	0.13
1981	FEB	Feb-81	15190	92151	7915.89	226.89	273.51	2115	137	15190	92151	7915.89	226.89	273.51	2115	137	0	0.065
1981	MAR	Mar-81	15583	83715	7909.95	220.95	253.43	1905	86	15583	83715	7909.95	220.95	253.43	1905	86	0	0.045
1981	APR	Apr-81	25807	69337	7898.80	209.80	433.69	3766	169	25804	69340	7898.80	209.80	433.64	3766	169	0	0.045
1981	MAY	May-81	5289	83356	7909.69	220.69	0.00	0	0	5289	83359	7909.69	220.69	0.00	0	0	0	0.045
1981	JUN	Jun-81	5970	110359	7927.39	238.39	100.33	228	12	5970	110362	7927.40	238.40	100.33	228	12	0	0.05416
1981	JUL	Jul-81	7258	122405	7934.20	245.20	118.04	631	39	7258	122402	7934.20	245.20	118.04	631	39	0	0.06176
1981	AUG	Aug-81	22273	109651	7926.98	237.98	362.23	3907	418	22270	109651	7926.98	237.98	362.18	3907	418	0	0.10693

Table 5
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Three Reservoirs Equal Allocation

			Base							Equal Allocation								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	SEP	Sep-81	19446	98932	7920.37	231.37	326.80	3100	182	19445	98932	7920.37	231.37	326.78	3100	182	0	0.05866
1981	OCT	Oct-81	12966	92652	7916.23	227.23	210.87	1503	58	12966	92652	7916.23	227.23	210.87	1503	58	0	0.03878
1981	NOV	Nov-81	14892	85879	7911.51	222.51	250.26	1845	120	14892	85879	7911.51	222.51	250.26	1845	120	0	0.06502
1981	DEC	Dec-81	13696	79459	7906.80	217.80	222.74	1415	149	13696	79459	7906.80	217.80	222.74	1415	149	0	0.10541
1982	JAN	Jan-82	13431	73439	7902.14	213.14	218.43	1237	161	13431	73439	7902.14	213.14	218.43	1237	161	0	0.13
1982	FEB	Feb-82	11351	68007	7897.68	208.68	204.38	851	55	11351	68007	7897.68	208.68	204.38	851	55	0	0.065
1982	MAR	Mar-82	10833	63969	7894.18	205.18	176.18	499	22	10831	63970	7894.18	205.18	176.15	499	22	0	0.045
1982	APR	Apr-82	14858	58835	7889.47	200.47	249.69	1248	56	14858	58836	7889.47	200.47	249.69	1248	56	0	0.045
1982	MAY	May-82	5289	79717	7907.00	218.00	0.00	0	0	5289	79718	7907.00	218.00	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	129037	7937.75	248.75	100.33	435	24	9067	129037	7937.75	248.75	152.37	1168	63	40	0.05416
1982	JUL	Jul-82	56634	152997	7949.70	260.70	921.05	13098	809	56645	152997	7949.70	260.70	921.23	13101	809	0	0.06176
1982	AUG	Aug-82	34304	150691	7948.60	259.60	557.89	7565	809	34304	150691	7948.60	259.60	557.89	7565	809	0	0.10693
1982	SEP	Sep-82	21382	148503	7947.55	258.55	359.33	4394	258	21382	148503	7947.55	258.55	359.33	4394	258	0	0.05866
1982	OCT	Oct-82	20961	142312	7944.53	255.53	340.89	4167	162	20961	142312	7944.53	255.53	340.89	4167	162	0	0.03878
1982	NOV	Nov-82	27691	123593	7934.85	245.85	465.36	5471	356	27691	123593	7934.85	245.85	465.36	5471	356	0	0.06502
1982	DEC	Dec-82	25936	105244	7924.33	235.33	421.80	4650	490	25936	105244	7924.33	235.33	421.80	4650	490	0	0.10541
1983	JAN	Jan-83	25060	87296	7912.52	223.52	407.56	4039	525	25060	87296	7912.52	223.52	407.56	4039	525	0	0.13
1983	FEB	Feb-83	24106	69934	7899.29	210.29	434.05	3535	230	24106	69934	7899.29	210.29	434.05	3535	230	0	0.065
1983	MAR	Mar-83	23807	54935	7885.66	196.66	387.18	2852	128	23807	54935	7885.66	196.66	387.18	2852	128	0	0.045
1983	APR	Apr-83	16472	46192	7876.32	187.32	276.82	1204	54	16472	46192	7876.32	187.32	276.82	1204	54	0	0.045
1983	MAY	May-83	5289	70791	7900.00	211.00	0.00	0	0	5289	70791	7900.00	211.00	0.00	0	0	0	0.045
1983	JUN	Jun-83	112817	131454	7939.02	250.02	1500.00	18000	975	112817	131454	7939.02	250.02	1500.00	18000	975	0	0.05416
1983	JUL	Jul-83	127497	152994	7949.70	260.70	1500.00	18600	1149	127497	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62879	153088	7949.74	260.74	1022.61	14635	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	25870	153173	7949.78	260.78	434.75	5567	327	27365	151679	7949.07	260.07	459.88	5909	347	20	0.05866
1983	OCT	Oct-83	17200	151135	7948.81	259.81	279.73	3382	131	17200	149643	7948.10	259.10	279.73	3361	130	-1	0.03878
1983	NOV	Nov-83	30874	131848	7939.23	250.23	518.85	6387	415	30575	130655	7938.60	249.60	513.82	6292	409	-6	0.06502
1983	DEC	Dec-83	31982	111436	7928.03	239.03	520.13	6168	650	31684	110541	7927.50	238.50	515.28	6079	641	-9	0.10541
1984	JAN	Jan-84	29642	91423	7915.39	226.39	482.07	5146	669	29344	90827	7914.98	225.98	477.23	5065	658	-11	0.13
1984	FEB	Feb-84	26794	71998	7900.98	211.98	465.81	4101	267	26496	71700	7900.74	211.74	460.63	4030	262	-5	0.065
1984	MAR	Mar-84	20592	61032	7891.57	202.57	334.89	2405	108	20296	61030	7891.57	202.57	330.08	2345	106	-3	0.045
1984	APR	Apr-84	17808	58043	7888.71	199.71	299.27	1817	82	17808	58040	7888.71	199.71	299.27	1817	82	0	0.045
1984	MAY	May-84	91645	94702	7917.60	228.60	1490.44	18600	837	91643	94701	7917.60	228.60	1490.41	18600	837	0	0.045
1984	JUN	Jun-84	155457	131401	7938.99	249.99	1500.00	18000	975	155456	131401	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	127128	152994	7949.70	260.70	1500.00	18600	1149	127128	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	81017	153088	7949.74	260.74	1317.60	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	35687	153173	7949.78	260.78	599.73	7980	468	35687	153173	7949.78	260.78	599.73	7980	468	0	0.05866
1984	OCT	Oct-84	23558	153342	7949.86	260.86	383.13	4975	193	23558	153342	7949.86	260.86	383.13	4975	193	0	0.03878
1984	NOV	Nov-84	32940	135612	7941.17	252.17	553.57	6957	452	32940	135612	7941.17	252.17	553.57	6957	452	0	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	33445	116759	7931.07	242.07	543.92	6630	699	0	0.10541
1985	JAN	Jan-85	30448	98306	7919.97	230.97	495.18	5502	715	30448	98306	7919.97	230.97	495.18	5502	715	0	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	28571	80438	7907.54	218.54	514.44	4760	309	0	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	25961	64927	7895.03	206.03	422.21	3611	163	0	0.045
1985	APR	Apr-85	26623	64819	7894.93	205.93	447.41	3798	171	26623	64819	7894.93	205.93	447.41	3798	171	0	0.045
1985	MAY	May-85	53155	98074	7919.82	230.82	864.47	10563	475	53155	98074	7919.82	230.82	864.47	10563	475	0	0.045
1985	JUN	Jun-85	100470	131394	7938.99	249.99	1500.00	18000	975	100470	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	47306	150198	7948.37	259.37	769.35	10737	663	49048	150198	7948.37	259.37	797.68	11163	689	26	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	20206	148184	7947.40	258.40	339.57	4102	241	0	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	8954	151947	7949.20	260.20	145.62	1370	53	0	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	30187	134497	7940.59	251.59	507.30	6276	408	0	0.06502
1985	DEC	Dec-85	28810	116555	7930.96	241.96	468.54	5552	585	28810	116555	7930.96	241.96	468.54	5552	585	0	0.10541
1986	JAN	Jan-86	28596	98170	7919.88	230.88	465.06	5085	661	28596	98170	7919.88	230.88	465.06	5085	661	0	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	26592	81570	7908.38	219.38	478.81	4366	284	0	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	27331	64926	7895.03	206.03	444.49	3891	175	0	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	16277	64819	7894.93	205.93	273.54	1684	76	0	0.045
1986	MAY	May-86	32194	98074	7919.82	230.82	523.58	5886	265	32194	98074	7919.82	230.82	523.58	5886	265	0	0.045
1986	JUN	Jun-86	103802	131394	7938.99	249.99	1500.00	18000	975	103802	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	54802	152994	7949.70	260.70	891.26	12648	781	57063	152188	7949.31	260.31	928.03	13181	814	33	0.06176
1986	AUG	Aug-86	19863	150691	7948.60	259.60	323.04	4028	431	19057	150692	7948.60	259.60	309.93	3830	410	-21	0.10693
1986	SEP	Sep-86	13432	150697	7948.61	259.61	225.73	2480	145	13432	150697	7948.61	259.61	225.73	2480	145	0	0.05866
1986	OCT	Oct-86	9607	151945	7949.20	260.20	156.24	1530	59	9607	151945	7949.20	260.20	156.24	1530	59	0	0.03878
1986	NOV	Nov-86	29317	134496	7940.59	251.59	492.68	6068	395	29317	134496	7940.59	251.59	492.68	6068	395	0	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	27466	115922	7930.60	241.60	446.69	5228	551	0	0.10541
1987	JAN	Jan-87	25065	97747	7919.61	230.61	407.64	4288	557	25065	97747	7919.61	230.61	407.64	4288	557	0	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	24052	80159	7907.33	218.33	433.07	3787	246	0	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	23437	64927	7895.03	206.03	381.16	3095	139	0	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	12195	64819	7894.93	205.93	204.94	850	38	0	0.045
1987	MAY	May-87	8828	96476	7918.78	229.78	143.57	649	29	8828	96476	7918.78	229.78	143.57	649	29	0	0.045
1987	JUN	Jun-87	37857	129001	7937.74	248.74	636.20	7982	432	37857	129001	7937.74	248.74	636.20	7982	432	0	0.05416
1987	JUL	Jul-87	8541	150202	7948.37	259.37	138.90	1250	77	8541	150202	7948.37	259.37	138.90	1250	77	0	0.06176
1987	AUG	Aug-87	26795	146955	7946.81	257.81	435.77	5660	605	26795	146955	7946.81	257.81	435.77	5660	605	0	0.10693
1987	SEP	Sep-87	26443	134964	7940.83	251.83	444.38	5391	316	26443	134964	7940.83	251.83	444.38	5391	316	0	0.05866
1987	OCT	Oct-87	21345	124088	7935.11	246.11	347.14	3957	153	21345	124088	7935.11	246.11	347.14	3957	153	0	0.03878
1987	NOV	Nov-87	21731	111018	7927.78	238.78	365.20	3847	250	21731	111018	7927.78	238.78	365.20	3847	250	0	0.06502
1987	DEC	Dec-87	20232	98313	7919.97	230.97	329.04	3222	340	20232	98313	7919.97	230.97	329.04	3222	340	0	0.10541
1988	JAN	Jan-88	19936	86008	7911.61	222.61	324.22	2895	376	19936	86008	7911.61	222.61	324.22	2895	376	0	0.13
1988	FEB	Feb-88	18101	74291	7902.81	213.81	314.68	2337	152	18101	74291	7902.81	213.81	314.68	2337	152	0	0.065
1988	MAR	Mar-88	16898	64929	7895.03	206.03	274.82	1759	79	16898	64929	7895.03	206.03	274.82	1759	79	0	0.045
1988	APR	Apr-88	12593	64803	7894.92	205.92	211.63	931	42	12593	64803	7894.92	205.92	211.63	931	42	0	0.045
1988	MAY	May-88	5289	89574	7914.12	225.12	0.00	0	0	5289	89574	7914.12	225.12	0.00	0	0	0	0.045
1988	JUN	Jun-88	51027	129016	7937.74	248.74	857.52	11100	601	51027	129016	7937.74	248.74	857.52	11100	601	0	0.05416
1988	JUL	Jul-88	18685	149846	7948.20	259.20	303.88	3727	230	18685	149846	7948.20	259.20	303.88	3727	230	0	0.06176
1988	AUG	Aug-88	42120	130517	7938.53	249.53	685.01	8997	962	42120	130516	7938.53	249.53	685.01	8997	962	0	0.10693

Table 5
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Three Reservoirs Equal Allocation

			Base							Equal Allocation								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1988	SEP	Sep-88	19530	122971	7934.51	245.51	328.21	3547	208	19530	122971	7934.51	245.51	328.21	3547	208	0	0.05866
1988	OCT	Oct-88	34701	98412	7920.04	231.04	564.35	6454	250	34701	98411	7920.04	231.04	564.35	6454	250	0	0.03878
1988	NOV	Nov-88	17808	90484	7914.75	225.75	299.27	2571	167	17808	90484	7914.75	225.75	299.27	2571	167	0	0.06502
1988	DEC	Dec-88	14659	82913	7909.37	220.37	238.40	1690	178	14659	82913	7909.37	220.37	238.40	1690	178	0	0.10541
1989	JAN	Jan-89	14066	75742	7903.95	214.95	228.76	1418	184	14066	75741	7903.95	214.95	228.76	1418	184	0	0.13
1989	FEB	Feb-89	13103	69158	7898.65	209.65	235.93	1236	80	13103	69158	7898.65	209.65	235.93	1236	80	0	0.065
1989	MAR	Mar-89	15213	63403	7893.68	204.68	247.41	1378	62	15213	63403	7893.68	204.68	247.41	1378	62	0	0.045
1989	APR	Apr-89	14954	63422	7893.70	204.70	251.31	1381	62	14954	63422	7893.70	204.70	251.31	1381	62	0	0.045
1989	MAY	May-89	5289	86101	7911.67	222.67	0.00	0	0	5289	86101	7911.67	222.67	0.00	0	0	0	0.045
1989	JUN	Jun-89	20767	129023	7937.75	248.75	349.00	3937	213	20765	129023	7937.75	248.75	348.96	3937	213	0	0.05416
1989	JUL	Jul-89	23784	149684	7948.12	259.12	386.80	4972	307	23784	149684	7948.12	259.12	386.80	4972	307	0	0.06176
1989	AUG	Aug-89	33587	146237	7946.46	257.46	546.23	7300	781	33587	146237	7946.46	257.46	546.23	7300	781	0	0.10693
1989	SEP	Sep-89	26675	134301	7940.49	251.49	448.28	5434	319	26675	134301	7940.49	251.49	448.28	5434	319	0	0.05866
1989	OCT	Oct-89	18083	127198	7936.78	247.78	294.09	3241	126	18083	127198	7936.78	247.78	294.09	3241	126	0	0.03878
1989	NOV	Nov-89	22957	113504	7929.22	240.22	385.80	4176	272	22957	113504	7929.22	240.22	385.80	4176	272	0	0.06502
1989	DEC	Dec-89	21240	100178	7921.17	232.17	345.43	3485	367	21240	100178	7921.17	232.17	345.43	3485	367	0	0.10541
1990	JAN	Jan-90	19161	87252	7912.49	223.49	311.62	2754	358	19161	87252	7912.49	223.49	311.62	2754	358	0	0.13
1990	FEB	Feb-90	18046	74912	7903.30	214.30	324.93	2390	155	18046	74912	7903.30	214.30	324.93	2390	155	0	0.065
1990	MAR	Mar-90	18157	64539	7894.69	205.69	295.29	2006	90	18157	64539	7894.69	205.69	295.29	2006	90	0	0.045
1990	APR	Apr-90	21003	53220	7883.92	194.92	352.96	2304	104	21003	53220	7883.92	194.92	352.96	2304	104	0	0.045
1990	MAY	May-90	5289	66702	7896.57	207.57	0.00	0	0	5289	66702	7896.57	207.57	0.00	0	0	0	0.045
1990	JUN	Jun-90	16879	129067	7937.77	248.77	283.66	3018	163	16879	129067	7937.77	248.77	283.66	3018	163	0	0.05416
1990	JUL	Jul-90	21334	144634	7945.68	256.68	346.96	4294	265	21334	144634	7945.68	256.68	346.96	4294	265	0	0.06176
1990	AUG	Aug-90	46946	121496	7933.70	244.70	763.49	9893	1058	46946	121496	7933.70	244.70	763.49	9893	1058	0	0.10693
1990	SEP	Sep-90	32172	104467	7923.85	234.85	540.66	6083	357	32172	104467	7923.85	234.85	540.66	6083	357	0	0.05866
1990	OCT	Oct-90	21035	97687	7919.57	230.57	342.10	3388	131	21035	97687	7919.57	230.57	342.10	3388	131	0	0.03878
1990	NOV	Nov-90	19574	89906	7914.35	225.35	328.95	2946	192	19574	89906	7914.35	225.35	328.95	2946	192	0	0.06502
1990	DEC	Dec-90	17604	82479	7909.05	220.05	286.30	2315	244	17604	82479	7909.05	220.05	286.30	2315	244	0	0.10541
1991	JAN	Jan-91	15739	75452	7903.73	214.73	255.97	1765	229	15739	75452	7903.73	214.73	255.97	1765	229	0	0.13
1991	FEB	Feb-91	13259	69014	7898.53	209.53	238.74	1265	82	13259	69014	7898.53	209.53	238.74	1265	82	0	0.065
1991	MAR	Mar-91	12625	63731	7893.97	204.97	205.32	859	39	12625	63731	7893.97	204.97	205.32	859	39	0	0.045
1991	APR	Apr-91	16156	56563	7887.27	198.27	271.51	1447	65	16156	56563	7887.27	198.27	271.51	1447	65	0	0.045
1991	MAY	May-91	5289	85280	7911.09	222.09	0.00	0	0	5289	85280	7911.09	222.09	0.00	0	0	0	0.045
1991	JUN	Jun-91	29376	129025	7937.75	248.75	493.67	5975	324	29374	129025	7937.75	248.75	493.64	5975	324	0	0.05416
1991	JUL	Jul-91	21099	150202	7948.37	259.37	343.14	4323	267	21099	150202	7948.37	259.37	343.14	4323	267	0	0.06176
1991	AUG	Aug-91	29152	147328	7946.99	257.99	474.10	6241	667	29152	147328	7946.99	257.99	474.10	6241	667	0	0.10693
1991	SEP	Sep-91	30325	135777	7941.25	252.25	0.00	0	0	30325	135777	7941.25	252.25	0.00	0	0	0	0.05866
							Totals		$61,987,748							$62,088,361		
							Difference									$100,613		
							Average Annual									$5,918		

Table 6
SHOSHONE POWER PLANT
Foregone Power Revenues: Three Reservoirs Equal Allocation

			Base				Equal Allocation					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	66970	1089	9208	357	0	0.04
1974	NOV	Nov-74	66071	1110	9085	591	66071	1110	9085	591	0	0.07
1974	DEC	Dec-74	61830	1006	8502	896	61830	1006	8502	896	0	0.11
1975	JAN	Jan-75	59899	974	8236	1071	59899	974	8236	1071	0	0.13
1975	FEB	Feb-75	58476	1053	8040	523	58476	1053	8040	523	0	0.07
1975	MAR	Mar-75	61181	995	8412	379	61181	995	8412	379	0	0.05
1975	APR	Apr-75	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1975	OCT	Oct-75	70098	1140	9638	374	70095	1140	9638	374	0	0.04
1975	NOV	Nov-75	79448	1335	10924	710	79445	1335	10924	710	0	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	71740	1167	9864	1040	0	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	68494	1114	9418	1224	0	0.13
1976	FEB	Feb-76	70614	1228	9709	631	70611	1228	9709	631	0	0.07
1976	MAR	Mar-76	76631	1246	10537	474	76628	1246	10536	474	0	0.05
1976	APR	Apr-76	82638	1389	11363	511	82638	1389	11363	511	0	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1976	SEP	Sep-76	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1976	OCT	Oct-76	74383	1210	10228	397	74383	1210	10228	397	0	0.04
1976	NOV	Nov-76	59697	1003	8208	534	59697	1003	8208	534	0	0.07
1976	DEC	Dec-76	49447	804	6799	717	49447	804	6799	717	0	0.11
1977	JAN	Jan-77	47151	767	6483	843	47151	767	6483	843	0	0.13
1977	FEB	Feb-77	47230	850	6494	422	47230	850	6494	422	0	0.07
1977	MAR	Mar-77	49872	811	6857	309	49872	811	6857	309	0	0.05
1977	APR	Apr-77	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1977	MAY	May-77	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1977	JUN	Jun-77	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1977	JUL	Jul-77	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1977	SEP	Sep-77	52714	886	7248	425	52714	886	7248	425	0	0.06
1977	OCT	Oct-77	58234	947	8007	311	58234	947	8007	311	0	0.04
1977	NOV	Nov-77	45851	771	6304	410	45851	771	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	46458	756	6388	673	0	0.11
1978	JAN	Jan-78	45729	744	6288	817	44236	719	6082	791	-27	0.13
1978	FEB	Feb-78	39553	712	5438	353	38061	685	5233	340	-13	0.07
1978	MAR	Mar-78	53027	862	7291	328	51543	838	7087	319	-9	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	86576	1408	11904	1273	25	0.11
1978	SEP	Sep-78	65053	1093	8945	525	65053	1093	8945	525	0	0.06
1978	OCT	Oct-78	60476	984	8315	322	59538	968	8186	317	-5	0.04
1978	NOV	Nov-78	63938	1074	8791	572	62486	1050	8592	559	-13	0.07
1978	DEC	Dec-78	53625	872	7373	777	52174	849	7174	756	-21	0.11
1979	JAN	Jan-79	49664	808	6829	888	48212	784	6629	862	-26	0.13
1979	FEB	Feb-79	50049	901	6882	447	48597	875	6682	434	-13	0.07
1979	MAR	Mar-79	61728	1004	8487	382	60276	980	8288	373	-9	0.05
1979	APR	Apr-79	80714	1356	11098	499	81913	1377	11263	507	7	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	64845	1090	8916	523	0	0.06
1979	OCT	Oct-79	64083	1042	8811	342	64049	1042	8807	342	0	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70113	1178	9640	627	0	0.07
1979	DEC	Dec-79	67970	1105	9346	985	67952	1105	9343	985	0	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67108	1091	9227	1200	0	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62070	1079	8535	555	0	0.07
1980	MAR	Mar-80	63444	1032	8723	393	63426	1032	8721	392	0	0.05
1980	APR	Apr-80	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05

Table 6
SHOSHONE POWER PLANT
Foregone Power Revenues: Three Reservoirs Equal Allocation

1980 JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980 AUG	Aug-80	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1980 SEP	Sep-80	70872	1191	9745	572	70816	1190	9737	571	0	0.06
1980 OCT	Oct-80	59823	973	8226	319	59787	972	8221	319	0	0.04
1980 NOV	Nov-80	63271	1063	8700	566	63246	1063	8696	565	0	0.07
1980 DEC	Dec-80	59613	969	8197	864	59594	969	8194	864	0	0.11
1981 JAN	Jan-81	51581	839	7092	922	51567	839	7090	922	0	0.13
1981 FEB	Feb-81	46680	841	6418	417	46669	840	6417	417	0	0.07
1981 MAR	Mar-81	50048	814	6881	310	50039	814	6880	310	0	0.05
1981 APR	Apr-81	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1981 MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981 JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981 JUL	Jul-81	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1981 AUG	Aug-81	69790	1135	9596	1026	69794	1135	9597	1026	0	0.11
1981 SEP	Sep-81	63221	1062	8693	510	63221	1062	8693	510	0	0.06
1981 OCT	Oct-81	61933	1007	8516	330	61933	1007	8516	330	0	0.04
1981 NOV	Nov-81	51751	870	7116	463	51751	870	7116	463	0	0.07
1981 DEC	Dec-81	45812	745	6299	664	45812	745	6299	664	0	0.11
1982 JAN	Jan-82	44243	720	6083	791	44243	720	6083	791	0	0.13
1982 FEB	Feb-82	38976	702	5359	348	38977	702	5359	348	0	0.07
1982 MAR	Mar-82	50770	826	6981	314	50770	826	6981	314	0	0.05
1982 APR	Apr-82	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1982 MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982 JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982 JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982 AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982 SEP	Sep-82	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1982 OCT	Oct-82	82000	1334	11275	437	81988	1333	11273	437	0	0.04
1982 NOV	Nov-82	80279	1349	11038	718	80268	1349	11037	718	0	0.07
1982 DEC	Dec-82	68395	1112	9404	991	68383	1112	9403	991	0	0.11
1983 JAN	Jan-83	64588	1050	8881	1154	64577	1050	8879	1154	0	0.13
1983 FEB	Feb-83	60401	1088	8305	540	60390	1087	8304	540	0	0.07
1983 MAR	Mar-83	68328	1111	9395	423	68317	1111	9393	423	0	0.05
1983 APR	Apr-83	70275	1181	9663	435	70275	1181	9663	435	0	0.05
1983 MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983 JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983 JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983 AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983 SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983 OCT	Oct-83	81342	1323	11184	434	81340	1323	11184	434	0	0.04
1983 NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983 DEC	Dec-83	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1984 JAN	Jan-84	75666	1231	10404	1353	75367	1226	10363	1347	-5	0.13
1984 FEB	Feb-84	74251	1291	10209	664	73951	1286	10168	661	-3	0.07
1984 MAR	Mar-84	71770	1167	9868	444	71472	1162	9827	442	-2	0.05
1984 APR	Apr-84	79696	1339	10958	493	79696	1339	10958	493	0	0.05
1984 MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984 JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984 JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984 AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984 SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984 OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984 NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984 DEC	Dec-84	85925	1397	11815	1245	85925	1397	11815	1245	0	0.11
1985 JAN	Jan-85	80865	1315	11119	1445	80865	1315	11119	1445	0	0.13
1985 FEB	Feb-85	76628	1380	10536	685	76628	1380	10536	685	0	0.07
1985 MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985 MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985 JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985 AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985 SEP	Sep-85	75129	1263	10330	606	75129	1263	10330	606	0	0.06
1985 OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985 NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985 DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986 JAN	Jan-86	85651	1393	11777	1531	85651	1393	11777	1531	0	0.13
1986 FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986 MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986 MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986 JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06

Table 6
SHOSHONE POWER PLANT
Foregone Power Revenues: Three Reservoirs Equal Allocation

1986 AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986 SEP	Sep-86	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1986 OCT	Oct-86	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1986 NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986 DEC	Dec-86	78786	1281	10833	1142	78785	1281	10833	1142	0	0.11
1987 JAN	Jan-87	69058	1123	9495	1234	69058	1123	9495	1234	0	0.13
1987 FEB	Feb-87	66954	1206	9206	598	66953	1206	9206	598	0	0.07
1987 MAR	Mar-87	77469	1260	10652	479	77469	1260	10652	479	0	0.05
1987 APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987 MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987 JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987 JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987 AUG	Aug-87	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1987 SEP	Sep-87	62419	1049	8582	503	62419	1049	8582	503	0	0.06
1987 OCT	Oct-87	63624	1035	8748	339	63624	1035	8748	339	0	0.04
1987 NOV	Nov-87	79093	1329	10875	707	79093	1329	10875	707	0	0.07
1987 DEC	Dec-87	68906	1121	9474	999	68906	1121	9474	999	0	0.11
1988 JAN	Jan-88	70055	1139	9632	1252	70055	1139	9632	1252	0	0.13
1988 FEB	Feb-88	64279	1117	8838	574	64279	1117	8838	574	0	0.07
1988 MAR	Mar-88	71897	1169	9886	445	71897	1169	9886	445	0	0.05
1988 APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988 MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988 JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988 JUL	Jul-88	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1988 AUG	Aug-88	81837	1331	11252	1203	81837	1331	11252	1203	0	0.11
1988 SEP	Sep-88	56113	943	7715	453	56113	943	7715	453	0	0.06
1988 OCT	Oct-88	71010	1155	9764	379	71010	1155	9764	379	0	0.04
1988 NOV	Nov-88	60510	1017	8320	541	60510	1017	8320	541	0	0.07
1988 DEC	Dec-88	56962	926	7832	826	56962	926	7832	826	0	0.11
1989 JAN	Jan-89	59364	965	8162	1061	59364	965	8162	1061	0	0.13
1989 FEB	Feb-89	52009	936	7151	465	52009	936	7151	465	0	0.07
1989 MAR	Mar-89	76345	1242	10497	472	76345	1242	10497	472	0	0.05
1989 APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989 MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989 JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989 JUL	Jul-89	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1989 AUG	Aug-89	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1989 SEP	Sep-89	54165	910	7448	437	54165	910	7448	437	0	0.06
1989 OCT	Oct-89	51573	839	7091	275	51573	839	7091	275	0	0.04
1989 NOV	Nov-89	61037	1026	8392	546	61037	1026	8392	546	0	0.07
1989 DEC	Dec-89	61907	1007	8512	897	61907	1007	8512	897	0	0.11
1990 JAN	Jan-90	57901	942	7961	1035	57901	942	7961	1035	0	0.13
1990 FEB	Feb-90	49568	893	6816	443	49568	893	6816	443	0	0.07
1990 MAR	Mar-90	62558	1017	8602	387	62558	1017	8602	387	0	0.05
1990 APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990 MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990 JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990 JUL	Jul-90	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1990 AUG	Aug-90	78519	1277	10796	1154	78519	1277	10796	1154	0	0.11
1990 SEP	Sep-90	62931	1058	8653	508	62931	1058	8653	508	0	0.06
1990 OCT	Oct-90	63305	1030	8704	338	63305	1030	8704	338	0	0.04
1990 NOV	Nov-90	60470	1016	8315	541	60469	1016	8314	541	0	0.07
1990 DEC	Dec-90	53934	877	7416	782	53933	877	7416	782	0	0.11
1991 JAN	Jan-91	49706	808	6834	888	49705	808	6834	888	0	0.13
1991 FEB	Feb-91	46476	837	6390	415	46475	837	6390	415	0	0.07
1991 MAR	Mar-91	52128	848	7167	323	52128	848	7167	323	0	0.05
1991 APR	Apr-91	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1991 MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991 JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991 JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991 AUG	Aug-91	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1991 SEP	9/1	71767	1206	9868	579	71767	1206	9868	579	0	0.06
	Totals				$ 137,670,795				$ 137,553,696		
	Difference								-$117,100		
	Average Annual								-$6,888		

Table 7
SHOSHONE POWER PLANT
Foregone Power Revenues: Total Release from Granby Reservoir

			Base				Release from Granby					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	66970	1089	9208	357	0	0.04
1974	NOV	Nov-74	66071	1110	9085	591	66071	1110	9085	591	0	0.07
1974	DEC	Dec-74	61830	1006	8502	896	61830	1006	8502	896	0	0.11
1975	JAN	Jan-75	59899	974	8236	1071	59899	974	8236	1071	0	0.13
1975	FEB	Feb-75	58476	1053	8040	523	58476	1053	8040	523	0	0.07
1975	MAR	Mar-75	61181	995	8412	379	61181	995	8412	379	0	0.05
1975	APR	Apr-75	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1975	OCT	Oct-75	70098	1140	9638	374	70098	1140	9638	374	0	0.04
1975	NOV	Nov-75	79448	1335	10924	710	79448	1335	10924	710	0	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	71743	1167	9865	1040	0	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	68497	1114	9418	1224	0	0.13
1976	FEB	Feb-76	70614	1228	9709	631	70614	1228	9709	631	0	0.07
1976	MAR	Mar-76	76631	1246	10537	474	76631	1246	10537	474	0	0.05
1976	APR	Apr-76	82638	1389	11363	511	82638	1389	11363	511	0	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1976	SEP	Sep-76	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1976	OCT	Oct-76	74383	1210	10228	397	74383	1210	10228	397	0	0.04
1976	NOV	Nov-76	59697	1003	8208	534	59697	1003	8208	534	0	0.07
1976	DEC	Dec-76	49447	804	6799	717	49447	804	6799	717	0	0.11
1977	JAN	Jan-77	47151	767	6483	843	47151	767	6483	843	0	0.13
1977	FEB	Feb-77	47230	850	6494	422	47230	850	6494	422	0	0.07
1977	MAR	Mar-77	49872	811	6857	309	49872	811	6857	309	0	0.05
1977	APR	Apr-77	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1977	MAY	May-77	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1977	JUN	Jun-77	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1977	JUL	Jul-77	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1977	SEP	Sep-77	52714	886	7248	425	52714	886	7248	425	0	0.06
1977	OCT	Oct-77	58234	947	8007	311	58234	947	8007	311	0	0.04
1977	NOV	Nov-77	45851	771	6304	410	45851	771	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	46458	756	6388	673	0	0.11
1978	JAN	Jan-78	45729	744	6288	817	44236	719	6082	791	-27	0.13
1978	FEB	Feb-78	39553	712	5438	353	38061	685	5233	340	-13	0.07
1978	MAR	Mar-78	53027	862	7291	328	51543	838	7087	319	-9	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	85812	1396	11799	1262	14	0.11
1978	SEP	Sep-78	65053	1093	8945	525	65053	1093	8945	525	0	0.06
1978	OCT	Oct-78	60476	984	8315	322	60476	984	8315	322	0	0.04
1978	NOV	Nov-78	63938	1074	8791	572	63746	1071	8765	570	-2	0.07
1978	DEC	Dec-78	53625	872	7373	777	53433	869	7347	774	-3	0.11
1979	JAN	Jan-79	49664	808	6829	888	49472	805	6802	884	-3	0.13
1979	FEB	Feb-79	50049	901	6882	447	49856	898	6855	446	-2	0.07
1979	MAR	Mar-79	61728	1004	8487	382	61535	1001	8461	381	-1	0.05
1979	APR	Apr-79	80714	1356	11098	499	81913	1377	11263	507	7	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	64845	1090	8916	523	0	0.06
1979	OCT	Oct-79	64083	1042	8811	342	64083	1042	8811	342	0	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70147	1179	9645	627	0	0.07
1979	DEC	Dec-79	67970	1105	9346	985	67985	1106	9348	985	0	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67142	1092	9232	1200	0	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62104	1080	8539	555	0	0.07
1980	MAR	Mar-80	63444	1032	8723	393	63460	1032	8726	393	0	0.05
1980	APR	Apr-80	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05

Table 7
SHOSHONE POWER PLANT
Foregone Power Revenues: Total Release from Granby Reservoir

1980 JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980 AUG	Aug-80	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1980 SEP	Sep-80	70872	1191	9745	572	70907	1192	9750	572	0	0.06
1980 OCT	Oct-80	59823	973	8226	319	59839	973	8228	319	0	0.04
1980 NOV	Nov-80	63271	1063	8700	566	63278	1063	8701	566	0	0.07
1980 DEC	Dec-80	59613	969	8197	864	59618	970	8197	864	0	0.11
1981 JAN	Jan-81	51581	839	7092	922	51584	839	7093	922	0	0.13
1981 FEB	Feb-81	46680	841	6418	417	46682	841	6419	417	0	0.07
1981 MAR	Mar-81	50048	814	6881	310	50049	814	6882	310	0	0.05
1981 APR	Apr-81	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1981 MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981 JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981 JUL	Jul-81	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1981 AUG	Aug-81	69790	1135	9596	1026	69790	1135	9596	1026	0	0.11
1981 SEP	Sep-81	63221	1062	8693	510	63221	1062	8693	510	0	0.06
1981 OCT	Oct-81	61933	1007	8516	330	61933	1007	8516	330	0	0.04
1981 NOV	Nov-81	51751	870	7116	463	51751	870	7116	463	0	0.07
1981 DEC	Dec-81	45812	745	6299	664	45812	745	6299	664	0	0.11
1982 JAN	Jan-82	44243	720	6083	791	44243	720	6083	791	0	0.13
1982 FEB	Feb-82	38976	702	5359	348	38976	702	5359	348	0	0.07
1982 MAR	Mar-82	50770	826	6981	314	50770	826	6981	314	0	0.05
1982 APR	Apr-82	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1982 MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982 JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982 JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982 AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982 SEP	Sep-82	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1982 OCT	Oct-82	82000	1334	11275	437	82000	1334	11275	437	0	0.04
1982 NOV	Nov-82	80279	1349	11038	718	80279	1349	11038	718	0	0.07
1982 DEC	Dec-82	68395	1112	9404	991	68395	1112	9404	991	0	0.11
1983 JAN	Jan-83	64588	1050	8881	1154	64588	1050	8881	1154	0	0.13
1983 FEB	Feb-83	60401	1088	8305	540	60401	1088	8305	540	0	0.07
1983 MAR	Mar-83	68328	1111	9395	423	68328	1111	9395	423	0	0.05
1983 APR	Apr-83	70275	1181	9663	435	70275	1181	9663	435	0	0.05
1983 MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983 JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983 JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983 AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983 SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983 OCT	Oct-83	81342	1323	11184	434	81342	1323	11184	434	0	0.04
1983 NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983 DEC	Dec-83	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1984 JAN	Jan-84	75666	1231	10404	1353	75368	1226	10363	1347	-5	0.13
1984 FEB	Feb-84	74251	1291	10209	664	73953	1286	10168	661	-3	0.07
1984 MAR	Mar-84	71770	1167	9868	444	71474	1162	9828	442	-2	0.05
1984 APR	Apr-84	79696	1339	10958	493	79696	1339	10958	493	0	0.05
1984 MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984 JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984 JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984 AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984 SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984 OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984 NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984 DEC	Dec-84	85925	1397	11815	1245	85925	1397	11815	1245	0	0.11
1985 JAN	Jan-85	80865	1315	11119	1445	80865	1315	11119	1445	0	0.13
1985 FEB	Feb-85	76628	1380	10536	685	76628	1380	10536	685	0	0.07
1985 MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985 MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985 JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985 AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985 SEP	Sep-85	75129	1263	10330	606	75129	1263	10330	606	0	0.06
1985 OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985 NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985 DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986 JAN	Jan-86	85651	1393	11777	1531	85651	1393	11777	1531	0	0.13
1986 FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986 MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986 MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986 JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06

Table 7
SHOSHONE POWER PLANT
Foregone Power Revenues: Total Release from Granby Reservoir

1986 AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986 SEP	Sep-86	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1986 OCT	Oct-86	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1986 NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986 DEC	Dec-86	78786	1281	10833	1142	78785	1281	10833	1142	0	0.11
1987 JAN	Jan-87	69058	1123	9495	1234	69057	1123	9495	1234	0	0.13
1987 FEB	Feb-87	66954	1206	9206	598	66953	1206	9206	598	0	0.07
1987 MAR	Mar-87	77469	1260	10652	479	77468	1260	10652	479	0	0.05
1987 APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987 MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987 JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987 JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987 AUG	Aug-87	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1987 SEP	Sep-87	62419	1049	8582	503	62419	1049	8582	503	0	0.06
1987 OCT	Oct-87	63624	1035	8748	339	63623	1035	8748	339	0	0.04
1987 NOV	Nov-87	79093	1329	10875	707	79093	1329	10875	707	0	0.07
1987 DEC	Dec-87	68906	1121	9474	999	68905	1121	9474	999	0	0.11
1988 JAN	Jan-88	70055	1139	9632	1252	70055	1139	9632	1252	0	0.13
1988 FEB	Feb-88	64279	1117	8838	574	64279	1117	8838	574	0	0.07
1988 MAR	Mar-88	71897	1169	9886	445	71896	1169	9886	445	0	0.05
1988 APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988 MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988 JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988 JUL	Jul-88	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1988 AUG	Aug-88	81837	1331	11252	1203	81837	1331	11252	1203	0	0.11
1988 SEP	Sep-88	56113	943	7715	453	56112	943	7715	453	0	0.06
1988 OCT	Oct-88	71010	1155	9764	379	71010	1155	9764	379	0	0.04
1988 NOV	Nov-88	60510	1017	8320	541	60510	1017	8320	541	0	0.07
1988 DEC	Dec-88	56962	926	7832	826	56962	926	7832	826	0	0.11
1989 JAN	Jan-89	59364	965	8162	1061	59364	965	8162	1061	0	0.13
1989 FEB	Feb-89	52009	936	7151	465	52009	936	7151	465	0	0.07
1989 MAR	Mar-89	76345	1242	10497	472	76345	1242	10497	472	0	0.05
1989 APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989 MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989 JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989 JUL	Jul-89	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1989 AUG	Aug-89	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1989 SEP	Sep-89	54165	910	7448	437	54165	910	7448	437	0	0.06
1989 OCT	Oct-89	51573	839	7091	275	51573	839	7091	275	0	0.04
1989 NOV	Nov-89	61037	1026	8392	546	61037	1026	8392	546	0	0.07
1989 DEC	Dec-89	61907	1007	8512	897	61907	1007	8512	897	0	0.11
1990 JAN	Jan-90	57901	942	7961	1035	57901	942	7961	1035	0	0.13
1990 FEB	Feb-90	49568	893	6816	443	49568	893	6816	443	0	0.07
1990 MAR	Mar-90	62558	1017	8602	387	62558	1017	8602	387	0	0.05
1990 APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990 MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990 JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990 JUL	Jul-90	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1990 AUG	Aug-90	78519	1277	10796	1154	78519	1277	10796	1154	0	0.11
1990 SEP	Sep-90	62931	1058	8653	508	62931	1058	8653	508	0	0.06
1990 OCT	Oct-90	63305	1030	8704	338	63305	1030	8704	338	0	0.04
1990 NOV	Nov-90	60470	1016	8315	541	60469	1016	8314	541	0	0.07
1990 DEC	Dec-90	53934	877	7416	782	53933	877	7416	782	0	0.11
1991 JAN	Jan-91	49706	808	6834	888	49705	808	6834	888	0	0.13
1991 FEB	Feb-91	46476	837	6390	415	46475	837	6390	415	0	0.07
1991 MAR	Mar-91	52128	848	7167	323	52128	848	7167	323	0	0.05
1991 APR	Apr-91	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1991 MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991 JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991 JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991 AUG	Aug-91	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1991 SEP	9/1	71767	1206	9868	579	71767	1206	9868	579	0	0.06

Totals	$ 137,670,795	$ 137,623,571
Difference		-$47,225
Average Annual		-$2,778

TECHNICAL MEMORANDUM NO. 8:
INVESTIGATION OF ALTERNATIVE 5A, EAST SLOPE POWER OPERATIONS AND SCHEDULING AND ALTERNATIVE 1D, WEST SLOPE FACILITIES OPERATIONS

DRAFT

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OCTOBER 2001

TECHNICAL MEMORANDUM NO. 8:
INVESTIGATION OF ALTERNATIVE 5A, EAST SLOPE POWER OPERATIONS AND SCHEDULING AND ALTERNATIVE 1D, WEST SLOPE FACILITIES OPERATIONS

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Figure 1: Granby Reservoir Storage

Figure 2: Adams Tunnel Deliveries

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Table 1: Shoshone Power Plant Foregone Revenues: Total Release from Granby Reservoir

EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 8 is to present the results from the investigation of Alternative 5a, East Slope Power Operations and Scheduling, and Alternative 1d, West Slope Facilities Operations.

These alternatives as originally conceived (Colorado Water Conservation Board, September 2000) involved rescheduling a portion of winter Colorado-Big Thompson (CBT) deliveries of water for irrigation and other beneficial uses from the west slope to the east slope via the Adams Tunnel until later in the spring and summer. Specifically these alternatives involved:

- Releases from Granby Reservoir for transmission through the Adams Tunnel would be reduced by 5,000 acre-feet per month for the months of November through February for a total of 20,000 acre-feet.

- Some portion of this delayed 20,000 acre-feet of releases could be replaced through diversion under the priorities of Northern Colorado Water Conservancy District's (NCWCD) east slope water rights.

- Beginning in March, the portion of the delayed 20,000 acre-feet that could not be replaced through diversion under NCWCD's east slope water rights would then be released from Granby Reservoir and transported to the east slope via the Adams Tunnel during the March through June period at a rate depending on available capacity in the Adams Tunnel.

- The 20,000 acre-feet release to the 15-Mile Reach would be made from Granby Reservoir during the May-June period in the eight years during the study period when this release could have been required.

These alternatives cannot be fully investigated using StateMod and the C1 data set because StateMod and the C1 data set only cover the Colorado River basin in Colorado and do not extend to east slope facilities and systems. Specifically, StateMod and the C1 data set cannot be used to determine the quantity of deliveries through the Adams Tunnel that could be replaced through use of NCWCD's east slope water rights.

Investigation of these alternatives has been complicated by the October 6, 2000 letter from the Colorado River Water Conservation District to the Colorado State Engineer which alleges that the CBT Project has been operated in a manner that is inconsistent with Senate Document 80 by failing to use the CBT's east slope water rights. This letter states Senate Document 80 contemplated the use of snowmelt run-off forecasts to determine the amount of space that should be reserved in east slope reservoirs for storage of water diverted from east slope rivers and streams. The feasibility of changing CBT operations in response to the October 6, 2000 Colorado River Water Conservation District letter is challenged by the Bureau of Reclamation in its October 12, 2001 response to the October 6, 2000 River District letter. Specifically, the Bureau of Reclamation concludes that it is not feasible for a number of reasons to delay winter and early spring deliveries of west slope water to the east slope via the Adams Tunnel in order to keep east slope reservoir

storage relatively low. Furthermore, the Bureau of Reclamation recommends in its October 12, 2001 letter that, "…the re-timing of pre-emptive spills from Granby Reservoir to add to the spring peak flows for the 15-Mile Reach of the Colorado River be examined within the context of CFOPS" (p. 6 October 12, 2001 letter). Therefore, as a result of these findings and conclusions by the Bureau of Reclamation, analysis of Alternative 5a is directed toward the feasibility of supplying all or a portion of the 20,000 acre-feet to the 15-Mile Reach without delaying winter and early spring deliveries to the east slope via the Adams tunnel.

Analysis completed for Alternatives 1f, Bypass Diversions to Storage, and 1g, Reduce Constraints on CROP, and reported in Technical Memorandum No. 7 (CWCB, October 2001) provides results which characterize the feasibility of Alternatives 5a and 1d with respect to: (1) providing sufficient water in Granby Reservoir to make the 20,000 acre-feet release to the 15-Mile Reach in the eight years during the study period when the release could be required, and (2) the effects on Granby Reservoir and other west slope facilities and operations from making this 20,000 acre-feet release entirely from Granby Reservoir. These results from Technical Memorandum 7 include:

1. Granby Reservoir had sufficient available stored water to make the 20,000 acre-feet release for all eight years during the 1974-91 study period when the release could have been required.

2. The primary effect on Granby Reservoir storage from making the 20,000 acre-feet release during eight years of the 1974-91 study period was to reduce annual average storage in Granby Reservoir by approximately 16,000 acre-feet for the period 1979-1982.

3. There was no measurable effect on storage in other west slope reservoirs from making the 20,000 acre-feet release from Granby.

4. Hydropower generation at the Shoshone Power Plant was reduced by approximately $47,000 for the study period, or approximately $2,800 per year.

5. There was no effect on Adams Tunnel deliveries from making the 20,000 acre-feet release.

The following conclusions and recommendations are based on this additional information received from NCWCD and the analysis completed in Technical Memorandum No. 7:

- Relying on Granby Reservoir for supplying the 20,000 acre-feet to the 15-Mile Reach appears feasible. The reservoir could supply the 20,000 acre-feet in the eight years during the study period when these releases could be required.
- It is recommended that the alternative using Granby Reservoir as the sole source of supply for the 20,000 acre-feet be further considered. This recommendation is consistent with that made in Technical Memorandum 7 where the feasibility of using Granby Reservoir as the sole source for the 20,000 acre-feet release to the 15-Mile Reach was investigated and found to be worthy of further consideration.
- If the 16,000 acre-feet average annual reduction in Granby Reservoir storage resulting from making the 20,000 acre-feet release during eight years of the 1974-91 study

period is unacceptable, this storage reduction can be reduced by distributing responsibility for making a portion of this release to other reservoirs.

- The feasibility of supplying all, or a portion of, the 20,000 acre-feet for the 15-Mile Reach from Granby Reservoir will need to be further considered by the Executive Committee from institutional, operational and legal perspectives.

INTRODUCTION AND PURPOSE

The Phase 1 investigation (CWCB, September 2000) recommended that Alternative 5a, East Slope Power Operations and Scheduling, and Alternative 1d, West Slope Facilities Operations, should be investigated. As originally conceived in the Phase 1 investigation, Alternatives 5a and 1d involved rescheduling some portion of winter CBT deliveries of water for irrigation and other beneficial uses from the west slope to the east slope CBT facilities until March through June. These winter deliveries are also used for power generation purposes and provide power to meet peak winter power demands.

Investigation of this alternatives has been complicated by the October 6, 2000 letter from the Colorado River Water Conservation District to the Colorado State Engineer, which states that the CBT Project has been operated in a manner that is inconsistent with Senate Document 80 by failing to use the CBT's east slope water rights. This letter further states Senate Document 80 contemplated the use of snowmelt run-off forecasts to determine the amount of space that should be reserved in east slope reservoirs for storage of water diverted from east slope rivers and streams. The feasibility of changing CBT operations as recommended in the October 6, 2000 Colorado River Water Conservation District letter is challenged by the Bureau of Reclamation in its October 12, 2001 response to the October 6, 2000 River District letter. Specifically, the Bureau of Reclamation concludes that it is not feasible for a number of reasons to delay winter and early spring deliveries of west slope water to the east slope via the Adams Tunnel in order to keep east slope reservoir storage relatively low. Furthermore, the Bureau of Reclamation recommends in its October 12, 2001 letter that, "…the re-timing of pre-emptive spills from Granby Reservoir to add to the spring peak flows for the 15-Mile Reach of the Colorado River be examined within the context of CFOPS" (p. 6 October 12, 2001 letter). Therefore, as a result of these findings and conclusions by the Bureau of Reclamation, analysis of Alternative 5a is directed toward the feasibility of supplying all or a portion of the 20,000 acre-feet to the 15-Mile Reach from Granby Reservoir without delaying winter and early spring deliveries to the east slope via the Adams tunnel.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following general procedures, tools, and assumptions were employed in the analysis of Alternatives 5a and 1d:

1. The StateMod surface water model (which is limited to the Colorado River Basin) and the C1 data set were used for baseline hydrology for the period 1975-1991, using a monthly time step.
2. Because StateMod and the associated C1 data set are limited to the Colorado River basin, it was only possible to analyze the effects of Alternatives 5a and 1d on facilities in the Colorado River basin and not on east slope facilities.
3. The baseline conditions were the StateMod C1 scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000)*. These components of RIPRAP flows include:
    - 5,000 acre-feet per year from Ruedi Reservoir,
    - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
    - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
    - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
    - 6,000 acre-feet per year from Wolford Mountain Reservoir, and
    - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated on the C1 data set but not modeled.
4. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee review the analysis and any revisions made by the consultant and determine that the methodology and calculations employed in the analysis of Alternative 5a are acceptable, the necessary sensitivity analysis will be completed.

CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

5. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.
6. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

   The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

7. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,
   - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
   - A reservoir fill according to the criteria of the Blue River Decree.

   The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

   Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

   Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

8. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
   - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and

- Sufficient HUP Surplus water exists to make the release.

Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. StateMod and the C1 data set do not explicitly model releases of HUP Surplus water under the Municipal Recreational Agreement and there is no demand specified at a node for the Municipal Recreational water.

SPECIFIC PROCEDURES

Making the total 20,000 acre-feet release to the 15-Mile Reach from Granby Reservoir was analyzed in Technical Memorandum No. 7 (Colorado Water Conservation Board, October 2001). The specific analysis procedures employed are described in Technical Memorandum No. 7, but primarily included:

- The 20,000 acre-feet release to the 15-Mile Reach was made during the May-June period in the eight years during the study period when this release could have been required.
- These results were then compared to the base case, the C1 data set, to determine the effects of Alternative 5a on west slope facilities and operations.

USE OF STATEMOD

The use of StateMod for this analysis is described in Technical Memorandum No. 7 (Colorado Water Conservation Board, October 2001).

RESULTS

EFFECTS ON WEST SLOPE RESERVOIR STORAGE

The only west slope reservoir storage affected by this alternative is Granby Reservoir storage (see Figure 1). Making the entire 20,000 acre-feet release from Granby Reservoir resulted in an annual average decrease in storage of approximately 16,000 acre-feet for the 1974-91 study period.

EFFECTS ON WEST SLOPE POWER GENERATION

Shoshone Power Plant

Table 1 indicates the total foregone power revenue from Shoshone Power Plant for the 1975-91 study period for Alternatives 5a and 1d operations policy is approximately $42,000, or approximately $2,800 per year.

Orchard Mesa Power Plant

The Alternatives 5a and 1d operations policy did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternatives 5a and 1d operations policy.

EFFECT ON ADAMS TUNNEL DELIVERIES

Figure 2 indicates there were no effects on Adams Tunnel deliveries from the Alternatives 5a and 1d operations policy except for March 1978 when there was approximately 8,500 acre-feet more water delivered through the Adams Tunnel under the Alternative 5a and 1d operations policy.

The reasons for StateMod estimating this additional Adams Tunnel delivery in only March 1978 is not completely understood. This is due to an increase in the exchange from Green Mountain Reservoir to Granby Reservoir from Dec 1977 to March 1978. This, in turn, allows an increase in the exchange from Granby Reservoir to the Adams Tunnel in March 1978. It is unclear at this time why StateMod (or the priority system) allows this but it does not appear to have any impact on the overall objective of evaluating the impact of various alternatives for providing the 20,000 acre-foot release for the 15- Mile Reach. Consequently, we have concluded that State Mod with the C1 data set is providing a reasonable estimate of Adams Tunnel deliveries in all months other than March 1978 and that this unexplained increase in Adams Tunnel Deliveries in March 1978 does not bias the overall findings from these model runs concerning the feasibility of Alternatives 5a and 1d.

OTHER WEST SLOPE EFFECTS

Shoshone Priority Calls

The frequency and duration of Shoshone priority calls were not altered to any measurable degree by implementation of the Alternatives 5a and 1d operations policy for the 1975-91 study period.

Check Case Settlement

Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternative 1f and 1g operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternative 5a and 1d operations policy should not affect the Check Case settlement.

Channel Capacity Constraints

Results produced herein indicate that the additional releases and/or bypasses of diversions to storage could be made from each of the reservoirs without violating channel flow constraints on: (1) the Blue River or Colorado River downstream from Green Mountain Reservoir and (2) on the Frying Pan River downstream from Ruedi Reservoir.

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CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on this additional information received from NCWCD and the analysis completed in Technical Memorandum No. 7:

1. Relying on Granby Reservoir for supplying the 20,000 acre-feet releases to the 15-Mile Reach appears feasible. The reservoir could supply these releases in the eight years during the study period when these releases could be required.

2. There do not appear to be any fatal flaws which would preclude further consideration of this alternative.

3. It is recommended that the alternative using Granby Reservoir as the sole source of supply for making the 20,000 acre-feet release be further considered. This recommendation is consistent with that made in Technical Memorandum 7 where the feasibility of using Granby Reservoir as the sole source for the 20,000 acre-feet release to the 15-Mile Reach was investigated.

4. If the 16,000 acre-feet average annual reduction in Granby Reservoir storage resulting from making the 20,000 acre-feet release during eight years of the 1974-91 study period is unacceptable, this storage deficiency can be reduced by distributing responsibility for making a portion of this release to other reservoirs.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River*.

Colorado Water Conservation Board, October 2001, *Technical Memorandum No. 7, Investigation of Alternative 1f, Bypass Diversions to Storage, and Alternative 1g, Reduce Constraints on CROP Draft.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1

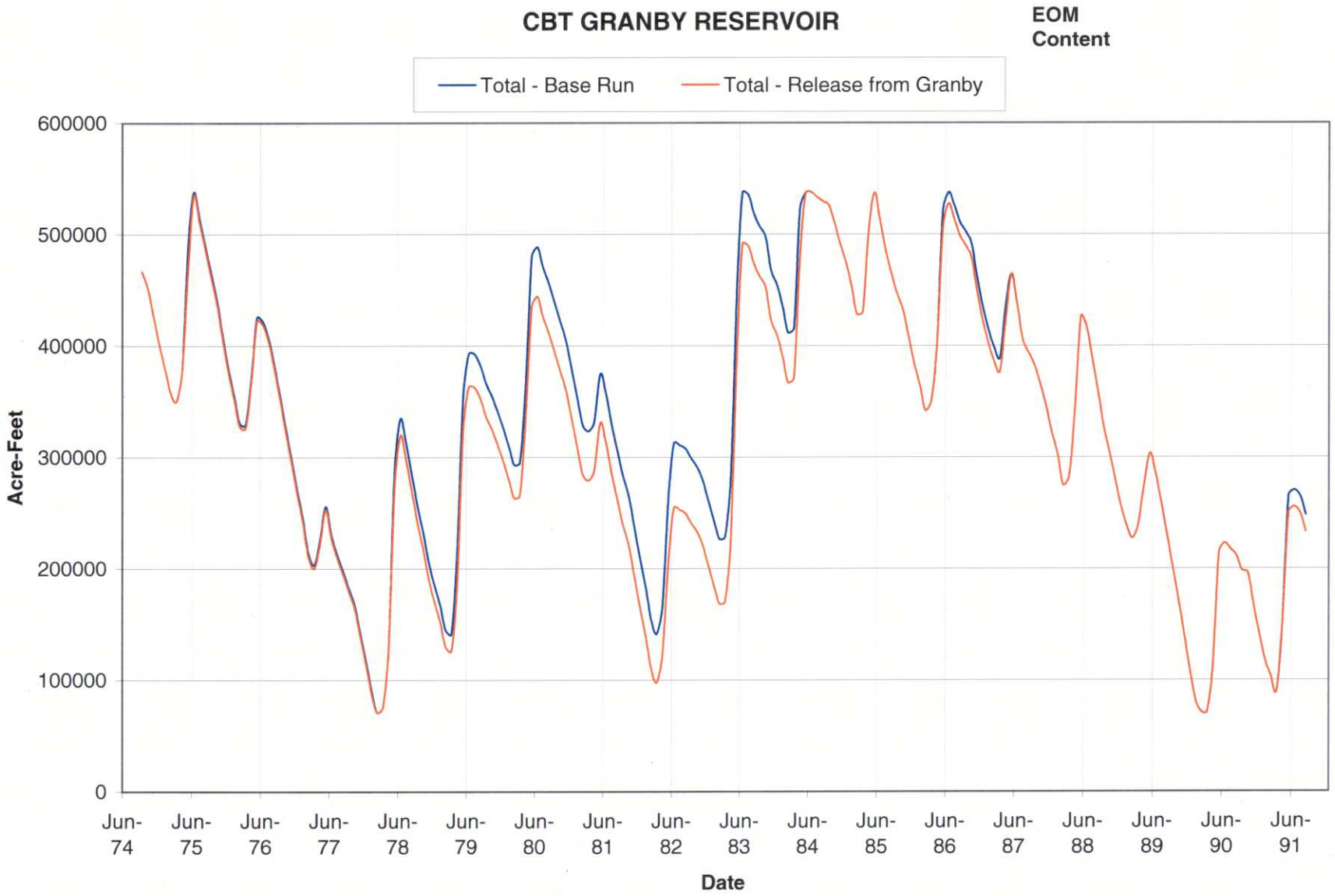
CBT GRANBY RESERVOIR
EOM Content
Total - Base Run
Total - Release from Granby
600000
500000
400000
300000
200000
100000
0
Acre-Feet
Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Figure 2

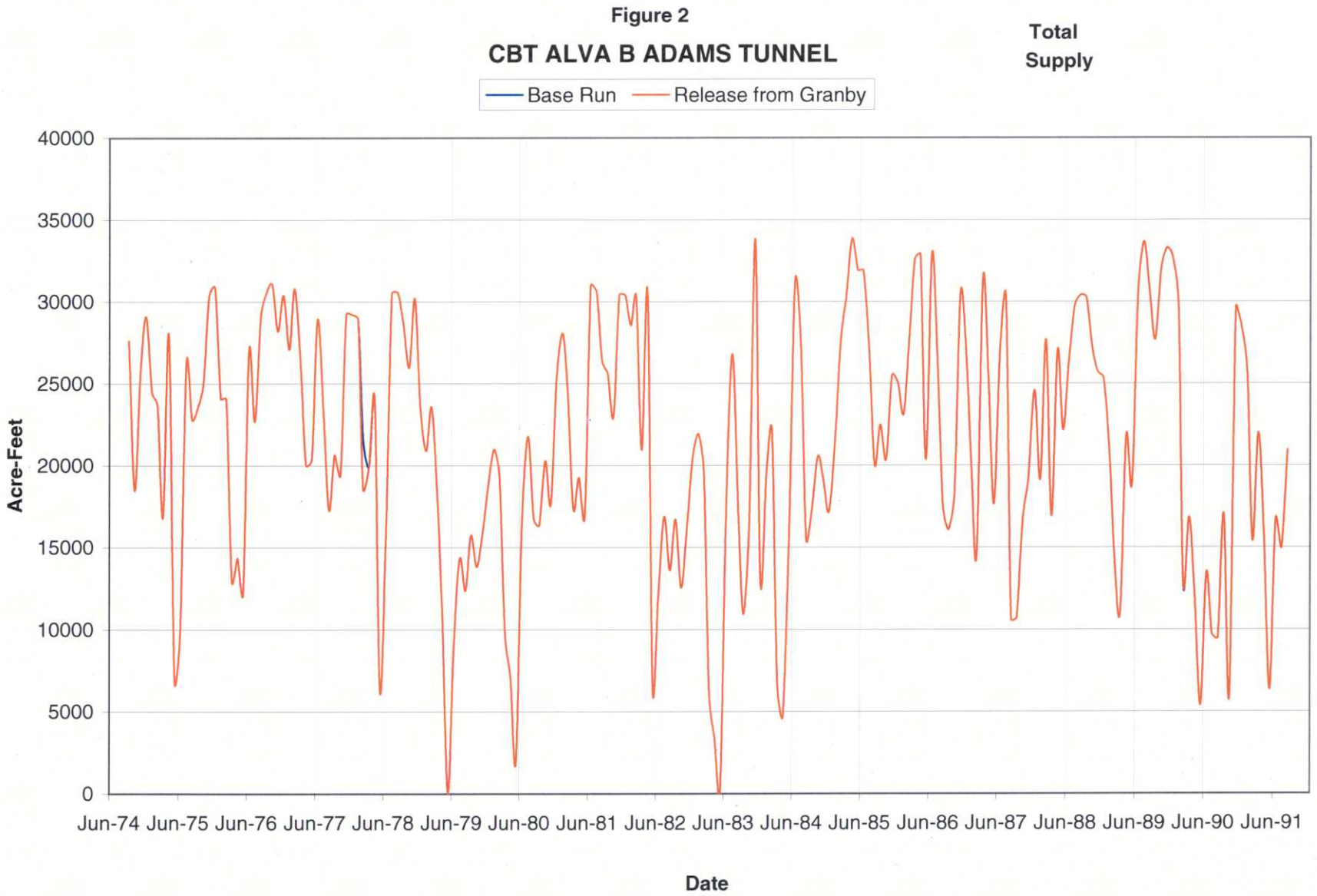
CBT ALVA B ADAMS TUNNEL
Total Supply
Base Run
Release from Granby
40000
35000
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Table 1
SHOSHONE POWER PLANT
Foregone Power Revenues: Total Release from Granby Reservoir

			Base				Granby Release					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	66970	1089	9208	357	0	0.04
1974	NOV	Nov-74	66071	1110	9085	591	66071	1110	9085	591	0	0.07
1974	DEC	Dec-74	61830	1006	8502	896	61830	1006	8502	896	0	0.11
1975	JAN	Jan-75	59899	974	8236	1071	59899	974	8236	1071	0	0.13
1975	FEB	Feb-75	58476	1053	8040	523	58476	1053	8040	523	0	0.07
1975	MAR	Mar-75	61181	995	8412	379	61181	995	8412	379	0	0.05
1975	APR	Apr-75	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1975	OCT	Oct-75	70098	1140	9638	374	70098	1140	9638	374	0	0.04
1975	NOV	Nov-75	79448	1335	10924	710	79448	1335	10924	710	0	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	71743	1167	9865	1040	0	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	68497	1114	9418	1224	0	0.13
1976	FEB	Feb-76	70614	1228	9709	631	70614	1228	9709	631	0	0.07
1976	MAR	Mar-76	76631	1246	10537	474	76631	1246	10537	474	0	0.05
1976	APR	Apr-76	82638	1389	11363	511	82638	1389	11363	511	0	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1976	SEP	Sep-76	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1976	OCT	Oct-76	74383	1210	10228	397	74383	1210	10228	397	0	0.04
1976	NOV	Nov-76	59697	1003	8208	534	59697	1003	8208	534	0	0.07
1976	DEC	Dec-76	49447	804	6799	717	49447	804	6799	717	0	0.11
1977	JAN	Jan-77	47151	767	6483	843	47151	767	6483	843	0	0.13
1977	FEB	Feb-77	47230	850	6494	422	47230	850	6494	422	0	0.07
1977	MAR	Mar-77	49872	811	6857	309	49872	811	6857	309	0	0.05
1977	APR	Apr-77	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1977	MAY	May-77	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1977	JUN	Jun-77	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1977	JUL	Jul-77	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1977	SEP	Sep-77	52714	886	7248	425	52714	886	7248	425	0	0.06
1977	OCT	Oct-77	58234	947	8007	311	58234	947	8007	311	0	0.04
1977	NOV	Nov-77	45851	771	6304	410	45851	771	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	46458	756	6388	673	0	0.11
1978	JAN	Jan-78	45729	744	6288	817	44236	719	6082	791	-27	0.13
1978	FEB	Feb-78	39553	712	5438	353	38061	685	5233	340	-13	0.07
1978	MAR	Mar-78	53027	862	7291	328	51543	838	7087	319	-9	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	85812	1396	11799	1262	14	0.11
1978	SEP	Sep-78	65053	1093	8945	525	65053	1093	8945	525	0	0.06
1978	OCT	Oct-78	60476	984	8315	322	60476	984	8315	322	0	0.04
1978	NOV	Nov-78	63938	1074	8791	572	63746	1071	8765	570	-2	0.07
1978	DEC	Dec-78	53625	872	7373	777	53433	869	7347	774	-3	0.11
1979	JAN	Jan-79	49664	808	6829	888	49472	805	6802	884	-3	0.13
1979	FEB	Feb-79	50049	901	6882	447	49856	898	6855	446	-2	0.07
1979	MAR	Mar-79	61728	1004	8487	382	61535	1001	8461	381	-1	0.05
1979	APR	Apr-79	80714	1356	11098	499	81913	1377	11263	507	7	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	64845	1090	8916	523	0	0.06
1979	OCT	Oct-79	64083	1042	8811	342	64083	1042	8811	342	0	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70147	1179	9645	627	0	0.07
1979	DEC	Dec-79	67970	1105	9346	985	67985	1106	9348	985	0	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67142	1092	9232	1200	0	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62104	1080	8539	555	0	0.07
1980	MAR	Mar-80	63444	1032	8723	393	63460	1032	8726	393	0	0.05
1980	APR	Apr-80	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05

Table 1
SHOSHONE POWER PLANT
Foregone Power Revenues: Total Release from Granby Reservoir

1980	JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980	AUG	Aug-80	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1980	SEP	Sep-80	70872	1191	9745	572	70907	1192	9750	572	0	0.06
1980	OCT	Oct-80	59823	973	8226	319	59839	973	8228	319	0	0.04
1980	NOV	Nov-80	63271	1063	8700	566	63278	1063	8701	566	0	0.07
1980	DEC	Dec-80	59613	969	8197	864	59618	970	8197	864	0	0.11
1981	JAN	Jan-81	51581	839	7092	922	51584	839	7093	922	0	0.13
1981	FEB	Feb-81	46680	841	6418	417	46682	841	6419	417	0	0.07
1981	MAR	Mar-81	50048	814	6881	310	50049	814	6882	310	0	0.05
1981	APR	Apr-81	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1981	MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981	JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981	JUL	Jul-81	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1981	AUG	Aug-81	69790	1135	9596	1026	69790	1135	9596	1026	0	0.11
1981	SEP	Sep-81	63221	1062	8693	510	63221	1062	8693	510	0	0.06
1981	OCT	Oct-81	61933	1007	8516	330	61933	1007	8516	330	0	0.04
1981	NOV	Nov-81	51751	870	7116	463	51751	870	7116	463	0	0.07
1981	DEC	Dec-81	45812	745	6299	664	45812	745	6299	664	0	0.11
1982	JAN	Jan-82	44243	720	6083	791	44243	720	6083	791	0	0.13
1982	FEB	Feb-82	38976	702	5359	348	38976	702	5359	348	0	0.07
1982	MAR	Mar-82	50770	826	6981	314	50770	826	6981	314	0	0.05
1982	APR	Apr-82	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1982	MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982	JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982	JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982	AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982	SEP	Sep-82	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1982	OCT	Oct-82	82000	1334	11275	437	82000	1334	11275	437	0	0.04
1982	NOV	Nov-82	80279	1349	11038	718	80279	1349	11038	718	0	0.07
1982	DEC	Dec-82	68395	1112	9404	991	68395	1112	9404	991	0	0.11
1983	JAN	Jan-83	64588	1050	8881	1154	64588	1050	8881	1154	0	0.13
1983	FEB	Feb-83	60401	1088	8305	540	60401	1088	8305	540	0	0.07
1983	MAR	Mar-83	68328	1111	9395	423	68328	1111	9395	423	0	0.05
1983	APR	Apr-83	70275	1181	9663	435	70275	1181	9663	435	0	0.05
1983	MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983	JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983	JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983	AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983	SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983	OCT	Oct-83	81342	1323	11184	434	81342	1323	11184	434	0	0.04
1983	NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983	DEC	Dec-83	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1984	JAN	Jan-84	75666	1231	10404	1353	75368	1226	10363	1347	-5	0.13
1984	FEB	Feb-84	74251	1291	10209	664	73953	1286	10168	661	-3	0.07
1984	MAR	Mar-84	71770	1167	9868	444	71474	1162	9828	442	-2	0.05
1984	APR	Apr-84	79696	1339	10958	493	79696	1339	10958	493	0	0.05
1984	MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984	JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984	JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984	AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984	SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984	OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984	NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984	DEC	Dec-84	85925	1397	11815	1245	85925	1397	11815	1245	0	0.11
1985	JAN	Jan-85	80865	1315	11119	1445	80865	1315	11119	1445	0	0.13
1985	FEB	Feb-85	76628	1380	10536	685	76628	1380	10536	685	0	0.07
1985	MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985	APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985	MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985	JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985	JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985	AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985	SEP	Sep-85	75129	1263	10330	606	75129	1263	10330	606	0	0.06
1985	OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985	NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985	DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986	JAN	Jan-86	85651	1393	11777	1531	85651	1393	11777	1531	0	0.13
1986	FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986	MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986	APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986	MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986	JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986	JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06

Table 1
SHOSHONE POWER PLANT
Foregone Power Revenues: Total Release from Granby Reservoir

1986 AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986 SEP	Sep-86	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1986 OCT	Oct-86	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1986 NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986 DEC	Dec-86	78786	1281	10833	1142	78785	1281	10833	1142	0	0.11
1987 JAN	Jan-87	69058	1123	9495	1234	69057	1123	9495	1234	0	0.13
1987 FEB	Feb-87	66954	1206	9206	598	66953	1206	9206	598	0	0.07
1987 MAR	Mar-87	77469	1260	10652	479	77468	1260	10652	479	0	0.05
1987 APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987 MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987 JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987 JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987 AUG	Aug-87	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1987 SEP	Sep-87	62419	1049	8582	503	62419	1049	8582	503	0	0.06
1987 OCT	Oct-87	63624	1035	8748	339	63623	1035	8748	339	0	0.04
1987 NOV	Nov-87	79093	1329	10875	707	79093	1329	10875	707	0	0.07
1987 DEC	Dec-87	68906	1121	9474	999	68905	1121	9474	999	0	0.11
1988 JAN	Jan-88	70055	1139	9632	1252	70055	1139	9632	1252	0	0.13
1988 FEB	Feb-88	64279	1117	8838	574	64279	1117	8838	574	0	0.07
1988 MAR	Mar-88	71897	1169	9886	445	71896	1169	9886	445	0	0.05
1988 APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988 MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988 JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988 JUL	Jul-88	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1988 AUG	Aug-88	81837	1331	11252	1203	81837	1331	11252	1203	0	0.11
1988 SEP	Sep-88	56113	943	7715	453	56112	943	7715	453	0	0.06
1988 OCT	Oct-88	71010	1155	9764	379	71010	1155	9764	379	0	0.04
1988 NOV	Nov-88	60510	1017	8320	541	60510	1017	8320	541	0	0.07
1988 DEC	Dec-88	56962	926	7832	826	56962	926	7832	826	0	0.11
1989 JAN	Jan-89	59364	965	8162	1061	59364	965	8162	1061	0	0.13
1989 FEB	Feb-89	52009	936	7151	465	52009	936	7151	465	0	0.07
1989 MAR	Mar-89	76345	1242	10497	472	76345	1242	10497	472	0	0.05
1989 APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989 MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989 JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989 JUL	Jul-89	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1989 AUG	Aug-89	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1989 SEP	Sep-89	54165	910	7448	437	54165	910	7448	437	0	0.06
1989 OCT	Oct-89	51573	839	7091	275	51573	839	7091	275	0	0.04
1989 NOV	Nov-89	61037	1026	8392	546	61037	1026	8392	546	0	0.07
1989 DEC	Dec-89	61907	1007	8512	897	61907	1007	8512	897	0	0.11
1990 JAN	Jan-90	57901	942	7961	1035	57901	942	7961	1035	0	0.13
1990 FEB	Feb-90	49568	893	6816	443	49568	893	6816	443	0	0.07
1990 MAR	Mar-90	62558	1017	8602	387	62558	1017	8602	387	0	0.05
1990 APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990 MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990 JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990 JUL	Jul-90	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1990 AUG	Aug-90	78519	1277	10796	1154	78519	1277	10796	1154	0	0.11
1990 SEP	Sep-90	62931	1058	8653	508	62931	1058	8653	508	0	0.06
1990 OCT	Oct-90	63305	1030	8704	338	63305	1030	8704	338	0	0.04
1990 NOV	Nov-90	60470	1016	8315	541	60469	1016	8314	541	0	0.07
1990 DEC	Dec-90	53934	877	7416	782	53933	877	7416	782	0	0.11
1991 JAN	Jan-91	49706	808	6834	888	49705	808	6834	888	0	0.13
1991 FEB	Feb-91	46476	837	6390	415	46475	837	6390	415	0	0.07
1991 MAR	Mar-91	52128	848	7167	323	52128	848	7167	323	0	0.05
1991 APR	Apr-91	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1991 MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991 JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991 JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991 AUG	Aug-91	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1991 SEP	9/1	71767	1206	9868	579	71767	1206	9868	579	0	0.06

Totals	$ 137,670,795	$ 137,623,571
Difference		-$47,225
Average Annual		-$2,778

TECHNICAL MEMORANDUM NO. 9:
INVESTIGATION OF ALTERNATIVE 5B,
EXPANDED COORDINATED RESERVOIR OPRATIONS,
SHOSHONE POWER PLANT

DRAFT

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OCTOBER 2001

TECHNICAL MEMORANDUM NO. 9:
INVESTIGATION OF ALTERNATIVE 5B,
EXPANDED COORDINATED RESERVOIR OPRATIONS,
SHOSHONE POWER PLANT

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EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 9 is to present the results from the investigation of Alternative 5b, Expanded Coordinated Reservoir Operations: Shoshone Power Plant. As presented in the Phase 1 analysis (Colorado Water Conservation Board, September 2000), this alternative focused on the feasibility of:

- Removing the Shoshone priority call (1/7/1902 for 1,250 cfs and 5/15/1929 for 158 cfs).

- Using the additional water stored in upstream reservoirs as a result of removing the Shoshone priority call to offset any reduced storage in these nine reservoirs from making the 20,000 acre-feet release.

Discussion of this alternative in the Phase 1 investigation (Colorado Water Conservation Board, September 2000) indicated that this alternative could not be implemented as a selective call. Therefore, this investigation of Alternative 5a has focused on evaluating:

- The quantity of increased storage in eight reservoirs upstream from Shoshone (Dillon, Granby, Green Mountain, Homestake, Williams Fork, Willow Creek, Wolford Mountain and Vega) that would result from removing the Shoshone priority call for both water rights.

- The reduced storage in these eight reservoirs and the effects on other west slope facilities from removing the Shoshone priority call and making the 20,000 acre-feet release to the 15-Mile Reach in the nine years during the study period when this release could be required.

- The estimated cost of foregone power generation at the Shoshone Power Plant as a result of: (1) removal of the Shoshone call and (2) removal of the Shoshone call and making the 20,000 acre-feet release.

Increased storage in the eight reservoirs as a result of removing the Shoshone priority call for the 1974-91 study period is presented in Table ES-1. Table ES-1 presents the increase in storage, compared to the C1 base case scenario, from removing the Shoshone priority call. Data in Table ES-1 indicate a general increase in storage for the eight reservoirs with the exception of Willow Creek and Vega Reservoirs.

Table ES-1. Summary of Increased Reservoir Storage with Removal of Shoshone Priority Call

Reservoir	Ave. Monthly Increase in Storage[1] (acre-feet)
Dillon	2,667
Granby	2,879
Green Mountain	5,162
Homestake	11,471
Williams Fork	4,974
Willow Creek	-61
Wolford	1,640
Vega	-14

[1]average of monthly storage, 1974-1991

Data in Table ES-2 indicate the increases in reservoir storage, compared to the C1 base case scenario, resulting from removal of the Shoshone call and release of 20,000 acre-feet to the 15-Mile Reach in those eight years when this release could have been required during the 1974-91 study period. Responsibility for making the 20,000 acre-feet release was prorated among five reservoirs (Dillon, Granby, Green Mountain, Williams Fork and Wolford Mountain) on the basis of increased storage accrued to each reservoir as a result of removing the Shoshone priority call. Releases toward the 20,000 acre-feet target were not made from Homestake because of uncertainty concerning the adequacy of how StateMod and the C1 data set were modeling Homestake and the correctness of results involving this reservoir. No releases toward the 20,000 acre-feet target were specified for Willow Creek and Vega Reservoirs because of the absence of any increased storage accrued to these reservoirs from removal of the Shoshone priority call.

Table ES-2. Summary of Changes in Reservoir Storage from Removal of the Shoshone Call and Making 20,000 Acre-Feet Release to 15-Mile Reach[1]

Reservoir	Ave. Monthly Change in Storage[2] (acre-feet)
Dillon	2,703
Granby	2,445
Green Mountain	5,109
Homestake[3]	11,471
Williams Fork	4,902
Willow Creek[3]	-61
Wolford	1,439
Vega[3]	-14

[1] Reservoir Releases (acre-feet/year): Dillon, 3080; Granby, 3324; Gr. Mtn., 5960; Williams Fork, 5743; Wolford Mtn., 1894

[2]average of differences between annual peak storage values, 1974-1991.

[3]No releases toward the 20,000 acre-feet target were required from Homestake, Willow Creek and Vega Reservoirs.

Specific results from the StateMod/C1 analysis of Alternative 5b include:

- **Dillon Reservoir.** Average monthly storage in Dillon Reservoir was increased by 2,667 acre-feet during the 1974-91 study period by eliminating the Shoshone priority call. Eliminating the Shoshone priority call resulted in increased or equivalent storage in Dillon Reservoir as compared to the C1 base case in every year except for temporary periods during June 1977 through June 1978, and June 1981 through June 1982. During these periods drawdown in Dillon Reservoir was greater than the C1 base case. Comparison of storage in Williams Fork Reservoir with Dillon Reservoir for these periods indicate that this period of increased storage in Dillon resulted from the exchange of water to Dillon from Williams Fork during June 1977 to June 1978 and June 1981 to June 1982.

  Average monthly storage in Dillon Reservoir was increased by 2,703 acre-feet during the 1974-1991 study period by eliminating the Shoshone priority call and making a release of 3,080 acre-feet from Dillon towards the 20,000 acre-feet target release to the 15-Mile Reach. Eliminating the Shoshone priority call and making the proportionate release resulted in increased or equivalent storage in Dillon Reservoir as compared to the C1 base case in every year except for temporary periods during June 1977 through June 1978 and June 1981 through June 1982. During these periods drawdown in Dillon Reservoir was greater with elimination of the Shoshone priority call and making the proportionate release as compared to the base case. The reason for this apparent anomaly involves the exchange with Williams Fork, as described above.

- **Granby Reservoir.** Average monthly storage in Granby Reservoir was increased by 2,879 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call. Storage in Granby Reservoir with elimination of the Shoshone priority call was equal to, or greater than storage in the C1 base case in all years during the 1974-91 study period except for June 1981 through June 1983. During these periods, storage in Granby Reservoir for the C1 baseline scenario slightly exceeded the scenario in which the Shoshone priority call was eliminated. Brown and Caldwell believes the reason for this apparent anomaly involves how StateMod models the exchange between Green Mountain and Granby Reservoirs.

  Storage in Granby Reservoir as a result of eliminating the Shoshone priority call and making Granby Reservoir's proportionate share of the 20,000 acre-feet release for the 15-Mile Reach (3,324 acre-feet) was increased by an annual average of 2,445 acre feet. Eliminating the Shoshone priority call and making the proportionate release resulted in increased or equivalent storage in Granby Reservoir as compared to the C1 base case in every year except for a period from January 1981 through March 1983. During this period, drawdown in Granby Reservoir was greater with elimination of the Shoshone priority call and making the proportionate release as compared to the C1 base case. The reason for this apparent anomaly is likely the same as described in the previous scenario above.

- **Green Mountain Reservoir.** Average monthly storage in Green Mountain Reservoir was increased by 5,162 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call as compared to the C1 baseline scenario. Storage in Green Mountain Reservoir as a result of eliminating the Shoshone priority call was equivalent to, or greater than, storage in the C1 base case in all years of the study period.

  Average monthly storage in Green Mountain Reservoir was increased by 5,109 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call and making Green Mountain Reservoir's proportionate share of the 20,000 acre-feet release to the 15-Mile Reach (5,960 acre-feet) as compared to the C1 baseline scenario. Storage in Green Mountain Reservoir as a result of eliminating the Shoshone priority call and making the 5,960 acre-feet release was equivalent to, or greater than, storage in the C1 base case in all years of the study period.

  Eliminating the Shoshone priority call increased total power revenues from Green Mountain Reservoir for the 1974-91 study period by approximately $923,000 for an annual average increase of approximately $54,000 as compared to the C1 baseline scenario.

  Eliminating the Shoshone priority call and making the 5,960 acre-feet proportionate release to the 15-Mile Reach increased total power revenues from Green Mountain Reservoir for the 1974-91 study period by approximately $1.2 million for an annual average of approximately $71,000 as compared to the C1 baseline scenario.

- **Homestake Reservoir.** Average monthly storage in Homestake Reservoir was increased by 11,741 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call. Storage in Homestake Reservoir as a result of eliminating the Shoshone priority call was equivalent to, or greater than, storage in the C1 base case with the Shoshone priority call in all years of the study period.

  Review of estimated storage in Homestake Reservoir for the study period indicates apparently eroneous behavior of Homestake Reservoir during the 1980s, a wetter than average period. Brown and Caldwell believes this erroneous behavior of Homestake Reservoir is due to the inadequacies in the modeling of Homestake Reservoir by StateMod and the C1 data set. Brown and Caldwell does not believe that this problem with modeling Homestake Reservoir has biased the results of this analysis, other than those for Homestake Reservoir.

  Because of the suspected modeling problem, Homestake Reservoir was not required to make a proportionate share of the 20,000 acre-feet release to the 15-Mile Reach. Consequently, average monthly storage in Homestake Reservoir was not affected by making the 20,000 acre-feet release.

- **Williams Fork Reservoir.** Average monthly storage in Williams Fork Reservoir was increased by 4,974 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call as compared to the C1 baseline scenario. Storage in Williams

Fork Reservoir as a result of eliminating the Shoshone priority call was greater than, or equivalent, to storage in the C1 base run in all years of the study period.

Average monthly storage in Williams Fork Reservoir was increased by 4,902 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call and making Williams Forks Reservoir's proportionate share of the 20,000 acre-feet release (5,743 acre-feet) as compared to the C1 baseline scenario. Storage in Williams Fork Reservoir as a result of eliminating the Shoshone priority call and making the proportionate release was greater than, or equivalent, to storage in the C1 base run in all years of the study period.

- **Willow Creek Reservoir.** Average monthly storage in Willow Creek Reservoir was decreased by 61 acre-feet over the 1974-91 study period as a result of eliminating the Shoshone priority call. During the spring and early summer runoff periods for ten years of the 17-year study period, storage under the C1 base was temporarily higher than storage with elimination of the Shoshone call. In each of these ten years, however, storage in the C1 base case returned, in a few months, to the same level of storage as the alternative eliminating the Shoshone call.

  Because there was no increase in Willow Creek Reservoir storage as a result of removing the Shoshone priority call, Willow Creek Reservoir was not required to make a proportionate share of the 20,000 acre-feet release to the 15-Mile Reach. Consequently, average monthly storage in Willow Creek Reservoir was not affected by making the 20,000 acre-feet release.

- **Wolford Mountain Reservoir.** Average monthly storage in Wolford Mountain Reservoir was increased by 1,640 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call as compared to the C1 baseline scenario. Storage with removal of the Shoshone call was higher in all years as compared to the C1 baseline scenario except for a brief period in 1978-79 when storage under the C1 baseline scenario was slightly greater.

  Average monthly storage in Wolford Mountain Reservoir was increased by 1,439 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call and making Wolford Mountain Reservoir's proportionate share of the 20,000 acre-feet release (1,894 acre-feet) as compared to the C1 baseline scenario. Storage in Wolford Mountain Reservoir as a result of eliminating the Shoshone priority call and making the proportionate release was greater than, or equivalent to, storage in the C1 base run in all years of the study period with the exception of brief periods in 1975, 1978 and 1991, when storage under the C1 baseline scenario was slightly greater.

- **Vega Reservoir.** Storage in Vega Reservoir was essentially unaffected by elimination of the Shoshone priority call. Average monthly storage in Vega Reservoir was decreased by 14 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call.

Because there was no increase in Vega Reservoir storage as a result of removing the Shoshone priority call, Vega Reservoir was not required to make a proportionate share of the 20,000 acre-feet release to the 15-Mile Reach. Consequently, average monthly storage in Vega Reservoir was not affected by making the 20,000 acre-feet release.

- **Shoshone power production.** Elimination of the Shoshone priority call decreased the value of Shoshone power production by approximately $1.976 million for the entire 1974-91 study period, or approximately $116,000 per year.

  Making the 20,000 acre-feet release to the 15-Mile Reach had little effect on hydropower production at Shoshone as compared to the previous scenario without the 20,000 acre-feet release. Making the 20,000 acre-feet release and removing the Shoshone priority call resulted in a reduction of Shoshone hydropower production by approximately $1.970 over the study period with an annual average reduction of approximately $116,000.

- **Orchard Mesa power plant.** Eliminating the Shoshone priority call and making the 20,000 acre-feet release to the 15-Mile Reach did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternative 5b operations policy.

- **Check Case Settlement.** Comparison of flows at the head of the 15-Mile Reach indicated only a few small changes in flows as a result of eliminating the Shoshone priority call and making the 20,000 acre-feet release. Settlement of Case No. 91 CW 247 focuses on the irrigation season when the Alternative 5b operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternative 5b operations policy should not affect the Check Case settlement

- **Channel Capacity Constraints.** Results produced herein and in previous Technical Memoranda (CWCB, October 2001a, d) indicate that the additional releases and/or bypasses of diversions to storage could be made from each of the reservoirs without violating channel flow constraints on: (1) the Blue River or Colorado River downstream from Green Mountain Reservoir and (2) on the Frying Pan River or Roaring Fork River downstream from Ruedi Reservoir

The following conclusions and recommendations are based on the results of the analysis herein:

1. Alternative 5b, Expanded Coordinated Reservoir Operations, Shoshone Power Plant, can provide the 20,000 acre-feet to the 15-Mile Reach during the eight years in which this release would be required for the 1974-91 study period.

2. Storage in west slope reservoirs from making the 20,000 acre-feet release to the 15-Mile Reach during the eight years in which this release would be required was only slightly reduced as a result of removing the Shoshone priority call. The average annual storage reduction for the five participating reservoirs (Dillon, Granby, Green Mountain,

Williams Fork and Wolford Mountain) from making the 20,000 acre-feet release was 724 acre-feet or approximately 150 acre-feet per reservoir. In contrast, the average annual increased storage resulting from removal of the Shoshone priority call is 17,322 acre-feet or an average of approximately 3,500 acre-feet for each of the five participating reservoirs. The relatively small decrease in average annual storage from making the 20,000 acre-feet release to the 15-Mile Reach indicates that the participating reservoirs are replacing the water released by filling under their refill rights and are not depending on the increased storage from elimination of the Shoshone priority call for replacement purposes.

3. The average annual estimated cost of foregone power generation at Shoshone Power Plant as a result of removing the Shoshone call is approximately $116,000 per year. This would be partially offset by an average annual increase in Green Mountain Reservoir power revenue of approximately $54,000 per year.

   The average annual estimated cost of foregone power generation at Shoshone Power Plant as a result of removing the Shoshone call and making the 20,000 acre-feet release to the 15-Mile Reach is approximately $116,000 per year. This would be partially offset by an average annual increase in Green Mountain Reservoir power revenue of approximately $71,000 per year.

4. Effects of this alternative on west slope facilities, operation of these facilities and flexibility of these facilities do not appear to constitute a fatal flaw. The calculated effects of Alternative 5b on west slope facilities, however, should be reviewed by water users, State officials and Federal officials to determine the acceptability, or unacceptability, of these effects on the yields, operation and flexibility for individual reservoirs and other water management structures.

5. The analysis of the effects of these alternatives and scenarios was limited to west slope facilities and systems because east slope facilities and systems are not included in the existing version of StateMod and the C1 data set. Consequently, further consideration of Alternative 5b should include analysis of these alternatives by concerned east slope entities using their own models, data sets and calculation procedures.

6. It is recommended that Alternative 5b be given further consideration as a potential source of supply for the 20,000 acre-feet to the 15-Mile Reach.

7. This further consideration should include sensitivity analysis of the performance of these alternatives with an additional 60,000 to 120,000 acre-feet of future depletions to the Colorado River.

8. Removal of the Shoshone priority call was done in a non-selective manner to avoid the selective call issue. Even with general elimination of the Shoshone priority call, the five participating reservoirs (Dillon, Granby, Green Mountain, Williams Fork and Wolford Mountain) had increased storage in almost all months throughout the study period as a result of eliminating the Shoshone priority call.

9. Alternative 5b could provide an initial model for development of the Insurance Pool alternative (Alternative 6a). This alternative should reduce the risk to individual facilities by: (1) spreading responsibility for making the 20,000 acre-feet release among five reservoirs and (2) providing additional storage to these reservoirs by eliminating the Shoshone call. Therefore, rather than providing one insurance pool, Alternative 5b would produce five insurance pools to partially mitigate the risk.

INTRODUCTION AND PURPOSE

The Phase 1 investigation (CWCB, September 2000) recommended that Alternative 5b, Expanded Coordinated Reservoir Operations, Shoshone Power Plant, should be investigated in Phase 2 despite concerns expressed in the Phase 1 report concerning selective removal of a senior priority call. As originally presented in the Phase 1 investigation, Alternative 5b would involve:

- All or a portion of the Shoshone Power Plant priority call would be selectively removed for one, or possibly a few reservoirs.
- This action would reduce the requirements for participating upstream junior reservoirs to release water, or bypass diversions to storage, to satisfy the senior call.
- This action would subsequently preserve storage in the participating upstream reservoirs.
- The water stored against the Shoshone priority call could be subsequently used to offset the 20,000 acre-feet release to the 15-Mile Reach.

In order to avoid the selective call issue, an initial set of calculations was completed to determine how much storage would be preserved in upstream reservoirs by a non-selective removal of the Shoshone call. It was then determined whether the storage preserved in these reservoirs would offer sufficient replacement of the 20,000 acre-feet release to warrant further consideration of this alternative. After completion of these initial model runs, the feasibility of making the 20,000 acre-feet release to the 15-Mile Reach, together with removing the Shoshone priority call, was investigated.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following general procedures, tools, and assumptions were employed in the analysis of Alternative 5b:

1. The StateMod surface water model and C1 dataset were used for baseline hydrology for the period 1975-1991, using a monthly timestep.

2. The baseline conditions were the StateMod C1 Scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000)*. These components of RIPRAP flows include:

   - 5,000 acre-feet per year from Ruedi Reservoir,
   - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
   - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
   - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
   - 6,000 acre-feet per year from Wolford Mountain Reservoir, and
   - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated on the C1 dataset but not modeled.

3. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee review the analysis and any revisions made by the consultant and determine that the methodology and calculations employed in the analysis of Alternative 5b are acceptable, the necessary sensitivity analysis will be completed.

   CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP

will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

4. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

5. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

   The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

   A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 dataset's lack of simulation of the hydropower maintenance periods.

6. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,

- A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
- A reservoir fill according to the criteria of the Blue River Decree.

The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

7. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:
   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
   - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
   - Sufficient HUP Surplus water exists to make the release.

   Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. StateMod and the C1 data set do not explicitly model releases of HUP Surplus water under the Municipal Recreational Agreement and there is no demand specified at a node for the Municipal Recreational water.

SPECIFIC PROCEDURES

The following specific procedures were employed.

1. The Shoshone priority calls (1/7/1902 for 1,250 cfs and 5/15/1929 for 158 cfs) were eliminated from StateMod and the C1 data set and the resulting effects on reservoir storage calculated.

2. The allocation of responsibility for releasing a total of 20,000 acre-feet among the reservoirs for meeting the 20,000 acre-feet target release was based on the average annual increase in storage in a particular reservoir resulting from elimination of the Shoshone Power Plant priority call divided by the total increased average annual reservoir storage resulting from removal of the Shoshone Power Plant priority call. The following reservoirs were included in this calculation: Dillon, Granby, Green Mountain, Williams Fork, and Wolford Mountain Reservoirs. Homestake Reservoir was not included because StateMod is apparently not correctly modeling Homestake Reservoir. Willow Creek and Vega Reservoirs were not included because these reservoirs did not have increased yield resulting from elimination of the Shoshone priority call. Responsibility for making the 20,000 acre-feet release was assigned, for purposes of this alternative, proportionally on the basis of increased storage resulting from elimination of the Shoshone priority call.

3. StateMod and the C1 data set were then used to estimate: (1) the feasibility of making the 20,000 acre-feet release and (2) the potential to replace water released from storage for the 20,000 acre-feet release either from filling under reservoir refill rights and/or increased reservoir storage resulting from eliminating the Shoshone priority call.

USE OF STATEMOD

The C1 scenario was modified by adding full reservoir targets in Green Mountain Reservoir for the months of September and October. This prevented surplus water hydropower releases until after the irrigation season. In addition, monthly demands of 20,000 acre-feet were added to diversion ID #952001 corresponding to the projected 20,000 acre-feet releases to enhance the spring runoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1982, 1985, 1986 and 1991. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water in the stream when available. The Ruedi Reservoir refill right was incorrectly given a priority number of 99999.99 in the C1 run. The correct priority number of 47869 was used in the revised baseline. These changes constitute the revised C1 baseline scenario.

For Alternative 5b, the baseline scenario was modified by adding eight additional diversion nodes in the river system immediately downstream of the head of the 15-Mile Reach. Each diversion point then had a demand added corresponding to each respective release from the eight identified reservoirs. A new operation rule was added to each of the modeled reservoirs to allow a release to their respective demand. These changes released an additional 20,000 acre-feet of water in the appropriate ratio from each of the modeled reservoirs in those years when it would be required.

Several spreadsheets were then developed to allow side by side comparison of every aspect of the analysis in the two StateMod runs including reservoir storage, diversions, streamflows and operating releases.

RESULTS

EFFECTS ON RESERVOIR STORAGE

Dillon Reservoir

Average monthly storage in Dillon Reservoir was increased by approximately 2,667 acre-feet as a result of eliminating the Shoshone priority call as compared to storage under the C1 baseline scenario. Dillon Reservoir storage with elimination of the Shoshone priority call was higher than, or equivalent to, storage under the C1 baseline scenario throughout the study period with the exception of two periods: (1) approximately June 1977 to June 1978 and (2) approximately June 1981 to June 1982 (see Figure 1). Comparison of Figure 1, storage in Dillon Reservoir, with Figure 5, storage in Williams Fork Reservoir, for these two periods indicates that Williams Fork Reservoir had substantial increases in storage with the Alternative 5b elimination of the Shoshone call as compared to the C1 baseline scenario. Comparison of these two figures suggests that the cause of the decreased storage in Dillon in the Alternative 5b scenario resulted from how StateMod handles the Williams Fork to Dillon exchange. Brown and Caldwell has concluded that this anomaly is not sufficient to discredit the StateMod and C1 data set results for this alternative.

Average monthly storage in Dillon Reservoir was increased by 2,703 acre-feet during the 1974-1991 study period by eliminating the Shoshone priority call and making a release of 3,080 acre-feet from Dillon towards the 20,000 acre-feet release to the 15-Mile Reach as compared to the C1 baseline scenario. Eliminating the Shoshone priority call and making the proportionate release resulted in increased or equivalent storage in Dillon Reservoir as compared to the C1 base case in every year except for temporary periods during approximately June 1977 through June 1978 and June 1981 through June 1982 when drawdown in Dillon Reservoir was greater with elimination of the Shoshone priority call and making the proportionate release (see Figure 9). The reason for this apparent anomaly is the same as in the previous scenario when the Shoshone call was removed and the 2,703 acre-feet release was not made.

Granby Reservoir

Average monthly storage in Granby Reservoir was increased by 2,879 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call. Storage in Granby Reservoir with elimination of the Shoshone priority call was equal to, or greater than, storage in the C1 base case in all years during the 1974-91 study period except for approximately March 1982 through April 1983 when storage in Granby Reservoir for the C1 baseline scenario slightly exceeded the scenario in which the Shoshone priority call was eliminated (see Figure 2). Brown and Caldwell believes the reason for this apparent anomaly involves how StateMod models the exchange between Green Mountain and Granby Reservoirs. Brown and Caldwell does not believe this apparent anomaly has biased results from this investigation.

Storage in Granby Reservoir was increased by an annual average of 2,445 acre feet as compared to the C1 baseline case as a result of eliminating the Shoshone priority call and making Granby Reservoir's proportionate share of the 20,000 acre-feet release for the 15-Mile Reach (3,324 acre-feet). Eliminating the Shoshone priority call and making the proportionate release resulted in increased or equivalent storage in Granby Reservoir as compared to the C1 base case in every year except for a period from approximately January 1981 through March 1983 when drawdown in Dillon Reservoir was greater with elimination of the Shoshone priority call and making the proportionate release (see Figure 10). The reason for this apparent anomaly is likely the same as in the previous scenario when the Shoshone call was removed and the 3,324 acre-feet release was not made.

Green Mountain Reservoir

Average monthly storage in Green Mountain Reservoir with elimination of the Shoshone priority call was increased by 5,162 acre-feet as compared to storage under the C1 baseline scenario for the study period. Storage in Green Mountain Reservoir with elimination of the Shoshone priority call was higher than, or equal to, storage under the C1 baseline scenario throughout the study period (see Figure 4).

Average monthly storage in Green Mountain Reservoir was increased by 5,109 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call and making Green Mountain Reservoir's proportionate share of the 20,000 acre-feet release to the 15-Mile Reach (5,960 acre-feet) as compared to the C1 baseline scenario. Storage in Green Mountain Reservoir as a result of eliminating the Shoshone priority call and making the 5,960 acre-feet release was equivalent to, or greater than, storage in the C1 base case in all years of the study period (see Figure 11).

Homestake Reservoir

Average monthly storage in Homestake Reservoir with elimination of the Shoshone priority call was increased by 11,471 acre-feet as compared to storage under the C1 Scenario for the study period. Storage in Homestake Reservoir with elimination of the Shoshone priority call was higher than, or equal to, storage under the C1 baseline scenario throughout the study period (see Figure 4). Review of estimated storage in Homestake Reservoir for the study period indicates inexplicable behavior of Homestake Reservoir storage during the 1980s in the C1 baseline scenario. Figure 4 indicates a continuous decrease in reservoir storage in the C1 baseline scenario for the period from approximately June 1978 through June 1985, which was a wetter than average period. Based on this inexplicable reservoir behavior, the C1 data set used in modeling of Homestake Reservoir is suspect. Brown and Caldwell has concluded that the modeling problems involving Homestake Reservoir have only biased the Homestake Reservoir results and the modeling results for the other reservoirs have not been affected.

Because of the suspected modeling problem, Homestake Reservoir was not required to make a proportionate share of the 20,000 acre-feet release to the 15-Mile Reach. Consequently, average

monthly storage in Homestake Reservoir was not affected by making the 20,000 acre-feet release (see Figure 12).

Ruedi Reservoir

Storage in Ruedi Reservoir was unaffected by Alternative 5b because it is located on a downstream tributary from the Shoshone Power Plant.

Williams Fork Reservoir

Average monthly storage in Williams Fork Reservoir with elimination of the Shoshone priority call was increased by 4,974 acre-feet as compared to storage under the C1 baseline scenario for the study period. Storage in Williams Fork Reservoir with elimination of the Shoshone priority call was higher than, or equal to, storage under the C1 baseline scenario throughout the study period (see Figure 5). As discussed above, the substantial increase in Williams Fork Reservoir storage under the elimination of the Shoshone priority call scenario during June 1977 through June 1979 and June 1981 through June 1982 likely resulted from the exchange with Dillon Reservoir.

Average monthly storage in Williams Fork Reservoir was increased by 4,902 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call and making Williams Fork Reservoir's proportionate share of the 20,000 acre-feet release (5,743 acre-feet) as compared to the C1 baseline scenario. Storage in Williams Fork Reservoir as a result of eliminating the Shoshone priority call and making the proportionate release was greater than, or equivalent to, storage in the C1 base run in all years of the study period (see Figure 13).

Willow Creek Reservoir

Average monthly storage in Willow Creek Reservoir with elimination of the Shoshone priority call was decreased by 61 acre-feet as compared to storage under the C1 baseline scenario for the study period. During the spring and early summer runoff periods of ten years during the study period, storage under the C1 base case with the Shoshone priority call was temporarily higher than storage with elimination of the Shoshone call (see Figure 6). In each of these ten years, however, storage in the C1 base case returned to the same level as in the alternative eliminating the Shoshone call. Brown and Caldwell believes this apparent anomaly may result from how StateMod is handling exchanges among reservoirs with intervening senior priority calls. The present configuration of StateMod, however, does not permit determination of the calling water right for a specific period and, consequently, Brown and Caldwell has not been able to determine with certainty the reason for the apparent anomaly in Willow Creek Reservoir storage. Brown and Caldwell does not believe this anomaly is biasing the overall results of the Alternative 5b investigation.

Because there was no increase in Willow Creek Reservoir storage as a result of removing the Shoshone priority call, Willow Creek Reservoir was not required to make a proportionate share

of the 20,000 acre-feet release to the 15-Mile Reach. Consequently, average monthly storage in Willow Creek Reservoir was not affected by making the 20,000 acre-feet release (see Figure 14).

Wolford Mountain Reservoir

Average monthly storage in Wolford Mountain Reservoir with elimination of the Shoshone priority call was increased by 1,640 acre-feet as compared to storage under the C1 baseline scenario for the study period. Storage in Wolford Mountain Reservoir with elimination of the Shoshone priority call was higher than, or equal to, storage under the C1 baseline scenario throughout the study period, with the exception of 1978 when the storage under the C1 baseline scenario was slightly higher (see Figure 7).

Average monthly storage in Wolford Mountain Reservoir was increased by 1,439 acre-feet over the 1974-91 study period by eliminating the Shoshone priority call and making Wolford Mountain Reservoir's proportionate share of the 20,000 acre-feet release (1,894 acre-feet) as compared to the C1 baseline scenario. Storage in Wolford Mountain Reservoir as a result of eliminating the Shoshone priority call and making the proportionate release was greater than, or equivalent to, storage in the C1 base run in all years of the study period, with the exception of brief periods in 1975, 1978 and 1991 when storage under the C1 baseline scenario was slightly greater (see Figure 15)

Vega Reservoir

Storage in Vega Reservoir was unaffected by imposition of the Alternative 5b operating rule (see Figure 8). Average monthly storage in Vega Reservoir with elimination of the Shoshone priority call was decreased by 14 acre-feet as compared to storage under the C1 Scenario for the study period.

Because there was no increase in Vega Reservoir storage as a result of removing the Shoshone priority call, Vega Reservoir was not required to make a proportionate share of the 20,000 acre-feet release to the 15-Mile Reach. Consequently, average monthly storage in Vega Reservoir was not affected by making the 20,000 acre-feet release (see Figure 16).

EFFECTS ON POWER GENERATION

Green Mountain Reservoir Power Plant

As indicated in Table 1, Green Mountain Reservoir Power Plant would produce slightly more power with elimination of the Shoshone priority call during the 1974-91 study period as compared to the C1 baseline scenario. Total power revenues would have increased by approximately $923,000 for the 1974-915 study period or an average of approximately $54,000 per year.

Eliminating the Shoshone priority call and making the 5,960 acre-feet proportionate release from Green Mountain Reservoir to the 15-Mile Reach increased total power revenues from Green Mountain Reservoir for the 1974-91 study period by approximately $1.2 million, or an annual average of approximately $71,000 as compared to the C1 baseline scenario (see Table 4).

Shoshone Power Plant

Table 2 indicates the total decrease in power revenue from Shoshone Power Plant for the 1974-91 study period with elimination of the Shoshone priority call is $1.976 million, or approximately $116,000 per year.

Making the 20,000 acre-feet release to the 15-Mile Reach had little effect on hydropower production at Shoshone. With making the 20,000 acre-feet release and removing the Shoshone priority call, Shoshone hydropower production was reduced by approximately $1.970 million over the study period with an annual average reduction of approximately $116,000.

Orchard Mesa Power Plant

Flow data at the head of the 15-Mile Reach (Node No. 952001) were analyzed to determine if the frequency and/or duration of flow periods with 800 cfs or less had been changed under this alternative. This node is at the point where return flows from the Orchard Mesa Power Plant return to the Colorado River. The maximum reduction in monthly flow between the C1 baseline scenario and the Alternative 5b scenario (elimination of the Shoshone priority call and making the 20,000 acre-feet release to the 15-Mile Reach) was 13 cfs. Therefore, it was concluded that the Alternative 5b operations policy with elimination of the Shoshone priority call did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternative 5b operations policy.

OTHER EFFECTS

Check Case Settlement

Comparison of flows at the head of the 15-Mile Reach indicated only a few small changes in flows as a result of eliminating the Shoshone priority call and making the 20,000 acre-feet release. Settlement of Case No 91 CW 247 focuses on the irrigation season when the Alternative 5a operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternative 5a operations policy should not affect the Check Case settlement

Channel Capacity Constraints

Results produced herein, together with the results from previous investigations of alternatives with respect to channel capacity constraints (Colorado Water Conservation Board, 2001a, b, c and d) indicate that the additional releases and/or bypasses of diversions to storage could be made from each of the reservoirs without violating channel flow constraints on: (1) the Blue River or Colorado River downstream from Green Mountain Reservoir and (2) on the Frying Pan River downstream from Ruedi Reservoir.

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CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. Alternative 5b, Expanded Coordinated Reservoir Operations, Shoshone Power Plant, can provide the 20,000 acre-feet to the 15-Mile Reach during the eight years in which this release could be required for the 1974-91 study period.

2. Storage in west slope reservoirs from making the 20,000 acre-feet release to the 15-Mile Reach during the eight years in which this release could be required was only slightly reduced as a result of removing the Shoshone priority call. The average annual total storage reduction for the five participating reservoirs (Dillon, Granby, Green Mountain, Williams Fork and Wolford Mountain) from making the 20,000 acre-feet release was 724 acre-feet, or approximately 150 acre-feet per reservoir. In contrast, the average annual increased storage resulting from removal of the Shoshone priority call was 17,322 acre-feet or an average of approximately 3,500 acre-feet for each of the five participating reservoirs. The relatively small decrease in average annual storage from making the 20,000 acre-feet release to the 15-Mile Reach indicates that the participating reservoirs are replacing the water released for the 15-Mile Reach by filling under their refill rights and are not depending on the increased storage from elimination of the Shoshone priority call for replacement purposes.

3. The average annual estimated cost of foregone power generation at Shoshone Power Plant as a result of removing the Shoshone call is approximately $116,000 per year. This would be partially offset by an average annual increase in Green Mountain Reservoir power revenue of approximately $54,000 per year.

   The average annual estimated cost of foregone power generation at Shoshone Power Plant as a result of removing the Shoshone call and making the 20,000 acre-feet release to the 15-Mile Reach is also approximately $116,000 per year. This would be partially offset by an average annual increase in Green Mountain Reservoir power revenue of approximately $71,000 per year.

4. Effects of this alternative on west slope facilities, operation of these facilities and flexibility of these facilities do not appear to constitute a fatal flaw. The calculated effects of Alternative 5b on west slope facilities, however, should be reviewed by water users, State officials and Federal officials to determine the acceptability, or unacceptability of these effects on the yields, operation and flexibility of operation for individual reservoirs and other water management structures.

5. The analysis of the effects of these alternatives and scenarios was limited to west slope facilities and systems because east slope facilities and systems are not included in the existing version of StateMod and the C1 data set. Consequently, further consideration of Alternative 5b should include analysis of these alternatives by concerned east slope entities using their own models, data sets and calculation procedures.

6. It is recommended that Alternative 5b be given further consideration as a potential source of supply for the 20,000 acre-feet to the 15-Mile Reach.

7. This further consideration should include sensitivity analysis of the performance of these alternatives with an additional 60,000 to 120,000 acre-feet of future depletions to the Colorado River.

8. Removal of the Shoshone priority call was done in a non-selective manner to avoid the selective call issue. Even with general elimination of the Shoshone priority call, the five participating reservoirs (Dillon, Granby, Green Mountain, Williams Fork and Wolford Mountain) had increased storage in almost all months throughout the study period as a result of eliminating the Shoshone priority call.

9. Alternative 5b could provide an initial model for development of the Insurance Pool alternative (Alternative 6a). This alternative should reduce the risk to individual facilities by: (1) spreading responsibility for making the 20,000 acre-feet release among five reservoirs and (2) providing additional storage to these reservoirs by eliminating the Shoshone call. Therefore, rather than providing one insurance pool, Alternative 5b would produce five insurance pools to partially mitigate the risk.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River* .

Colorado Water Conservation Board, October 2001a (Revised), *Technical Memorandum No. 1 Concerning Analysis of Alternative 1a, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Reduced Winter Power Operations.*

Colorado Water Conservation Board, October 2001b, *Technical Memorandum No. 2, Expanded Coordinated Reservoir Operations of Green Mountain Reservoir, Including Green Mountain Reservoir Preemptive Release and Release of Water Carried over in Green Mountain Reservoir.*

Colorado Water Conservation Board, October 2001c, *Technical Memorandum No. 3, Analysis of Alternative 1a Expanded Coordinated Reservoir operations of Green Mountain Reservoir, Conjunctive Pool Operations.*

Colorado Water Conservation Board, October 2001d, Technical Memorandum No. 5, *Analysis of Alternative 1b, Expanded Coordinated Reservoir Operations of Ruedi Reservoir.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1

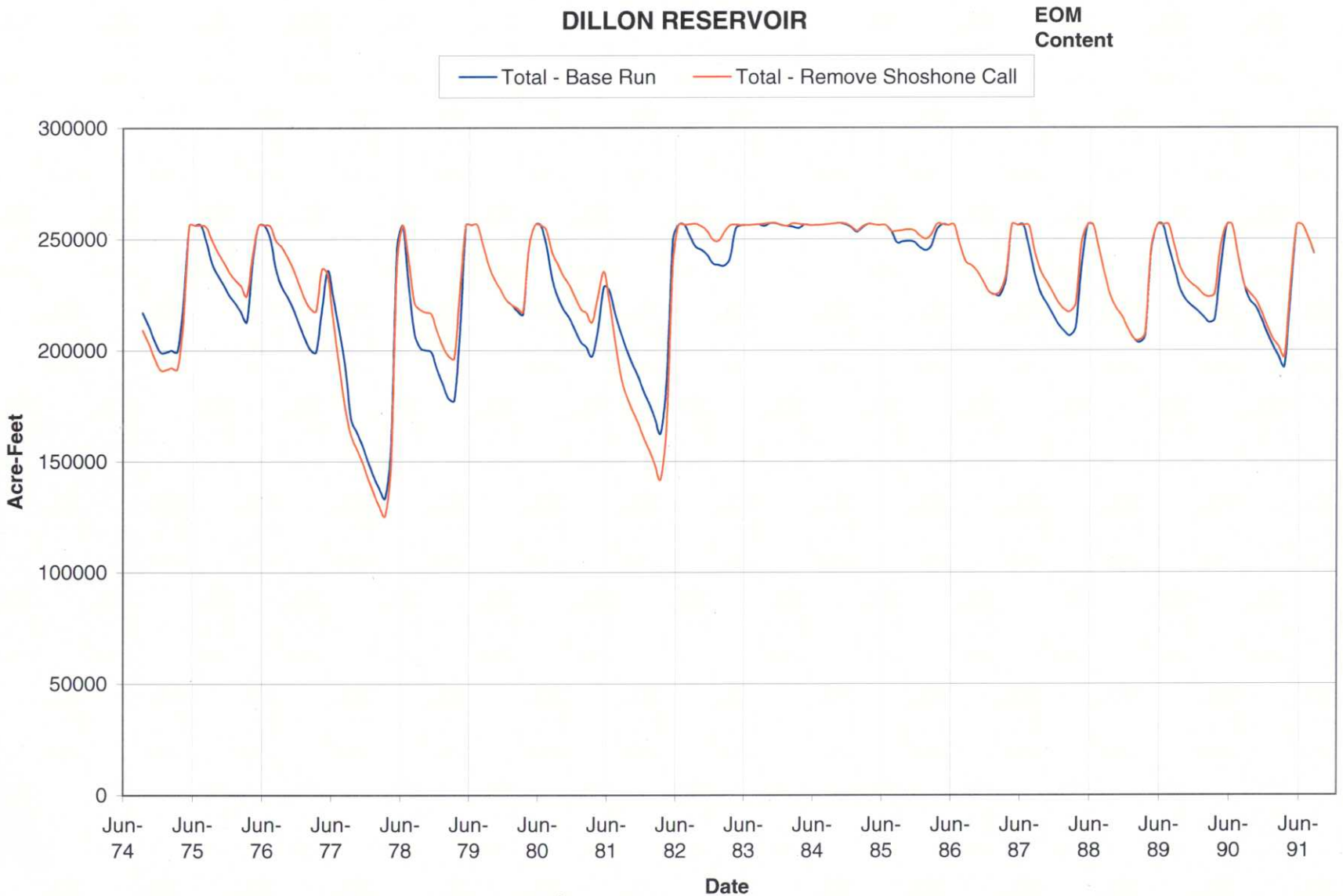
DILLON RESERVOIR
EOM Content
Total - Base Run
Total - Remove Shoshone Call
300000
250000
200000
150000
100000
50000
0
Acre-Feet
Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Figure 2

CBT GRANBY RESERVOIR

EOM Content

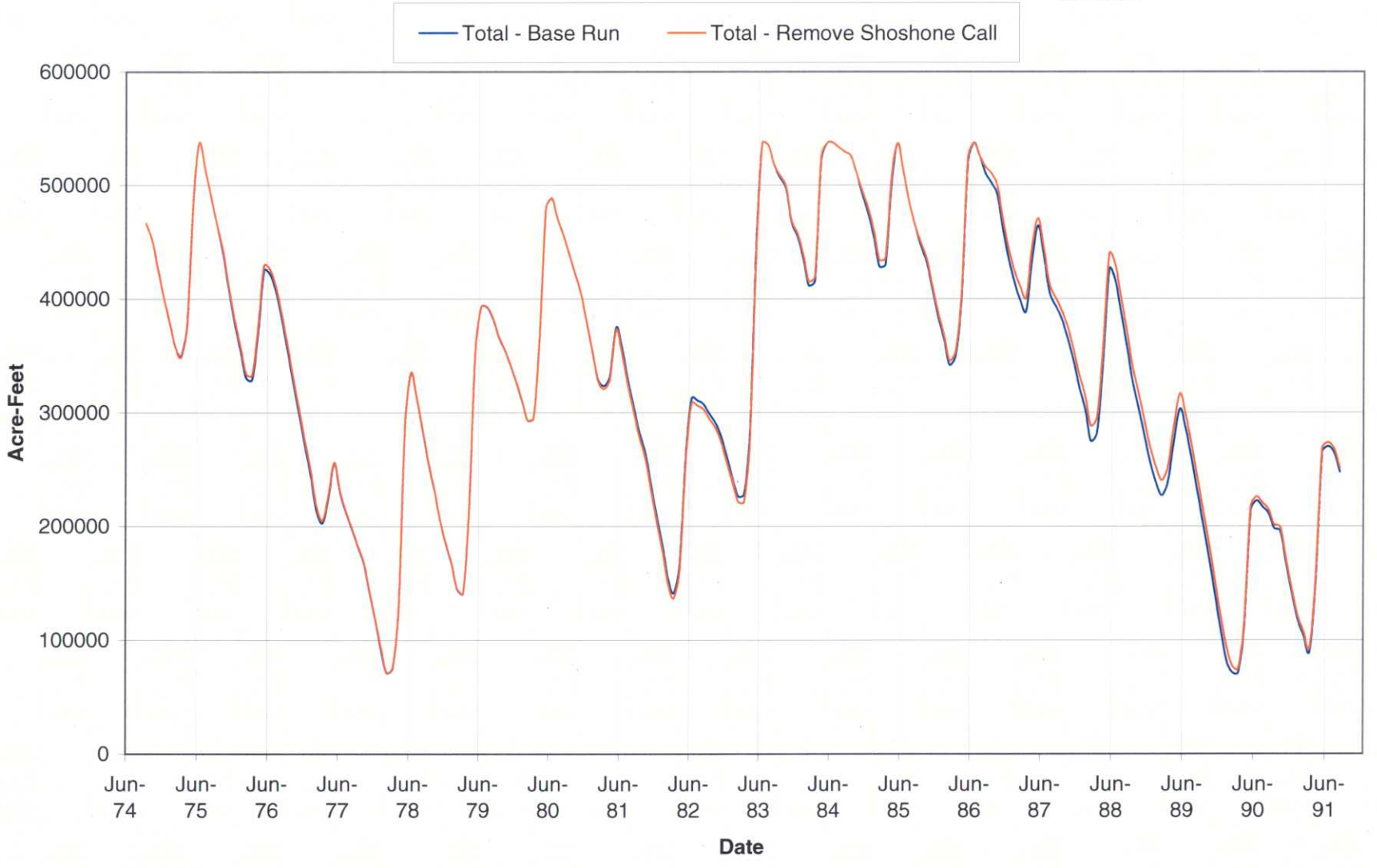

Figure 3

GREEN MOUNTAIN RESERVOIR

EOM Content

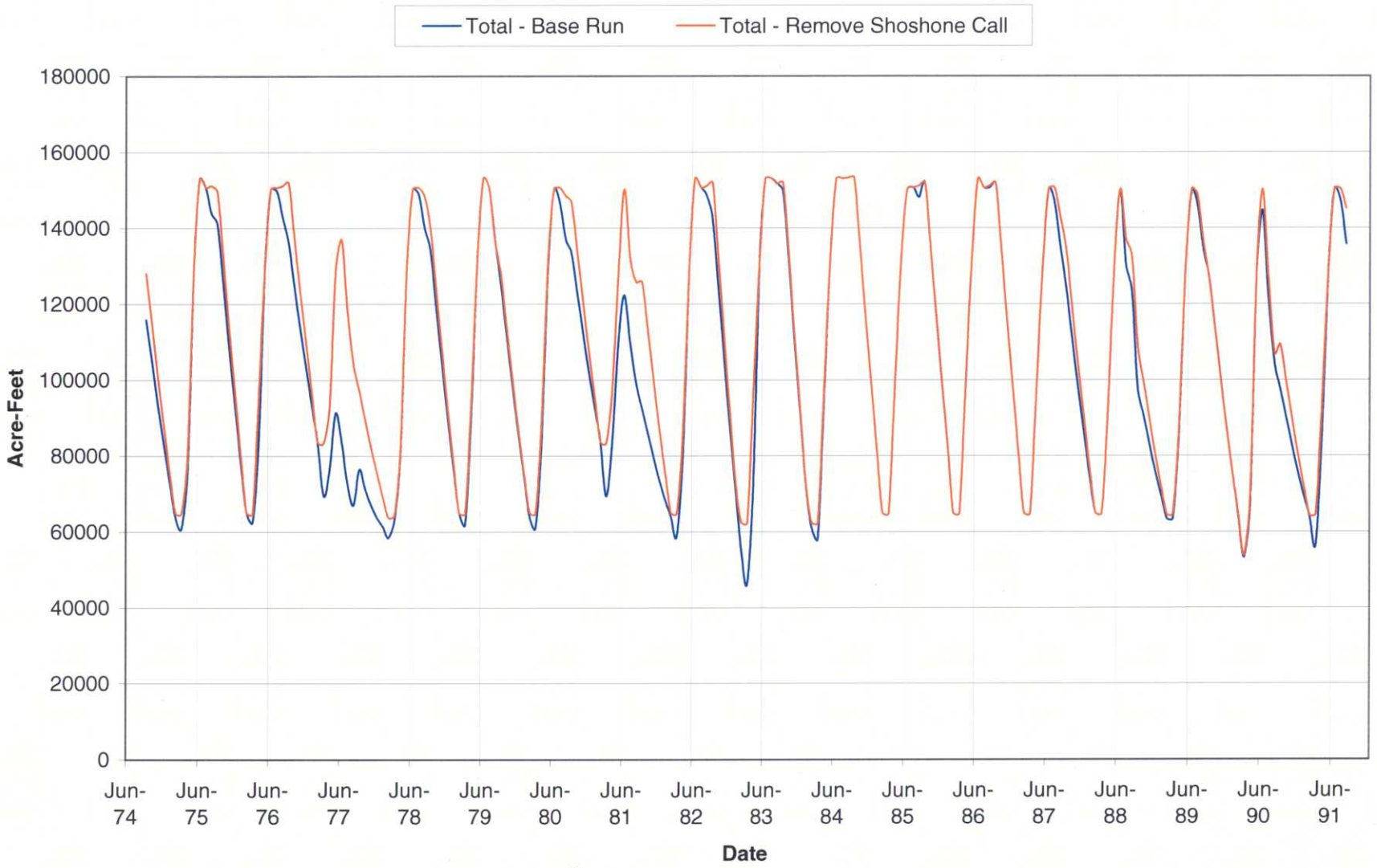

Figure 4

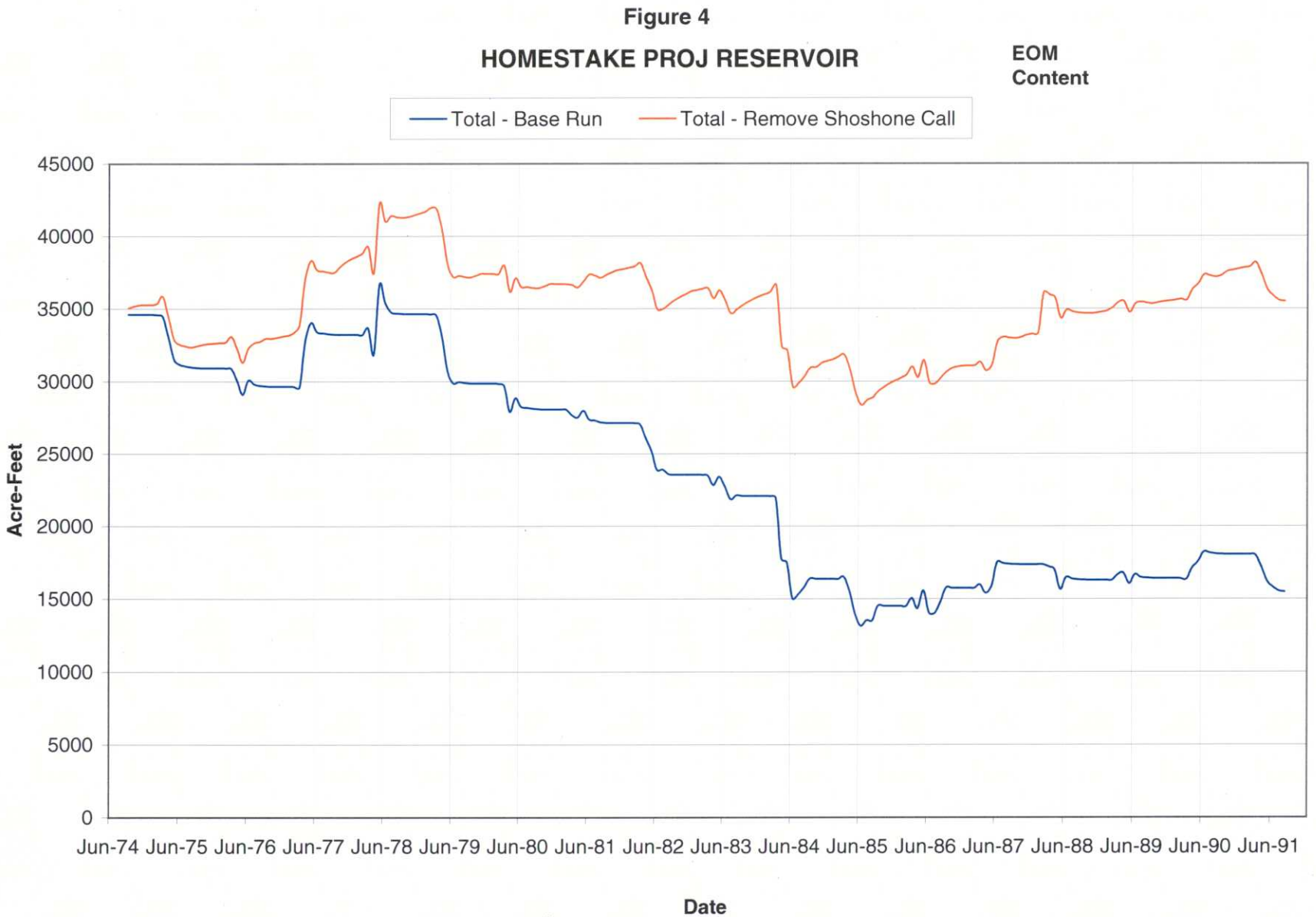
HOMESTAKE PROJ RESERVOIR
EOM Content
Total - Base Run
Total - Remove Shoshone Call
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Figure 5

WILLIAMS FORK RESERVOIR

EOM Content

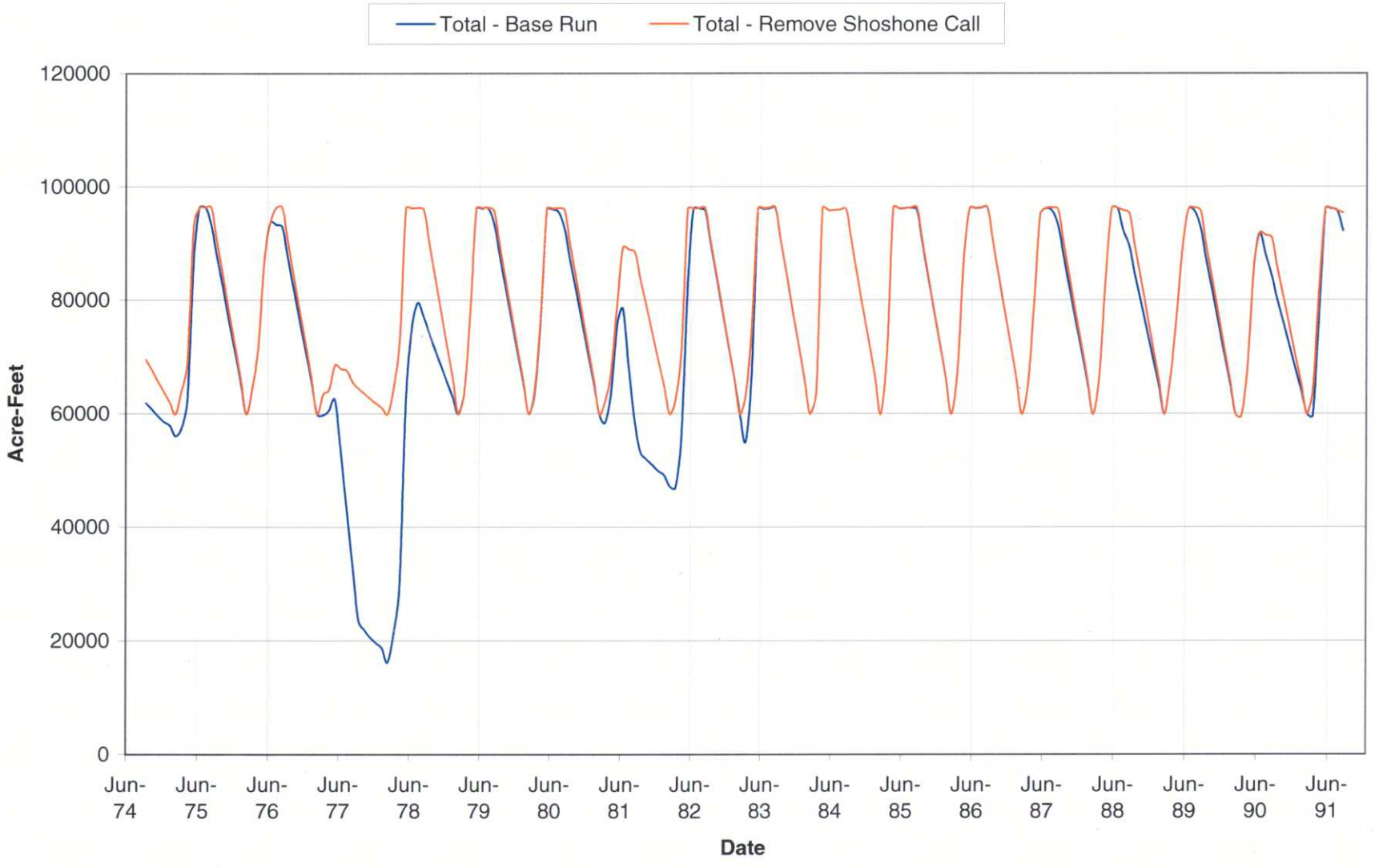

Figure 6

CBT WILLOW CREEK RES

EOM Content

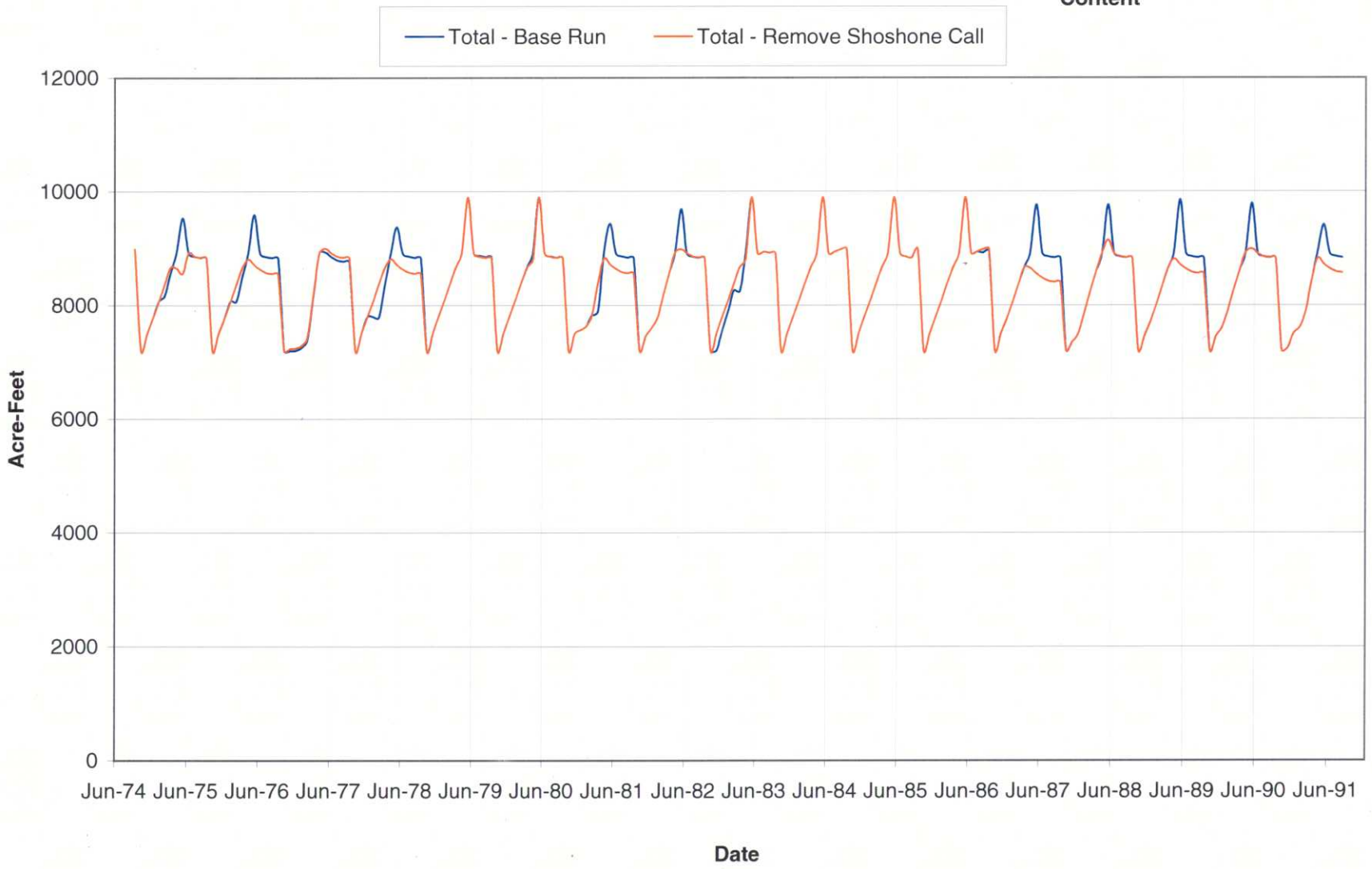

Figure 7

WOLFORD_MOUNTAIN_RES

EOM Content

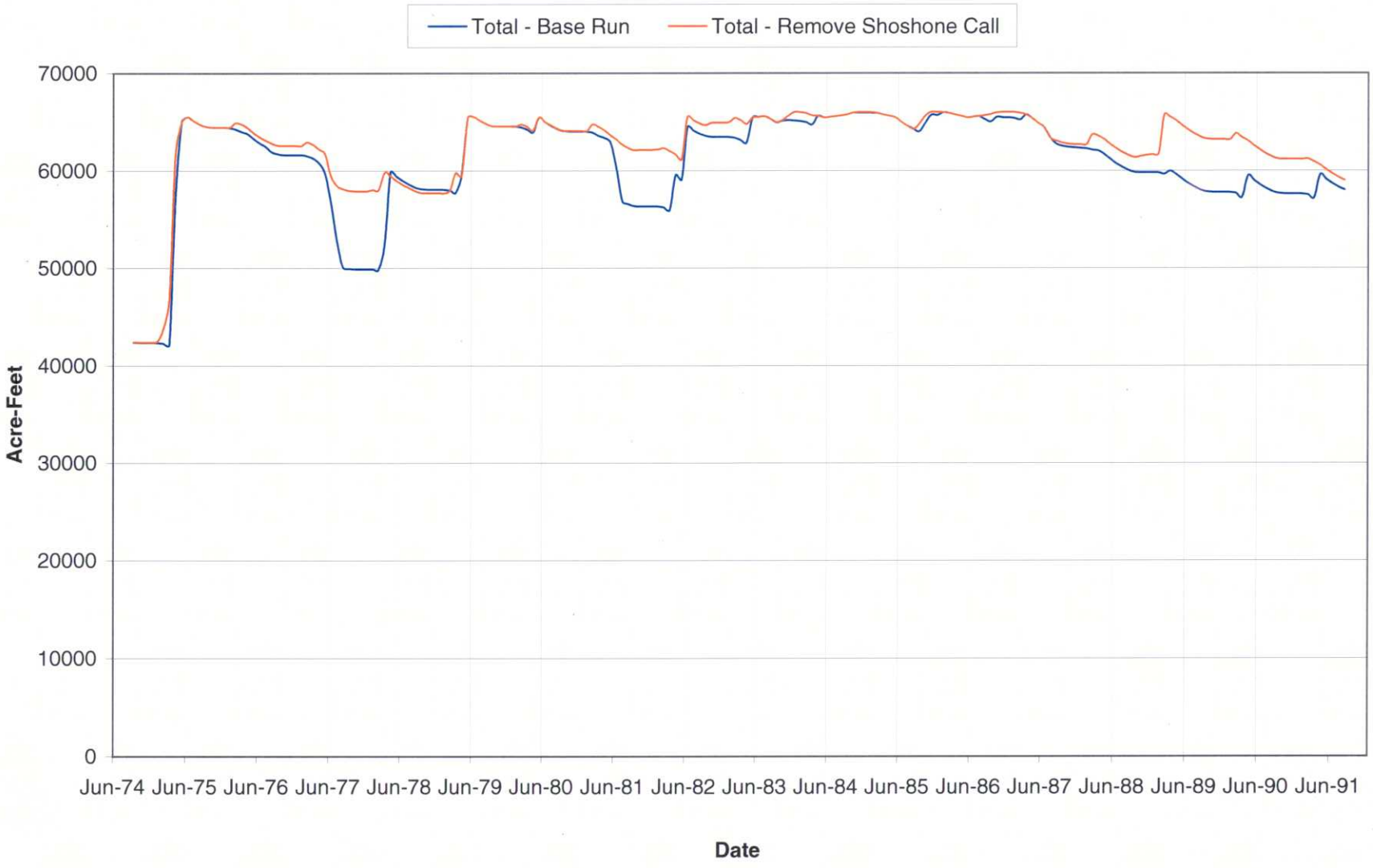

Figure 8

VEGA RESERVOIR

EOM Content

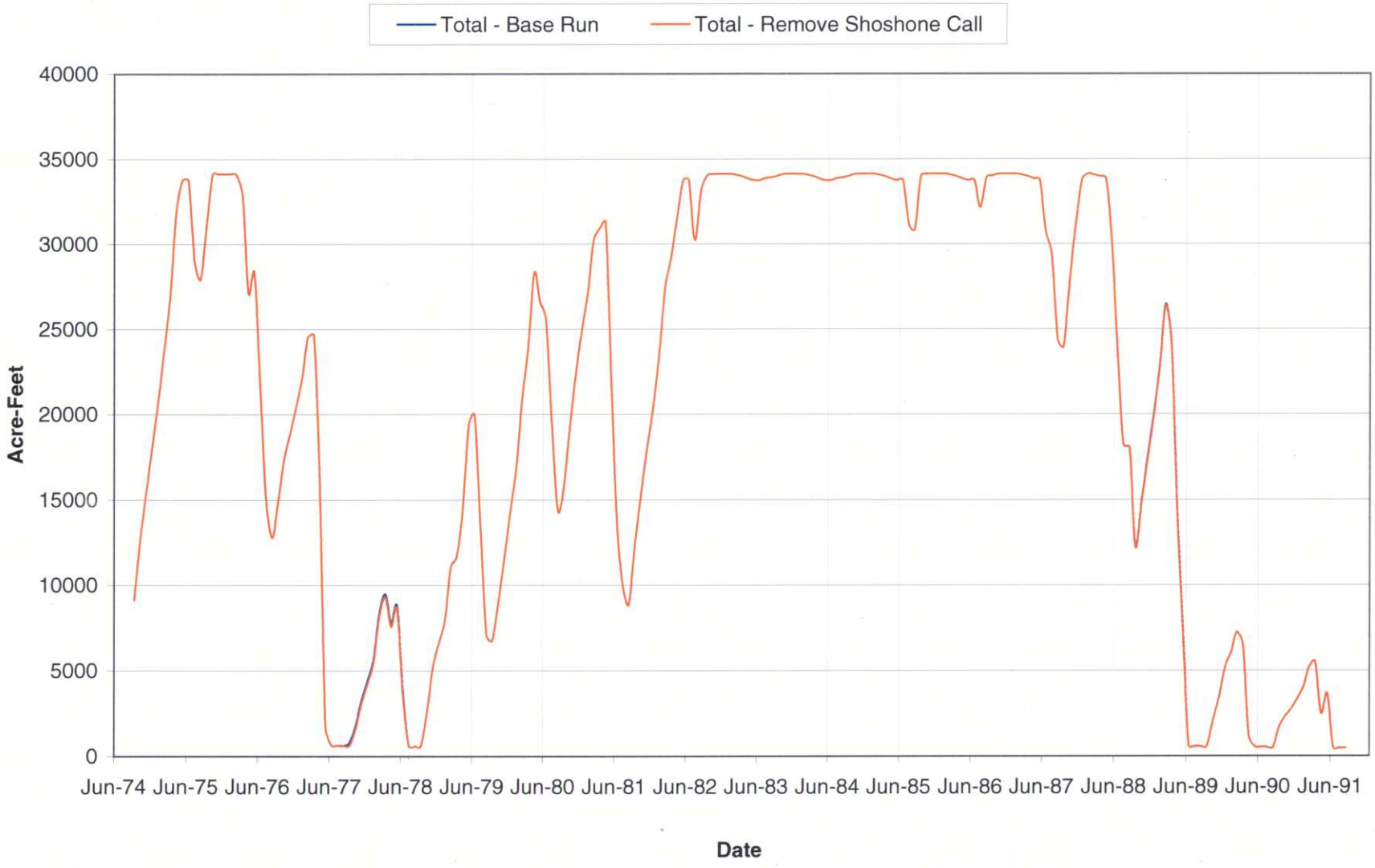

Figure 9

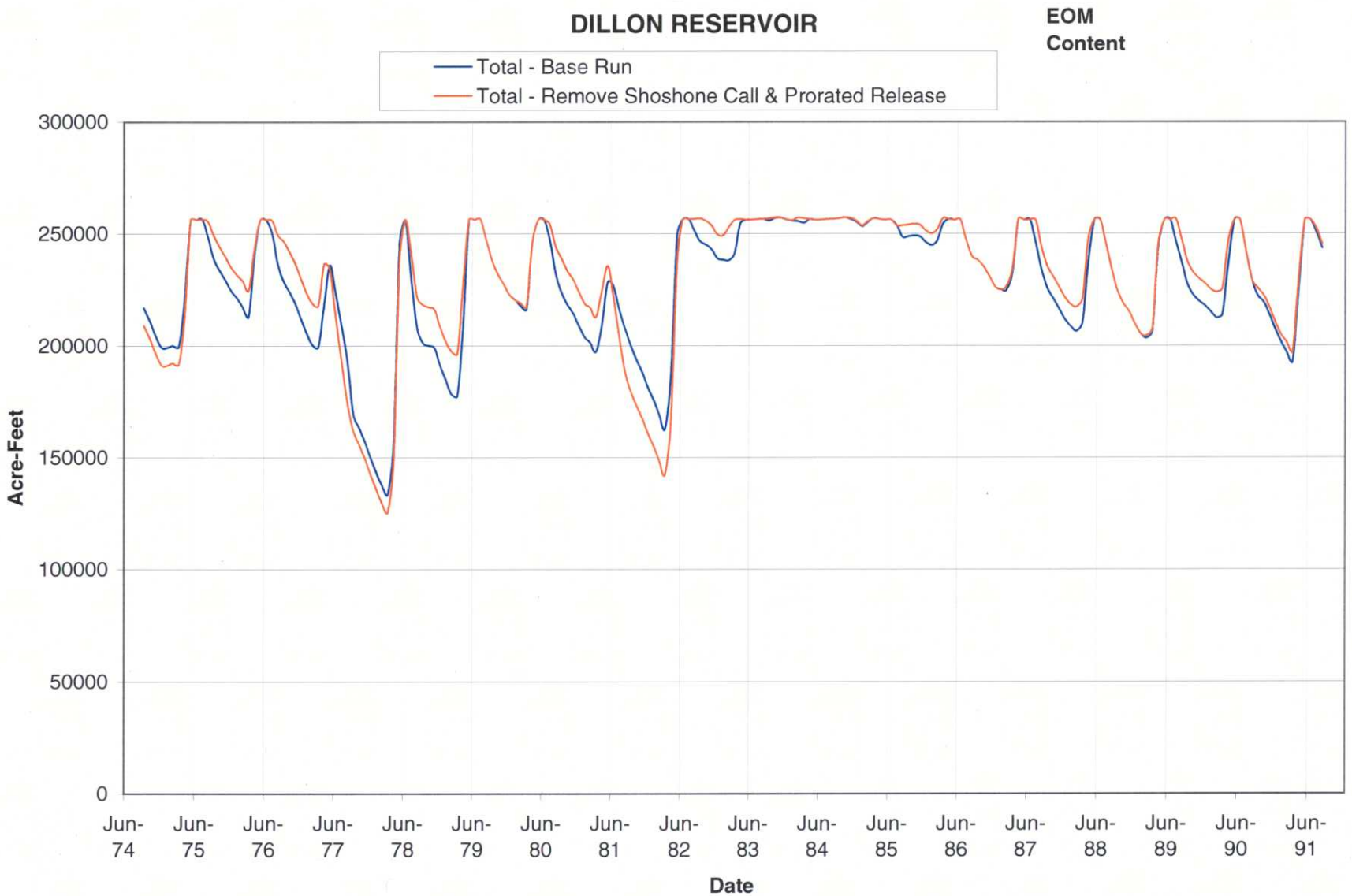
DILLON RESERVOIR
EOM Content
Total - Base Run
Total - Remove Shoshone Call & Prorated Release
300000
250000
200000
150000
100000
50000
0
Acre-Feet
Jun-74
Jun-75
Jun-76
Jun-77
Jun-78
Jun-79
Jun-80
Jun-81
Jun-82
Jun-83
Jun-84
Jun-85
Jun-86
Jun-87
Jun-88
Jun-89
Jun-90
Jun-91
Date

Figure 10

CBT GRANBY RESERVOIR

EOM Content

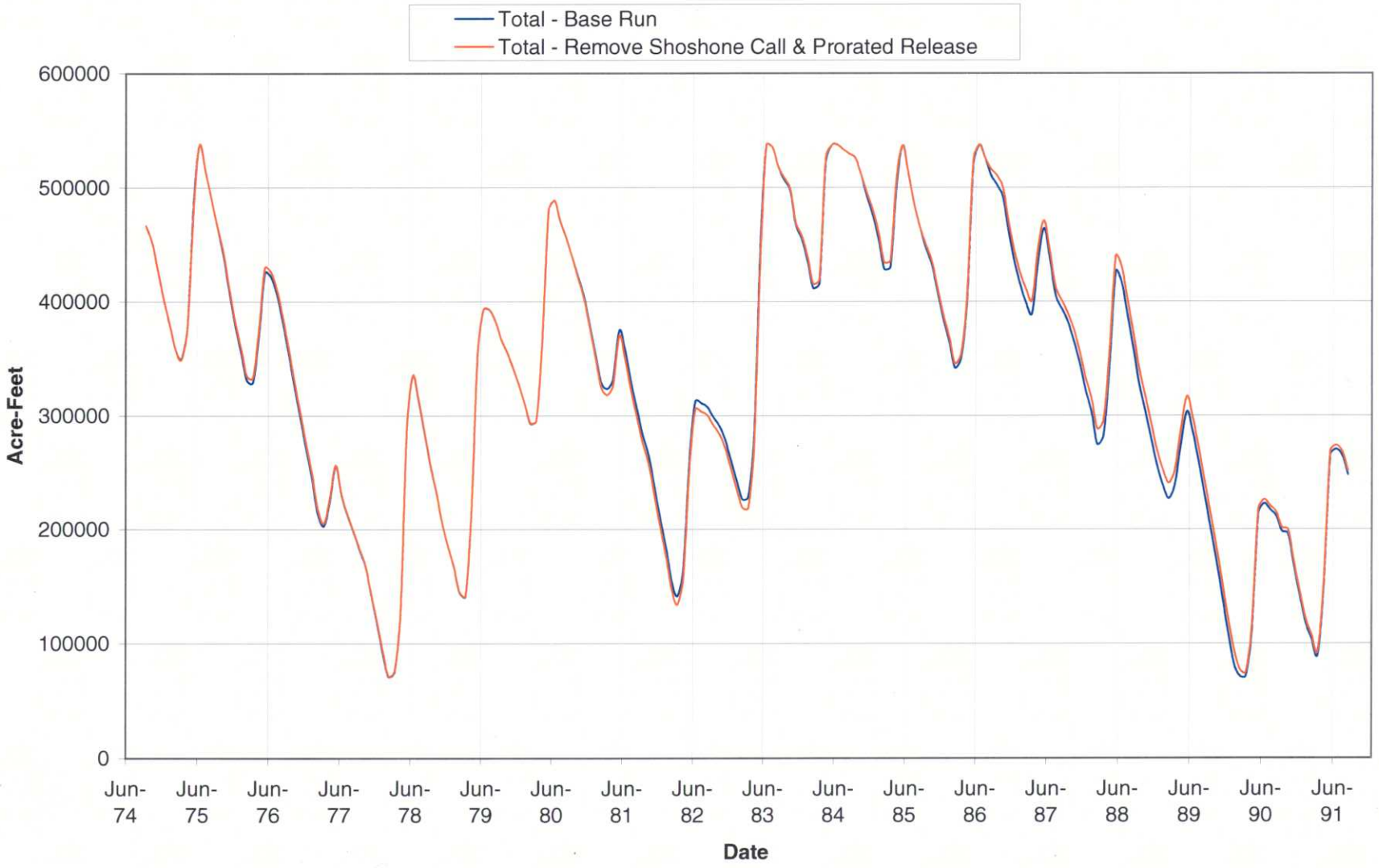

Figure 11

GREEN MOUNTAIN RESERVOIR

EOM Content

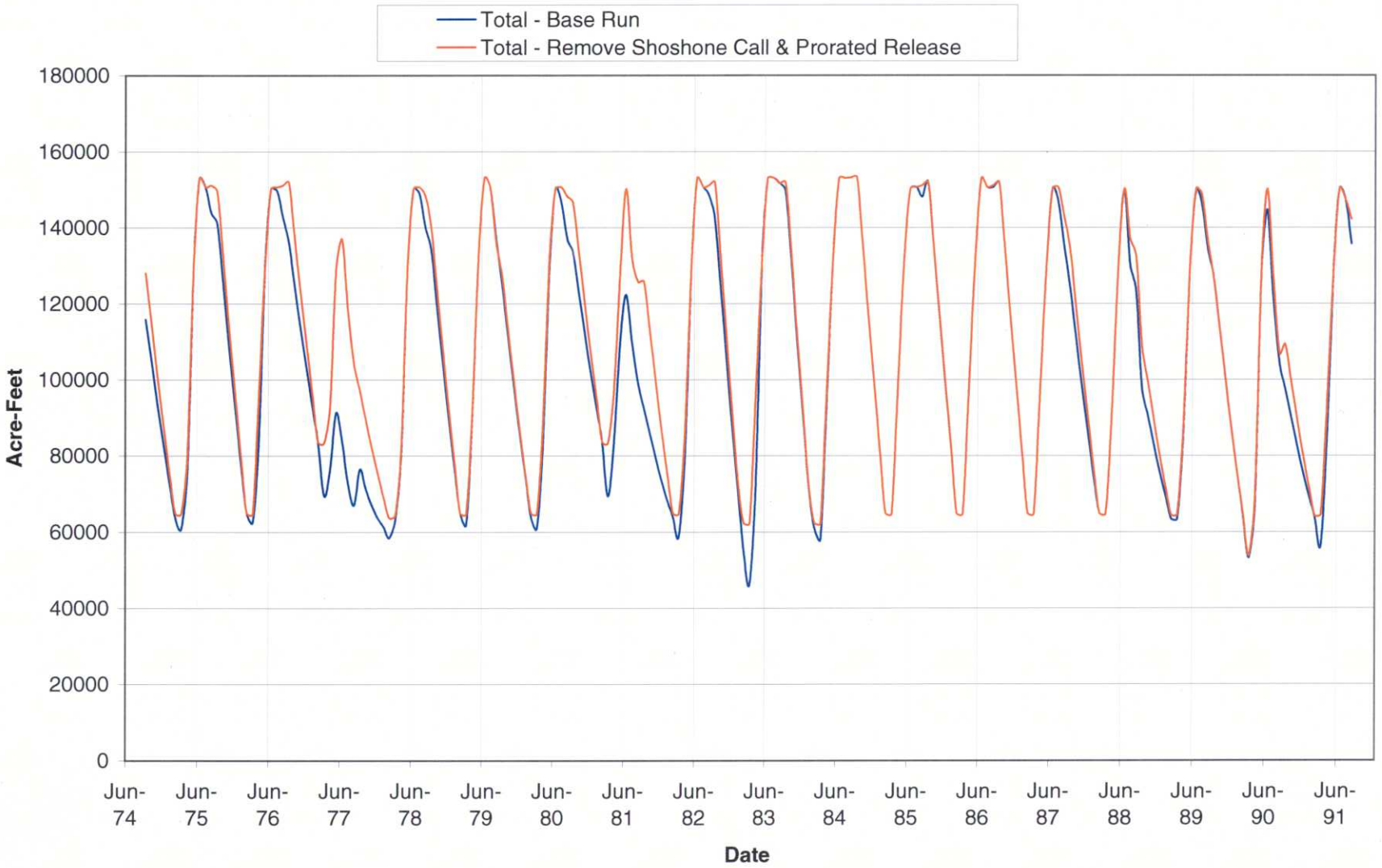

Figure 12

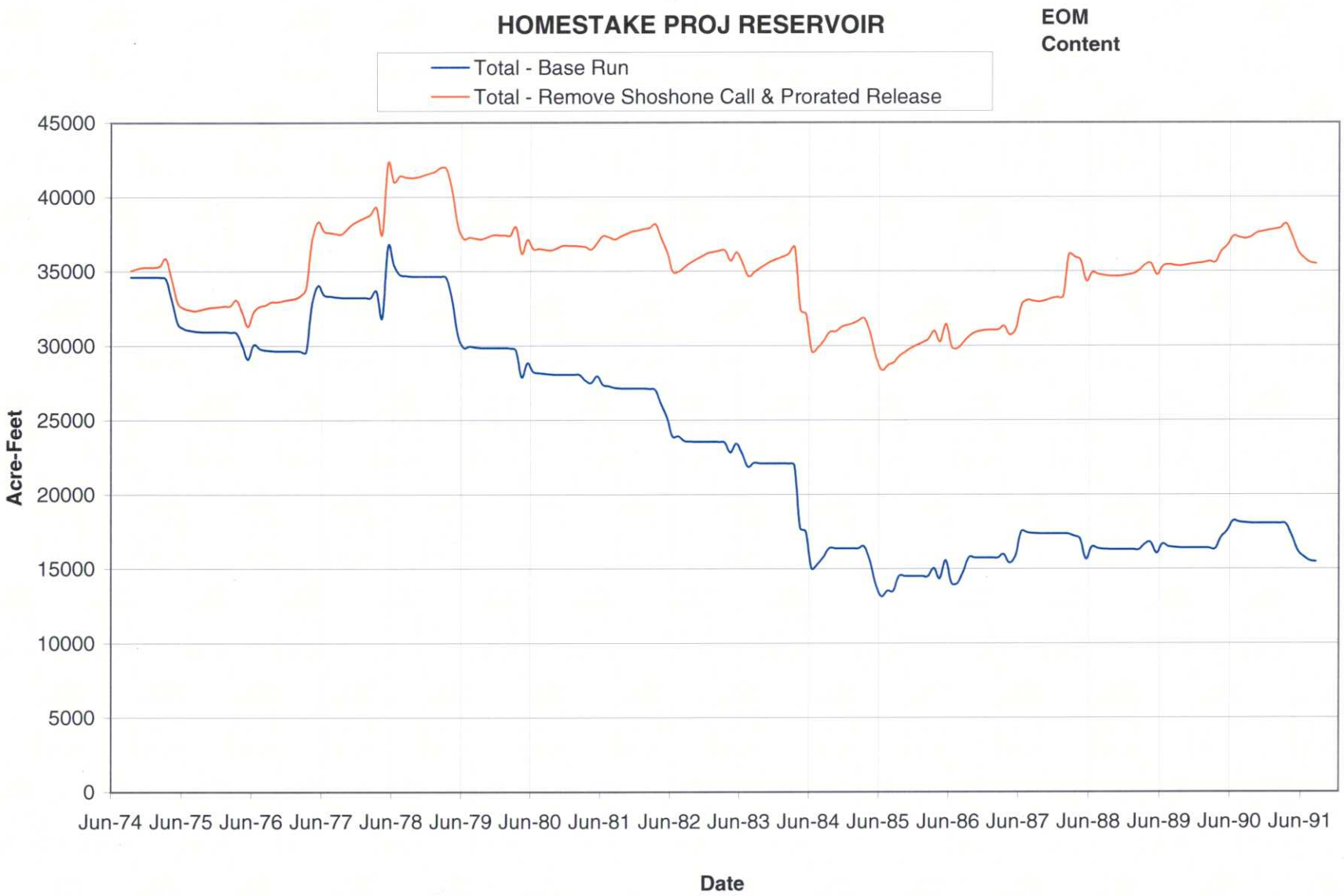
HOMESTAKE PROJ RESERVOIR
EOM Content
Total - Base Run
Total - Remove Shoshone Call & Prorated Release
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Figure 13

WILLIAMS FORK RESERVOIR

EOM Content

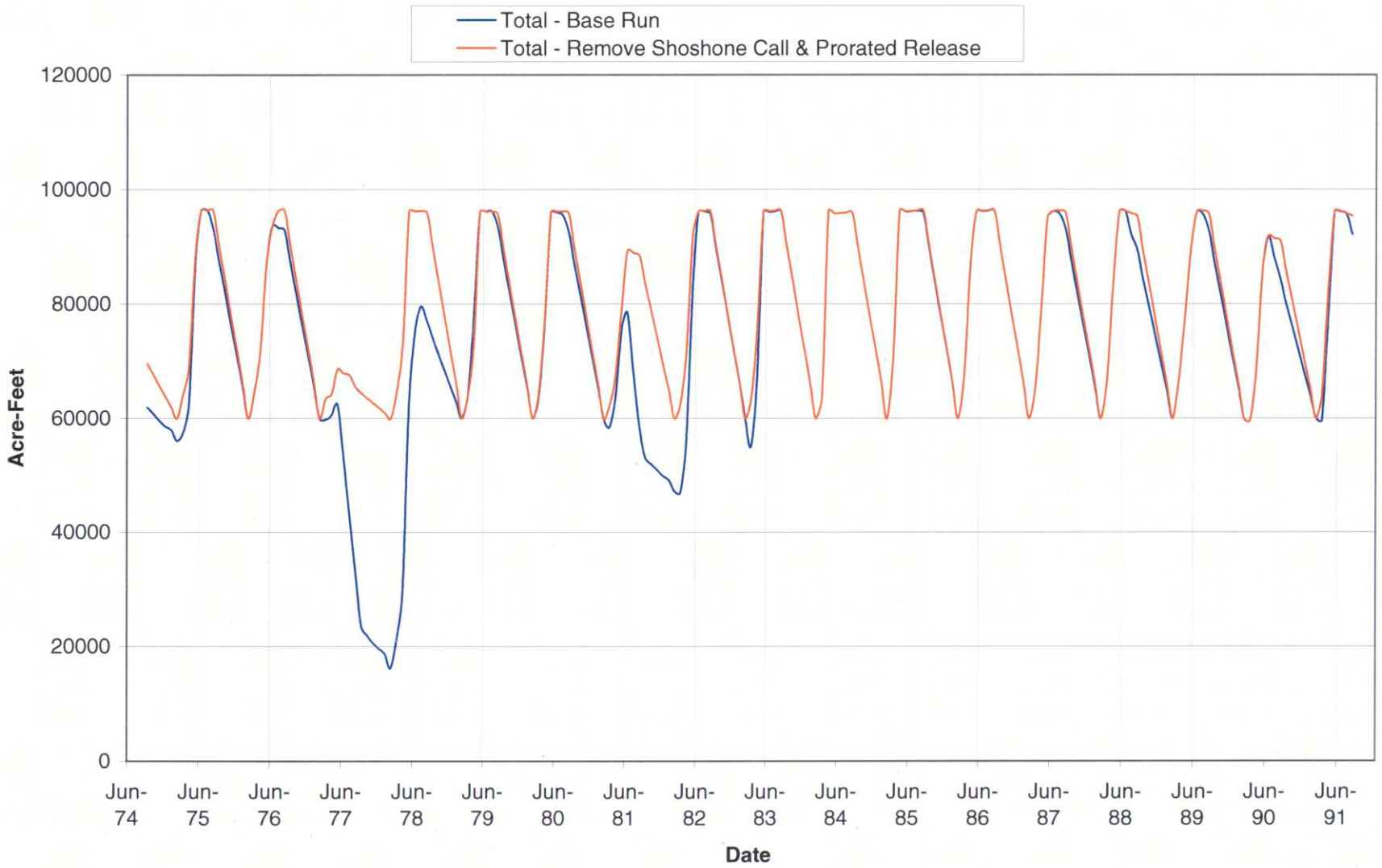

Figure 14

CBT WILLOW CREEK RES

EOM Content

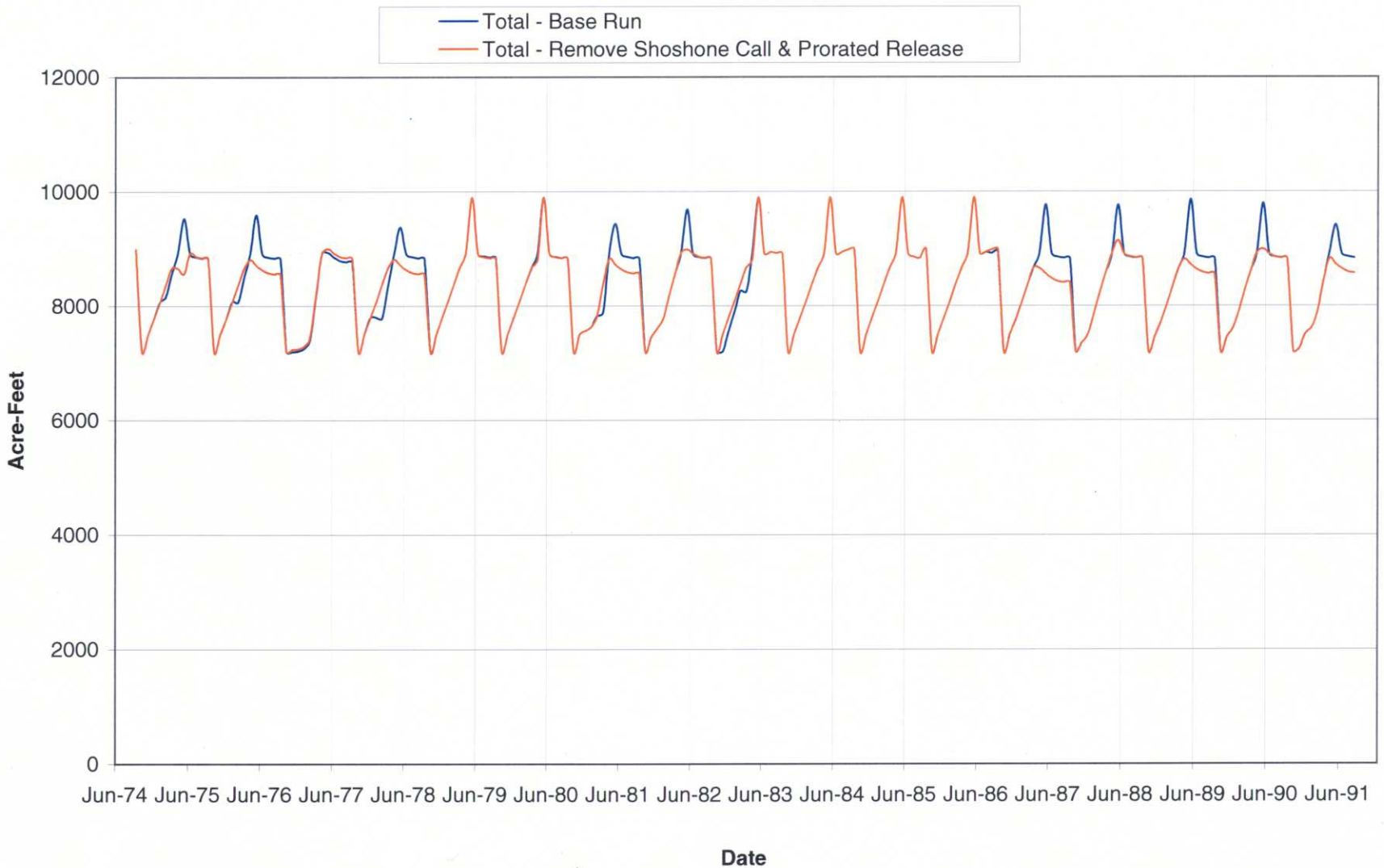

Figure 15

WOLFORD_MOUNTAIN_RES
EOM Content
Total - Base Run
Total - Remove Shoshone Call & Prorated Release
70000
60000
50000
40000
30000
20000
10000
0
Acre-Feet
Jun-74 Jun-75 Jun-76 Jun-77 Jun-78 Jun-79 Jun-80 Jun-81 Jun-82 Jun-83 Jun-84 Jun-85 Jun-86 Jun-87 Jun-88 Jun-89 Jun-90 Jun-91
Date

Figure 16

VEGA RESERVOIR

EOM Content

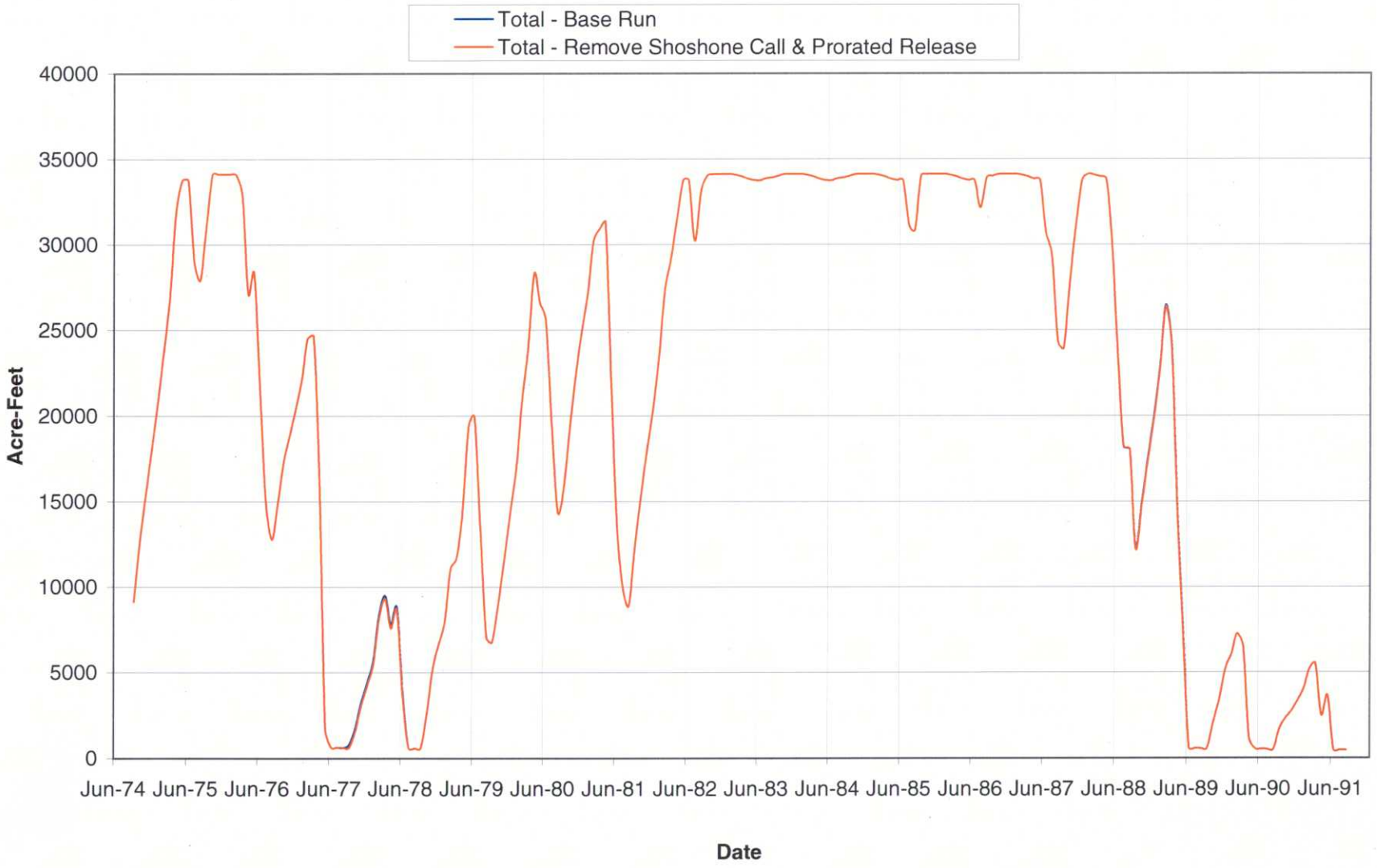

Table 1. Proportionate Share of 20,000 acre-feet Release Based on Increase in Storage Due to Removal of Shoshone Call

Reservoir	Prorated 20,000 AF Release (acre-feet)
Dillon	3080
Granby	3324
Green Mountain	5960
Homestake	0
Williams Fork	5743
Willow Creek	0
Wolford	1894
Vega	0

[1]average of monthly storage, 1974-1991

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call

		Base							Shoshone								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	6627	128059	7937.24	248.24	107.78	547	21	-37	0.03878
1974	NOV	Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	23763	114193	7929.62	240.62	399.34	4374	284	49	0.06502
1974	DEC	Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	22200	100694	7921.50	232.50	361.04	3711	391	73	0.10541
1975	JAN	Jan-75	18019	82713	7909.22	220.22	293.05	2409	313	20461	87596	7912.73	223.73	332.76	3045	396	83	0.13
1975	FEB	Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	19486	75084	7903.44	214.44	350.86	2697	175	37	0.065
1975	MAR	Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	17180	64929	7895.03	206.03	279.40	1817	82	13	0.045
1975	APR	Apr-75	12606	60993	7891.53	202.53	211.85	849	38	9989	64803	7894.92	205.92	167.87	399	18	-20	0.045
1975	MAY	May-75	5289	75596	7903.84	214.84	0.00	0	0	5289	79395	7906.75	217.75	0.00	0	0	0	0.045
1975	JUN	Jun-75	5970	118698	7932.16	243.16	100.33	323	18	6800	129038	7937.76	248.76	114.28	632	34	17	0.05416
1975	JUL	Jul-75	44909	153013	7949.70	260.70	730.36	10217	631	80734	152997	7949.70	260.70	1312.99	18600	1149	518	0.06176
1975	AUG	Aug-75	21079	150691	7948.60	259.60	342.81	4326	463	27709	150691	7948.60	259.60	450.64	5949	636	174	0.10693
1975	SEP	Sep-75	23444	143792	7945.26	256.26	393.98	4821	283	7058	151163	7948.83	259.83	118.61	923	54	-229	0.05866
1975	OCT	Oct-75	11435	141030	7943.90	254.90	185.97	1848	72	6627	149470	7948.02	259.02	107.78	774	30	-42	0.03878
1975	NOV	Nov-75	26431	124567	7935.37	246.37	444.18	5194	338	28138	131317	7938.95	249.95	472.87	5726	372	35	0.06502
1975	DEC	Dec-75	23515	108475	7926.28	237.28	382.43	4168	439	25208	113538	7929.24	240.24	409.96	4658	491	52	0.10541
1976	JAN	Jan-76	22349	92783	7916.31	227.31	363.47	3574	465	24038	96158	7918.57	229.57	390.93	4023	523	58	0.13
1976	FEB	Feb-76	22020	77678	7905.45	216.45	382.81	3245	211	23707	79365	7906.73	217.73	412.14	3645	237	26	0.065
1976	MAR	Mar-76	20868	64928	7895.03	206.03	339.38	2570	116	21102	64927	7895.03	206.03	343.19	2618	118	2	0.045
1976	APR	Apr-76	13538	62688	7893.04	204.04	227.51	1076	48	11420	64803	7894.92	205.92	191.92	692	31	-17	0.045
1976	MAY	May-76	5289	84396	7910.45	221.45	0.00	0	0	5289	95706	7918.27	229.27	0.00	0	0	0	0.045
1976	JUN	Jun-76	5970	118314	7931.95	242.95	100.33	319	17	35770	129003	7937.74	248.74	601.13	7488	406	388	0.05416
1976	JUL	Jul-76	7258	150218	7948.38	259.38	118.04	936	58	24216	150202	7948.37	259.37	393.83	5086	314	256	0.06176
1976	AUG	Aug-76	24202	150694	7948.60	259.60	393.60	5091	544	17274	150694	7948.60	259.60	280.93	3394	363	-181	0.10693
1976	SEP	Sep-76	26697	143787	7945.26	256.26	448.65	5609	329	11128	151177	7948.83	259.83	187.01	1921	113	-216	0.05866
1976	OCT	Oct-76	21292	137153	7941.95	252.95	346.28	4164	161	8491	151945	7949.20	260.20	138.09	1256	49	-113	0.03878
1976	NOV	Nov-76	19439	125465	7935.86	246.86	326.68	3566	232	23228	137295	7942.02	253.02	390.35	4661	303	71	0.06502
1976	DEC	Dec-76	17779	114148	7929.59	240.59	289.14	2957	312	20933	123021	7934.54	245.54	340.44	3842	405	93	0.10541
1977	JAN	Jan-77	16581	103232	7923.09	234.09	269.66	2496	324	19540	109147	7926.68	237.68	317.78	3274	426	101	0.13
1977	FEB	Feb-77	15679	92900	7916.39	227.39	282.31	2236	145	18636	95857	7918.37	229.37	335.55	2945	191	46	0.065
1977	MAR	Mar-77	16336	83715	7909.95	220.95	265.68	2068	93	18505	83714	7909.95	220.95	300.95	2535	114	21	0.045
1977	APR	Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	11482	83381	7909.71	220.71	192.96	1062	48	-118	0.045
1977	MAY	May-77	8210	76212	7904.32	215.32	133.52	190	9	5289	92990	7916.45	227.45	0.00	0	0	-9	0.045
1977	JUN	Jun-77	10496	89882	7914.33	225.33	176.39	958	52	6126	129008	7937.74	248.74	102.95	472	26	-26	0.05416
1977	JUL	Jul-77	20984	81600	7908.40	219.40	341.27	3021	187	13160	136980	7941.86	252.86	214.02	2211	137	-50	0.06176
1977	AUG	Aug-77	24562	70386	7899.66	210.66	399.46	3486	373	37237	118391	7931.99	242.99	605.59	7549	807	434	0.10693
1977	SEP	Sep-77	13060	64467	7894.62	205.62	219.48	1019	60	24046	104135	7923.65	234.65	404.10	4239	249	189	0.05866
1977	OCT	Oct-77	13113	78018	7905.71	216.71	213.26	1263	49	18603	97092	7919.18	230.18	302.54	2834	110	61	0.03878
1977	NOV	Nov-77	13832	72768	7901.60	212.60	232.45	1358	88	16243	89429	7914.02	225.02	272.97	2207	144	55	0.06502
1977	DEC	Dec-77	13180	68553	7898.14	209.14	214.35	1080	114	16277	82122	7908.79	219.79	264.72	2022	213	99	0.10541
1978	JAN	Jan-78	11540	65099	7895.18	206.18	187.68	668	87	14997	75214	7903.54	214.54	243.90	1603	208	122	0.13
1978	FEB	Feb-78	9980	62267	7892.68	203.68	179.70	458	30	13468	68895	7898.43	209.43	242.50	1306	85	55	0.065
1978	MAR	Mar-78	9924	59462	7890.06	201.06	161.40	217	10	12280	63732	7893.97	204.97	199.71	789	35	26	0.045
1978	APR	Apr-78	6764	63650	7893.90	204.90	113.67	0	0	10357	64323	7894.50	205.50	174.05	465	21	21	0.045
1978	MAY	May-78	5289	81623	7908.42	219.42	0.00	0	0	5289	82296	7908.92	219.92	0.00	0	0	0	0.045
1978	JUN	Jun-78	15778	129033	7937.75	248.75	265.15	2757	149	16452	129032	7937.75	248.75	276.48	2916	158	9	0.05416
1978	JUL	Jul-78	21971	150202	7948.37	259.37	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call

			Base							Shoshone								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	DEC	Dec-81	13712	79508	7906.84	217.84	223.00	1420	150	20332	99342	7920.63	231.63	330.66	3265	344	194	0.10541
1982	JAN	Jan-82	13447	73472	7902.16	213.16	218.69	1241	161	20065	86694	7912.10	223.10	326.32	2939	382	221	0.13
1982	FEB	Feb-82	11121	68270	7897.90	208.90	200.24	808	53	17984	74634	7903.08	214.08	323.81	2371	154	102	0.065
1982	MAR	Mar-82	10132	64931	7895.03	206.03	164.78	377	17	16500	64929	7895.03	206.03	268.34	1678	76	59	0.045
1982	APR	Apr-82	14708	59945	7890.51	201.51	247.17	1246	56	9846	64803	7894.92	205.92	165.47	370	17	-39	0.045
1982	MAY	May-82	5289	80823	7907.82	218.82	0.00	0	0	5289	85666	7911.36	222.36	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	128578	7937.51	248.51	100.33	430	23	6119	129024	7937.75	248.75	102.83	470	25	2	0.05416
1982	JUL	Jul-82	24246	150202	7948.37	259.37	394.32	5093	315	41333	152997	7949.70	260.70	672.21	9338	577	262	0.06176
1982	AUG	Aug-82	24277	150694	7948.60	259.60	394.82	5109	546	33862	150691	7948.60	259.60	550.70	7456	797	251	0.10693
1982	SEP	Sep-82	15141	147920	7947.27	258.27	254.45	2863	168	13435	151177	7948.83	259.83	225.78	2486	146	-22	0.05866
1982	OCT	Oct-82	17466	138534	7942.65	253.65	284.05	3267	127	8966	151945	7949.20	260.20	145.82	1373	53	-73	0.03878
1982	NOV	Nov-82	26574	120571	7933.20	244.20	446.58	5150	335	29256	131296	7938.94	249.94	491.66	5992	390	55	0.06502
1982	DEC	Dec-82	24978	102978	7922.93	233.93	406.22	4384	462	27862	111022	7927.78	238.78	453.13	5215	550	88	0.10541
1983	JAN	Jan-83	23515	85785	7911.45	222.45	382.43	3666	477	26992	91147	7915.20	226.20	438.98	4557	592	116	0.13
1983	FEB	Feb-83	22970	69180	7898.66	209.66	413.59	3280	213	25651	71860	7900.87	211.87	461.86	3910	254	41	0.065
1983	MAR	Mar-83	19106	54935	7885.66	196.66	310.72	1925	87	14309	62409	7892.80	203.80	232.71	1170	53	-34	0.045
1983	APR	Apr-83	16268	46395	7876.55	187.55	273.39	1171	53	7879	62234	7892.65	203.65	132.41	0	0	-53	0.045
1983	MAY	May-83	5289	65257	7895.32	206.32	0.00	0	0	8871	95191	7917.93	228.93	144.27	639	29	29	0.045
1983	JUN	Jun-83	50369	131466	7939.03	250.03	846.47	11013	596	139245	131400	7938.99	249.99	1500.00	18000	975	378	0.05416
1983	JUL	Jul-83	127864	152994	7949.70	260.70	1500.00	18600	1149	122483	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62884	153088	7949.74	260.74	1022.70	14637	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	27578	150624	7948.57	259.57	463.46	5943	349	27365	151679	7949.07	260.07	459.88	5909	347	-2	0.05866
1983	OCT	Oct-83	17200	148589	7947.60	258.60	279.73	3346	130	13862	151944	7949.20	260.20	225.44	2574	100	-30	0.03878
1983	NOV	Nov-83	30364	129812	7938.16	249.16	510.28	6225	405	31667	132495	7939.56	250.56	532.17	6589	428	24	0.06502
1983	DEC	Dec-83	31474	109909	7927.13	238.13	511.87	6016	634	32144	111921	7928.31	239.31	522.76	6217	655	21	0.10541
1984	JAN	Jan-84	29133	90406	7914.69	225.69	473.80	5008	651	29804	91747	7915.61	226.61	484.71	5190	675	24	0.13
1984	FEB	Feb-84	26279	71489	7900.57	211.57	456.86	3979	259	26966	72160	7901.11	212.11	468.80	4141	269	11	0.065
1984	MAR	Mar-84	20301	60815	7891.35	202.35	330.16	2339	105	18083	62415	7892.80	203.80	294.09	1935	87	-18	0.045
1984	APR	Apr-84	12328	58162	7888.82	199.82	207.18	726	33	14668	62240	7892.66	203.66	246.50	1295	58	26	0.045
1984	MAY	May-84	74916	94762	7917.64	228.64	1218.37	15260	687	95638	96790	7918.98	229.98	1500.00	18600	837	150	0.045
1984	JUN	Jun-84	155640	131401	7938.99	249.99	1500.00	18000	975	157543	131396	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	126134	152994	7949.70	260.70	1500.00	18600	1149	124352	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	85268	153088	7949.74	260.74	1386.73	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	36965	153173	7949.78	260.78	621.21	8295	487	35687	153173	7949.78	260.78	599.73	7980	468	-18	0.05866
1984	OCT	Oct-84	23289	153342	7949.86	260.86	378.75	4909	190	23558	153342	7949.86	260.86	383.13	4975	193	3	0.03878
1984	NOV	Nov-84	33427	135612	7941.17	252.17	561.75	7073	460	32940	135612	7941.17	252.17	553.57	6957	452	-8	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	33048	116759	7931.07	242.07	537.47	6538	689	-10	0.10541
1985	JAN	Jan-85	30448	98306	7919.97	230.97	495.18	5502	715	30448	98306	7919.97	230.97	495.18	5502	715	0	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	28571	80438	7907.54	218.54	514.44	4760	309	0	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	25961	64927	7895.03	206.03	422.21	3611	163	0	0.045
1985	APR	Apr-85	20008	64819	7894.93	205.93	336.24	2446	110	27019	64819	7894.93	205.93	454.06	3879	175	64	0.045
1985	MAY	May-85	53196	98074	7919.82	230.82	865.14	10572	476	53155	98074	7919.82	230.82	864.47	10563	475	0	0.045
1985	JUN	Jun-85	100533	131394	7938.99	249.99	1500.00	18000	975	100470	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	48123	150198	7948.37	259.37	782.63	10937	675	47306	150198	7948.37	259.37	769.35	10737	663	-12	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	12022	151177	7948.83	259.83	202.03	2140	126	-115	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	11890	152002	7949.23	260.23	193.37	2091	81	28	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	30198	134542	7940.62	251.62	507.49	6280	408	0	0.06502
1985	DEC	Dec-85	28811	116554	7930.96	241.96	468.56	5552	585	28509	116901	7931.15	242.15	463.65	5490	579	-7	0.10541
1986	JAN	Jan-86	28595	98169	7919.88	230.88	465.05	5085	661	28714	98400	7920.03	231.03	466.98	5117	665	4	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	26707	81686	7908.47	219.47	480.88	4393	286	2	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	27446	64926	7895.03	206.03	446.36	3915	176	1	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	19014	64819	7894.93	205.93	319.54	2243	101	25	0.045
1986	MAY	May-86	5289	98074	7919.82	230.82	0.00	0	0	34587	98074	7919.82	230.82	562.50	6420	289	289	0.045
1986	JUN	Jun-86	97345	131394	7938.99	249.99	1500.00	18000	975	103799	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	55132	150198	7948.37	259.37	896.62	12652	781	54802	152994	7949.70	260.70	891.26	12648	781	0	0.06176
1986	AUG	Aug-86	16820	150694	7948.60	259.60	273.55	3283	351	19863	150691	7948.60	259.60	323.04	4028	431	80	0.10693
1986	SEP	Sep-86	15989	149012	7947.80	258.80	268.70	3084	181	12951	151177	7948.83	259.83	217.65	2368	139	-42	0.05866
1986	OCT	Oct-86	7922	151946	7949.20	260.20	128.84	1116	43	10087	151945	7949.20	260.20	164.05	1648	64	21	0.03878
1986	NOV	Nov-86	29317	134497	7940.59	251.59	492.68	6069	395	29317	134496	7940.59	251.59	492.68	6068	395	0	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	27465	115922	7930.60	241.60	446.67	5227	551	0	0.10541
1987	JAN	Jan-87	25065	97748	7919.61	230.61	407.64	4288	557	25065	97747	7919.61	230.61	407.64	4288	557	0	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	24052	80159	7907.33	218.33	433.07	3787	246	0	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	21770	64927	7895.03	206.03	354.05	2755	124	-15	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	12194	64819	7894.93	205.93	204.92	850	38	0	0.045
1987	MAY	May-87	5289	88214	7913.17	224.17	0.00	0	0	10491	96476	7918.78	229.78	170.62	1018	46	46	0.045
1987	JUN	Jun-87	23733	129019	7937.75	248.75	398.84	4639	251	37859	129001	7937.74	248.74	636.23	7983	432	181	0.05416
1987	JUL	Jul-87	14257	145090	7945.90	256.90	231.86	2582	159	8540	150202	7948.37	259.37	138.89	1249	77	-82	0.06176
1987	AUG	Aug-87	31080	137711	7942.23	253.23	505.46	6523	698	12025	150694	7948.60	259.60	195.57	2108	225	-472	0.10693
1987	SEP	Sep-87	28201	123982	7935.06	246.06	473.93	5598	328	22402	142656	7944.70	255.70	376.47	4550	267	-61	0.05866
1987	OCT	Oct-87	22632	111836	7928.26	239.26	368.07	4032	156	19017	134057	7940.37	251.37	309.28	3570	138	-18	0.03878
1987	NOV	Nov-87	18662	101220	7921.83	232.83	313.62	2968	193	23725	118991	7932.32	243.32	398.71	4456	290	97	0.06502
1987	DEC	Dec-87	17624	90965	7915.08	226.08	286.62	2496	263	22228	104293	7923.75	234.75	361.50	3791	400	137	0.10541
1988	JAN	Jan-88	17487	81109	7908.04	219.04	284.39	2260	294	21929	89995	7914.41	225.41	356.64	3419	444	151	0.13
1988	FEB	Feb-88	15652	71842	7900.85	211.85	272.11	1770	115	20095	76284	7904.37	215.37	349.35	2804	182	67	0.065
1988	MAR	Mar-88	15649	63730	7893.97	204.97	254.50	1474	66	17250	64928	7895.03	206.03	280.54	1831	82	16	0.045
1988	APR	Apr-88	12778	63422	7893.70	204.70	214.74	938	42	12592	64803	7894.92	205.92	211.61	931	42	0	0.045
1988	MAY	May-88	5289	88197	7913.16	224.16	0.00	0	0	5289	89574	7914.12	225.12	0.00	0	0	0	0.045
1988	JUN	Jun-88	8470	129019	7937.75	248.75	142.34	1027	56	62424	129016	7937.74	248.74	1049.05	13797	747	692	0.05416
1988	JUL	Jul-88	15670	146906	7946.78	257.78	254.84	2950	182	18295	150202	7948.37	259.37	297.54	3637	225	42	0.06176
1988	AUG	Aug-88	42120	127583	7936.99	247.99	685.01	8923	954	35620	137249	7942.00	253.00	579.30	7603	813	-141	0.10693
1988	SEP	Sep-88	19530	120044	7932.91	243.91	328.21	3498	205	16937	132196	7939.41	250.41	284.63	3078	181	-25	0.05866
1988	OCT	Oct-88	34719	95471	7918.11	229.11	564.64	6377	247	32711	109480	7926.88	237.88	531.99	6289	244	-3	0.03878
1988	NOV	Nov-88	16847	88133	7913.11	224.11	283.12	2314	150	20060	99336	7920.63	231.63	337.11	3245	211	61	0.06502
1988	DEC	Dec-88	14071	81149	7908.07	219.07	228.84	1529	161	16896	89552	7914.10	225.10	274.78	2308	243	82	0.10541
1989	JAN	Jan-89	13478	74566	7903.03	214.03	219.20	1270	165	16297	80168	7907.34	218.34	265.04	1985	258	93	0.13
1989	FEB	Feb-89	12515	68570	7898.15	209.15	225.34	1102	72	15329	71371	7900.47	211.47	276.01	1744	113	42	0.065

Table 2
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call

			Base							Shoshone								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1989	MAR	Mar-89	15213	62815	7893.15	204.15	247.41	1363	61	14722	64468	7894.62	205.62	239.43	1303	59	-3	0.045
1989	APR	Apr-89	14366	63423	7893.70	204.70	241.43	1261	57	14746	64701	7894.83	205.83	247.81	1369	62	5	0.045
1989	MAY	May-89	5289	86102	7911.67	222.67	0.00	0	0	5289	87381	7912.58	223.58	0.00	0	0	0	0.045
1989	JUN	Jun-89	5970	118342	7931.96	242.96	100.33	319	17	23845	129020	7937.75	248.75	400.72	4666	253	235	0.05416
1989	JUL	Jul-89	16484	146771	7946.72	257.72	268.08	3147	194	23253	150202	7948.37	259.37	378.17	4850	300	105	0.06176
1989	AUG	Aug-89	33695	143238	7944.99	255.99	547.99	7266	777	21466	148773	7947.68	258.68	349.11	4391	470	-307	0.10693
1989	SEP	Sep-89	26680	131308	7938.95	249.95	448.37	5380	316	27320	136188	7941.46	252.46	459.12	5623	330	14	0.05866
1989	OCT	Oct-89	18106	124187	7935.17	246.17	294.46	3198	124	20131	126984	7936.67	247.67	327.39	3721	144	20	0.03878
1989	NOV	Nov-89	21686	111097	7927.83	238.83	364.44	3839	250	22914	113333	7929.12	240.12	385.08	4163	271	21	0.06502
1989	DEC	Dec-89	20323	98372	7920.01	231.01	330.52	3243	342	21202	100049	7921.09	232.09	344.81	3474	366	24	0.10541
1990	JAN	Jan-90	18559	86048	7911.63	222.63	301.83	2598	338	19118	87166	7912.43	223.43	310.92	2743	357	19	0.13
1990	FEB	Feb-90	17445	74310	7902.83	213.83	314.11	2251	146	18004	74869	7903.27	214.27	324.17	2380	155	8	0.065
1990	MAR	Mar-90	18102	63993	7894.20	205.20	294.40	1981	89	15892	64929	7895.03	206.03	258.45	1554	70	-19	0.045
1990	APR	Apr-90	21259	52420	7883.09	194.09	357.26	2328	105	20887	53725	7884.43	195.43	351.01	2297	103	-1	0.045
1990	MAY	May-90	5289	65904	7895.88	206.88	0.00	0	0	5289	68517	7898.11	209.11	0.00	0	0	0	0.045
1990	JUN	Jun-90	5970	104461	7923.85	234.85	100.33	157	9	29207	129063	7937.77	248.77	490.83	5936	321	313	0.05416
1990	JUL	Jul-90	10557	117531	7931.51	242.51	171.69	1339	83	15727	150202	7948.37	259.37	255.77	3008	186	103	0.06176
1990	AUG	Aug-90	23529	106801	7925.28	236.28	382.66	4137	442	47144	126789	7936.56	247.56	766.71	10087	1079	636	0.10693
1990	SEP	Sep-90	24948	91098	7915.17	226.17	419.26	4151	243	34972	106925	7925.35	236.35	587.72	6780	398	154	0.05866
1990	OCT	Oct-90	15739	84342	7910.41	221.41	255.97	1952	76	6627	109366	7926.81	237.81	107.78	328	13	-63	0.03878
1990	NOV	Nov-90	16712	79234	7906.63	217.63	280.85	2102	137	21910	99245	7920.57	231.57	368.20	3657	238	101	0.06502
1990	DEC	Dec-90	14136	74475	7902.96	213.96	229.90	1406	148	19808	89483	7914.05	225.05	322.14	2943	310	162	0.10541
1991	JAN	Jan-91	13069	70116	7899.44	210.44	212.54	1091	142	18073	80122	7907.30	218.30	293.92	2363	307	165	0.13
1991	FEB	Feb-91	9695	67241	7897.03	208.03	174.57	495	32	15594	71348	7900.45	211.45	280.78	1799	117	85	0.065
1991	MAR	Mar-91	9243	64008	7894.22	205.22	150.32	176	8	13156	64202	7894.39	205.39	213.96	978	44	36	0.045
1991	APR	Apr-91	15137	57856	7888.53	199.53	254.38	1279	58	8538	64641	7894.78	205.78	143.48	100	4	-53	0.045
1991	MAY	May-91	5289	86569	7912.01	223.01	0.00	0	0	5289	93334	7916.69	227.69	0.00	0	0	0	0.045
1991	JUN	Jun-91	5970	129022	7937.75	248.75	100.33	435	24	43892	129008	7937.74	248.74	737.62	9411	510	486	0.05416
1991	JUL	Jul-91	7258	147918	7947.27	258.27	118.04	912	56	19791	150202	7948.37	259.37	321.87	4003	247	191	0.06176
1991	AUG	Aug-91	27548	139243	7943.00	254.00	448.02	5704	610	25995	150314	7948.42	259.42	422.76	5523	591	-19	0.10693
1991	SEP	Sep-91	30332	127709	7937.05	248.05	0.00	0	0	22641	145139	7945.92	256.92	0.00	0	0	0	0.05866
						Totals			$52,385,492							$62,898,648		
						Difference										$10,513,156		
						Average Annual										$618,421		

Table 3
SHOSHONE POWER PLANT
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call

			Base				Shoshone					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	53985	878	7423	288	-69	0.04
1974	NOV	Nov-74	66071	1110	9085	591	69176	1163	9512	618	28	0.07
1974	DEC	Dec-74	61830	1006	8502	896	64893	1055	8923	941	44	0.11
1975	JAN	Jan-75	59899	974	8236	1071	63145	1027	8682	1129	58	0.13
1975	FEB	Feb-75	58476	1053	8040	523	62000	1116	8525	554	31	0.07
1975	MAR	Mar-75	61181	995	8412	379	62207	1012	8553	385	6	0.05
1975	APR	Apr-75	74381	1250	10227	460	67545	1135	9287	418	-42	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	54258	912	7460	438	-162	0.06
1975	OCT	Oct-75	70098	1140	9638	374	65514	1065	9008	349	-24	0.04
1975	NOV	Nov-75	79448	1335	10924	710	79841	1342	10978	714	4	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	73863	1201	10156	1071	31	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	70049	1139	9632	1252	28	0.13
1976	FEB	Feb-76	70614	1228	9709	631	72021	1252	9903	644	13	0.07
1976	MAR	Mar-76	76631	1246	10537	474	75711	1231	10410	468	-6	0.05
1976	APR	Apr-76	82638	1389	11363	511	79858	1342	10980	494	-17	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	75601	1230	10395	1112	-161	0.11
1976	SEP	Sep-76	74381	1250	10227	600	57685	969	7932	465	-135	0.06
1976	OCT	Oct-76	74383	1210	10228	397	61445	999	8449	328	-69	0.04
1976	NOV	Nov-76	59697	1003	8208	534	62948	1058	8655	563	29	0.07
1976	DEC	Dec-76	49447	804	6799	717	52915	861	7276	767	50	0.11
1977	JAN	Jan-77	47151	767	6483	843	50625	823	6961	905	62	0.13
1977	FEB	Feb-77	47230	850	6494	422	50750	914	6978	454	31	0.07
1977	MAR	Mar-77	49872	811	6857	309	51966	845	7145	322	13	0.05
1977	APR	Apr-77	74381	1250	10227	460	57653	969	7927	357	-104	0.05
1977	MAY	May-77	86576	1408	11904	536	83720	1362	11511	518	-18	0.05
1977	JUN	Jun-77	83783	1408	11520	624	80525	1353	11072	600	-24	0.05
1977	JUL	Jul-77	76861	1250	10568	653	61124	994	8404	519	-134	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76722	1248	10549	1128	-2	0.11
1977	SEP	Sep-77	52714	886	7248	425	53072	892	7297	428	3	0.06
1977	OCT	Oct-77	58234	947	8007	311	54842	892	7541	292	-18	0.04
1977	NOV	Nov-77	45851	771	6304	410	45847	770	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	47485	772	6529	688	15	0.11
1978	JAN	Jan-78	45729	744	6288	817	46000	748	6325	822	5	0.13
1978	FEB	Feb-78	39553	712	5438	353	39163	705	5385	350	-3	0.07
1978	MAR	Mar-78	53027	862	7291	328	49423	804	6796	306	-22	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	76356	1242	10499	1123	-125	0.11
1978	SEP	Sep-78	65053	1093	8945	525	50599	850	6957	408	-117	0.06
1978	OCT	Oct-78	60476	984	8315	322	62618	1018	8610	334	11	0.04
1978	NOV	Nov-78	63938	1074	8791	572	67957	1142	9344	608	36	0.07
1978	DEC	Dec-78	53625	872	7373	777	57569	936	7916	834	57	0.11
1979	JAN	Jan-79	49664	808	6829	888	53615	872	7372	958	71	0.13
1979	FEB	Feb-79	50049	901	6882	447	53980	972	7422	482	35	0.07
1979	MAR	Mar-79	61728	1004	8487	382	63141	1027	8682	391	9	0.05
1979	APR	Apr-79	80714	1356	11098	499	76964	1293	10582	476	-23	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	62509	1050	8595	504	-19	0.06
1979	OCT	Oct-79	64083	1042	8811	342	61696	1003	8483	329	-13	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70759	1189	9729	633	6	0.07
1979	DEC	Dec-79	67970	1105	9346	985	68610	1116	9434	994	9	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67933	1105	9341	1214	14	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62916	1094	8651	562	7	0.07
1980	MAR	Mar-80	63444	1032	8723	393	62216	1012	8555	385	-8	0.05
1980	APR	Apr-80	74381	1250	10227	460	72313	1215	9943	447	-13	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05

Table 3
SHOSHONE POWER PLANT
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call

1980 JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980 AUG	Aug-80	76861	1250	10568	1130	64774	1053	8906	952	-178	0.11
1980 SEP	Sep-80	70872	1191	9745	572	53720	903	7386	433	-138	0.06
1980 OCT	Oct-80	59823	973	8226	319	54665	889	7516	291	-28	0.04
1980 NOV	Nov-80	63271	1063	8700	566	66204	1113	9103	592	26	0.07
1980 DEC	Dec-80	59613	969	8197	864	62507	1017	8595	906	42	0.11
1981 JAN	Jan-81	51581	839	7092	922	54647	889	7514	977	55	0.13
1981 FEB	Feb-81	46680	841	6418	417	49813	897	6849	445	28	0.07
1981 MAR	Mar-81	50048	814	6881	310	53028	862	7291	328	18	0.05
1981 APR	Apr-81	74381	1250	10227	460	56991	958	7836	353	-108	0.05
1981 MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981 JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981 JUL	Jul-81	76861	1250	10568	653	68785	1119	9458	584	-69	0.06
1981 AUG	Aug-81	69790	1135	9596	1026	69815	1135	9599	1026	0	0.11
1981 SEP	Sep-81	63221	1062	8693	510	54527	916	7497	440	-70	0.06
1981 OCT	Oct-81	61933	1007	8516	330	54691	889	7520	292	-39	0.04
1981 NOV	Nov-81	51751	870	7116	463	61556	1034	8464	550	88	0.07
1981 DEC	Dec-81	45812	745	6299	664	55948	910	7693	811	147	0.11
1982 JAN	Jan-82	44243	720	6083	791	54333	884	7471	971	180	0.13
1982 FEB	Feb-82	38976	702	5359	348	49296	888	6778	441	92	0.07
1982 MAR	Mar-82	50770	826	6981	314	59788	972	8221	370	56	0.05
1982 APR	Apr-82	74381	1250	10227	460	66364	1115	9125	411	-50	0.05
1982 MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982 JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982 JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982 AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982 SEP	Sep-82	83783	1408	11520	676	74616	1254	10260	602	-74	0.06
1982 OCT	Oct-82	82000	1334	11275	437	69416	1129	9545	370	-67	0.04
1982 NOV	Nov-82	80279	1349	11038	718	81361	1367	11187	727	10	0.07
1982 DEC	Dec-82	68395	1112	9404	991	70093	1140	9638	1016	25	0.11
1983 JAN	Jan-83	64588	1050	8881	1154	66408	1080	9131	1187	33	0.13
1983 FEB	Feb-83	60401	1088	8305	540	61891	1114	8510	553	13	0.07
1983 MAR	Mar-83	68328	1111	9395	423	58285	948	8014	361	-62	0.05
1983 APR	Apr-83	70275	1181	9663	435	54985	924	7560	340	-95	0.05
1983 MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983 JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983 JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983 AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983 SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983 OCT	Oct-83	81342	1323	11184	434	75183	1223	10338	401	-33	0.04
1983 NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983 DEC	Dec-83	86576	1408	11904	1255	86432	1406	11884	1253	-2	0.11
1984 JAN	Jan-84	75666	1231	10404	1353	74120	1205	10191	1325	-28	0.13
1984 FEB	Feb-84	74251	1291	10209	664	73347	1275	10085	656	-8	0.07
1984 MAR	Mar-84	71770	1167	9868	444	68994	1122	9487	427	-17	0.05
1984 APR	Apr-84	79696	1339	10958	493	75862	1275	10431	469	-24	0.05
1984 MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984 JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984 JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984 AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984 SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984 OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984 NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984 DEC	Dec-84	85925	1397	11815	1245	81846	1331	11254	1186	-59	0.11
1985 JAN	Jan-85	80865	1315	11119	1445	79252	1289	10897	1417	-29	0.13
1985 FEB	Feb-85	76628	1380	10536	685	75284	1356	10351	673	-12	0.07
1985 MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985 MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985 JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985 AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985 SEP	Sep-85	75129	1263	10330	606	66112	1111	9090	533	-73	0.06
1985 OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985 NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985 DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986 JAN	Jan-86	85651	1393	11777	1531	84556	1375	11626	1511	-20	0.13
1986 FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986 MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986 MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986 JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06

Table 3
SHOSHONE POWER PLANT
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call

1986 AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986 SEP	Sep-86	83783	1408	11520	676	77327	1300	10632	624	-52	0.06
1986 OCT	Oct-86	86576	1408	11904	462	84773	1379	11656	452	-10	0.04
1986 NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986 DEC	Dec-86	78786	1281	10833	1142	78287	1273	10764	1135	-7	0.11
1987 JAN	Jan-87	69058	1123	9495	1234	68260	1110	9386	1220	-14	0.13
1987 FEB	Feb-87	66954	1206	9206	598	66094	1190	9088	591	-8	0.07
1987 MAR	Mar-87	77469	1260	10652	479	73550	1196	10113	455	-24	0.05
1987 APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987 MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987 JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987 JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987 AUG	Aug-87	76861	1250	10568	1130	59772	972	8219	879	-251	0.11
1987 SEP	Sep-87	62419	1049	8582	503	55884	939	7684	451	-53	0.06
1987 OCT	Oct-87	63624	1035	8748	339	61816	1005	8500	330	-10	0.04
1987 NOV	Nov-87	79093	1329	10875	707	77986	1311	10723	697	-10	0.07
1987 DEC	Dec-87	68906	1121	9474	999	71057	1156	9770	1030	31	0.11
1988 JAN	Jan-88	70055	1139	9632	1252	71541	1163	9837	1279	27	0.13
1988 FEB	Feb-88	64279	1117	8838	574	65798	1144	9047	588	14	0.07
1988 MAR	Mar-88	71897	1169	9886	445	66600	1083	9157	412	-33	0.05
1988 APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988 MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988 JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988 JUL	Jul-88	86576	1408	11904	735	85736	1394	11789	728	-7	0.06
1988 AUG	Aug-88	81837	1331	11252	1203	71863	1169	9881	1057	-147	0.11
1988 SEP	Sep-88	56113	943	7715	453	51080	858	7023	412	-41	0.06
1988 OCT	Oct-88	71010	1155	9764	379	70115	1140	9641	374	-5	0.04
1988 NOV	Nov-88	60510	1017	8320	541	63495	1067	8730	568	27	0.07
1988 DEC	Dec-88	56962	926	7832	826	59953	975	8243	869	43	0.11
1989 JAN	Jan-89	59364	965	8162	1061	62321	1014	8569	1114	53	0.13
1989 FEB	Feb-89	52009	936	7151	465	55010	990	7564	492	27	0.07
1989 MAR	Mar-89	76345	1242	10497	472	73062	1188	10046	452	-20	0.05
1989 APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989 MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989 JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989 JUL	Jul-89	86576	1408	11904	735	86008	1399	11826	730	-5	0.06
1989 AUG	Aug-89	76861	1250	10568	1130	62617	1018	8610	921	-209	0.11
1989 SEP	Sep-89	54165	910	7448	437	52272	878	7187	422	-15	0.06
1989 OCT	Oct-89	51573	839	7091	275	54066	879	7434	288	13	0.04
1989 NOV	Nov-89	61037	1026	8392	546	61008	1025	8388	545	0	0.07
1989 DEC	Dec-89	61907	1007	8512	897	62165	1011	8548	901	4	0.11
1990 JAN	Jan-90	57901	942	7961	1035	58182	946	8000	1040	5	0.13
1990 FEB	Feb-90	49568	893	6816	443	49876	898	6858	446	3	0.07
1990 MAR	Mar-90	62558	1017	8602	387	60239	980	8283	373	-14	0.05
1990 APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990 MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990 JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990 JUL	Jul-90	86576	1408	11904	735	80201	1304	11027	681	-54	0.06
1990 AUG	Aug-90	78519	1277	10796	1154	75395	1226	10367	1109	-46	0.11
1990 SEP	Sep-90	62931	1058	8653	508	62195	1045	8552	502	-6	0.06
1990 OCT	Oct-90	63305	1030	8704	338	49566	806	6815	264	-73	0.04
1990 NOV	Nov-90	60470	1016	8315	541	63475	1067	8728	567	27	0.07
1990 DEC	Dec-90	53934	877	7416	782	57039	928	7843	827	45	0.11
1991 JAN	Jan-91	49706	808	6834	888	52969	861	7283	947	58	0.13
1991 FEB	Feb-91	46476	837	6390	415	49768	896	6843	445	29	0.07
1991 MAR	Mar-91	52128	848	7167	323	53909	877	7412	334	11	0.05
1991 APR	Apr-91	74381	1250	10227	460	63099	1060	8676	390	-70	0.05
1991 MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991 JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991 JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991 AUG	Aug-91	76861	1250	10568	1130	74814	1217	10287	1100	-30	0.11
1991 SEP	9/1	71767	1206	9868	579	60567	1018	8328	489	-90	0.06
	Totals				$ 137,670,795				$ 135,694,657		
	Difference								-$1,976,138		
	Average Annual								-$116,243		

Table 4
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call and Making the 20,000 Acre-feet Release

		Base							Shoshone & Release								
Year	Mo Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	6627	128059	7937.24	248.24	107.78	547	21	-37	0.03878
1974	NOV Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	23763	114193	7929.62	240.62	399.34	4374	284	49	0.06502
1974	DEC Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	22200	100694	7921.50	232.50	361.04	3711	391	73	0.10541
1975	JAN Jan-75	18019	82713	7909.22	220.22	293.05	2409	313	20461	87596	7912.73	223.73	332.76	3045	396	83	0.13
1975	FEB Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	19486	75084	7903.44	214.44	350.86	2697	175	37	0.065
1975	MAR Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	17180	64929	7895.03	206.03	279.40	1817	82	13	0.045
1975	APR Apr-75	12606	60993	7891.53	202.53	211.85	849	38	9989	64803	7894.92	205.92	167.87	399	18	-20	0.045
1975	MAY May-75	5289	75596	7903.84	214.84	0.00	0	0	5289	79395	7906.75	217.75	0.00	0	0	0	0.045
1975	JUN Jun-75	5970	118698	7932.16	243.16	100.33	323	18	8360	129038	7937.76	248.76	140.49	1001	54	37	0.05416
1975	JUL Jul-75	44909	153013	7949.70	260.70	730.36	10217	631	84335	152997	7949.70	260.70	1371.56	18600	1149	518	0.06176
1975	AUG Aug-75	21079	150691	7948.60	259.60	342.81	4326	463	27765	150691	7948.60	259.60	451.55	5963	638	175	0.10693
1975	SEP Sep-75	23444	143792	7945.26	256.26	393.98	4821	283	7058	151163	7948.83	259.83	118.61	923	54	-229	0.05866
1975	OCT Oct-75	11435	141030	7943.90	254.90	185.97	1848	72	6627	149470	7948.02	259.02	107.78	774	30	-42	0.03878
1975	NOV Nov-75	26431	124567	7935.37	246.37	444.18	5194	338	28138	131317	7938.95	249.95	472.87	5726	372	35	0.06502
1975	DEC Dec-75	23515	108475	7926.28	237.28	382.43	4168	439	25208	113538	7929.24	240.24	409.96	4658	491	52	0.10541
1976	JAN Jan-76	22349	92783	7916.31	227.31	363.47	3574	465	24038	96158	7918.57	229.57	390.93	4023	523	58	0.13
1976	FEB Feb-76	22020	77678	7905.45	216.45	382.81	3245	211	23707	79365	7906.73	217.73	412.14	3645	237	26	0.065
1976	MAR Mar-76	20868	64928	7895.03	206.03	339.38	2570	116	21102	64927	7895.03	206.03	343.19	2618	118	2	0.045
1976	APR Apr-76	13538	62688	7893.04	204.04	227.51	1076	48	11420	64803	7894.92	205.92	191.92	692	31	-17	0.045
1976	MAY May-76	5289	84396	7910.45	221.45	0.00	0	0	5289	95706	7918.27	229.27	0.00	0	0	0	0.045
1976	JUN Jun-76	5970	118314	7931.95	242.95	100.33	319	17	35770	129003	7937.74	248.74	601.13	7488	406	388	0.05416
1976	JUL Jul-76	7258	150218	7948.38	259.38	118.04	936	58	24216	150202	7948.37	259.37	393.83	5086	314	256	0.06176
1976	AUG Aug-76	24202	150694	7948.60	259.60	393.60	5091	544	17274	150694	7948.60	259.60	280.93	3394	363	-181	0.10693
1976	SEP Sep-76	26697	143787	7945.26	256.26	448.65	5609	329	11128	151177	7948.83	259.83	187.01	1921	113	-216	0.05866
1976	OCT Oct-76	21292	137153	7941.95	252.95	346.28	4164	161	8491	151945	7949.20	260.20	138.09	1256	49	-113	0.03878
1976	NOV Nov-76	19439	125465	7935.86	246.86	326.68	3566	232	23228	137295	7942.02	253.02	390.35	4661	303	71	0.06502
1976	DEC Dec-76	17779	114148	7929.59	240.59	289.14	2957	312	20933	123021	7934.54	245.54	340.44	3842	405	93	0.10541
1977	JAN Jan-77	16581	103232	7923.09	234.09	269.66	2496	324	19540	109147	7926.68	237.68	317.78	3274	426	101	0.13
1977	FEB Feb-77	15679	92900	7916.39	227.39	282.31	2236	145	18636	95857	7918.37	229.37	335.55	2945	191	46	0.065
1977	MAR Mar-77	16336	83715	7909.95	220.95	265.68	2068	93	18505	83714	7909.95	220.95	300.95	2535	114	21	0.045
1977	APR Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	11482	83381	7909.71	220.71	192.96	1062	48	-118	0.045
1977	MAY May-77	8210	76212	7904.32	215.32	133.52	190	9	5289	92990	7916.45	227.45	0.00	0	0	-9	0.045
1977	JUN Jun-77	10496	89882	7914.33	225.33	176.39	958	52	6126	129008	7937.74	248.74	102.95	472	26	-26	0.05416
1977	JUL Jul-77	20984	81600	7908.40	219.40	341.27	3021	187	13160	136980	7941.86	252.86	214.02	2211	137	-50	0.06176
1977	AUG Aug-77	24562	70386	7899.66	210.66	399.46	3486	373	37237	118391	7931.99	242.99	605.59	7549	807	434	0.10693
1977	SEP Sep-77	13060	64467	7894.62	205.62	219.48	1019	60	24046	104135	7923.65	234.65	404.10	4239	249	189	0.05866
1977	OCT Oct-77	13113	78018	7905.71	216.71	213.26	1263	49	18603	97092	7919.18	230.18	302.54	2834	110	61	0.03878
1977	NOV Nov-77	13832	72768	7901.60	212.60	232.45	1358	88	16243	89429	7914.02	225.02	272.97	2207	144	55	0.06502
1977	DEC Dec-77	13180	68553	7898.14	209.14	214.35	1080	114	16277	82122	7908.79	219.79	264.72	2022	213	99	0.10541
1978	JAN Jan-78	11540	65099	7895.18	206.18	187.68	668	87	14997	75214	7903.54	214.54	243.90	1603	208	122	0.13
1978	FEB Feb-78	9980	62267	7892.68	203.68	179.70	458	30	13468	68895	7898.43	209.43	242.50	1306	85	55	0.065
1978	MAR Mar-78	9924	59462	7890.06	201.06	161.40	217	10	12280	63732	7893.97	204.97	199.71	789	35	26	0.045
1978	APR Apr-78	6764	63650	7893.90	204.90	113.67	0	0	10357	64323	7894.50	205.50	174.05	465	21	21	0.045
1978	MAY May-78	5289	81623	7908.42	219.42	0.00	0	0	5289	82296	7908.92	219.92	0.00	0	0	0	0.045
1978	JUN Jun-78	15778	129033	7937.75	248.75	265.15	2757	149	16451	129032	7937.75	248.75	276.46	2916	158	9	0.05416
1978	JUL Jul-78	21971	150202	7948.37	259.37	357.32	4537	280	36531	150202	7948.37	259.37	594.11	8100	500	220	0.06176
1978	AUG Aug-78	21921	148134	7947.38	258.38	356.51	4492	480	19356	150694	7948.60	259.60	314.79	3904	417	-63	0.10693
1978	SEP Sep-78	19762	139065	7942.92	253.92	332.11	3857	226	15049	148235	7947.43	258.43	252.90	2844	167	-59	0.05866
1978	OCT Oct-78	12203	133012	7939.83	250.83	198.46	1930	75	14635	139753	7943.26	254.26	238.01	2603	101	26	0.03878
1978	NOV Nov-78	21014	118154	7931.86	242.86	353.15	3811	248	23357	123545	7934.82	245.82	392.52	4453	290	42	0.06502
1978	DEC Dec-78	21293	103665	7923.36	234.36	346.29	3567	376	22643	107708	7925.82	236.82	368.25	3954	417	41	0.10541
1979	JAN Jan-79	21068	89577	7914.12	225.12	342.63	3221	419	22416	92272	7915.97	226.97	364.56	3577	465	46	0.13
1979	FEB Feb-79	19457	76075	7904.21	215.21	350.34	2714	176	20805	77422	7905.25	216.25	374.61	3030	197	21	0.065
1979	MAR Mar-79	16954	64928	7895.03	206.03	275.73	1771	80	18302	64928	7895.03	206.03	297.65	2046	92	12	0.045
1979	APR Apr-79	13825	61990	7892.45	203.45	232.33	1119	50	11010	64803	7894.92	205.92	185.03	608	27	-23	0.045
1979	MAY May-79	5289	90705	7914.90	225.90	0.00	0	0	7556	91251	7915.27	226.27	122.88	290	13	13	0.045
1979	JUN Jun-79	20861	129013	7937.74	248.74	350.58	3960	214	68935	131408	7939.00	250.00	1158.47	15423	835	621	0.05416
1979	JUL Jul-79	23975	150202	7948.37	259.37	389.91	5027	310	63882	152994	7949.70	260.70	1038.93	14879	919	608	0.06176
1979	AUG Aug-79	20958	148984	7947.79	258.79	340.84	4270	457	28239	150691	7948.60	259.60	459.26	6079	650	193	0.10693
1979	SEP Sep-79	22551	135133	7940.92	251.92	378.98	4463	262	29162	135990	7941.36	252.36	490.08	6060	355	94	0.05866
1979	OCT Oct-79	18003	123500	7934.80	245.80	292.79	3163	123	18464	127330	7936.85	247.85	300.28	3333	129	7	0.03878
1979	NOV Nov-79	20877	110547	7927.50	238.50	350.84	3643	237	22527	113610	7929.28	240.28	378.57	4079	265	28	0.06502
1979	DEC Dec-79	20318	97960	7919.74	230.74	330.44	3234	341	21151	100257	7921.22	232.22	343.98	3467	365	25	0.10541
1980	JAN Jan-80	20742	85773	7911.44	222.44	337.33	3065	398	21495	87304	7912.53	223.53	349.58	3263	424	26	0.13
1980	FEB Feb-80	19673	74173	7902.72	213.72	342.01	2665	173	20429	74939	7903.32	214.32	355.15	2842	185	12	0.065
1980	MAR Mar-80	17602	63729	7893.97	204.97	286.26	1872	84	17161	64929	7895.03	206.03	279.09	1813	82	-3	0.045
1980	APR Apr-80	11520	61533	7892.06	203.06	193.60	643	29	9440	64803	7894.92	205.92	158.64	287	13	-16	0.045
1980	MAY May-80	5289	83232	7909.60	220.60	0.00	0	0	5289	88691	7913.50	224.50	0.00	0	0	0	0.045
1980	JUN Jun-80	10607	129029	7937.75	248.75	178.25	1533	83	96922	131262	7938.92	249.92	1500.00	18000	975	892	0.05416
1980	JUL Jul-80	39005	150202	7948.37	259.37	634.35	8705	538	43966	150198	7948.37	259.37	715.03	9919	613	75	0.06176
1980	AUG Aug-80	23458	147127	7946.89	257.89	381.50	4851	519	12530	150694	7948.60	259.60	203.78	2232	239	-280	0.10693
1980	SEP Sep-80	24612	137351	7942.05	253.05	413.61	4994	293	10939	148196	7947.41	258.41	183.83	1841	108	-185	0.05866
1980	OCT Oct-80	12204	133712	7940.19	251.19	198.48	1940	75	6627	146507	7946.59	257.59	107.78	744	29	-46	0.03878
1980	NOV Nov-80	19793	122714	7934.37	245.37	332.63	3604	234	22512	132947	7939.80	250.80	378.32	4417	287	53	0.06502
1980	DEC Dec-80	17958	112085	7928.40	239.40	292.05	2963	312	20516	119760	7932.75	243.75	333.66	3688	389	76	0.10541
1981	JAN Jan-81	16216	101856	7922.23	233.23	263.72	2389	311	18774	106973	7925.38	236.38	305.33	3059	398	87	0.13
1981	FEB Feb-81	15251	92213	7915.93	226.93	274.60	2130	138	17809	94771	7917.65	228.65	320.66	2741	178	40	0.065
1981	MAR Mar-81	15645	83715	7909.95	220.95	254.44	1919	86	17611	83714	7909.95	220.95	286.41	2343	105	19	0.045
1981	APR Apr-81	25714	69430	7898.87	209.87	432.13	3750	169	11748	83381	7909.71	220.71	197.43	1119	50	-118	0.045
1981	MAY May-81	5289	83449	7909.76	220.76	0.00	0	0	5289	97356	7919.35	230.35	0.00	0	0	0	0.045
1981	JUN Jun-81	5970	110452	7927.45	238.45	100.33	229	12	5970	128999	7937.73	248.73	100.33	435	24	11	0.05416
1981	JUL Jul-81	11443	117545	7931.51	242.51	186.10	1544	95	7258	150202	7948.37	259.37	118.04	936	58	-38	0.06176
1981	AUG Aug-81	17337	109732	7927.03	238.03	281.96	2781	297	35436	131766	7939.18	250.18	576.30	7438	795	498	0.10693
1981	SEP Sep-81	19445	99013	7920.42	231.42	326.78	3101	182	19876	125659	7935.96	246.96	334.02	3672	215	33	0.05866
1981	OCT Oct-81	12966	92734	7916.28	227.28	210.87	1504	58	6627	125804	7936.04	247.04	107.78	522	20	-38	0.03878
1981	NOV Nov-81	14909	85944	7911.56	222.56	250.55	1850	120	21534	112390	7928.58	239.58	361.89	3828	249	129	0.06502

Table 4
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call and Making the 20,000 Acre-feet Release

			Base							Shoshone & Release								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	DEC	Dec-81	13712	79508	7906.84	217.84	223.00	1420	150	20332	99342	7920.63	231.63	330.66	3265	344	194	0.10541
1982	JAN	Jan-82	13447	73472	7902.16	213.16	218.69	1241	161	20065	86694	7912.10	223.10	326.32	2939	382	221	0.13
1982	FEB	Feb-82	11121	68270	7897.90	208.90	200.24	808	53	17984	74634	7903.08	214.08	323.81	2371	154	102	0.065
1982	MAR	Mar-82	10132	64931	7895.03	206.03	164.78	377	17	16500	64929	7895.03	206.03	268.34	1678	76	59	0.045
1982	APR	Apr-82	14708	59945	7890.51	201.51	247.17	1246	56	9846	64803	7894.92	205.92	165.47	370	17	-39	0.045
1982	MAY	May-82	5289	80823	7907.82	218.82	0.00	0	0	5289	85666	7911.36	222.36	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	128578	7937.51	248.51	100.33	430	23	8360	129024	7937.75	248.75	140.49	1001	54	31	0.05416
1982	JUL	Jul-82	24246	150202	7948.37	259.37	394.32	5093	315	44013	152997	7949.70	260.70	715.79	9996	617	303	0.06176
1982	AUG	Aug-82	24277	150694	7948.60	259.60	394.82	5109	546	34328	150691	7948.60	259.60	558.28	7571	810	263	0.10693
1982	SEP	Sep-82	15141	147920	7947.27	258.27	254.45	2863	168	13435	151177	7948.83	259.83	225.78	2486	146	-22	0.05866
1982	OCT	Oct-82	17466	138534	7942.65	253.65	284.05	3267	127	8967	151945	7949.20	260.20	145.83	1373	53	-73	0.03878
1982	NOV	Nov-82	26574	120571	7933.20	244.20	446.58	5150	335	29256	131296	7938.94	249.94	491.66	5992	390	55	0.06502
1982	DEC	Dec-82	24978	102978	7922.93	233.93	406.22	4384	462	27862	111022	7927.78	238.78	453.13	5215	550	88	0.10541
1983	JAN	Jan-83	23515	85785	7911.45	222.45	382.43	3666	477	26992	91147	7915.20	226.20	438.98	4557	592	116	0.13
1983	FEB	Feb-83	22970	69180	7898.66	209.66	413.59	3280	213	25651	71860	7900.87	211.87	461.86	3910	254	41	0.065
1983	MAR	Mar-83	19106	54935	7885.66	196.66	310.72	1925	87	14308	62409	7892.80	203.80	232.69	1170	53	-34	0.045
1983	APR	Apr-83	16268	46395	7876.55	187.55	273.39	1171	53	7879	62234	7892.65	203.65	132.41	0	0	-53	0.045
1983	MAY	May-83	5289	65257	7895.32	206.32	0.00	0	0	8871	95191	7917.93	228.93	144.27	639	29	29	0.045
1983	JUN	Jun-83	50369	131466	7939.03	250.03	846.47	11013	596	139245	131400	7938.99	249.99	1500.00	18000	975	378	0.05416
1983	JUL	Jul-83	127864	152994	7949.70	260.70	1500.00	18600	1149	122483	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62884	153088	7949.74	260.74	1022.70	14637	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	27578	150624	7948.57	259.57	463.46	5943	349	27365	151679	7949.07	260.07	459.88	5909	347	-2	0.05866
1983	OCT	Oct-83	17200	148589	7947.60	258.60	279.73	3346	130	13862	151944	7949.20	260.20	225.44	2574	100	-30	0.03878
1983	NOV	Nov-83	30364	129812	7938.16	249.16	510.28	6225	405	31667	132495	7939.56	250.56	532.17	6589	428	24	0.06502
1983	DEC	Dec-83	31474	109909	7927.13	238.13	511.87	6016	634	32144	111921	7928.31	239.31	522.76	6217	655	21	0.10541
1984	JAN	Jan-84	29133	90406	7914.69	225.69	473.80	5008	651	29804	91747	7915.61	226.61	484.71	5190	675	24	0.13
1984	FEB	Feb-84	26279	71489	7900.57	211.57	456.86	3979	259	26966	72160	7901.11	212.11	468.80	4141	269	11	0.065
1984	MAR	Mar-84	20301	60815	7891.35	202.35	330.16	2339	105	18083	62415	7892.80	203.80	294.09	1935	87	-18	0.045
1984	APR	Apr-84	12328	58162	7888.82	199.82	207.18	726	33	14668	62240	7892.66	203.66	246.50	1295	58	26	0.045
1984	MAY	May-84	74916	94762	7917.64	228.64	1218.37	15260	687	95638	96790	7918.98	229.98	1500.00	18600	837	150	0.045
1984	JUN	Jun-84	155640	131401	7938.99	249.99	1500.00	18000	975	157543	131396	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	126134	152994	7949.70	260.70	1500.00	18600	1149	124352	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	85268	153088	7949.74	260.74	1386.73	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	36965	153173	7949.78	260.78	621.21	8295	487	35687	153173	7949.78	260.78	599.73	7980	468	-18	0.05866
1984	OCT	Oct-84	23289	153342	7949.86	260.86	378.75	4909	190	23558	153342	7949.86	260.86	383.13	4975	193	3	0.03878
1984	NOV	Nov-84	33427	135612	7941.17	252.17	561.75	7073	460	32940	135612	7941.17	252.17	553.57	6957	452	-8	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	33048	116759	7931.07	242.07	537.47	6538	689	-10	0.10541
1985	JAN	Jan-85	30448	98306	7919.97	230.97	495.18	5502	715	30448	98306	7919.97	230.97	495.18	5502	715	0	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	28571	80438	7907.54	218.54	514.44	4760	309	0	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	25961	64927	7895.03	206.03	422.21	3611	163	0	0.045
1985	APR	Apr-85	20008	64819	7894.93	205.93	336.24	2446	110	27019	64819	7894.93	205.93	454.06	3879	175	64	0.045
1985	MAY	May-85	53196	98074	7919.82	230.82	865.14	10572	476	53155	98074	7919.82	230.82	864.47	10563	475	0	0.045
1985	JUN	Jun-85	100533	131394	7938.99	249.99	1500.00	18000	975	100470	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	48123	150198	7948.37	259.37	782.63	10937	675	49048	150198	7948.37	259.37	797.68	11163	689	14	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	12022	151177	7948.83	259.83	202.03	2140	126	-115	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	11890	152002	7949.23	260.23	193.37	2091	81	28	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	30198	134542	7940.62	251.62	507.49	6280	408	0	0.06502
1985	DEC	Dec-85	28811	116554	7930.96	241.96	468.56	5552	585	28509	116901	7931.15	242.15	463.65	5490	579	-7	0.10541
1986	JAN	Jan-86	28595	98169	7919.88	230.88	465.05	5085	661	28714	98400	7920.03	231.03	466.98	5117	665	4	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	26707	81686	7908.47	219.47	480.88	4393	286	2	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	27446	64926	7895.03	206.03	446.36	3915	176	1	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	19014	64819	7894.93	205.93	319.54	2243	101	25	0.045
1986	MAY	May-86	5289	98074	7919.82	230.82	0.00	0	0	34587	98074	7919.82	230.82	562.50	6420	289	289	0.045
1986	JUN	Jun-86	97345	131394	7938.99	249.99	1500.00	18000	975	103799	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	55132	150198	7948.37	259.37	896.62	12652	781	56256	152994	7949.70	260.70	914.90	13005	803	22	0.06176
1986	AUG	Aug-86	16820	150694	7948.60	259.60	273.55	3283	351	19863	150691	7948.60	259.60	323.04	4028	431	80	0.10693
1986	SEP	Sep-86	15989	149012	7947.80	258.80	268.70	3084	181	12951	151177	7948.83	259.83	217.65	2368	139	-42	0.05866
1986	OCT	Oct-86	7922	151946	7949.20	260.20	128.84	1116	43	10087	151945	7949.20	260.20	164.05	1648	64	21	0.03878
1986	NOV	Nov-86	29317	134497	7940.59	251.59	492.68	6069	395	29317	134496	7940.59	251.59	492.68	6068	395	0	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	27465	115922	7930.60	241.60	446.67	5227	551	0	0.10541
1987	JAN	Jan-87	25065	97748	7919.61	230.61	407.64	4288	557	25065	97747	7919.61	230.61	407.64	4288	557	0	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	24052	80159	7907.33	218.33	433.07	3787	246	0	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	21770	64927	7895.03	206.03	354.05	2755	124	-15	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	12194	64819	7894.93	205.93	204.92	850	38	0	0.045
1987	MAY	May-87	5289	88214	7913.17	224.17	0.00	0	0	10491	96476	7918.78	229.78	170.62	1018	46	46	0.045
1987	JUN	Jun-87	23733	129019	7937.75	248.75	398.84	4639	251	37859	129001	7937.74	248.74	636.23	7983	432	181	0.05416
1987	JUL	Jul-87	14257	145090	7945.90	256.90	231.86	2582	159	8540	150202	7948.37	259.37	138.89	1249	77	-82	0.06176
1987	AUG	Aug-87	31080	137711	7942.23	253.23	505.46	6523	698	12025	150694	7948.60	259.60	195.57	2108	225	-472	0.10693
1987	SEP	Sep-87	28201	123982	7935.06	246.06	473.93	5598	328	22402	142656	7944.70	255.70	376.47	4550	267	-61	0.05866
1987	OCT	Oct-87	22632	111836	7928.26	239.26	368.07	4032	156	19017	134057	7940.37	251.37	309.28	3570	138	-18	0.03878
1987	NOV	Nov-87	18662	101220	7921.83	232.83	313.62	2968	193	23725	118991	7932.32	243.32	398.71	4456	290	97	0.06502
1987	DEC	Dec-87	17624	90965	7915.08	226.08	286.62	2496	263	22228	104293	7923.75	234.75	361.50	3791	400	137	0.10541
1988	JAN	Jan-88	17487	81109	7908.04	219.04	284.39	2260	294	21929	89995	7914.41	225.41	356.64	3419	444	151	0.13
1988	FEB	Feb-88	15652	71842	7900.85	211.85	272.11	1770	115	20095	76284	7904.37	215.37	349.35	2804	182	67	0.065
1988	MAR	Mar-88	15649	63730	7893.97	204.97	254.50	1474	66	17250	64928	7895.03	206.03	280.54	1831	82	16	0.045
1988	APR	Apr-88	12778	63422	7893.70	204.70	214.74	938	42	12592	64803	7894.92	205.92	211.61	931	42	0	0.045
1988	MAY	May-88	5289	88197	7913.16	224.16	0.00	0	0	5289	89574	7914.12	225.12	0.00	0	0	0	0.045
1988	JUN	Jun-88	8470	129019	7937.75	248.75	142.34	1027	56	62424	129016	7937.74	248.74	1049.05	13797	747	692	0.05416
1988	JUL	Jul-88	15670	146906	7946.78	257.78	254.84	2950	182	18295	150202	7948.37	259.37	297.54	3637	225	42	0.06176
1988	AUG	Aug-88	42120	127583	7936.99	247.99	685.01	8923	954	35620	137249	7942.00	253.00	579.30	7603	813	-141	0.10693
1988	SEP	Sep-88	19530	120044	7932.91	243.91	328.21	3498	205	16937	132196	7939.41	250.41	284.63	3078	181	-25	0.05866
1988	OCT	Oct-88	34719	95471	7918.11	229.11	564.64	6377	247	32711	109480	7926.88	237.88	531.99	6289	244	-3	0.03878
1988	NOV	Nov-88	16847	88133	7913.11	224.11	283.12	2314	150	20060	99336	7920.63	231.63	337.11	3245	211	61	0.06502
1988	DEC	Dec-88	14071	81149	7908.07	219.07	228.84	1529	161	16896	89552	7914.10	225.10	274.78	2308	243	82	0.10541
1989	JAN	Jan-89	13478	74566	7903.03	214.03	219.20	1270	165	16297	80168	7907.34	218.34	265.04	1985	258	93	0.13
1989	FEB	Feb-89	12515	68570	7898.15	209.15	225.34	1102	72	15329	71371	7900.47	211.47	276.01	1744	113	42	0.065

Table 4

GREEN MOUNTAIN RESERVOIR

Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call and Making the 20,000 Acre-feet Release

			Base							Shoshone & Release								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1989	MAR	Mar-89	15213	62815	7893.15	204.15	247.41	1363	61	14722	64468	7894.62	205.62	239.43	1303	59	-3	0.045
1989	APR	Apr-89	14366	63423	7893.70	204.70	241.43	1261	57	14746	64701	7894.83	205.83	247.81	1369	62	5	0.045
1989	MAY	May-89	5289	86102	7911.67	222.67	0.00	0	0	5289	87381	7912.58	223.58	0.00	0	0	0	0.045
1989	JUN	Jun-89	5970	118342	7931.96	242.96	100.33	319	17	23845	129020	7937.75	248.75	400.72	4666	253	235	0.05416
1989	JUL	Jul-89	16484	146771	7946.72	257.72	268.08	3147	194	23253	150202	7948.37	259.37	378.17	4850	300	105	0.06176
1989	AUG	Aug-89	33695	143238	7944.99	255.99	547.99	7266	777	21466	148773	7947.68	258.68	349.11	4391	470	-307	0.10693
1989	SEP	Sep-89	26680	131308	7938.95	249.95	448.37	5380	316	27320	136188	7941.46	252.46	459.12	5623	330	14	0.05866
1989	OCT	Oct-89	18106	124187	7935.17	246.17	294.46	3198	124	20131	126984	7936.67	247.67	327.39	3721	144	20	0.03878
1989	NOV	Nov-89	21686	111097	7927.83	238.83	364.44	3839	250	22914	113333	7929.12	240.12	385.08	4163	271	21	0.06502
1989	DEC	Dec-89	20323	98372	7920.01	231.01	330.52	3243	342	21202	100049	7921.09	232.09	344.81	3474	366	24	0.10541
1990	JAN	Jan-90	18559	86048	7911.63	222.63	301.83	2598	338	19118	87166	7912.43	223.43	310.92	2743	357	19	0.13
1990	FEB	Feb-90	17445	74310	7902.83	213.83	314.11	2251	146	18004	74869	7903.27	214.27	324.17	2380	155	8	0.065
1990	MAR	Mar-90	18102	63993	7894.20	205.20	294.40	1981	89	15892	64929	7895.03	206.03	258.45	1554	70	-19	0.045
1990	APR	Apr-90	21259	52420	7883.09	194.09	357.26	2328	105	20887	53725	7884.43	195.43	351.01	2297	103	-1	0.045
1990	MAY	May-90	5289	65904	7895.88	206.88	0.00	0	0	5289	68517	7898.11	209.11	0.00	0	0	0	0.045
1990	JUN	Jun-90	5970	104461	7923.85	234.85	100.33	157	9	29207	129063	7937.77	248.77	490.83	5936	321	313	0.05416
1990	JUL	Jul-90	10557	117531	7931.51	242.51	171.69	1339	83	15727	150202	7948.37	259.37	255.77	3008	186	103	0.06176
1990	AUG	Aug-90	23529	106801	7925.28	236.28	382.66	4137	442	47144	126789	7936.56	247.56	766.71	10087	1079	636	0.10693
1990	SEP	Sep-90	24948	91098	7915.17	226.17	419.26	4151	243	34972	106925	7925.35	236.35	587.72	6780	398	154	0.05866
1990	OCT	Oct-90	15739	84342	7910.41	221.41	255.97	1952	76	6627	109366	7926.81	237.81	107.78	328	13	-63	0.03878
1990	NOV	Nov-90	16712	79234	7906.63	217.63	280.85	2102	137	21910	99245	7920.57	231.57	368.20	3657	238	101	0.06502
1990	DEC	Dec-90	14136	74475	7902.96	213.96	229.90	1406	148	19808	89483	7914.05	225.05	322.14	2943	310	162	0.10541
1991	JAN	Jan-91	13069	70116	7899.44	210.44	212.54	1091	142	18073	80122	7907.30	218.30	293.92	2363	307	165	0.13
1991	FEB	Feb-91	9695	67241	7897.03	208.03	174.57	495	32	15594	71348	7900.45	211.45	280.78	1799	117	85	0.065
1991	MAR	Mar-91	9243	64008	7894.22	205.22	150.32	176	8	13156	64202	7894.39	205.39	213.96	978	44	36	0.045
1991	APR	Apr-91	15137	57856	7888.53	199.53	254.38	1279	58	8538	64641	7894.78	205.78	143.48	100	4	-53	0.045
1991	MAY	May-91	5289	86569	7912.01	223.01	0.00	0	0	5289	93334	7916.69	227.69	0.00	0	0	0	0.045
1991	JUN	Jun-91	5970	129022	7937.75	248.75	100.33	435	24	43892	129008	7937.74	248.74	737.62	9411	510	486	0.05416
1991	JUL	Jul-91	7258	147918	7947.27	258.27	118.04	912	56	21037	150202	7948.37	259.37	342.13	4308	266	210	0.06176
1991	AUG	Aug-91	27548	139243	7943.00	254.00	448.02	5704	610	27365	147335	7946.99	257.99	445.04	5806	621	11	0.10693
1991	SEP	Sep-91	30332	127709	7937.05	248.05	0.00	0	0	22641	142166	7944.46	255.46	0.00	0	0	0	0.05866
						Totals			$52,385,492							$63,179,905		
						Difference										$10,794,413		
						Average Annual										$634,965		

Table 5

SHOSHONE POWER PLANT

Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call and Making 20,000 Acre-feet release

			Base				Shoshone & Release					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	53985	878	7423	288	-69	0.04
1974	NOV	Nov-74	66071	1110	9085	591	69176	1163	9512	618	28	0.07
1974	DEC	Dec-74	61830	1006	8502	896	64893	1055	8923	941	44	0.11
1975	JAN	Jan-75	59899	974	8236	1071	63145	1027	8682	1129	58	0.13
1975	FEB	Feb-75	58476	1053	8040	523	62000	1116	8525	554	31	0.07
1975	MAR	Mar-75	61181	995	8412	379	62207	1012	8553	385	6	0.05
1975	APR	Apr-75	74381	1250	10227	460	67545	1135	9287	418	-42	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	54258	912	7460	438	-162	0.06
1975	OCT	Oct-75	70098	1140	9638	374	65513	1065	9008	349	-24	0.04
1975	NOV	Nov-75	79448	1335	10924	710	79841	1342	10978	714	4	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	73863	1201	10156	1071	31	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	70049	1139	9632	1252	28	0.13
1976	FEB	Feb-76	70614	1228	9709	631	72021	1252	9903	644	13	0.07
1976	MAR	Mar-76	76631	1246	10537	474	75711	1231	10410	468	-6	0.05
1976	APR	Apr-76	82638	1389	11363	511	79859	1342	10980	494	-17	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	75601	1230	10395	1112	-161	0.11
1976	SEP	Sep-76	74381	1250	10227	600	57685	969	7932	465	-135	0.06
1976	OCT	Oct-76	74383	1210	10228	397	61445	999	8449	328	-69	0.04
1976	NOV	Nov-76	59697	1003	8208	534	62948	1058	8655	563	29	0.07
1976	DEC	Dec-76	49447	804	6799	717	52915	861	7276	767	50	0.11
1977	JAN	Jan-77	47151	767	6483	843	50625	823	6961	905	62	0.13
1977	FEB	Feb-77	47230	850	6494	422	50750	914	6978	454	31	0.07
1977	MAR	Mar-77	49872	811	6857	309	51966	845	7145	322	13	0.05
1977	APR	Apr-77	74381	1250	10227	460	57653	969	7927	357	-104	0.05
1977	MAY	May-77	86576	1408	11904	536	83720	1362	11511	518	-18	0.05
1977	JUN	Jun-77	83783	1408	11520	624	80525	1353	11072	600	-24	0.05
1977	JUL	Jul-77	76861	1250	10568	653	61124	994	8404	519	-134	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76722	1248	10549	1128	-2	0.11
1977	SEP	Sep-77	52714	886	7248	425	53072	892	7297	428	3	0.06
1977	OCT	Oct-77	58234	947	8007	311	54842	892	7541	292	-18	0.04
1977	NOV	Nov-77	45851	771	6304	410	45847	770	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	47485	772	6529	688	15	0.11
1978	JAN	Jan-78	45729	744	6288	817	46000	748	6325	822	5	0.13
1978	FEB	Feb-78	39553	712	5438	353	39163	705	5385	350	-3	0.07
1978	MAR	Mar-78	53027	862	7291	328	49423	804	6796	306	-22	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	76355	1242	10499	1123	-125	0.11
1978	SEP	Sep-78	65053	1093	8945	525	50599	850	6957	408	-117	0.06
1978	OCT	Oct-78	60476	984	8315	322	62618	1018	8610	334	11	0.04
1978	NOV	Nov-78	63938	1074	8791	572	67957	1142	9344	608	36	0.07
1978	DEC	Dec-78	53625	872	7373	777	57569	936	7916	834	57	0.11
1979	JAN	Jan-79	49664	808	6829	888	53615	872	7372	958	71	0.13
1979	FEB	Feb-79	50049	901	6882	447	53980	972	7422	482	35	0.07
1979	MAR	Mar-79	61728	1004	8487	382	63141	1027	8682	391	9	0.05
1979	APR	Apr-79	80714	1356	11098	499	75113	1262	10328	465	-35	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	62509	1050	8595	504	-19	0.06
1979	OCT	Oct-79	64083	1042	8811	342	61680	1003	8481	329	-13	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70634	1187	9712	631	4	0.07
1979	DEC	Dec-79	67970	1105	9346	985	68486	1114	9417	993	7	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67809	1103	9324	1212	12	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62792	1092	8634	561	6	0.07
1980	MAR	Mar-80	63444	1032	8723	393	62092	1010	8538	384	-8	0.05
1980	APR	Apr-80	74381	1250	10227	460	72313	1215	9943	447	-13	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05

Table 5

SHOSHONE POWER PLANT

Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call and Making 20,000 Acre-feet release

1980 JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980 AUG	Aug-80	76861	1250	10568	1130	64773	1053	8906	952	-178	0.11
1980 SEP	Sep-80	70872	1191	9745	572	53737	903	7389	433	-138	0.06
1980 OCT	Oct-80	59823	973	8226	319	54664	889	7516	291	-28	0.04
1980 NOV	Nov-80	63271	1063	8700	566	67420	1133	9270	603	37	0.07
1980 DEC	Dec-80	59613	969	8197	864	62884	1023	8646	911	47	0.11
1981 JAN	Jan-81	51581	839	7092	922	54684	889	7519	977	55	0.13
1981 FEB	Feb-81	46680	841	6418	417	50706	913	6972	453	36	0.07
1981 MAR	Mar-81	50048	814	6881	310	52977	862	7284	328	18	0.05
1981 APR	Apr-81	74381	1250	10227	460	56991	958	7836	353	-108	0.05
1981 MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981 JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981 JUL	Jul-81	76861	1250	10568	653	68785	1119	9458	584	-69	0.06
1981 AUG	Aug-81	69790	1135	9596	1026	69815	1135	9599	1026	0	0.11
1981 SEP	Sep-81	63221	1062	8693	510	54527	916	7497	440	-70	0.06
1981 OCT	Oct-81	61933	1007	8516	330	54691	889	7520	292	-39	0.04
1981 NOV	Nov-81	51751	870	7116	463	61556	1034	8464	550	88	0.07
1981 DEC	Dec-81	45812	745	6299	664	55948	910	7693	811	147	0.11
1982 JAN	Jan-82	44243	720	6083	791	54333	884	7471	971	180	0.13
1982 FEB	Feb-82	38976	702	5359	348	49296	888	6778	441	92	0.07
1982 MAR	Mar-82	50770	826	6981	314	59788	972	8221	370	56	0.05
1982 APR	Apr-82	74381	1250	10227	460	66364	1115	9125	411	-50	0.05
1982 MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982 JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982 JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982 AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982 SEP	Sep-82	83783	1408	11520	676	74616	1254	10260	602	-74	0.06
1982 OCT	Oct-82	82000	1334	11275	437	69415	1129	9544	370	-67	0.04
1982 NOV	Nov-82	80279	1349	11038	718	81361	1367	11187	727	10	0.07
1982 DEC	Dec-82	68395	1112	9404	991	70093	1140	9638	1016	25	0.11
1983 JAN	Jan-83	64588	1050	8881	1154	66408	1080	9131	1187	33	0.13
1983 FEB	Feb-83	60401	1088	8305	540	61891	1114	8510	553	13	0.07
1983 MAR	Mar-83	68328	1111	9395	423	58285	948	8014	361	-62	0.05
1983 APR	Apr-83	70275	1181	9663	435	54985	924	7560	340	-95	0.05
1983 MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983 JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983 JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983 AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983 SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983 OCT	Oct-83	81342	1323	11184	434	75183	1223	10338	401	-33	0.04
1983 NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983 DEC	Dec-83	86576	1408	11904	1255	86432	1406	11884	1253	-2	0.11
1984 JAN	Jan-84	75666	1231	10404	1353	74120	1205	10191	1325	-28	0.13
1984 FEB	Feb-84	74251	1291	10209	664	73347	1275	10085	656	-8	0.07
1984 MAR	Mar-84	71770	1167	9868	444	68994	1122	9487	427	-17	0.05
1984 APR	Apr-84	79696	1339	10958	493	75862	1275	10431	469	-24	0.05
1984 MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984 JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984 JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984 AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984 SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984 OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984 NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984 DEC	Dec-84	85925	1397	11815	1245	81846	1331	11254	1186	-59	0.11
1985 JAN	Jan-85	80865	1315	11119	1445	79252	1289	10897	1417	-29	0.13
1985 FEB	Feb-85	76628	1380	10536	685	75284	1356	10351	673	-12	0.07
1985 MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985 MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985 JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985 AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985 SEP	Sep-85	75129	1263	10330	606	66112	1111	9090	533	-73	0.06
1985 OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985 NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985 DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986 JAN	Jan-86	85651	1393	11777	1531	84556	1375	11626	1511	-20	0.13
1986 FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986 MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986 MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986 JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06

Table 5

SHOSHONE POWER PLANT

Foregone Power Revenues: Removal of Shoshone Power Plant Priority Call and Making 20,000 Acre-feet release

1986 AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986 SEP	Sep-86	83783	1408	11520	676	77327	1300	10632	624	-52	0.06
1986 OCT	Oct-86	86576	1408	11904	462	84773	1379	11656	452	-10	0.04
1986 NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986 DEC	Dec-86	78786	1281	10833	1142	78287	1273	10764	1135	-7	0.11
1987 JAN	Jan-87	69058	1123	9495	1234	68260	1110	9386	1220	-14	0.13
1987 FEB	Feb-87	66954	1206	9206	598	66094	1190	9088	591	-8	0.07
1987 MAR	Mar-87	77469	1260	10652	479	73550	1196	10113	455	-24	0.05
1987 APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987 MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987 JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987 JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987 AUG	Aug-87	76861	1250	10568	1130	59772	972	8219	879	-251	0.11
1987 SEP	Sep-87	62419	1049	8582	503	55884	939	7684	451	-53	0.06
1987 OCT	Oct-87	63624	1035	8748	339	61816	1005	8500	330	-10	0.04
1987 NOV	Nov-87	79093	1329	10875	707	77986	1311	10723	697	-10	0.07
1987 DEC	Dec-87	68906	1121	9474	999	71057	1156	9770	1030	31	0.11
1988 JAN	Jan-88	70055	1139	9632	1252	71541	1163	9837	1279	27	0.13
1988 FEB	Feb-88	64279	1117	8838	574	65798	1144	9047	588	14	0.07
1988 MAR	Mar-88	71897	1169	9886	445	66600	1083	9157	412	-33	0.05
1988 APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988 MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988 JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988 JUL	Jul-88	86576	1408	11904	735	85736	1394	11789	728	-7	0.06
1988 AUG	Aug-88	81837	1331	11252	1203	71863	1169	9881	1057	-147	0.11
1988 SEP	Sep-88	56113	943	7715	453	51080	858	7023	412	-41	0.06
1988 OCT	Oct-88	71010	1155	9764	379	70115	1140	9641	374	-5	0.04
1988 NOV	Nov-88	60510	1017	8320	541	63495	1067	8730	568	27	0.07
1988 DEC	Dec-88	56962	926	7832	826	59953	975	8243	869	43	0.11
1989 JAN	Jan-89	59364	965	8162	1061	62321	1014	8569	1114	53	0.13
1989 FEB	Feb-89	52009	936	7151	465	55010	990	7564	492	27	0.07
1989 MAR	Mar-89	76345	1242	10497	472	73062	1188	10046	452	-20	0.05
1989 APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989 MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989 JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989 JUL	Jul-89	86576	1408	11904	735	86008	1399	11826	730	-5	0.06
1989 AUG	Aug-89	76861	1250	10568	1130	62617	1018	8610	921	-209	0.11
1989 SEP	Sep-89	54165	910	7448	437	52272	878	7187	422	-15	0.06
1989 OCT	Oct-89	51573	839	7091	275	54066	879	7434	288	13	0.04
1989 NOV	Nov-89	61037	1026	8392	546	61008	1025	8388	545	0	0.07
1989 DEC	Dec-89	61907	1007	8512	897	62165	1011	8548	901	4	0.11
1990 JAN	Jan-90	57901	942	7961	1035	58182	946	8000	1040	5	0.13
1990 FEB	Feb-90	49568	893	6816	443	49876	898	6858	446	3	0.07
1990 MAR	Mar-90	62558	1017	8602	387	60239	980	8283	373	-14	0.05
1990 APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990 MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990 JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990 JUL	Jul-90	86576	1408	11904	735	80201	1304	11027	681	-54	0.06
1990 AUG	Aug-90	78519	1277	10796	1154	75395	1226	10367	1109	-46	0.11
1990 SEP	Sep-90	62931	1058	8653	508	62195	1045	8552	502	-6	0.06
1990 OCT	Oct-90	63305	1030	8704	338	49566	806	6815	264	-73	0.04
1990 NOV	Nov-90	60470	1016	8315	541	63475	1067	8728	567	27	0.07
1990 DEC	Dec-90	53934	877	7416	782	57039	928	7843	827	45	0.11
1991 JAN	Jan-91	49706	808	6834	888	52969	861	7283	947	58	0.13
1991 FEB	Feb-91	46476	837	6390	415	49768	896	6843	445	29	0.07
1991 MAR	Mar-91	52128	848	7167	323	53909	877	7412	334	11	0.05
1991 APR	Apr-91	74381	1250	10227	460	63099	1060	8676	390	-70	0.05
1991 MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991 JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991 JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991 AUG	Aug-91	76861	1250	10568	1130	74786	1216	10283	1100	-31	0.11
1991 SEP	9/1	71767	1206	9868	579	60567	1018	8328	489	-90	0.06

Totals	$ 137,670,795	$ 135,700,461
Difference		-$1,970,334
Average Annual		-$115,902

TECHNICAL MEMORANDUM NO. 10:
INVESTIGATION OF ALTERNATIVE 6A:
INSURANCE POOL

DRAFT

PRODUCED FOR:

Colorado Water Conservation Board

PRODUCED BY:

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OCTOBER 2001

TECHNICAL MEMORANDUM NO. 10:
INVESTIGATION OF ALTERNATIVE 6A:
INSURANCE POOL

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EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 10 is to present the results from investigation of Alternative 6a, Insurance Pool.

The need for an insurance pool is somewhat reduced by two important findings of previous technical memoranda:

- The 20,000 acre-feet release to the 15-Mile Reach is not required to be made every year, and
- The release is definitely not required in exceptionally dry years, thereby reducing the competition for firm yield water.

Establishing an insurance pool in one or more reservoirs will serve the purpose of lowering the risk of reduced storage and yield in those reservoirs responsible for making the 20,000 acre-feet release to the 15-Mile Reach. This is operationally equivalent to placing responsibility for making the release on a larger number of reservoirs. The feasibility of making three and nine reservoirs responsible for the 20,000 acre-feet release has been investigated in Technical Memorandum No. 7 (CWCB, October 2001b) which demonstrates that the risk of reduced storage and yield can be lowered by making more reservoirs responsible for making some portion of the 20,000 acre-feet release.

Another alternative for an insurance pool, which appears to be feasible from economic and engineering standpoints, is general removal (i.e. not selective removal) of the Shoshone priority call. This alternative was analyzed in Technical Memorandum No. 9 and has the additional benefit of not requiring implementation in every year.

From engineering and economic perspectives, the above alternatives for establishing an insurance pool appear to be feasible. These alternatives must, however, be reviewed by the Executive Committee and Colorado River basin water users to determine their institutional feasibility.

INTRODUCTION AND PURPOSE

The purpose of Technical Memorandum No. 10 is to present the results from the investigation of Alternative 6a, Insurance Pool.

The basic concept of the insurance pool is to spread the risk associated with making the 20,000 acre-feet release to the 15-Mile Reach among a group of structures and water users. Some basic findings from the previous technical memoranda provide guidance for how an insurance pool or fund could best be established to spread the risk associated with making the 20,000 acre-feet release. These findings include:

- The 20,000 acre-feet release to the 15-Mile Reach will not be required every year. During the 1975-91 study period, the 20,000 acre-feet release would have been definitely required in only six years and possibly required in two additional years.

- The 20,000 acre-feet is not required in exceptionally dry years because the release is not required in those years in which the peak discharge at the head of the 15-Mile Reach is less than 12,900 cfs. During the study period, the release would not have been required in two exceptionally dry years, 1977 and 1981. As per the investigation detailed in Technical Memorandum No. 6 (Colorado Water Conservation Board, October 2001a), the 20,000 acre-feet release would not have been required in 2001.

- Not having to make the 20,000 acre-feet release in exceptionally dry years has important effects on the feasibility of sources of water for making this release and on the design of an insurance pool, or fund, for spreading the risk resulting from making the release among a wider group of structures and water users.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following general procedures, tools, and assumptions have been employed in the analysis of alternatives investigated as possible sources of water for making the 20,000 acre-feet release to the 15-Mile Reach.

1. The StateMod surface water model and C1 data set were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 Scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000)*. These components of RIPRAP flows include:

   - 5,000 acre-feet per year from Ruedi Reservoir,
   - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
   - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
   - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
   - 6,000 acre-feet per year from Wolford Mountain Reservoir, and
   - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated on the C1 dataset but not modeled.

3. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: *"At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology."* Consequently, if the CWCB and the Executive Committee review the analysis and any revisions made by the consultant and determine that the methodology and calculations employed in the analysis of Alternative 1a are acceptable, the necessary sensitivity analysis will be completed.

   CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP

will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

4. Electric power purchase and sales prices were obtained from the Western Area Power Administration for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

5. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when these two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 baseline scenario, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 baseline scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by C1 data set's lack of simulation of the hydropower maintenance periods.

   The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenues from hydropower generation for those alternatives which result in reduced water availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation. Brown and Caldwell does not believe this omission by the C1 data sets creates a significant bias in the results which would affect conclusions from this investigation.

   A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by C1 data set's lack of simulation of the hydropower maintenance periods.

6. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,

- A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
- A reservoir fill according to the criteria of the Blue River Decree.

The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

7. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:
   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,
   - Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
   - Sufficient HUP Surplus water exists to make the release.

   Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. StateMod and the C1 data set do not explicitly model releases of HUP Surplus water under the Municipal Recreational Agreement and there is no demand specified at a node for the Municipal Recreational water.

USE OF STATEMOD

StateMod was not directly used in the investigation of Alternative 6a.

SPECIFIC ANALYSIS PROCEDURES

Analysis of Alternative 6a focused on review of other alternatives which spread the risk among a number of structures or could provide a source of supply for the 20,000 acre-feet release to the 15-Mile Reach. These alternatives included:

- Alternatives investigated in Technical Memorandum No. 7 , which relied on three reservoirs and nine reservoirs as a source of supply for the 20,000 acre-feet release.
- Alternatives in Technical Memorandum No. 9 for removing the Shoshone priority call that would have the capability of providing water in selected years.

RESULTS

Analysis of the results provided in other Technical Memoranda with respect to development of an insurance pool demonstrate the following:

1. Spreading responsibility for making the 20,000 acre-feet release among a larger number of structures lowers the risk of reduced yield from these participating reservoirs as compared to placing responsibility for making the release on only one or two reservoirs. Analysis completed in Technical Memorandum No. 7 (Colorado Water Conservation Board, October 2001b) shows the reduced effects on reservoir storage from placing responsibility on three and nine reservoirs for the 20,000 acre-feet release as compared to requiring one reservoir to make the entire release. Costs resulting from reduced power generation and potentially reduced deliveries through the Adams, Roberts, Boustead and Busk-Ivanhoe Tunnels are detailed in Technical Memorandum No. 7.

2. As demonstrated in Technical Memorandum No. 9, (Colorado Water Conservation Board, October 2001c) removing the Shoshone priority call can also lower the risk of reduced reservoir storage and yield as a result of making the 20,000 acre-feet release. Although the Shoshone priority call cannot be selectively removed to only benefit those reservoirs charged with responsibility for making the 20,000 acre-feet release to the 15-Mile Reach, general removal of the Shoshone priority call will lower the risk of reduced storage and yield for those reservoirs making the 20,000 acre-feet release. Payment of foregone power revenues as a result of removing the Shoshone priority call would be necessary only in those years in which mitigation for making the 20,000 acre-feet release would be necessary. Costs resulting from reduced power generation and potentially reduced deliveries through the Adams, Roberts, Boustead and Busk-Ivanhoe Tunnels are detailed in Technical Memorandum No. 9.

3. Development of an insurance pool or fund consisting of stored water in a particular reservoir or reservoirs for release or exchange to the reservoir, or reservoirs, responsible for making the 20,000 acre-feet release is functionally equivalent to the alternatives analyzed in Technical Memorandum No. 7. Consequently, the results from the investigation detailed in Technical Memorandum No. 7 demonstrate feasibility from economic and engineering perspectives of providing an insurance pool or fund for lowering the risk of reduced yield and storage as a result of making the 20,000 acre-feet release to the 15-Mile Reach.

CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the above results and analysis:

1. Establishing an insurance pool in one or more reservoirs to lower the possibility of reduced reservoir storage in those reservoirs responsible for making the 20,000 acre-feet release is equivalent to spreading responsibility for making the release among a larger number of reservoirs rather than placing that responsibility on only one or two reservoirs.

2. Analysis completed in Technical Memorandum No. 7 (CWCB, 2001b) indicates the feasibility of spreading responsibility for the release among three and nine reservoirs. Based on analysis completed in Technical Memorandum 7, the risk of reduced storage in any one reservoir is reduced by spreading responsibility among a number of reservoirs.

3. Analysis completed in Technical Memorandum No. 9 for Alternative 5b, Shoshone Power Plant (CWCB, October 2001c) demonstrates the economic and engineering feasibility of another method of reducing the risk to reservoirs responsible for making the 20,000 acre-feet release. Technical Memorandum No. 9 considered only the general, and not selective, removal of the Shoshone priority call. This alternative has the additional potential benefit in that payment for foregone power generation could be made only in those years in which risk reduction was definitely required and would not be needed in every year.

4. From an engineering and economic perspective, the above alternatives for establishing an insurance pool appear to be feasible. These alternatives must, however, be reviewed by the Executive Committee and Colorado River basin water users to determine their institutional feasibility.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River*.

Colorado Water Conservation Board, October 2001a, *Technical Memorandum No. 6, Analysis of 2001 Spring Peak Flow conditions and Comparison to Results of StateMod Modeling for CFOPS Alternatives Investigation*.

Colorado Water Conservation Board, October 2001b, *Technical Memorandum No. 7, Investigation of Alternative 1f, Bypass Diversions to Storage and Alternative 1g, Reduce Constraints on CROP, Draft.*

Colorado Water Conservation Board, October 2001c, *Technical Memorandum No. 9, Investigation of Alternative 5b, Expanded Coordinated Reservoir Operations, Shoshone Power Plant, Draft*.

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

TECHNICAL MEMORANDUM NO. 11:
INVESTIGATION OF ALTERNATIVE 1E,
EXPANDED COORDINATED RESERVOIR OPERATIONS,
DENVER WATER SYSTEMS OPERATIONS

DRAFT

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TECHNICAL MEMORANDUM NO. 11:
INVESTIGATION OF ALTERNATIVE 1E,
EXPANDED COORDINATED RESERVOIR OPERATIONS,
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EXECUTIVE SUMMARY

The purpose of Technical Memorandum No. 11 is to present results from an investigation of Alternative 1e, Expanded Coordinated Reservoir Operations for Denver Water Systems Operations. This alternative involves re-operation of Denver Water's reservoir system, primarily Dillon and Williams Fork Reservoirs, to make a 20,000 acre-feet release to the 15-Mile Reach for recovery of endangered fish in those eight years during the 1974-91 study period when the release could be required.

Analysis of this alternative focused on the feasibility of making the 20,000 acre-feet release from Williams Fork Reservoir. Brown and Caldwell, with approval from Denver Water Board, chose to model this alternative using Williams Fork Reservoir because: (1) its purpose is to act as a supply of augmentation water for Dillon, (2) its location is further downstream than Dillon, and (3) it is not a direct water supply for Denver. The analysis was completed using StateMod with the C1 data set. Because the C1 data set only includes the Colorado River basin, major components of the Denver Water system located on the east slope are not included. Because of this, the initial results from the StateMod analysis have been provided to Denver Water for further analysis using Denver Water's own models, data sets and computation procedures.

Specific results from the StateMod/C1 analysis for west slope facilities include:

1. **Williams Fork Reservoir.** Storage in Williams Fork Reservoir was the only reservoir affected by imposition of the Alternative 1e operating rule as compared to storage under the C1 Scenario for the study period. During 1975, 1980 and 1982 Williams Fork Reservoir did not completely fill under the Alternative 1e scenario as it did in the C1 baseline scenario. Releases of 20,000 acre-feet to the 15-Mile Reach were made in all those years. Storage deficits ranged from approximately 2,000 acre-feet in 1982 to approximately 4,900 acre-feet in 1980. By the end of the irrigation season the total storage in the reservoir did match the values in the C1 base run in each of those years. In 1979 the reservoir did fill as in the C1 baseline scenario, but filling occurred one month later. In August 1978, Williams Fork Reservoir storage was approximately 19,000 acre-feet lower than in the baseline scenario as a result of making the 20,000 acre-feet release in that year. This storage deficit remained in Williams Fork Reservoir until the following summer (1979) when the reservoir filled. Williams Fork Reservoir was not completely drawn down at any time during the 1974-91 study period under either the C1 base run scenario or the Alternative 1e scenario.

2. **Dillon Reservoir.** Storage in Dillon Reservoir was unaffected by imposition of the Alternative 1e operating rule as compared to storage under the C1 scenario for the study period. Because Williams Fork Reservoir never emptied under this alternative, and its primary purpose is to augment Dillon Reservoir, the total storage in Dillon was unchanged**.**

3. **Green Mountain Reservoir**. For practical purposes, storage in Green Mountain Reservoir was unaffected by imposition of the Alternative 1e operating rule as compared to storage under the C1 baseline scenario for the study period. Annual average power revenues at Green Mountain Reservoir, however, were increased by approximately $800 per year as a

result of making the 20,000 acre-feet release from Williams Fork Reservoir under the Alternative 1e operating rule.

4. **Ruedi Reservoir.** For practical purposes, storage in Ruedi Reservoir was unaffected by imposition of the Alternative 1e operating rule as compared to storage under the C1 Scenario for the study period. A slight increase, however, in total storage was observed in 1978 due to partially satisfying a calling right with the 20,000 release from Williams Fork Reservoir. Power revenues at Ruedi Reservoir increased by an annual average of approximately $3,100 as a result of the Alternative 1e operating rule.

5. **Shoshone power production.** Average annual Shoshone power revenues were reduced by approximately $15,000 per year by implementation of the Alternative 1e operations policy for the 1975-91 study period. It was observed that in those years when Williams Fork made a 20,000 acre-feet release, power generation at Shoshone was slightly less in the following autumn.

6. **Shoshone priority calls.** The frequency and duration of Shoshone priority calls were not altered to any measurable degree by implementation of the Alternative 1e operations policy for the 1975-91 study period.

7. **Orchard Mesa power plant.** The Alternative 1e operating policy for Green Mountain Reservoir did not increase the frequency or duration of periods with less than 800 cfs flow at the point of diversion for the Orchard Mesa Power Plant. Therefore, power production at the Orchard Mesa Power Plant should be unaffected by the Alternative 1e operating policy.

8. **Check Case settlement.** Settlement of Case No. 91 CW 247 focuses on the irrigation season when the Alternative 1e operations policy will make releases of the 20,000 acre-feet. Consequently, implementation of the Alternative 1e operations policy should not affect the Check case settlement.

The following recommendations and conclusions are based on results of the investigation detailed above:

1. Alternative 1e, Expanded Coordinated Reservoir Operations, Denver Water Systems Operations, was able to make the 20,000 acre-feet release to the 15-Mile Reach in each of the eight years when the release could have been required.

2. Effects on west slope facilities from Alternative 1e are limited to Williams Fork Reservoir storage, which is reduced in a few years during and after making the 20,000 acre-feet release. During the 1974-91 study period, however, Williams Fork Reservoir refilled eventually and was never completely drawn down.

3. Therefore, unless the analysis by Denver Water of their east slope facilities demonstrates a fatal flaw in the alternative, it is recommended that Alternative 1e be further considered as a possible source of the 20,000 acre-feet release to the15-Mile Reach.

INTRODUCTION AND PURPOSE

The Phase 1 investigation (CWCB, September 2000) recommended that Alternative 1e, Expanded Coordinated Reservoir Operations, Denver Water Systems Operations, be further explored. The purpose of this Technical Memorandum is to describe the details and results of this investigation.

Brown and Caldwell, with approval from Denver Water Board, chose to model this alternative using Williams Fork Reservoir because: (1) its purpose is to act as a supply of augmentation water for Dillon, (2) its location is further downstream than Dillon, and (3) it is not a direct water supply for Denver.

StateMod and the C1 data set, which include only those components of Denver Water's system located in the Colorado River Basin, were used to explore Alternative 1e. The feasibility of this alternative was first examined using StateMod and the C1 data set. The results were subsequently provided to Denver Water for review and further analysis to determine Alternative 1e effects on Denver Water's east slope facilities and systems.

ANALYSIS PROCEDURES AND ASSUMPTIONS

GENERAL

The following general procedures, tools, and assumptions were employed in the analysis of Alternative 1e:

1. StateMod surface water model and the C1 data set were used for baseline hydrology for the period 1975-1991, using a monthly time step.

2. The baseline conditions were the StateMod C1 Scenario, with the RIPRAP projects and without the 60,000 acre-feet or 120,000 acre-feet of new depletions, as detailed in Appendix D of the PBO. The components of RIPRAP flows incorporated in C1 are detailed in Section 2.3.3, *Baseline Conditions* of *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River (CWCB, 2000)*. These components of RIPRAP flows include:

    - 5,000 acre-feet per year from Ruedi Reservoir,
    - An additional 5,000 acre-feet in 4 out of 5 years from Ruedi Reservoir,
    - 10,825 acre-feet per year from Ruedi Reservoir under long-term lease,
    - 10,825 acre-feet per year on a permanent basis divided equally between east slope and west slope water users (presently Williams Fork and Wolford Mountain Reservoirs),
    - 6,000 acre-feet per year from Wolford Mountain Reservoir, and
    - Up to 28,400 acre-feet per year of water resulting from construction of improved water management features for the Grand Valley Water Management Project were incorporated on the C1 dataset but not modeled

3. Flow Targets: Releases of 20,000 acre-feet over a 10-day period were made from Williams Fork Reservoir when the expected spring peak flow at the head of the 15-Mile Reach was between 12,900 cfs and less than 26,600 cfs.

4. CROP and 120,000 acre-feet of future depletions were not included in the baseline hydrology. The Phase 1 report states: "*At the conclusion of investigating each of the alternatives to be analyzed in Phase 2, the alternative will be subjected to necessary and appropriate sensitivity analysis to determine if feasibility of the alternative is affected by including the 120,000 acre-feet per year of future depletions in the baseline hydrology.*" Consequently, if the CWCB and the Executive Committee review the analysis and any revisions made by the consultant and determine that the methodology and calculations employed in the analysis of Alternative 1e are acceptable, the necessary sensitivity analysis will be completed.

CROP is a voluntary program, the participation in which is determined on a yearly basis. Individual participation in CROP is dependent on conditions that are present each year, including snowpack, forecasted streamflows, and reservoir storage levels, among others. CFOPS is perceived to be a firmer commitment, once made, as part of the Biological Opinion. CFOPS will likely be expected to operate each year that flow in the stream in the 15-Mile Reach is within the target range during the spring run-off. There is no guarantee that CROP will actually provide water every year. Therefore, CFOPS should have priority over CROP when in competition for the same acre-foot of supply.

5. Electric power purchase and sales prices were obtained from the Western Area Power Administration (WAPA) for estimating the value of power generation foregone at Green Mountain Reservoir as a result of this alternative (Personal communication from John Gierard, WAPA, to Leo Eisel and Bruce Rindahl, January 23, 2001). The sales prices were used in evaluating foregone power generation at both Shoshone and Green Mountain Power Plants. The Executive Committee requested at the April 6, 2001 meeting that the consultant submit the power rate schedules employed in the analysis to WAPA and to Excel Energy for comment concerning the appropriateness of these rate schedules for use in the analysis and specifically concerning the cost of replacement power. The consultant is still awaiting a response to our May 2001 request to WAPA and Excel Energy concerning this matter.

6. Maintenance schedules for hydropower generation facilities at Green Mountain and Ruedi Reservoirs and the Shoshone Power Plant are not incorporated into StateMod and the C1 data set. The normal procedure for Green Mountain is two outages (one for each unit) of 4.5 weeks each. Typically one of the outages is in January and the other in March. The units are not normally worked on at the same time thus maintaining capacity to deliver through at least one unit. Ruedi Reservoir hydropower facilities are generally maintained during a period of approximately two weeks sometime during the year. There is no set schedule for when this two weeks will occur during the year (personal communication with Phillip Harris, High Country Engineering, September 12, 2001). A typical maintenance schedule for Shoshone Power Plant will have Unit A out for January and Unit B out for February. The C1 data set, however, assumes that power generation facilities are always available at full capacity and does not acknowledge these periods of downtime for maintenance.

   In the analysis herein, the total kilowatt-hours of power generation are calculated for the C1 base case scenario and compared to the calculated total kilowatt-hours generated with the alternative scenario. Therefore, the two scenarios should be affected equally by the C1 baseline scenario's lack of simulation of the hydropower maintenance periods.

   The effects of not specifically considering these maintenance periods is to: (1) slightly overestimate the foregone revenue from hydropower generation for those alternatives which decrease water supply availability and (2) slightly overestimate the additional power generated by those alternatives that increase water availability for hydropower generation.

Brown and Caldwell does not believe this omission by the C1 data set creates a significant bias in the results which would affect conclusions from this investigation.

A similar situation exists with respect to frequency of calls from Shoshone. The frequency of calls from Shoshone is determined for both the C1 base run scenario and for the alternative under investigation. Therefore these two scenarios should be affected equally by the C1 baseline scenario's lack of simulation of the hydropower maintenance periods.

7. There are three categories of reservoir fill for Green Mountain Reservoir:

   - The physical fill,
   - A reservoir fill according to the criteria of the Division 5 Engineer which requires that the allowable fill under a first fill right cannot exceed the difference between: (a) storage on a reservoir's Start of Fill Date (usually April 1- 15) and (b) the maximum decreed storage amount under the reservoir's first fill right, and
   - A reservoir fill according to the criteria of the Blue River Decree.

   The 20,000 acre-feet release to the 15-Mile Reach will count against the first fill right of a reservoir because under Water Division 5 policy, the allowable fill under a first fill right cannot exceed the difference between a reservoir's Start of Fil1 Date storage and the maximum decreed storage amount under the first fill right (personal communication with Alan Martellaro, July 2001). This limitation does not apply to a refill right where water can be diverted under a reservoir's refill priority up to the decreed amount of the refill right. StateMod and the C1 data set correctly handle this situation.

   Power releases made under the direct flow power right are not debited against the "paper fill" of Green Mountain reservoir by the Division 5 Engineer. StateMod and the C1 data set are currently not modeling this situation accordingly. StateMod and the C1 data set are debiting such power releases made under the direct flow power right against Green Mountain Reservoir's first fill right.

   Power releases made under the direct flow power right are debited in the accounting against the "paper fill" specified in the Blue River Decree, which defines the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir. Based on the results of the analysis described later in the report, however, StateMod and the C1 data set are not correctly modeling the exchange among Williams Fork Reservoir, Wolford Mountain Reservoir and Dillon Reservoir. Consequently, it is uncertain whether the fill obligations of Dillon Reservoir in relationship to Green Mountain Reservoir under the Blue River Decree are being handled correctly.

8. The June 19, 2001 Municipal Recreation Agreement Between the United States, the Town of Palisade, the City of Grand Junction, and the City of Fruita allows for a release of HUP Surplus Water to be made from Green Mountain Reservoir for municipal recreational purposes if:

   - HUP Surplus Water is not needed to generate power at the Grand Valley Power Plant,

- Target flows for recovery of the endangered fishes in the 15-Mile Reach, as specified in USFWS (May 1955, p. 65), are not being met, and
- Sufficient HUP Surplus water exists to make the release.

Releases of Green Mountain Reservoir HUP water for municipal recreational purposes generally begin in approximately mid-August and can continue into the fall. StateMod and the C1 data set do not explicitly model releases of HUP Surplus water under the Municipal Recreational Agreement and there is no demand specified at a node for the Municipal Recreational water.

USE OF STATEMOD

The C1 scenario was modified by adding full reservoir targets in Green Mountain Reservoir for the months of September and October. This prevented surplus water hydropower releases until after the irrigation season. In addition, monthly demands of 20,000 acre-feet were added to diversion ID #952001 corresponding to the projected 20,000 acre-feet releases to enhance the spring runoff in the 15-Mile Reach in 1975, 1978, 1979, 1980, 1982, 1985, 1986 and 1991. Finally, any water rights were eliminated from that diversion to prevent the right from simply taking credit for water in the stream when available. The Ruedi Reservoir refill right was incorrectly given a priority number of 99999.99 in the C1 run. The correct priority number of 47869 was used in the revised baseline. These changes constituted the revised C1 baseline scenario.

For Alternative 1e, the baseline scenario was modified in only one way. A new operation rule was added to allow a release from Williams Fork Reservoir to Diversion ID# 952001 (the 15-Mile Reach fish requirement). This change released an additional 20,000 acre-feet of water from Williams Fork Reservoir in those years when it would be required.

Several spreadsheets were then developed that allowed side by side comparison of every aspect of the analysis in the two StateMod runs including reservoir storage, diversions, streamflows and operating releases.

RESULTS

EFFECTS ON RESERVOIR STORAGE

Williams Fork Reservoir Storage

Storage in Williams Fork Reservoir was the only reservoir affected by imposition of the Alternative 1e operating rule as compared to storage under the C1 Scenario for the study period. During the years 1975, 1980 and 1982 Williams Fork Reservoir did not completely fill as in the baseline scenario (see Figure 1). By the end of the irrigation season the total storage in the reservoir did match the values in the base run in each of those years. In 1979 the reservoir filled to the same level as in the baseline scenario but not until one month later. In 1978, the reservoir remained significantly lower than in the baseline scenario from June until the following summer in 1979 when it filled. At no time did the model show Williams Fork Reservoir going completely empty.

Dillon Reservoir Storage

Storage in Dillon Reservoir was unaffected by imposition of the Alternative 1e operating rule as compared to storage under the C1 Scenario for the study period (see Figure 2). Since Williams Fork Reservoir never emptied under this alternative, and its primary purpose is to augment Dillon Reservoir, the total storage in Dillon was unchanged.

Green Mountain Storage

Storage in Green Mountain Reservoir was unaffected by imposition of the Alternative 1e operating rule as compared to storage under the C1 Scenario for the study period (see Figure 3).

Ruedi Reservoir

For practical purposes, storage in Ruedi Reservoir was unaffected by imposition of the Alternative 1e operating rule as compared to storage under the C1 Scenario for the study period. A slight increase in total storage, however, was observed in 1978 due to partially satisfying a calling right with the 20,000 release from Williams Fork Reservoir (see Figure 4).

EFFECTS ON POWER GENERATION

Green Mountain Reservoir Power Generation

Results of the analysis indicate that no significant impact occurred to Green Mountain Reservoir power generation. Slight modifications to the releases were observed due to the 20,000 acre-feet release mitigating the requirements on the HUP pool. This resulted in a total increase in power revenues of approximately $13,500 over the study period or an average annual increase of approximately $800 from Green Mountain Reservoir. Table 1 and Figure 5 show the comparison of power generation from the two scenarios.

Ruedi Reservoir Power Generation

Results of the analysis indicate that total Ruedi Reservoir power revenues would be increased by $52,466 over the study period or an average annual increase of $3,086. This slight increase is due to a minor increase in power generation in the summer of 1979. Table 2 presents the comparison of power generation from the two scenarios.

Shoshone Power Generation

Results of the analysis indicate that total Shoshone power revenues for the study period would be decreased by approximately $253,000 for an average annual reduction of approximately $15,000 (see Table 3, Figures 6 and 7). This decrease in power generation occurs in several autumn seasons after Williams Fork makes a 20,000 acre-feet release in June.

OTHER EFFECTS

Colorado River Channel Constraints

Review of *Coordinated Reservoir Operations Bypasses for Endangered Fish, Annual Summary of Operations for 1997 to Benefit the Endangered Fishes of the Upper Colorado River Basin* provides information concerning flooding from the mainstem Colorado River that occurred in 1997 in the Kremmling, Cameo and Grand Valley areas. This report contains locations and extent of flooding that occurred in early June, 1997 when the spring hydrograph peaked at 26,500 cfs at the Palisade gauge and 37,200 cfs at the State line gauge. Data provided in this report indicate only minimal flooding of rural floodplain areas and high water on the I-70 bridge downstream from Fruita, with no indication of property damage from these flows.

The recorded 1997 peak Colorado River flow at the Palisade gauge of 26,500 cfs is very close to the upper limit for making releases to the fish of 26,600 cfs. For practical purposes, it would appear feasible to develop operations rules that would require reduction or cessation of releases for

the fish when flows at the Palisade gauge approached, say 25,000 cfs. Selection of this upper cutoff number should allow 2 to 3 days travel time from Green Mountain Reservoir to the Palisade gauge to insure that releases for the fish would not be responsible for additional flooding above the approximately 26,000 cfs flow at the Palisade gauge.

General Pinch Points and Channel Constraints

The above referenced 1997 Coordinated Reservoir Operations Review recommended that additional investigations of channel capacity constraints ("pinch points") in the Colorado River basin in Colorado are necessary. Specifically:

- Work with the State of Colorado and National Weather Service to resolve differing flood stage levels or determinations at stream gages.
- Obtain aerial photography downstream of all participating reservoirs and in the 15-Mile Reach to determine "pinch points" on the system when out-of-bank flooding is close to occurring and document the benefits of peak flows to critical habitat.
- Work with the State of Colorado and National Weather Service to identify high flow levels and locations potentially flooded or adversely affected by the Coordinated Reservoir Operations Study.

Implementation of these recommendations would be of significant assistance in facilitating releases from reservoirs for the endangered fish without creating additional damage from flooding.

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CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations are based on the results and analysis of the StateMod/C1 scenario:

1. It was possible to make the 20,000 acre-feet release to the 15-Mile Reach from Williams Fork Reservoir during the eight years in which it could be required.

2. The effects on west slope structures from making this 20,000 acre-feet release do not appear to constitute fatal flaws.

3. The results from the StateMod/C1 scenario analysis have been provided to Denver Water for further analysis using Denver Water's analysis procedures and models that include east slope components of Denver Water's system. When the results of Denver Water's analysis become available, these results will be provided.

4. Based on the StateMod/C1 analysis which did not include east slope components of Denver Water's system, it is recommended that Alternative 1e be further considered as a possible means of providing the 20,000 acre-feet release to the 15-Mile Reach.

REFERENCES

Colorado Water Conservation Board, September 2000, *Phase 1 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River.*

U.S. Fish and Wildlife Service, May 1995, *Relationships Between Flow and Rare Fish Habitat in the 15-Mile Reach of the Upper Colorado River, Final Report.*

Figure 1

WILLIAMS FORK RESERVOIR

EOM Content

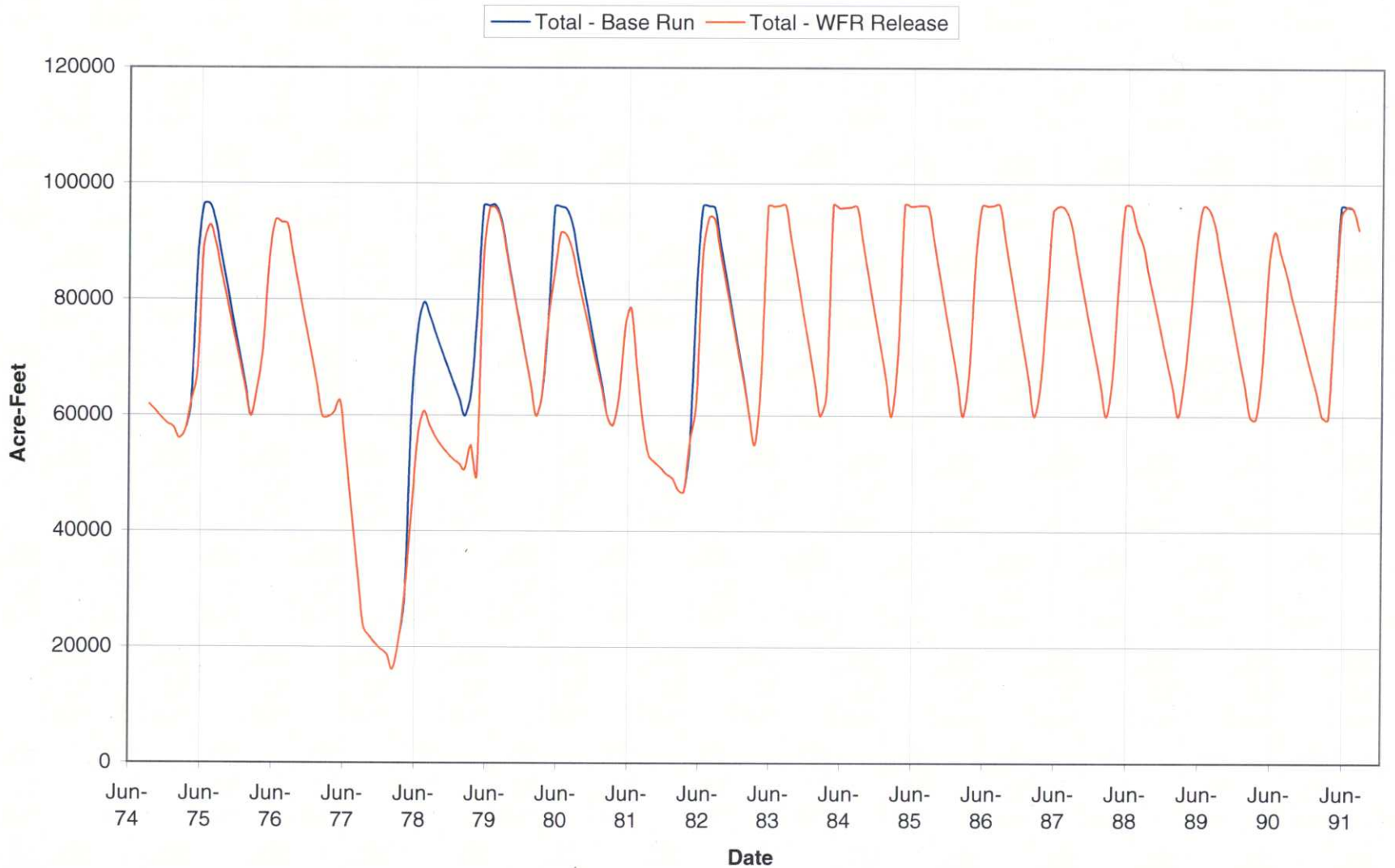

Figure 2

DILLON RESERVOIR

EOM Content

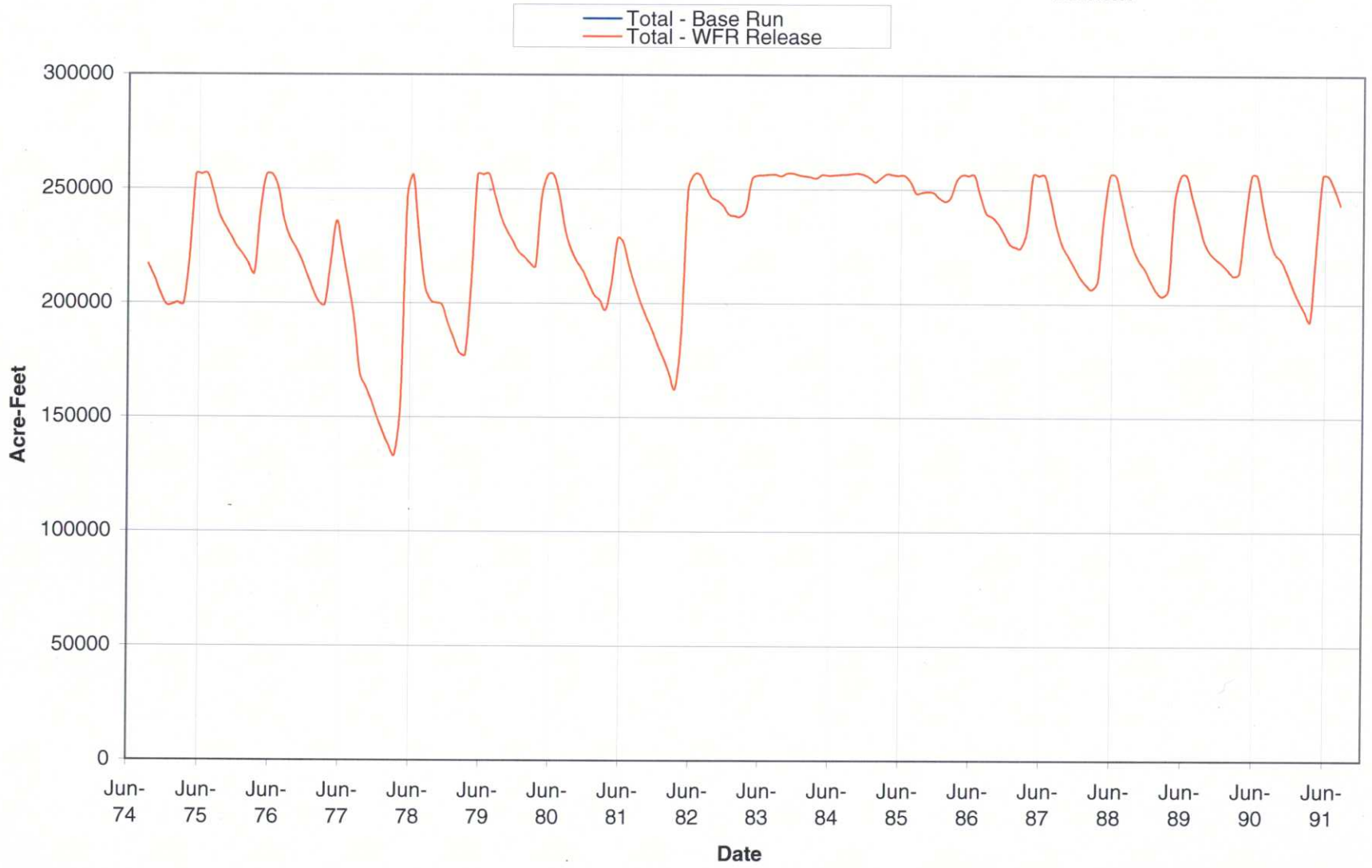

Figure 3

GREEN MOUNTAIN RESERVOIR

EOM Content

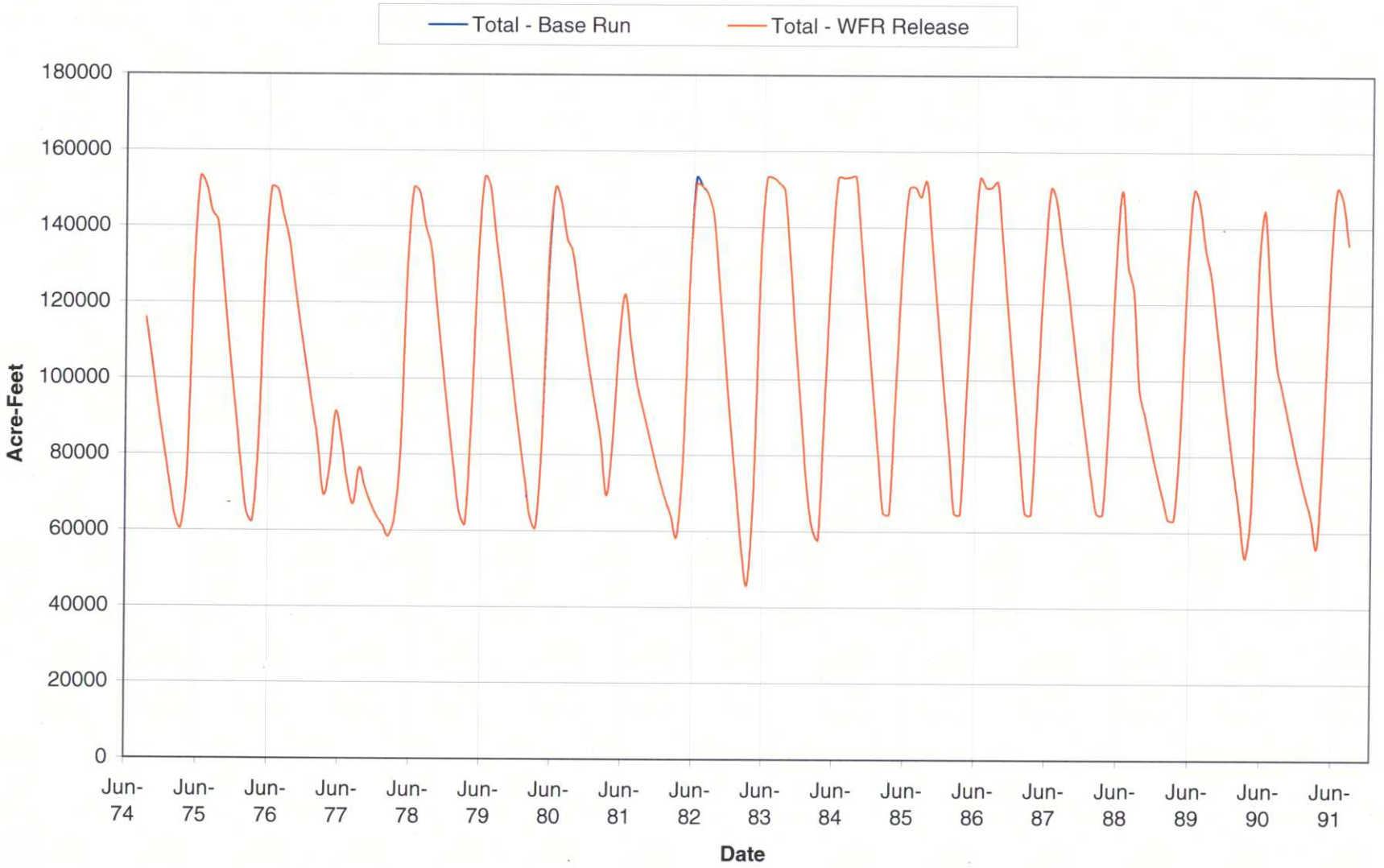

Figure 4

RUEDI_RESERVOIR

EOM Content

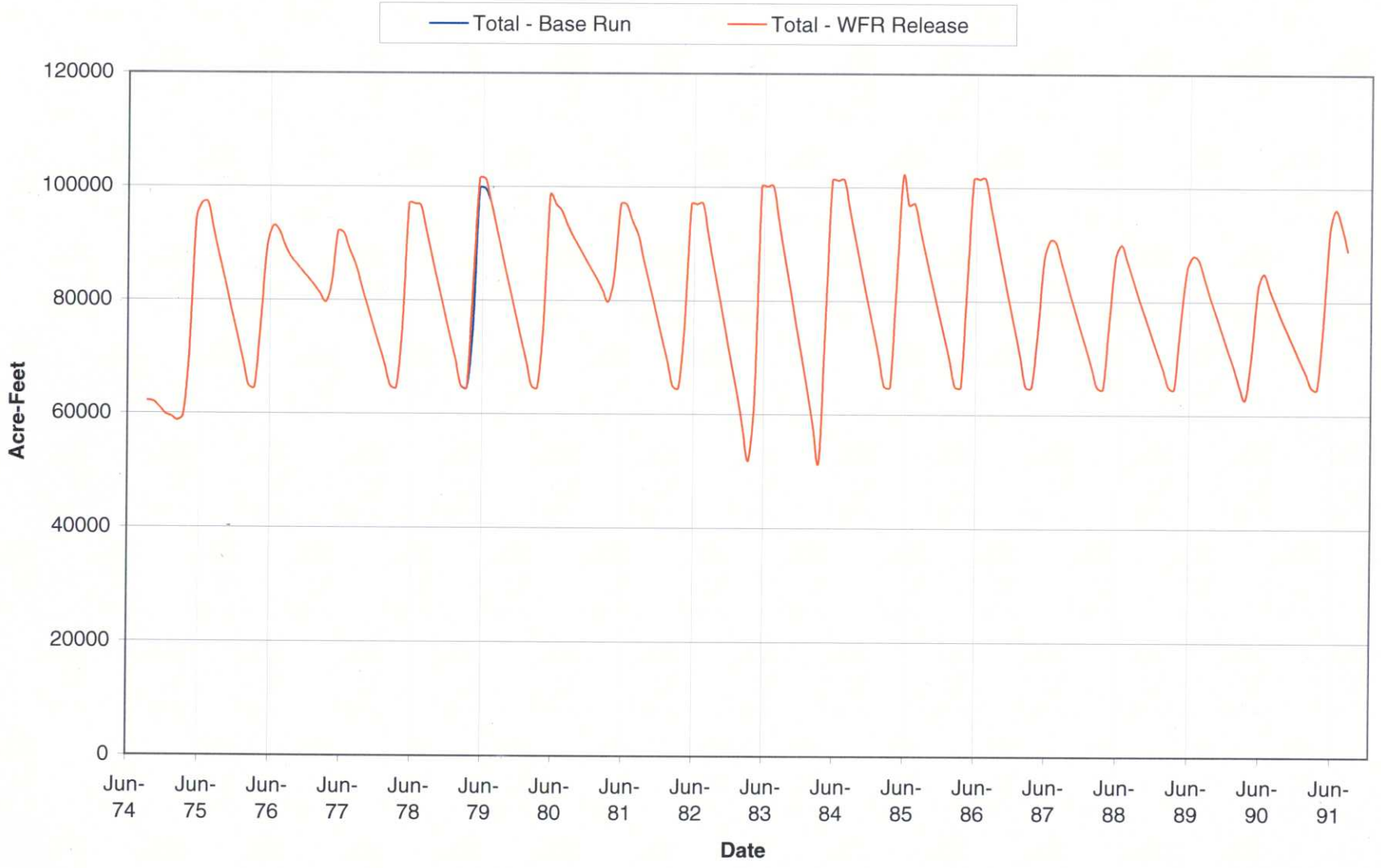

Figure 5

POWER PRODUCTION AT GMR

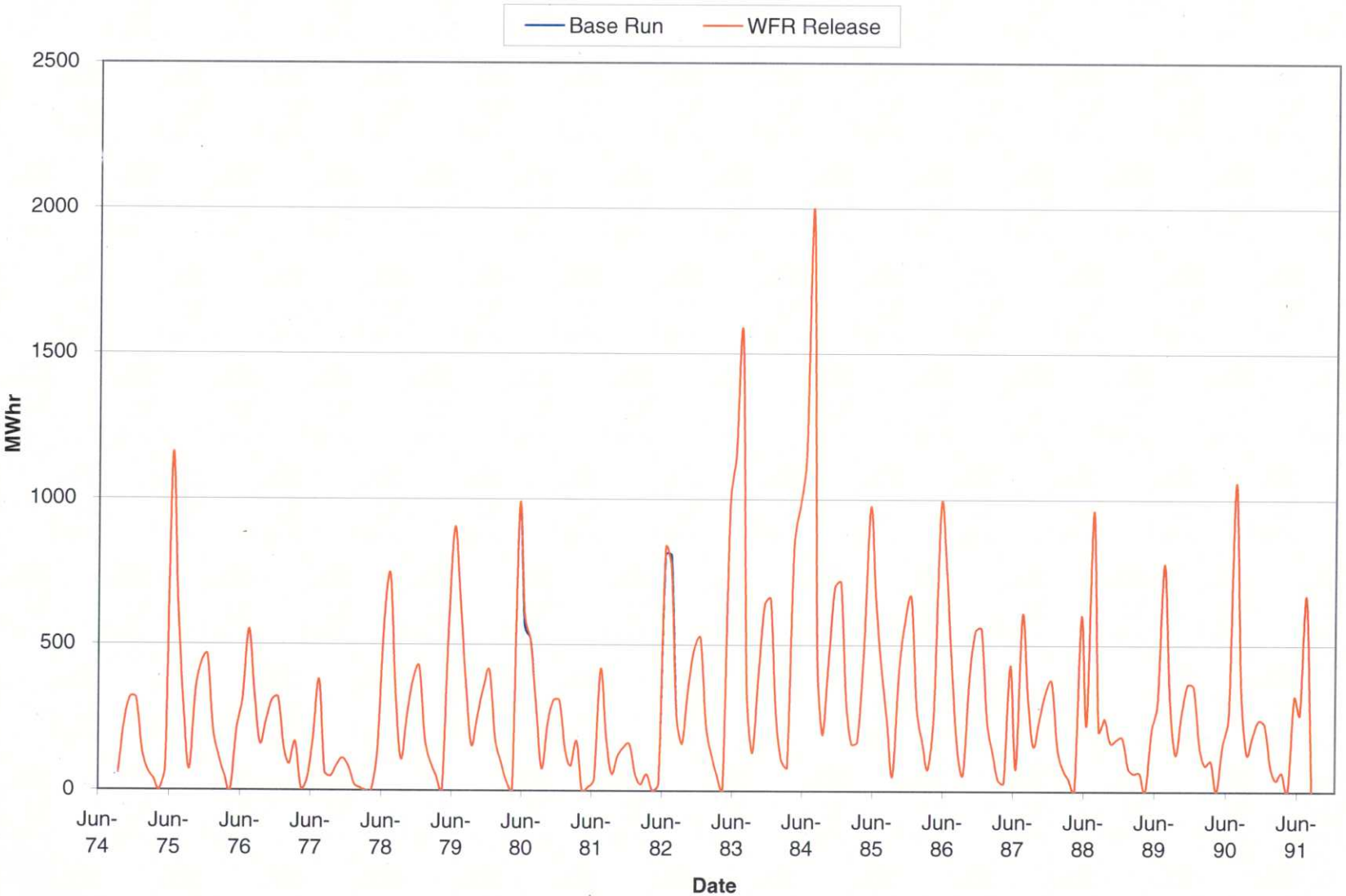

Figure 6

SHOSHONE POWER PRODUCTION

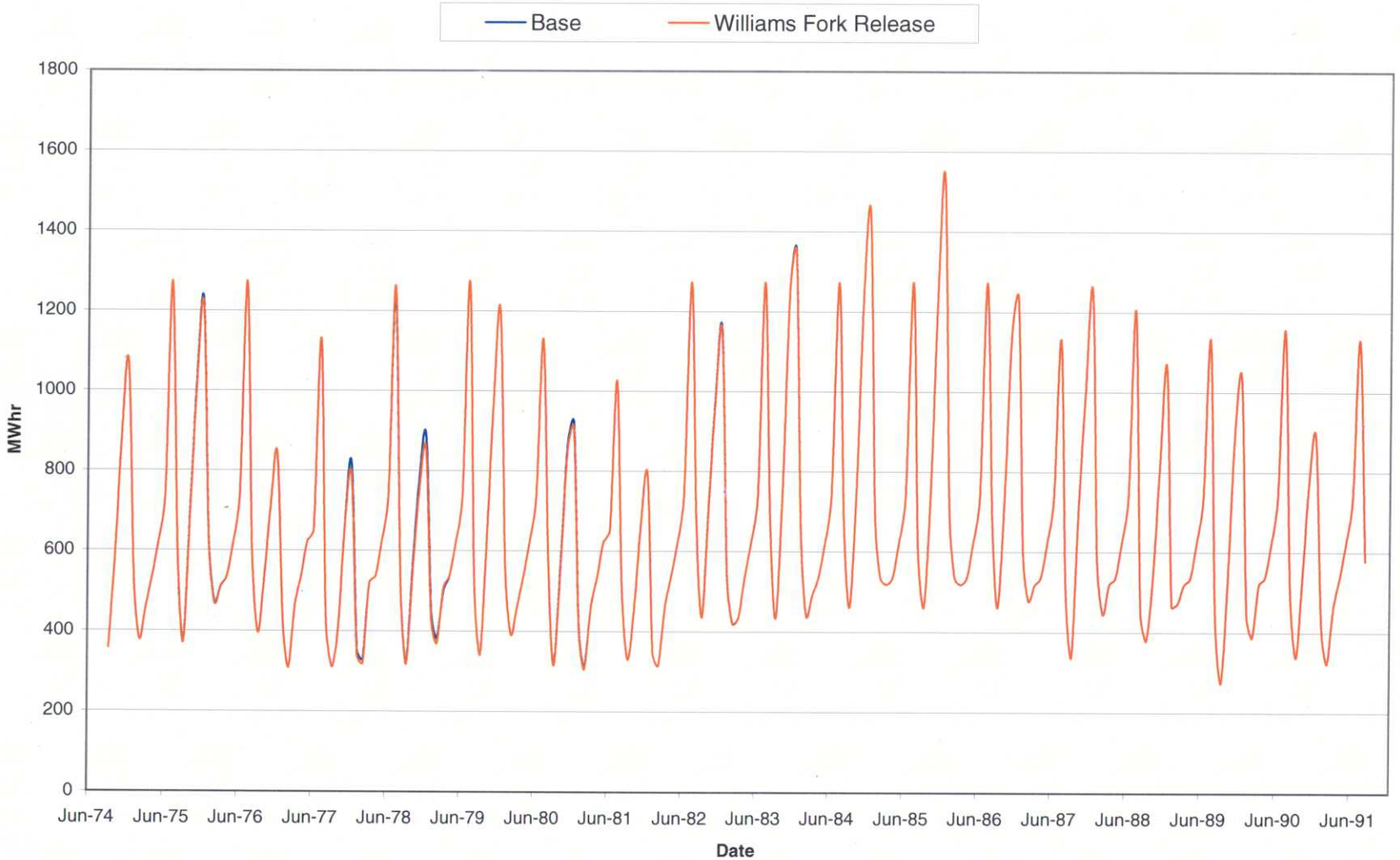

Figure 7

SHOSHONE POWER PLANT

Total Supply

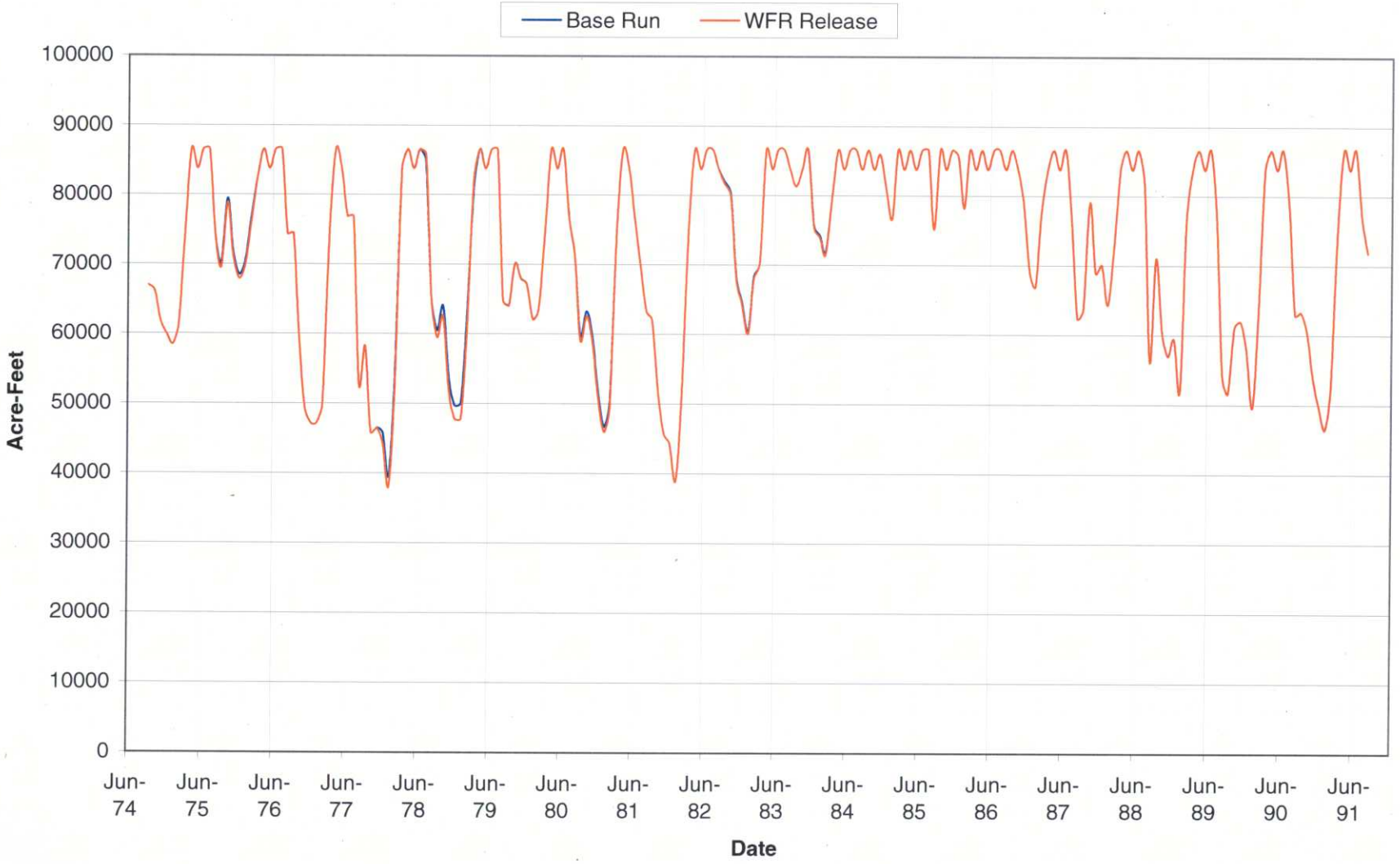

Table 1
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Williams Fork Release

		Base							WFR Release								
Year	Mo Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT Oct-74	11357	115846	7930.56	241.56	184.70	1501	58	11357	115846	7930.56	241.56	184.70	1501	58	0	0.03878
1974	NOV Nov-74	21320	104427	7923.83	234.83	358.29	3628	236	21320	104427	7923.83	234.83	358.29	3628	236	0	0.06502
1974	DEC Dec-74	19759	93370	7916.71	227.71	321.34	3015	318	19759	93370	7916.71	227.71	321.34	3015	318	0	0.10541
1975	JAN Jan-75	18019	82713	7909.22	220.22	293.05	2409	313	18019	82713	7909.22	220.22	293.05	2409	313	0	0.13
1975	FEB Feb-75	17044	72644	7901.50	212.50	306.89	2130	138	17044	72644	7901.50	212.50	306.89	2130	138	0	0.065
1975	MAR Mar-75	15939	63730	7893.97	204.97	259.22	1533	69	15939	63730	7893.97	204.97	259.22	1533	69	0	0.045
1975	APR Apr-75	12710	60889	7891.43	202.43	213.60	867	39	12710	60889	7891.43	202.43	213.60	867	39	0	0.045
1975	MAY May-75	5289	75493	7903.76	214.76	0.00	0	0	5289	75493	7903.76	214.76	0.00	0	0	0	0.045
1975	JUN Jun-75	10362	129047	7937.76	248.76	174.14	1475	80	10362	129047	7937.76	248.76	174.14	1475	80	0	0.05416
1975	JUL Jul-75	84336	152997	7949.70	260.70	1371.57	18600	1149	84336	152997	7949.70	260.70	1371.57	18600	1149	0	0.06176
1975	AUG Aug-75	27765	150691	7948.60	259.60	451.55	5963	638	27765	150691	7948.60	259.60	451.55	5963	638	0	0.10693
1975	SEP Sep-75	23444	143784	7945.26	256.26	393.98	4821	283	23444	143784	7945.26	256.26	393.98	4821	283	0	0.05866
1975	OCT Oct-75	11432	141023	7943.89	254.89	185.92	1847	72	11432	141023	7943.89	254.89	185.92	1847	72	0	0.03878
1975	NOV Nov-75	26434	124561	7935.37	246.37	444.23	5194	338	26434	124561	7935.37	246.37	444.23	5194	338	0	0.06502
1975	DEC Dec-75	23514	108470	7926.28	237.28	382.41	4167	439	23514	108470	7926.28	237.28	382.41	4167	439	0	0.10541
1976	JAN Jan-76	22347	92780	7916.31	227.31	363.43	3573	465	22347	92780	7916.31	227.31	363.43	3573	465	0	0.13
1976	FEB Feb-76	22018	77676	7905.45	216.45	382.78	3244	211	22018	77676	7905.45	216.45	382.78	3244	211	0	0.065
1976	MAR Mar-76	20867	64928	7895.03	206.03	339.36	2570	116	20867	64928	7895.03	206.03	339.36	2570	116	0	0.045
1976	APR Apr-76	13611	62615	7892.97	203.97	228.74	1089	49	13611	62615	7892.97	203.97	228.74	1089	49	0	0.045
1976	MAY May-76	5289	84324	7910.40	221.40	0.00	0	0	5289	84324	7910.40	221.40	0.00	0	0	0	0.045
1976	JUN Jun-76	20309	129027	7937.75	248.75	341.30	3829	207	20309	129027	7937.75	248.75	341.30	3829	207	0	0.05416
1976	JUL Jul-76	24273	150202	7948.37	259.37	394.76	5100	315	24273	150202	7948.37	259.37	394.76	5100	315	0	0.06176
1976	AUG Aug-76	24579	149741	7948.15	259.15	399.73	5167	553	24579	149741	7948.15	259.15	399.73	5167	553	0	0.10693
1976	SEP Sep-76	26715	142820	7944.78	255.78	448.95	5597	328	26715	142820	7944.78	255.78	448.95	5597	328	0	0.05866
1976	OCT Oct-76	21293	136188	7941.46	252.46	346.29	4149	161	21293	136188	7941.46	252.46	346.29	4149	161	0	0.03878
1976	NOV Nov-76	20049	124693	7935.44	246.44	336.93	3697	240	20049	124693	7935.44	246.44	336.93	3697	240	0	0.06502
1976	DEC Dec-76	17772	113570	7929.26	240.26	289.03	2946	311	17772	113570	7929.26	240.26	289.03	2946	311	0	0.10541
1977	JAN Jan-77	16388	102846	7922.85	233.85	266.52	2445	318	16388	102846	7922.85	233.85	266.52	2445	318	0	0.13
1977	FEB Feb-77	15486	92708	7916.26	227.26	278.84	2190	142	15486	92708	7916.26	227.26	278.84	2190	142	0	0.065
1977	MAR Mar-77	16143	83715	7909.95	220.95	262.54	2026	91	16143	83715	7909.95	220.95	262.54	2026	91	0	0.045
1977	APR Apr-77	25403	69475	7898.91	209.91	426.91	3687	166	25403	69475	7898.91	209.91	426.91	3687	166	0	0.045
1977	MAY May-77	8191	76232	7904.33	215.33	133.21	186	8	8191	76232	7904.33	215.33	133.21	186	8	0	0.045
1977	JUN Jun-77	9204	91191	7915.23	226.23	154.68	695	38	9204	91191	7915.23	226.23	154.68	695	38	0	0.05416
1977	JUL Jul-77	19715	84169	7910.28	221.28	320.63	2807	173	19715	84169	7910.28	221.28	320.63	2807	173	0	0.06176
1977	AUG Aug-77	24562	72947	7901.74	212.74	399.46	3558	380	24562	72947	7901.74	212.74	399.46	3558	380	0	0.10693
1977	SEP Sep-77	13059	67022	7896.84	207.84	219.46	1075	63	13059	67022	7896.84	207.84	219.46	1075	63	0	0.05866
1977	OCT Oct-77	13233	76527	7904.56	215.56	215.21	1258	49	13233	76527	7904.56	215.56	215.21	1258	49	0	0.03878
1977	NOV Nov-77	13832	71278	7900.39	211.39	232.45	1326	86	13832	71278	7900.39	211.39	232.45	1326	86	0	0.06502
1977	DEC Dec-77	13180	67062	7896.88	207.88	214.35	1047	110	13180	67062	7896.88	207.88	214.35	1047	110	0	0.10541
1978	JAN Jan-78	11540	63609	7893.86	204.86	187.68	635	83	11540	63609	7893.86	204.86	187.68	635	83	0	0.13
1978	FEB Feb-78	9468	61290	7891.83	202.83	170.48	336	22	9468	61290	7891.83	202.83	170.48	336	22	0	0.065
1978	MAR Mar-78	9956	58454	7889.10	200.10	161.92	201	9	9956	58454	7889.10	200.10	161.92	201	9	0	0.045
1978	APR Apr-78	6333	63350	7893.63	204.63	106.43	0	0	6333	63350	7893.63	204.63	106.43	0	0	0	0.045
1978	MAY May-78	5289	81325	7908.20	219.20	0.00	0	0	5289	81325	7908.20	219.20	0.00	0	0	0	0.045
1978	JUN Jun-78	15480	129034	7937.75	248.75	260.15	2686	145	15480	129034	7937.75	248.75	260.15	2686	145	0	0.05416
1978	JUL Jul-78	41372	150202	7948.37	259.37	672.84	9285	573	41372	150202	7948.37	259.37	672.84	9285	573	0	0.06176
1978	AUG Aug-78	31882	149026	7947.81	258.81	518.50	6940	742	31882	149026	7947.81	258.81	518.50	6940	742	0	0.10693
1978	SEP Sep-78	26756	139955	7943.36	254.36	449.64	5556	326	26756	139955	7943.36	254.36	449.64	5556	326	0	0.05866
1978	OCT Oct-78	15652	133901	7940.29	251.29	254.55	2765	107	15652	133901	7940.29	251.29	254.55	2765	107	0	0.03878
1978	NOV Nov-78	22180	118865	7932.25	243.25	372.74	4095	266	22180	118865	7932.25	243.25	372.74	4095	266	0	0.06502
1978	DEC Dec-78	21471	104199	7923.69	234.69	349.19	3618	381	21471	104199	7923.69	234.69	349.19	3618	381	0	0.10541
1979	JAN Jan-79	21246	89932	7914.36	225.36	345.53	3268	425	21246	89932	7914.36	225.36	345.53	3268	425	0	0.13
1979	FEB Feb-79	19635	76253	7904.35	215.35	353.54	2756	179	19635	76253	7904.35	215.35	353.54	2756	179	0	0.065
1979	MAR Mar-79	19094	64928	7895.03	206.03	310.53	2208	99	19094	64928	7895.03	206.03	310.53	2208	99	0	0.045
1979	APR Apr-79	13825	61991	7892.45	203.45	232.33	1119	50	13825	61991	7892.45	203.45	232.33	1119	50	0	0.045
1979	MAY May-79	5289	90705	7914.90	225.90	0.00	0	0	5289	90705	7914.90	225.90	0.00	0	0	0	0.045
1979	JUN Jun-79	47652	131409	7939.00	250.00	800.81	10366	561	47652	131409	7939.00	250.00	800.81	10366	561	0	0.05416
1979	JUL Jul-79	62920	152994	7949.70	260.70	1023.28	14643	904	62920	152994	7949.70	260.70	1023.28	14643	904	0	0.06176
1979	AUG Aug-79	28239	150691	7948.60	259.60	459.26	6079	650	28239	150691	7948.60	259.60	459.26	6079	650	0	0.10693
1979	SEP Sep-79	29407	136836	7941.79	252.79	494.19	6135	360	29407	136836	7941.79	252.79	494.19	6135	360	0	0.05866
1979	OCT Oct-79	21480	125196	7935.71	246.71	349.33	4008	155	21480	125196	7935.71	246.71	349.33	4008	155	0	0.03878
1979	NOV Nov-79	22123	111904	7928.30	239.30	371.78	3954	257	22123	111904	7928.30	239.30	371.78	3954	257	0	0.06502
1979	DEC Dec-79	20742	98978	7920.40	231.40	337.33	3349	353	20742	98978	7920.40	231.40	337.33	3349	353	0	0.10541
1980	JAN Jan-80	21081	86451	7911.92	222.92	342.84	3154	410	21081	86451	7911.92	222.92	342.84	3154	410	0	0.13
1980	FEB Feb-80	20012	74512	7902.99	213.99	347.90	2745	178	20012	74512	7902.99	213.99	347.90	2745	178	0	0.065
1980	MAR Mar-80	19707	63729	7893.97	204.97	320.50	2300	104	19707	63729	7893.97	204.97	320.50	2300	104	0	0.045
1980	APR Apr-80	12046	61008	7891.55	202.55	202.44	737	33	12046	61008	7891.55	202.55	202.44	737	33	0	0.045
1980	MAY May-80	5289	83658	7909.91	220.91	0.00	0	0	5289	83658	7909.91	220.91	0.00	0	0	0	0.045
1980	JUN Jun-80	92712	129028	7937.75	248.75	1500.00	18000	975	90114	131424	7939.01	250.01	1500.00	18000	975	0	0.05416
1980	JUL Jul-80	40746	150202	7948.37	259.37	662.66	9131	564	43146	150198	7948.37	259.37	701.69	9719	600	36	0.06176
1980	AUG Aug-80	23537	146821	7946.74	257.74	382.79	4865	520	23384	146817	7946.74	257.74	380.30	4827	516	-4	0.10693
1980	SEP Sep-80	24612	137044	7941.89	252.89	413.61	4989	293	24612	137040	7941.89	252.89	413.61	4989	293	0	0.05866
1980	OCT Oct-80	12204	133406	7940.03	251.03	198.48	1936	75	12204	133402	7940.03	251.03	198.48	1936	75	0	0.03878
1980	NOV Nov-80	19891	122468	7934.23	245.23	334.27	3623	236	19890	122465	7934.23	245.23	334.26	3623	236	0	0.06502
1980	DEC Dec-80	17897	111901	7928.30	239.30	291.06	2946	311	17896	111899	7928.29	239.29	291.05	2946	311	0	0.10541
1981	JAN Jan-81	16154	101734	7922.15	233.15	262.72	2373	308	16153	101732	7922.15	233.15	262.70	2373	308	0	0.13
1981	FEB Feb-81	15190	92151	7915.89	226.89	273.51	2115	137	15189	92151	7915.89	226.89	273.49	2115	137	0	0.065
1981	MAR Mar-81	15583	83715	7909.95	220.95	253.43	1905	86	15583	83715	7909.95	220.95	253.43	1905	86	0	0.045
1981	APR Apr-81	25804	69340	7898.80	209.80	433.64	3766	169	25809	69335	7898.79	209.79	433.73	3767	169	0	0.045
1981	MAY May-81	5289	83359	7909.69	220.69	0.00	0	0	5289	83354	7909.69	220.69	0.00	0	0	0	0.045
1981	JUN Jun-81	5970	110362	7927.40	238.40	100.33	228	12	5970	110357	7927.39	238.39	100.33	228	12	0	0.05416
1981	JUL Jul-81	7258	122402	7934.20	245.20	118.04	631	39	7258	122404	7934.20	245.20	118.04	631	39	0	0.06176
1981	AUG Aug-81	22270	109651	7926.98	237.98	362.18	3907	418	22275	109648	7926.98	237.98	362.26	3908	418	0	0.10693
1981	SEP Sep-81	19445	98932	7920.37	231.37	326.78	3100	182	19446	98929	7920.37	231.37	326.80	3100	182	0	0.05866
1981	OCT Oct-81	12966	92652	7916.23	227.23	210.87	1503	58	12966	92650	7916.22	227.22	210.87	1503	58	0	0.03878
1981	NOV Nov-81	14892	85879	7911.51	222.51	250.26	1845	120	14892	85877	7911.51	222.51	250.26	1845	120	0	0.06502

Table 1
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Williams Fork Release

			Base							WFR Release								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1981	DEC	Dec-81	13696	79459	7906.80	217.80	222.74	1415	149	13695	79457	7906.80	217.80	222.72	1415	149	0	0.10541
1982	JAN	Jan-82	13431	73439	7902.14	213.14	218.43	1237	161	13430	73438	7902.14	213.14	218.41	1236	161	0	0.13
1982	FEB	Feb-82	11351	68007	7897.68	208.68	204.38	851	55	11351	68006	7897.68	208.68	204.38	851	55	0	0.065
1982	MAR	Mar-82	10831	63970	7894.18	205.18	176.15	499	22	10833	63968	7894.18	205.18	176.18	499	22	0	0.045
1982	APR	Apr-82	14858	58836	7889.47	200.47	249.69	1248	56	14858	58834	7889.46	200.46	249.69	1248	56	0	0.045
1982	MAY	May-82	5289	79718	7907.00	218.00	0.00	0	0	5289	79716	7907.00	218.00	0.00	0	0	0	0.045
1982	JUN	Jun-82	5970	129037	7937.75	248.75	100.33	435	24	5970	129037	7937.75	248.75	100.33	435	24	0	0.05416
1982	JUL	Jul-82	56645	152997	7949.70	260.70	921.23	13101	809	58326	151318	7948.90	259.90	948.57	13466	832	23	0.06176
1982	AUG	Aug-82	34304	150691	7948.60	259.60	557.89	7565	809	32724	150693	7948.60	259.60	532.20	7178	768	-41	0.10693
1982	SEP	Sep-82	21382	148503	7947.55	258.55	359.33	4394	258	21382	148505	7947.56	258.56	359.33	4394	258	0	0.05866
1982	OCT	Oct-82	20961	142312	7944.53	255.53	340.89	4167	162	20961	142314	7944.53	255.53	340.89	4167	162	0	0.03878
1982	NOV	Nov-82	27691	123593	7934.85	245.85	465.36	5471	356	27692	123594	7934.85	245.85	465.37	5471	356	0	0.06502
1982	DEC	Dec-82	25936	105244	7924.33	235.33	421.80	4650	490	25937	105245	7924.33	235.33	421.82	4650	490	0	0.10541
1983	JAN	Jan-83	25060	87296	7912.52	223.52	407.56	4039	525	25060	87297	7912.52	223.52	407.56	4039	525	0	0.13
1983	FEB	Feb-83	24106	69934	7899.29	210.29	434.05	3535	230	24106	69934	7899.29	210.29	434.05	3535	230	0	0.065
1983	MAR	Mar-83	23807	54935	7885.66	196.66	387.18	2852	128	23807	54935	7885.66	196.66	387.18	2852	128	0	0.045
1983	APR	Apr-83	16472	46192	7876.32	187.32	276.82	1204	54	16472	46192	7876.32	187.32	276.82	1204	54	0	0.045
1983	MAY	May-83	5289	70791	7900.00	211.00	0.00	0	0	5289	70791	7900.00	211.00	0.00	0	0	0	0.045
1983	JUN	Jun-83	112817	131454	7939.02	250.02	1500.00	18000	975	112816	131454	7939.02	250.02	1500.00	18000	975	0	0.05416
1983	JUL	Jul-83	127497	152994	7949.70	260.70	1500.00	18600	1149	127497	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1983	AUG	Aug-83	62879	153088	7949.74	260.74	1022.61	14635	1565	62879	153088	7949.74	260.74	1022.61	14635	1565	0	0.10693
1983	SEP	Sep-83	27365	151679	7949.07	260.07	459.88	5909	347	27365	151679	7949.07	260.07	459.88	5909	347	0	0.05866
1983	OCT	Oct-83	17200	149643	7948.10	259.10	279.73	3361	130	17200	149643	7948.10	259.10	279.73	3361	130	0	0.03878
1983	NOV	Nov-83	30575	130655	7938.60	249.60	513.82	6292	409	30575	130655	7938.60	249.60	513.82	6292	409	0	0.06502
1983	DEC	Dec-83	31684	110541	7927.50	238.50	515.28	6079	641	31684	110541	7927.50	238.50	515.28	6079	641	0	0.10541
1984	JAN	Jan-84	29344	90827	7914.98	225.98	477.23	5065	658	29344	90827	7914.98	225.98	477.23	5065	658	0	0.13
1984	FEB	Feb-84	26496	71700	7900.74	211.74	460.63	4030	262	26496	71700	7900.74	211.74	460.63	4030	262	0	0.065
1984	MAR	Mar-84	20296	61030	7891.57	202.57	330.08	2345	106	20296	61030	7891.57	202.57	330.08	2345	106	0	0.045
1984	APR	Apr-84	17808	58040	7888.71	199.71	299.27	1817	82	17808	58040	7888.71	199.71	299.27	1817	82	0	0.045
1984	MAY	May-84	91643	94701	7917.60	228.60	1490.41	18600	837	91643	94701	7917.60	228.60	1490.41	18600	837	0	0.045
1984	JUN	Jun-84	155456	131401	7938.99	249.99	1500.00	18000	975	155456	131401	7938.99	249.99	1500.00	18000	975	0	0.05416
1984	JUL	Jul-84	127128	152994	7949.70	260.70	1500.00	18600	1149	127128	152994	7949.70	260.70	1500.00	18600	1149	0	0.06176
1984	AUG	Aug-84	81017	153088	7949.74	260.74	1317.60	18600	1989	81017	153088	7949.74	260.74	1317.60	18600	1989	0	0.10693
1984	SEP	Sep-84	35687	153173	7949.78	260.78	599.73	7980	468	35687	153173	7949.78	260.78	599.73	7980	468	0	0.05866
1984	OCT	Oct-84	23558	153342	7949.86	260.86	383.13	4975	193	23558	153342	7949.86	260.86	383.13	4975	193	0	0.03878
1984	NOV	Nov-84	32940	135612	7941.17	252.17	553.57	6957	452	32940	135612	7941.17	252.17	553.57	6957	452	0	0.06502
1984	DEC	Dec-84	33445	116759	7931.07	242.07	543.92	6630	699	33445	116759	7931.07	242.07	543.92	6630	699	0	0.10541
1985	JAN	Jan-85	30448	98306	7919.97	230.97	495.18	5502	715	30448	98306	7919.97	230.97	495.18	5502	715	0	0.13
1985	FEB	Feb-85	28571	80438	7907.54	218.54	514.44	4760	309	28571	80438	7907.54	218.54	514.44	4760	309	0	0.065
1985	MAR	Mar-85	25961	64927	7895.03	206.03	422.21	3611	163	25961	64927	7895.03	206.03	422.21	3611	163	0	0.045
1985	APR	Apr-85	26623	64819	7894.93	205.93	447.41	3798	171	26623	64819	7894.93	205.93	447.41	3798	171	0	0.045
1985	MAY	May-85	53155	98074	7919.82	230.82	864.47	10563	475	53155	98074	7919.82	230.82	864.47	10563	475	0	0.045
1985	JUN	Jun-85	100470	131394	7938.99	249.99	1500.00	18000	975	100470	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1985	JUL	Jul-85	47306	150198	7948.37	259.37	769.35	10737	663	47306	150198	7948.37	259.37	769.35	10737	663	0	0.06176
1985	AUG	Aug-85	19594	150694	7948.60	259.60	318.66	3962	424	19594	150694	7948.60	259.60	318.66	3962	424	0	0.10693
1985	SEP	Sep-85	20206	148184	7947.40	258.40	339.57	4102	241	20206	148184	7947.40	258.40	339.57	4102	241	0	0.05866
1985	OCT	Oct-85	8954	151947	7949.20	260.20	145.62	1370	53	8954	151947	7949.20	260.20	145.62	1370	53	0	0.03878
1985	NOV	Nov-85	30187	134497	7940.59	251.59	507.30	6276	408	30187	134497	7940.59	251.59	507.30	6276	408	0	0.06502
1985	DEC	Dec-85	28810	116555	7930.96	241.96	468.54	5552	585	28810	116555	7930.96	241.96	468.54	5552	585	0	0.10541
1986	JAN	Jan-86	28596	98170	7919.88	230.88	465.06	5085	661	28596	98170	7919.88	230.88	465.06	5085	661	0	0.13
1986	FEB	Feb-86	26592	81570	7908.38	219.38	478.81	4366	284	26592	81570	7908.38	219.38	478.81	4366	284	0	0.065
1986	MAR	Mar-86	27331	64926	7895.03	206.03	444.49	3891	175	27331	64926	7895.03	206.03	444.49	3891	175	0	0.045
1986	APR	Apr-86	16277	64819	7894.93	205.93	273.54	1684	76	16277	64819	7894.93	205.93	273.54	1684	76	0	0.045
1986	MAY	May-86	32194	98074	7919.82	230.82	523.58	5886	265	32194	98074	7919.82	230.82	523.58	5886	265	0	0.045
1986	JUN	Jun-86	103802	131394	7938.99	249.99	1500.00	18000	975	103802	131394	7938.99	249.99	1500.00	18000	975	0	0.05416
1986	JUL	Jul-86	54802	152994	7949.70	260.70	891.26	12648	781	54802	152994	7949.70	260.70	891.26	12648	781	0	0.06176
1986	AUG	Aug-86	19863	150691	7948.60	259.60	323.04	4028	431	19863	150691	7948.60	259.60	323.04	4028	431	0	0.10693
1986	SEP	Sep-86	13432	150697	7948.61	259.61	225.73	2480	145	13432	150697	7948.61	259.61	225.73	2480	145	0	0.05866
1986	OCT	Oct-86	9607	151945	7949.20	260.20	156.24	1530	59	9607	151945	7949.20	260.20	156.24	1530	59	0	0.03878
1986	NOV	Nov-86	29317	134496	7940.59	251.59	492.68	6068	395	29317	134496	7940.59	251.59	492.68	6068	395	0	0.06502
1986	DEC	Dec-86	27466	115922	7930.60	241.60	446.69	5228	551	27466	115922	7930.60	241.60	446.69	5228	551	0	0.10541
1987	JAN	Jan-87	25065	97747	7919.61	230.61	407.64	4288	557	25065	97747	7919.61	230.61	407.64	4288	557	0	0.13
1987	FEB	Feb-87	24052	80159	7907.33	218.33	433.07	3787	246	24052	80159	7907.33	218.33	433.07	3787	246	0	0.065
1987	MAR	Mar-87	23437	64927	7895.03	206.03	381.16	3095	139	23437	64927	7895.03	206.03	381.16	3095	139	0	0.045
1987	APR	Apr-87	12195	64819	7894.93	205.93	204.94	850	38	12195	64819	7894.93	205.93	204.94	850	38	0	0.045
1987	MAY	May-87	8828	96476	7918.78	229.78	143.57	649	29	8828	96476	7918.78	229.78	143.57	649	29	0	0.045
1987	JUN	Jun-87	37857	129001	7937.74	248.74	636.20	7982	432	37857	129001	7937.74	248.74	636.20	7982	432	0	0.05416
1987	JUL	Jul-87	8541	150202	7948.37	259.37	138.90	1250	77	8541	150202	7948.37	259.37	138.90	1250	77	0	0.06176
1987	AUG	Aug-87	26795	146955	7946.81	257.81	435.77	5660	605	26795	146955	7946.81	257.81	435.77	5660	605	0	0.10693
1987	SEP	Sep-87	26443	134964	7940.83	251.83	444.38	5391	316	26443	134964	7940.83	251.83	444.38	5391	316	0	0.05866
1987	OCT	Oct-87	21345	124088	7935.11	246.11	347.14	3957	153	21345	124088	7935.11	246.11	347.14	3957	153	0	0.03878
1987	NOV	Nov-87	21731	111018	7927.78	238.78	365.20	3847	250	21731	111018	7927.78	238.78	365.20	3847	250	0	0.06502
1987	DEC	Dec-87	20232	98313	7919.97	230.97	329.04	3222	340	20232	98313	7919.97	230.97	329.04	3222	340	0	0.10541
1988	JAN	Jan-88	19936	86008	7911.61	222.61	324.22	2895	376	19936	86008	7911.61	222.61	324.22	2895	376	0	0.13
1988	FEB	Feb-88	18101	74291	7902.81	213.81	314.68	2337	152	18101	74291	7902.81	213.81	314.68	2337	152	0	0.065
1988	MAR	Mar-88	16898	64929	7895.03	206.03	274.82	1759	79	16898	64929	7895.03	206.03	274.82	1759	79	0	0.045
1988	APR	Apr-88	12593	64803	7894.92	205.92	211.63	931	42	12593	64803	7894.92	205.92	211.63	931	42	0	0.045
1988	MAY	May-88	5289	89574	7914.12	225.12	0.00	0	0	5289	89574	7914.12	225.12	0.00	0	0	0	0.045
1988	JUN	Jun-88	51027	129016	7937.74	248.74	857.52	11100	601	51027	129016	7937.74	248.74	857.52	11100	601	0	0.05416
1988	JUL	Jul-88	18685	149846	7948.20	259.20	303.88	3727	230	18685	149846	7948.20	259.20	303.88	3727	230	0	0.06176
1988	AUG	Aug-88	42120	130517	7938.53	249.53	685.01	8997	962	42120	130517	7938.53	249.53	685.01	8997	962	0	0.10693
1988	SEP	Sep-88	19530	122971	7934.51	245.51	328.21	3547	208	19530	122971	7934.51	245.51	328.21	3547	208	0	0.05866
1988	OCT	Oct-88	34701	98412	7920.04	231.04	564.35	6454	250	34701	98412	7920.04	231.04	564.35	6454	250	0	0.03878
1988	NOV	Nov-88	17808	90484	7914.75	225.75	299.27	2571	167	17808	90484	7914.75	225.75	299.27	2571	167	0	0.06502
1988	DEC	Dec-88	14659	82913	7909.37	220.37	238.40	1690	178	14659	82913	7909.37	220.37	238.40	1690	178	0	0.10541
1989	JAN	Jan-89	14066	75742	7903.95	214.95	228.76	1418	184	14066	75742	7903.95	214.95	228.76	1418	184	0	0.13
1989	FEB	Feb-89	13103	69158	7898.65	209.65	235.93	1236	80	13103	69158	7898.65	209.65	235.93	1236	80	0	0.065

Table 1
GREEN MOUNTAIN RESERVOIR
Foregone Power Revenues: Williams Fork Release

			Base							WFR Release								
Year	Mo	Date	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Elevation (ft)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1989	MAR	Mar-89	15213	63403	7893.68	204.68	247.41	1378	62	15213	63403	7893.68	204.68	247.41	1378	62	0	0.045
1989	APR	Apr-89	14954	63422	7893.70	204.70	251.31	1381	62	14954	63422	7893.70	204.70	251.31	1381	62	0	0.045
1989	MAY	May-89	5289	86101	7911.67	222.67	0.00	0	0	5289	86101	7911.67	222.67	0.00	0	0	0	0.045
1989	JUN	Jun-89	20767	129023	7937.75	248.75	349.00	3937	213	20767	129023	7937.75	248.75	349.00	3937	213	0	0.05416
1989	JUL	Jul-89	23784	149684	7948.12	259.12	386.80	4972	307	23784	149684	7948.12	259.12	386.80	4972	307	0	0.06176
1989	AUG	Aug-89	33587	146237	7946.46	257.46	546.23	7300	781	33587	146237	7946.46	257.46	546.23	7300	781	0	0.10693
1989	SEP	Sep-89	26675	134301	7940.49	251.49	448.28	5434	319	26675	134301	7940.49	251.49	448.28	5434	319	0	0.05866
1989	OCT	Oct-89	18083	127198	7936.78	247.78	294.09	3241	126	18083	127198	7936.78	247.78	294.09	3241	126	0	0.03878
1989	NOV	Nov-89	22957	113504	7929.22	240.22	385.80	4176	272	22957	113504	7929.22	240.22	385.80	4176	272	0	0.06502
1989	DEC	Dec-89	21240	100178	7921.17	232.17	345.43	3485	367	21240	100178	7921.17	232.17	345.43	3485	367	0	0.10541
1990	JAN	Jan-90	19161	87252	7912.49	223.49	311.62	2754	358	19161	87252	7912.49	223.49	311.62	2754	358	0	0.13
1990	FEB	Feb-90	18046	74912	7903.30	214.30	324.93	2390	155	18046	74912	7903.30	214.30	324.93	2390	155	0	0.065
1990	MAR	Mar-90	18157	64539	7894.69	205.69	295.29	2006	90	18157	64539	7894.69	205.69	295.29	2006	90	0	0.045
1990	APR	Apr-90	21003	53220	7883.92	194.92	352.96	2304	104	21003	53220	7883.92	194.92	352.96	2304	104	0	0.045
1990	MAY	May-90	5289	66702	7896.57	207.57	0.00	0	0	5289	66702	7896.57	207.57	0.00	0	0	0	0.045
1990	JUN	Jun-90	16879	129067	7937.77	248.77	283.66	3018	163	16879	129067	7937.77	248.77	283.66	3018	163	0	0.05416
1990	JUL	Jul-90	21334	144634	7945.68	256.68	346.96	4294	265	21334	144634	7945.68	256.68	346.96	4294	265	0	0.06176
1990	AUG	Aug-90	46946	121496	7933.70	244.70	763.49	9893	1058	46946	121496	7933.70	244.70	763.49	9893	1058	0	0.10693
1990	SEP	Sep-90	32172	104467	7923.85	234.85	540.66	6083	357	32172	104467	7923.85	234.85	540.66	6083	357	0	0.05866
1990	OCT	Oct-90	21035	97687	7919.57	230.57	342.10	3388	131	21035	97687	7919.57	230.57	342.10	3388	131	0	0.03878
1990	NOV	Nov-90	19574	89906	7914.35	225.35	328.95	2946	192	19574	89906	7914.35	225.35	328.95	2946	192	0	0.06502
1990	DEC	Dec-90	17604	82479	7909.05	220.05	286.30	2315	244	17604	82479	7909.05	220.05	286.30	2315	244	0	0.10541
1991	JAN	Jan-91	15739	75452	7903.73	214.73	255.97	1765	229	15739	75452	7903.73	214.73	255.97	1765	229	0	0.13
1991	FEB	Feb-91	13259	69014	7898.53	209.53	238.74	1265	82	13259	69014	7898.53	209.53	238.74	1265	82	0	0.065
1991	MAR	Mar-91	12625	63731	7893.97	204.97	205.32	859	39	12625	63731	7893.97	204.97	205.32	859	39	0	0.045
1991	APR	Apr-91	16156	56563	7887.27	198.27	271.51	1447	65	16156	56563	7887.27	198.27	271.51	1447	65	0	0.045
1991	MAY	May-91	5289	85280	7911.09	222.09	0.00	0	0	5289	85280	7911.09	222.09	0.00	0	0	0	0.045
1991	JUN	Jun-91	29376	129025	7937.75	248.75	493.67	5975	324	29376	129025	7937.75	248.75	493.67	5975	324	0	0.05416
1991	JUL	Jul-91	21099	150202	7948.37	259.37	343.14	4323	267	21099	150202	7948.37	259.37	343.14	4323	267	0	0.06176
1991	AUG	Aug-91	29152	147328	7946.99	257.99	474.10	6241	667	29152	147328	7946.99	257.99	474.10	6241	667	0	0.10693
1991	SEP	Sep-91	30325	135777	7941.25	252.25	0.00	0	0	30325	135777	7941.25	252.25	0.00	0	0	0	0.05866
						Totals			$61,975,772							$61,989,302		
						Difference										$13,530		
						Average Annual										$796		

Table 2
Ruedi Reservoir
Foregone Power Revenues: Williams Fork Release

		Base						WFR Release								
Year	Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr	
1974	OCT	9888	62221	222	161	1567	61	9888	62221	222	161	1567	61	0	0.03878	3.770038
1974	NOV	2321	61998	222	39	193	13	2321	61998	222	39	193	13	0	0.06502	
1974	DEC	2398	61041	221	39	185	20	2398	61041	221	39	185	20	0	0.10541	
1975	JAN	2741	59833	219	45	230	30	2741	59833	219	45	230	30	0	0.13	
1975	FEB	2166	59418	218	39	146	9	2166	59418	218	39	146	9	0	0.065	
1975	MAR	2398	58716	217	39	151	7	2398	58716	217	39	151	7	0	0.045	
1975	APR	2951	59612	219	50	274	12	2951	59612	219	50	274	12	0	0.045	
1975	MAY	9202	71131	234	150	1553	70	9202	71131	234	150	1553	70	0	0.045	
1975	JUN	9610	94081	261	161	1880	102	9610	94081	261	161	1880	102	0	0.05416	
1975	JUL	23906	96973	264	260	3063	189	23906	96973	264	260	3063	189	0	0.06176	
1975	AUG	7097	97094	264	115	1464	157	7097	97094	264	115	1464	157	0	0.10693	
1975	SEP	9259	92282	259	156	1798	105	9259	92282	259	156	1798	105	0	0.05866	
1975	OCT	7734	87616	253	126	1477	57	7734	87616	253	126	1477	57	0	0.03878	
1975	NOV	6969	83075	248	117	1288	84	6969	83075	248	117	1288	84	0	0.06502	
1975	DEC	5963	78556	243	97	1058	112	5963	78556	243	97	1058	112	0	0.10541	
1976	JAN	5584	74037	238	91	933	121	5584	74037	238	91	933	121	0	0.13	
1976	FEB	6056	69518	232	105	971	63	6056	69518	232	105	971	63	0	0.065	
1976	MAR	6443	64947	226	105	975	44	6443	64947	226	105	975	44	0	0.045	
1976	APR	6055	64621	226	102	907	41	6055	64621	226	102	907	41	0	0.045	
1976	MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045	
1976	JUN	9282	88993	255	156	1768	96	9282	88993	255	156	1768	96	0	0.05416	
1976	JUL	6764	92932	259	110	1360	84	6764	92932	259	110	1360	84	0	0.06176	
1976	AUG	6764	92249	259	110	1352	145	6764	92249	259	110	1352	145	0	0.10693	
1976	SEP	6527	89633	256	110	1278	75	6527	89633	256	110	1278	75	0	0.05866	
1976	OCT	5553	87610	253	90	1083	42	5553	87610	253	90	1083	42	0	0.03878	
1976	NOV	3041	86325	252	51	613	40	3041	86325	252	51	613	40	0	0.06502	
1976	DEC	2437	85060	251	40	492	52	2437	85060	251	40	492	52	0	0.10541	
1977	JAN	2544	83795	249	41	498	65	2544	83795	249	41	498	65	0	0.13	
1977	FEB	2670	82529	248	48	504	33	2670	82529	248	48	504	33	0	0.065	
1977	MAR	3115	81204	246	51	572	26	3115	81204	246	51	572	26	0	0.045	
1977	APR	6549	79702	245	110	1177	53	6549	79702	245	110	1177	53	0	0.045	
1977	MAY	9662	83125	249	157	1777	80	9662	83125	249	157	1777	80	0	0.045	
1977	JUN	8392	92080	258	141	1639	89	8392	92080	258	141	1639	89	0	0.05416	
1977	JUL	6764	91766	258	110	1347	83	6764	91766	258	110	1347	83	0	0.06176	
1977	AUG	6324	88805	255	103	1235	132	6324	88805	255	103	1235	132	0	0.10693	
1977	SEP	5168	86194	252	87	996	58	5168	86194	252	87	996	58	0	0.05866	
1977	OCT	6764	82548	248	110	1247	48	6764	82548	248	110	1247	48	0	0.03878	
1977	NOV	6026	79021	244	101	1075	70	6026	79021	244	101	1075	70	0	0.06502	
1977	DEC	5991	75516	240	97	1025	108	5991	75516	240	97	1025	108	0	0.10541	
1978	JAN	5906	72010	235	96	966	126	5906	72010	235	96	966	126	0	0.13	
1978	FEB	5714	68505	231	103	901	59	5714	68505	231	103	901	59	0	0.065	
1978	MAR	6381	64948	226	104	964	43	6381	64948	226	104	964	43	0	0.045	
1978	APR	8483	64621	226	143	1348	61	8483	64621	226	143	1348	61	0	0.045	
1978	MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045	
1978	JUN	11861	97007	264	199	2314	125	11861	97007	264	199	2314	125	0	0.05416	
1978	JUL	14325	96969	264	233	2763	171	14325	96969	264	233	2763	171	0	0.06176	
1978	AUG	6764	96637	264	110	1400	150	6764	96637	264	110	1400	150	0	0.10693	
1978	SEP	8598	91891	258	144	1675	98	8598	91891	258	144	1675	98	0	0.05866	
1978	OCT	7329	87291	253	119	1400	54	7329	87291	253	119	1400	54	0	0.03878	
1978	NOV	6520	82816	248	110	1204	78	6520	82816	248	110	1204	78	0	0.06502	
1978	DEC	6836	78362	243	111	1214	128	6836	78362	243	111	1214	128	0	0.10541	
1979	JAN	6598	73907	238	107	1115	145	6598	73907	238	107	1115	145	0	0.13	
1979	FEB	5818	69453	232	105	931	61	5818	69453	232	105	931	61	0	0.065	
1979	MAR	5886	64947	226	96	873	39	5886	64947	226	96	873	39	0	0.045	
1979	APR	5586	64621	226	94	821	37	5586	64621	226	94	821	37	0	0.045	
1979	MAY	9514	75758	240	155	1667	75	6764	83238	249	110	1254	56	-19	0.045	
1979	JUN	11745	99741	267	197	2319	126	17501	101452	268	260	3005	163	37	0.05416	
1979	JUL	13031	99688	267	212	2557	158	13025	101400	268	212	2572	159	1	0.06176	
1979	AUG	10504	97091	264	171	2077	222	12217	97090	264	199	2385	255	33	0.10693	
1979	SEP	8826	92279	259	148	1720	101	8825	92279	259	148	1720	101	0	0.05866	
1979	OCT	7994	87614	253	130	1524	59	7994	87613	253	130	1524	59	0	0.03878	
1979	NOV	7748	83074	248	130	1429	93	7748	83073	248	130	1429	93	0	0.06502	
1979	DEC	7253	78555	243	118	1292	136	7253	78555	243	118	1292	136	0	0.10541	
1980	JAN	7028	74036	238	114	1195	155	7028	74036	238	114	1195	155	0	0.13	
1980	FEB	6380	69518	232	111	1029	67	6380	69518	232	111	1029	67	0	0.065	
1980	MAR	6664	64947	226	108	1015	46	6664	64947	226	108	1015	46	0	0.045	
1980	APR	5670	64621	226	95	837	38	5670	64621	226	95	837	38	0	0.045	
1980	MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045	
1980	JUN	6546	98575	265	110	1373	74	6546	98575	265	110	1373	74	0	0.05416	
1980	JUL	13198	96967	264	215	2561	158	13198	96967	264	215	2561	158	0	0.06176	
1980	AUG	6764	95764	263	110	1390	149	6764	95764	263	110	1390	149	0	0.10693	

Table 2
Ruedi Reservoir
Foregone Power Revenues: Williams Fork Release

	Base						WFR Release							
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1980 SEP	6192	93142	260	104	1254	74	6192	93142	260	104	1254	74	0	0.05866
1980 OCT	4929	91117	257	80	1009	39	4929	91117	257	80	1009	39	0	0.03878
1980 NOV	4338	89246	255	73	879	57	4338	89246	255	73	879	57	0	0.06502
1980 DEC	4147	87397	253	67	827	87	4147	87397	253	67	827	87	0	0.10541
1981 JAN	3421	85547	251	56	675	88	3421	85547	251	56	675	88	0	0.13
1981 FEB	3584	83698	249	65	681	44	3584	83698	249	65	681	44	0	0.065
1981 MAR	4050	81788	247	66	747	34	4050	81788	247	66	747	34	0	0.045
1981 APR	8903	79829	245	150	1604	72	8903	79829	245	150	1604	72	0	0.045
1981 MAY	9664	84454	250	157	1791	81	9664	84454	250	157	1791	81	0	0.045
1981 JUN	8547	96989	264	144	1718	93	8547	96989	264	144	1718	93	0	0.05416
1981 JUL	10428	96969	264	170	2062	127	10428	96969	264	170	2062	127	0	0.06176
1981 AUG	8099	93998	261	132	1612	172	8099	93998	261	132	1612	172	0	0.10693
1981 SEP	6546	91424	258	110	1300	76	6546	91424	258	110	1300	76	0	0.05866
1981 OCT	7730	86902	253	126	1468	57	7730	86902	253	126	1468	57	0	0.03878
1981 NOV	7444	82505	248	125	1368	89	7444	82505	248	125	1368	89	0	0.06502
1981 DEC	7259	78128	243	118	1287	136	7259	78128	243	118	1287	136	0	0.10541
1982 JAN	7329	73752	237	119	1246	162	7329	73752	237	119	1246	162	0	0.13
1982 FEB	6656	69375	232	120	1082	70	6656	69375	232	120	1082	70	0	0.065
1982 MAR	7402	64947	226	120	1149	52	7402	64947	226	120	1149	52	0	0.045
1982 APR	6979	64621	226	117	1075	48	6979	64621	226	117	1075	48	0	0.045
1982 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1982 JUN	9978	97007	264	168	1976	107	9978	97007	264	168	1976	107	0	0.05416
1982 JUL	17315	96969	264	260	3062	189	17315	96969	264	260	3062	189	0	0.06176
1982 AUG	8572	97094	264	139	1730	185	8572	97094	264	139	1730	185	0	0.10693
1982 SEP	13407	91231	258	225	2535	149	13407	91231	258	225	2535	149	0	0.05866
1982 OCT	9483	85510	251	154	1770	69	9483	85510	251	154	1770	69	0	0.03878
1982 NOV	9312	79907	245	156	1679	109	9312	79907	245	156	1679	109	0	0.06502
1982 DEC	9637	74326	238	157	1671	176	9637	74326	238	157	1671	176	0	0.10541
1983 JAN	9145	68744	231	149	1513	197	9145	68744	231	149	1513	197	0	0.13
1983 FEB	8433	63162	224	152	1336	87	8433	63162	224	152	1336	87	0	0.065
1983 MAR	9138	57532	216	149	1364	61	9138	57532	216	149	1364	61	0	0.045
1983 APR	9580	51887	207	161	1377	62	9580	51887	207	161	1377	62	0	0.045
1983 MAY	8715	62734	223	142	1361	61	8715	62734	223	142	1361	61	0	0.045
1983 JUN	8833	100183	267	148	1800	97	8833	100183	267	148	1800	97	0	0.05416
1983 JUL	29507	100110	267	260	3092	191	29507	100110	267	260	3092	191	0	0.06176
1983 AUG	24667	100225	267	260	3093	331	24667	100225	267	260	3093	331	0	0.10693
1983 SEP	13603	93966	261	229	2598	152	13603	93966	261	229	2598	152	0	0.05866
1983 OCT	11014	87851	254	179	2071	80	11014	87851	254	179	2071	80	0	0.03878
1983 NOV	10664	81859	247	179	1944	126	10664	81859	247	179	1944	126	0	0.06502
1983 DEC	9851	75887	240	160	1729	182	9851	75887	240	160	1729	182	0	0.10541
1984 JAN	8561	69915	232	139	1422	185	8561	69915	232	139	1422	185	0	0.13
1984 FEB	7378	63943	225	128	1146	74	7378	63943	225	128	1146	74	0	0.065
1984 MAR	7793	57921	216	127	1124	51	7793	57921	216	127	1124	51	0	0.045
1984 APR	12302	51886	207	207	1875	84	12302	51886	207	207	1875	84	0	0.045
1984 MAY	9778	76893	241	159	1728	78	9778	76893	241	159	1728	78	0	0.045
1984 JUN	38640	101245	268	260	3003	163	38640	101245	268	260	3003	163	0	0.05416
1984 JUL	56215	101187	268	260	3103	192	56215	101187	268	260	3103	192	0	0.06176
1984 AUG	23404	101298	268	260	3104	332	23404	101298	268	260	3104	332	0	0.10693
1984 SEP	15127	95880	263	254	2891	170	15127	95880	263	254	2891	170	0	0.05866
1984 OCT	10031	90612	257	163	1923	75	10031	90612	257	163	1923	75	0	0.03878
1984 NOV	9302	85471	251	156	1735	113	9302	85471	251	156	1735	113	0	0.06502
1984 DEC	8937	80353	245	145	1616	170	8937	80353	245	145	1616	170	0	0.10541
1985 JAN	8340	75235	239	136	1447	188	8340	75235	239	136	1447	188	0	0.13
1985 FEB	7552	70117	233	136	1253	81	7552	70117	233	136	1253	81	0	0.065
1985 MAR	8860	64947	226	144	1415	64	8860	64947	226	144	1415	64	0	0.045
1985 APR	10744	64874	226	181	1763	79	10744	64874	226	181	1763	79	0	0.045
1985 MAY	8918	83365	249	145	1645	74	8918	83365	249	145	1645	74	0	0.045
1985 JUN	19386	101805	269	260	3008	163	19386	101805	269	260	3008	163	0	0.05416
1985 JUL	19160	96962	264	260	3062	189	19160	96962	264	260	3062	189	0	0.06176
1985 AUG	8241	97094	264	134	1670	179	8241	97094	264	134	1670	179	0	0.10693
1985 SEP	10827	92282	259	182	2080	122	10827	92282	259	182	2080	122	0	0.05866
1985 OCT	9664	87616	253	157	1825	71	9664	87616	253	157	1825	71	0	0.03878
1985 NOV	8749	83075	248	147	1610	105	8749	83075	248	147	1610	105	0	0.06502
1985 DEC	8455	78556	243	138	1509	159	8455	78556	243	138	1509	159	0	0.10541
1986 JAN	7696	74037	238	125	1316	171	7696	74037	238	125	1316	171	0	0.13
1986 FEB	7777	69518	232	140	1288	84	7777	69518	232	140	1288	84	0	0.065
1986 MAR	9462	64947	226	154	1524	69	9462	64947	226	154	1524	69	0	0.045
1986 APR	13041	64874	226	219	2181	98	13041	64874	226	219	2181	98	0	0.045
1986 MAY	9864	83365	249	160	1816	82	9864	83365	249	160	1816	82	0	0.045
1986 JUN	19191	101504	268	260	3005	163	19191	101504	268	260	3005	163	0	0.05416
1986 JUL	15347	101453	268	250	2990	185	15347	101453	268	250	2990	185	0	0.06176
1986 AUG	8327	101563	269	135	1730	185	8327	101563	269	135	1730	185	0	0.10693

Table 2
Ruedi Reservoir
Foregone Power Revenues: Williams Fork Release

	Base						WFR Release							
Year Mo	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	River Outflow (AF)	EOM Storage (AF)	Head (ft)	Turbine Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1986 SEP	11898	96106	263	200	2312	136	11898	96106	263	200	2312	136	0	0.05866
1986 OCT	8939	90799	257	145	1728	67	8939	90799	257	145	1728	67	0	0.03878
1986 NOV	8827	85621	251	148	1651	107	8827	85621	251	148	1651	107	0	0.06502
1986 DEC	8811	80466	246	143	1594	168	8811	80466	246	143	1594	168	0	0.10541
1987 JAN	8138	75310	239	132	1412	184	8138	75310	239	132	1412	184	0	0.13
1987 FEB	7680	70155	233	138	1277	83	7680	70155	233	138	1277	83	0	0.065
1987 MAR	8100	64947	226	132	1276	57	8100	64947	226	132	1276	57	0	0.045
1987 APR	9221	64874	226	155	1486	67	9221	64874	226	155	1486	67	0	0.045
1987 MAY	11041	74359	238	180	1926	87	11041	74359	238	180	1926	87	0	0.045
1987 JUN	9168	87118	253	154	1728	94	9168	87118	253	154	1728	94	0	0.05416
1987 JUL	6764	90707	257	110	1335	82	6764	90707	257	110	1335	82	0	0.06176
1987 AUG	6764	90350	257	110	1331	142	6764	90350	257	110	1331	142	0	0.10693
1987 SEP	7933	86512	252	133	1499	88	7933	86512	252	133	1499	88	0	0.05866
1987 OCT	7440	82812	248	121	1372	53	7440	82812	248	121	1372	53	0	0.03878
1987 NOV	7495	79233	244	126	1343	87	7495	79233	244	126	1343	87	0	0.06502
1987 DEC	6841	75674	240	111	1181	125	6841	75674	240	111	1181	125	0	0.10541
1988 JAN	6683	72116	235	109	1108	144	6683	72116	235	109	1108	144	0	0.13
1988 FEB	5370	68557	231	93	835	54	5370	68557	231	93	835	54	0	0.065
1988 MAR	5678	64948	226	92	836	38	5678	64948	226	92	836	38	0	0.045
1988 APR	8433	64621	226	142	1339	60	8433	64621	226	142	1339	60	0	0.045
1988 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1988 JUN	9282	87639	254	156	1754	95	9282	87639	254	156	1754	95	0	0.05416
1988 JUL	6764	89982	256	110	1327	82	6764	89982	256	110	1327	82	0	0.06176
1988 AUG	8520	87024	253	139	1612	172	8520	87024	253	139	1612	172	0	0.10693
1988 SEP	6919	83665	249	116	1286	75	6919	83665	249	116	1286	75	0	0.05866
1988 OCT	6506	80442	246	106	1177	46	6506	80442	246	106	1177	46	0	0.03878
1988 NOV	6173	77338	242	104	1082	70	6173	77338	242	104	1082	70	0	0.06502
1988 DEC	5877	74253	238	96	989	104	5877	74253	238	96	989	104	0	0.10541
1989 JAN	5614	71168	234	91	902	117	5614	71168	234	91	902	117	0	0.13
1989 FEB	5632	68084	230	101	882	57	5632	68084	230	101	882	57	0	0.065
1989 MAR	7221	64948	226	117	1116	50	7221	64948	226	117	1116	50	0	0.045
1989 APR	9719	64621	226	163	1573	71	9719	64621	226	163	1573	71	0	0.045
1989 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1989 JUN	9282	85491	251	156	1731	94	9282	85491	251	156	1731	94	0	0.05416
1989 JUL	6764	87953	254	110	1305	81	6764	87953	254	110	1305	81	0	0.06176
1989 AUG	6764	87324	253	110	1299	139	6764	87324	253	110	1299	139	0	0.10693
1989 SEP	6829	83922	249	115	1272	75	6829	83922	249	115	1272	75	0	0.05866
1989 OCT	6829	80656	246	111	1238	48	6829	80656	246	111	1238	48	0	0.03878
1989 NOV	6026	77508	242	101	1058	69	6026	77508	242	101	1058	69	0	0.06502
1989 DEC	5768	74381	238	94	970	102	5768	74381	238	94	970	102	0	0.10541
1990 JAN	5345	71254	234	87	854	111	5345	71254	234	87	854	111	0	0.13
1990 FEB	5241	68126	230	94	811	53	5241	68126	230	94	811	53	0	0.065
1990 MAR	6008	64948	226	98	896	40	6008	64948	226	98	896	40	0	0.045
1990 APR	8840	62918	224	149	1393	63	8840	62918	224	149	1393	63	0	0.045
1990 MAY	8866	70503	233	144	1484	67	8866	70503	233	144	1484	67	0	0.045
1990 JUN	9798	82489	248	165	1794	97	9798	82489	248	165	1794	97	0	0.05416
1990 JUL	6764	84962	251	110	1273	79	6764	84962	251	110	1273	79	0	0.06176
1990 AUG	7731	82014	247	126	1416	151	7731	82014	247	126	1416	151	0	0.10693
1990 SEP	6593	79379	244	111	1181	69	6593	79379	244	111	1181	69	0	0.05866
1990 OCT	6764	76874	241	110	1182	46	6764	76874	241	110	1182	46	0	0.03878
1990 NOV	5551	74483	238	93	935	61	5551	74483	238	93	935	61	0	0.06502
1990 DEC	5271	72112	235	86	852	90	5271	72112	235	86	852	90	0	0.10541
1991 JAN	4868	69741	232	79	749	97	4868	69741	232	79	749	97	0	0.13
1991 FEB	4588	67370	229	83	684	44	4588	67370	229	83	684	44	0	0.065
1991 MAR	5202	64948	226	85	749	34	5202	64948	226	85	749	34	0	0.045
1991 APR	6269	64621	226	105	946	43	6269	64621	226	105	946	43	0	0.045
1991 MAY	9514	75758	240	155	1667	75	9514	75758	240	155	1667	75	0	0.045
1991 JUN	9282	92572	259	156	1805	98	9282	92572	259	156	1805	98	0	0.05416
1991 JUL	6764	96233	263	110	1396	86	6764	96233	263	110	1396	86	0	0.06176
1991 AUG	9323	93263	260	152	1824	195	9323	93263	260	152	1824	195	0	0.10693
1991 SEP	9315	89004	255	157	1774	104	9315	89004	255	157	1774	104	0	0.05866
		Totals				$19,793,233						$19,845,699		
		Difference										$52,466		
		Average Annual										$3,086		

Table 3
SHOSHONE POWER PLANT
Foregone Power Revenues: Williams Fork Release

			Base				Williams Fork Release					
Year	Mo	Date	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Total Supply (AF)	Total Flow (cfs)	Power (MWhr)	Power ($1000)	Difference ($1000)	Power Cost $/KWhr
1974	OCT	Oct-74	66970	1089	9208	357	66970	1089	9208	357	0	0.04
1974	NOV	Nov-74	66071	1110	9085	591	66071	1110	9085	591	0	0.07
1974	DEC	Dec-74	61830	1006	8502	896	61830	1006	8502	896	0	0.11
1975	JAN	Jan-75	59899	974	8236	1071	59899	974	8236	1071	0	0.13
1975	FEB	Feb-75	58476	1053	8040	523	58476	1053	8040	523	0	0.07
1975	MAR	Mar-75	61181	995	8412	379	61181	995	8412	379	0	0.05
1975	APR	Apr-75	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1975	MAY	May-75	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1975	JUN	Jun-75	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1975	JUL	Jul-75	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1975	AUG	Aug-75	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1975	SEP	Sep-75	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1975	OCT	Oct-75	70098	1140	9638	374	69506	1130	9557	371	-3	0.04
1975	NOV	Nov-75	79448	1335	10924	710	78857	1325	10843	705	-5	0.07
1975	DEC	Dec-75	71743	1167	9865	1040	71153	1157	9783	1031	-9	0.11
1976	JAN	Jan-76	68497	1114	9418	1224	67907	1104	9337	1214	-11	0.13
1976	FEB	Feb-76	70614	1228	9709	631	70024	1217	9628	626	-5	0.07
1976	MAR	Mar-76	76631	1246	10537	474	76041	1237	10455	470	-4	0.05
1976	APR	Apr-76	82638	1389	11363	511	82638	1389	11363	511	0	0.05
1976	MAY	May-76	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1976	JUN	Jun-76	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1976	JUL	Jul-76	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1976	AUG	Aug-76	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1976	SEP	Sep-76	74381	1250	10227	600	74381	1250	10227	600	0	0.06
1976	OCT	Oct-76	74383	1210	10228	397	74383	1210	10228	397	0	0.04
1976	NOV	Nov-76	59697	1003	8208	534	59697	1003	8208	534	0	0.07
1976	DEC	Dec-76	49447	804	6799	717	49447	804	6799	717	0	0.11
1977	JAN	Jan-77	47151	767	6483	843	47151	767	6483	843	0	0.13
1977	FEB	Feb-77	47230	850	6494	422	47230	850	6494	422	0	0.07
1977	MAR	Mar-77	49872	811	6857	309	49872	811	6857	309	0	0.05
1977	APR	Apr-77	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1977	MAY	May-77	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1977	JUN	Jun-77	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1977	JUL	Jul-77	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1977	AUG	Aug-77	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1977	SEP	Sep-77	52714	886	7248	425	52714	886	7248	425	0	0.06
1977	OCT	Oct-77	58234	947	8007	311	58234	947	8007	311	0	0.04
1977	NOV	Nov-77	45851	771	6304	410	45851	771	6304	410	0	0.07
1977	DEC	Dec-77	46479	756	6391	674	46458	756	6388	673	0	0.11
1978	JAN	Jan-78	45729	744	6288	817	44236	719	6082	791	-27	0.13
1978	FEB	Feb-78	39553	712	5438	353	38061	685	5233	340	-13	0.07
1978	MAR	Mar-78	53027	862	7291	328	51543	838	7087	319	-9	0.05
1978	APR	Apr-78	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1978	MAY	May-78	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1978	JUN	Jun-78	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1978	JUL	Jul-78	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1978	AUG	Aug-78	84845	1380	11666	1247	85812	1396	11799	1262	14	0.11
1978	SEP	Sep-78	65053	1093	8945	525	65053	1093	8945	525	0	0.06
1978	OCT	Oct-78	60476	984	8315	322	59478	967	8178	317	-5	0.04
1978	NOV	Nov-78	63938	1074	8791	572	62440	1049	8585	558	-13	0.07
1978	DEC	Dec-78	53625	872	7373	777	51860	843	7131	752	-26	0.11
1979	JAN	Jan-79	49664	808	6829	888	47785	777	6570	854	-34	0.13
1979	FEB	Feb-79	50049	901	6882	447	47847	862	6579	428	-20	0.07
1979	MAR	Mar-79	61728	1004	8487	382	59613	969	8197	369	-13	0.05
1979	APR	Apr-79	80714	1356	11098	499	81913	1377	11263	507	7	0.05
1979	MAY	May-79	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1979	JUN	Jun-79	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1979	JUL	Jul-79	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1979	AUG	Aug-79	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1979	SEP	Sep-79	64845	1090	8916	523	64845	1090	8916	523	0	0.06
1979	OCT	Oct-79	64083	1042	8811	342	64015	1041	8802	341	0	0.04
1979	NOV	Nov-79	70132	1179	9643	627	70079	1178	9636	627	0	0.07
1979	DEC	Dec-79	67970	1105	9346	985	67918	1105	9339	984	-1	0.11
1980	JAN	Jan-80	67126	1092	9230	1200	67074	1091	9223	1199	-1	0.13
1980	FEB	Feb-80	62089	1079	8537	555	62036	1078	8530	554	0	0.07
1980	MAR	Mar-80	63444	1032	8723	393	63476	1032	8728	393	0	0.05
1980	APR	Apr-80	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1980	MAY	May-80	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1980	JUN	Jun-80	83783	1408	11520	624	83783	1408	11520	624	0	0.05

Table 3
SHOSHONE POWER PLANT
Foregone Power Revenues: Williams Fork Release

1980 JUL	Jul-80	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1980 AUG	Aug-80	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1980 SEP	Sep-80	70872	1191	9745	572	70907	1192	9750	572	0	0.06
1980 OCT	Oct-80	59823	973	8226	319	59096	961	8126	315	-4	0.04
1980 NOV	Nov-80	63271	1063	8700	566	62537	1051	8599	559	-7	0.07
1980 DEC	Dec-80	59613	969	8197	864	58877	958	8095	853	-11	0.11
1981 JAN	Jan-81	51581	839	7092	922	50843	827	6991	909	-13	0.13
1981 FEB	Feb-81	46680	841	6418	417	45941	827	6317	411	-7	0.07
1981 MAR	Mar-81	50048	814	6881	310	49308	802	6780	305	-5	0.05
1981 APR	Apr-81	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1981 MAY	May-81	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1981 JUN	Jun-81	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1981 JUL	Jul-81	76861	1250	10568	653	76861	1250	10568	653	0	0.06
1981 AUG	Aug-81	69790	1135	9596	1026	69790	1135	9596	1026	0	0.11
1981 SEP	Sep-81	63221	1062	8693	510	63221	1062	8693	510	0	0.06
1981 OCT	Oct-81	61933	1007	8516	330	61933	1007	8516	330	0	0.04
1981 NOV	Nov-81	51751	870	7116	463	51751	870	7116	463	0	0.07
1981 DEC	Dec-81	45812	745	6299	664	45812	745	6299	664	0	0.11
1982 JAN	Jan-82	44243	720	6083	791	44243	720	6083	791	0	0.13
1982 FEB	Feb-82	38976	702	5359	348	38976	702	5359	348	0	0.07
1982 MAR	Mar-82	50770	826	6981	314	50770	826	6981	314	0	0.05
1982 APR	Apr-82	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1982 MAY	May-82	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1982 JUN	Jun-82	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1982 JUL	Jul-82	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1982 AUG	Aug-82	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1982 SEP	Sep-82	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1982 OCT	Oct-82	82000	1334	11275	437	81670	1328	11229	435	-2	0.04
1982 NOV	Nov-82	80279	1349	11038	718	79951	1344	10993	715	-3	0.07
1982 DEC	Dec-82	68395	1112	9404	991	68067	1107	9359	987	-5	0.11
1983 JAN	Jan-83	64588	1050	8881	1154	64260	1045	8836	1149	-6	0.13
1983 FEB	Feb-83	60401	1088	8305	540	60074	1082	8260	537	-3	0.07
1983 MAR	Mar-83	68328	1111	9395	423	68000	1106	9350	421	-2	0.05
1983 APR	Apr-83	70275	1181	9663	435	70275	1181	9663	435	0	0.05
1983 MAY	May-83	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1983 JUN	Jun-83	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1983 JUL	Jul-83	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1983 AUG	Aug-83	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1983 SEP	Sep-83	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1983 OCT	Oct-83	81342	1323	11184	434	81340	1323	11184	434	0	0.04
1983 NOV	Nov-83	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1983 DEC	Dec-83	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1984 JAN	Jan-84	75666	1231	10404	1353	75366	1226	10363	1347	-5	0.13
1984 FEB	Feb-84	74251	1291	10209	664	73951	1286	10168	661	-3	0.07
1984 MAR	Mar-84	71770	1167	9868	444	71472	1162	9827	442	-2	0.05
1984 APR	Apr-84	79696	1339	10958	493	79696	1339	10958	493	0	0.05
1984 MAY	May-84	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1984 JUN	Jun-84	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1984 JUL	Jul-84	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1984 AUG	Aug-84	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1984 SEP	Sep-84	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1984 OCT	Oct-84	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1984 NOV	Nov-84	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1984 DEC	Dec-84	85925	1397	11815	1245	85925	1397	11815	1245	0	0.11
1985 JAN	Jan-85	80865	1315	11119	1445	80865	1315	11119	1445	0	0.13
1985 FEB	Feb-85	76628	1380	10536	685	76628	1380	10536	685	0	0.07
1985 MAR	Mar-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 APR	Apr-85	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1985 MAY	May-85	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1985 JUN	Jun-85	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1985 JUL	Jul-85	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1985 AUG	Aug-85	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1985 SEP	Sep-85	75129	1263	10330	606	75129	1263	10330	606	0	0.06
1985 OCT	Oct-85	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1985 NOV	Nov-85	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1985 DEC	Dec-85	86576	1408	11904	1255	86576	1408	11904	1255	0	0.11
1986 JAN	Jan-86	85651	1393	11777	1531	85651	1393	11777	1531	0	0.13
1986 FEB	Feb-86	78198	1408	10752	699	78198	1408	10752	699	0	0.07
1986 MAR	Mar-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 APR	Apr-86	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1986 MAY	May-86	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1986 JUN	Jun-86	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1986 JUL	Jul-86	86576	1408	11904	735	86576	1408	11904	735	0	0.06

Table 3
SHOSHONE POWER PLANT
Foregone Power Revenues: Williams Fork Release

1986 AUG	Aug-86	86576	1408	11904	1273	86576	1408	11904	1273	0	0.11
1986 SEP	Sep-86	83783	1408	11520	676	83783	1408	11520	676	0	0.06
1986 OCT	Oct-86	86576	1408	11904	462	86576	1408	11904	462	0	0.04
1986 NOV	Nov-86	83783	1408	11520	749	83783	1408	11520	749	0	0.07
1986 DEC	Dec-86	78786	1281	10833	1142	78786	1281	10833	1142	0	0.11
1987 JAN	Jan-87	69058	1123	9495	1234	69058	1123	9495	1234	0	0.13
1987 FEB	Feb-87	66954	1206	9206	598	66954	1206	9206	598	0	0.07
1987 MAR	Mar-87	77469	1260	10652	479	77469	1260	10652	479	0	0.05
1987 APR	Apr-87	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1987 MAY	May-87	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1987 JUN	Jun-87	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1987 JUL	Jul-87	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1987 AUG	Aug-87	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1987 SEP	Sep-87	62419	1049	8582	503	62419	1049	8582	503	0	0.06
1987 OCT	Oct-87	63624	1035	8748	339	63624	1035	8748	339	0	0.04
1987 NOV	Nov-87	79093	1329	10875	707	79093	1329	10875	707	0	0.07
1987 DEC	Dec-87	68906	1121	9474	999	68906	1121	9474	999	0	0.11
1988 JAN	Jan-88	70055	1139	9632	1252	70055	1139	9632	1252	0	0.13
1988 FEB	Feb-88	64279	1117	8838	574	64279	1117	8838	574	0	0.07
1988 MAR	Mar-88	71897	1169	9886	445	71897	1169	9886	445	0	0.05
1988 APR	Apr-88	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1988 MAY	May-88	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1988 JUN	Jun-88	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1988 JUL	Jul-88	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1988 AUG	Aug-88	81837	1331	11252	1203	81837	1331	11252	1203	0	0.11
1988 SEP	Sep-88	56113	943	7715	453	56113	943	7715	453	0	0.06
1988 OCT	Oct-88	71010	1155	9764	379	71010	1155	9764	379	0	0.04
1988 NOV	Nov-88	60510	1017	8320	541	60510	1017	8320	541	0	0.07
1988 DEC	Dec-88	56962	926	7832	826	56962	926	7832	826	0	0.11
1989 JAN	Jan-89	59364	965	8162	1061	59364	965	8162	1061	0	0.13
1989 FEB	Feb-89	52009	936	7151	465	52009	936	7151	465	0	0.07
1989 MAR	Mar-89	76345	1242	10497	472	76345	1242	10497	472	0	0.05
1989 APR	Apr-89	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1989 MAY	May-89	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1989 JUN	Jun-89	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1989 JUL	Jul-89	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1989 AUG	Aug-89	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1989 SEP	Sep-89	54165	910	7448	437	54165	910	7448	437	0	0.06
1989 OCT	Oct-89	51573	839	7091	275	51573	839	7091	275	0	0.04
1989 NOV	Nov-89	61037	1026	8392	546	61037	1026	8392	546	0	0.07
1989 DEC	Dec-89	61907	1007	8512	897	61907	1007	8512	897	0	0.11
1990 JAN	Jan-90	57901	942	7961	1035	57901	942	7961	1035	0	0.13
1990 FEB	Feb-90	49568	893	6816	443	49568	893	6816	443	0	0.07
1990 MAR	Mar-90	62558	1017	8602	387	62558	1017	8602	387	0	0.05
1990 APR	Apr-90	83783	1408	11520	518	83783	1408	11520	518	0	0.05
1990 MAY	May-90	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1990 JUN	Jun-90	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1990 JUL	Jul-90	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1990 AUG	Aug-90	78519	1277	10796	1154	78519	1277	10796	1154	0	0.11
1990 SEP	Sep-90	62931	1058	8653	508	62931	1058	8653	508	0	0.06
1990 OCT	Oct-90	63305	1030	8704	338	63305	1030	8704	338	0	0.04
1990 NOV	Nov-90	60470	1016	8315	541	60469	1016	8314	541	0	0.07
1990 DEC	Dec-90	53934	877	7416	782	53933	877	7416	782	0	0.11
1991 JAN	Jan-91	49706	808	6834	888	49705	808	6834	888	0	0.13
1991 FEB	Feb-91	46476	837	6390	415	46475	837	6390	415	0	0.07
1991 MAR	Mar-91	52128	848	7167	323	52128	848	7167	323	0	0.05
1991 APR	Apr-91	74381	1250	10227	460	74381	1250	10227	460	0	0.05
1991 MAY	May-91	86576	1408	11904	536	86576	1408	11904	536	0	0.05
1991 JUN	Jun-91	83783	1408	11520	624	83783	1408	11520	624	0	0.05
1991 JUL	Jul-91	86576	1408	11904	735	86576	1408	11904	735	0	0.06
1991 AUG	Aug-91	76861	1250	10568	1130	76861	1250	10568	1130	0	0.11
1991 SEP	9/1	71767	1206	9868	579	71767	1206	9868	579	0	0.06

Totals	$ 137,670,795	$ 137,417,611
Difference		-$253,184
Average Annual		-$14,893

TECHNICAL MEMORANDUM NO. 12

COMMENTS AND RESPONSES TO COMMENTS RECEIVED ON DRAFT, JANUARY 2003

PHASE 2 COORDINATED FACILITIES WATER AVAILABILITY STUDY FOR THE ENDANGERED FISHES OF THE UPPER COLORADO RIVER FINAL REPORT

March 2003

PREPARED FOR :

COLORADO WATER CONSERVATION BOARD

PREPARED BY:

Brown and Caldwell
Brownstein, Hyatt & Farber
Resource Engineering, Inc.
McLaughlin Water Engineers, Ltd.

EXECUTIVE SUMMARY

The comments received are attached with specific responses in Track Changes format. Changes in response to these comments will be included in the final report.

The reviewers in their comments noted many occurrences of "Why did this parameter go up when it should have gone down?" There were also a number of comments questioning the applicability/acceptability of the Ground Rules, Assumptions and Analysis Procedures agreed to at the start of the investigation. These Ground Rules, Assumptions and Analysis Procedures are repeated in Chapter 2 of the Draft Final Report and a copy of Chapter 2 is attached for your review. In response to these and other comments Brown and Caldwell offers the following:

- We have been working on this project since 1999.
- We have revised the C1 Data Set five times to model reality better. These revisions are detailed in the series of Technical Memoranda and the Phase 1 and Phase 2 Final Reports.
- StateMod was revised by CWCB and the State Engineer's Office to model reality better. These changes are detailed in the Phase 2 Final Report.
- We modeled 19 alternatives and did various modifications of these alternatives.
- Sensitivity analysis was performed to determine the feasibility of making the 20,000 acre-feet release under future forecast depletion conditions.

Despite all these changes and modifications of StateMod and the C1 Data Set, the basic conclusions have not changed:

1. Based on the 1975-91 hydrology study period and the assumptions and procedures incorporated in the StateMod monthly time step modeling with the revised C1 Data Set, there is adequate available storage and there are adequate available water rights to fill the storage thereby facilitating the release/bypass of 20,000 acre-feet in those years when the peak flow of the Colorado River at Palisade is between 12,900 and 26,600 cfs. Furthermore, based on the results of this investigation and the review of these results by study participants, the required 20,000 acre-foot release/bypass was made in 8 years of the 17 year study period without reducing existing projects' yields. This basic conclusion is true for a number of the alternatives, and combinations of alternatives, investigated.

2. A mainstem dam and reservoir could be constructed at the Webster Hill site, located immediately downstream from Rifle, which could provide the 20,000 acre-feet releases in the required years and perhaps even result in a profit from generation of hydropower. This alternative has two apparently fatal flaws which make it unacceptable to the U.S. Fish and Wildlife Service and environmental interests:

   - It's a dam and reservoir and
   - It would inundate designated Critical Habitat for the Endangered Species of fish.

Based on our four years of working on this project, and the results achieved during this four-year period, the Consultant Team believes that there is some version of the "Share the Pain" alternative coupled with some version of the Insurance Pool alternative that can meet the Fish and Wildlife Service's goal of releasing/bypassing 20,000 acre-feet on to the spring peak hydrograph in those years when the peak flow of the Colorado River at Palisade is between 12,900 cfs and 26,600 cfs without unacceptably:

- Reducing existing projects' yields,
- Increasing existing projects' operations and maintenance costs, or
- Affecting existing projects' operational flexibility and/or reliability.

Based on review of the comments, however, the Consultant Team believes that before the Executive Committee can effectively develop a recommendation from the CFOPS study, it will first have to seek agreement on several important concerns that surfaced in the comments. These concerns include:

1. Is making a CFOPS release voluntary or mandatory? If an agency has agreed to take part in the CFOPS effort and if an agency has responsibility for making some release/bypass from one of the agency's reservoirs, is this release/bypass voluntary or mandatory?

2. Are CFOPS releases/bypasses subordinate to CROS? Or, are CROS bypasses subordinate to CFOPS releases/bypasses?

3. Do the results of the numerous simulations produced with the original and modified StateMod and the five versions of the C1 Data Set provide adequate and sufficient basis for developing a workable CFOPS recommendation? The Study Team has concluded that the answer to this question is, "yes," but some additional Ground Rules may have to be developed, however.

4. The Consultant Team has concluded that the 1975-91 hydrologic study period provides adequate and sufficient basis for developing a workable CFOPS recommendation. Again, however, some additional Ground Rules may need to be developed.

5. Do the *Ground Rules, Assumptions and Analysis Procedures* under which the CFOPS investigation has been conducted provide sufficient basis on which to develop a CFOPS recommendation? Or, do additional Ground Rules need to be developed?

6. Comments focused on the situation in which an average of wet year would follow a drought year and the peak flow in the average year/wet year would be in the target range of 12,900 to 26,000 cfs. In this situation, concern was expressed about the reluctance of operators to bypass inflows. The Service indicates in their comment 5 (pages 2-3) indicates: *I believe that the Service would have no problem with language in any agreement worked out to allow reservoirs to opt out of participating in peak-flow augmentation under these conditions.* From the standpoint of the Consultant Team, this offer by the Service should considerably reduce the risk placed on CFOPS participants.

1.0 INTRODUCTION

The purpose of this memo is to provide: (1) a response to comments received from:

- Denver Water
- Western Slope (Ray D. Tenney)
- Bureau of Reclamation (Brent Uilenberg and Malcolm Wilson)
- Division 5 Engineer's Office (Alan Martellaro)
- Dan Luecke
- U.S. Fish and Wildlife Service

and (2) a draft recommendation for the Executive Committee's consideration.

2.0 RESPONSE TO COMMENTS

2.1 Responses to Specific Comments

Responses to specific comments are attached in Track Changes format for each of the responses received.

2.2 General Summary of Comments

1. A discussion of the protocols or "rules" under which CFOPS would be conducted needs to take place. USFWS will be the final decision-maker here, but the Executive Committee should consider this in formulating its recommendations.

2. While CFOPS is voluntary, does it supersede CROS?

3. An insurance pool must be part of the final recommendation.

4. While the "removal of the Shoshone Call" alternative should not be removed as a feasible alternative at Xcel's request, Xcel's position is a major institutional hurdle that must be overcome if this is to be a viable option.

5. Report needs to be revised to state the FWS objective of providing additional peak flow enhancement only in those years in which the current CROS activity is undertaken and the triggers at the Palisade gage are realized. CFOPS is not undertaken to achieve an **average annual** delivery of 20,000 acre-feet – but to provide an average of 20,000 acre-feet in the years where the triggers at the Palisade gage were realized.

6. Environmental community will not support the Webster Hill alternative.

7. Some reviewers believe that time period and monthly model "paint a rosy picture" of what can actually happen in the future.

8. Accounting of bypassed storable inflows and release of storage for peak flow support for decreed piscatorial uses are two issues which will affect administration of CFOPS and should be discussed and addressed.

9. StateMod does not match PACSIM results on a monthly basis for Denver Water's reservoirs.

10. Study does not predict future flows or if a fill is likely to occur, which make it difficult to apply results to real world – especially considering drought.

APPENDIX A
CHAPTER 2 FROM DRAFT FINAL PHASE 2 REPORT:
GROUND RULES, ASSUMPTIONS AND ANALYSIS PROCEDURES

APPENDIX B

COPY OF COMMENTS RECEIVED TOGETHER WITH RESPONSES IN TRACK CHANGES FORMAT

Appendix B

Alan Martallero's Comments

February 11, 2003

To: Randy Seaholm

From: Alan Martellaro

Re: Comments to Coordinated Facilities Operations Report

My comments are limited to water administration issues as they apply to the modeling efforts and eventual implementation of any alternative.

It may be out of the scope of this project, but the protocol will need to be fleshed out prior to implementation. This must include the means to convene a forum for making decisions, and the specific triggers (when, how, and how much) that require bypasses or storage releases. This is the responsibility of USFWS, with recommendations made by the Executive Committee on what the protocols should be. See Service's comments concerning allowing CFOPS participants to opt out of making the 20,000 acre-feet release in average/wet years after droughts.

The following is from the draft report (see Ground Rules/Administration 2.2.1 in the draft report). It leaves unresolved the accounting of bypassed storable inflow:

> *During Phase I, the issue of how bypassed diversions to storage would be administered has been discussed. Several alternatives for administration exist:*
>
> - *Bypassed diversions to storage would be credited toward a "paper fill" of the reservoir and the reservoir would attempt to achieve a subsequent physical fill using a junior refill right. This is essentially the administration agreed to by the SWAT team and used to decree the Clinton Gulch, Green Mountain and Dillon refills.*
> - *Bypassed diversions to storage would not be credited toward a paper fill under an administrative policy such that bypasses are regulatory in nature and the reservoir would attempt to fill later under its own priority.*
> - *Bypassed diversions to storage would not be administered toward a paper fill of the reservoir, but would be administered in Division 5 only, and under the PBO, as a regulatory bypass that would not count against the fill of the reservoir.*

The first two bullets correctly describe the manner in which storable inflows are administered in Water Division 5. The third bullet is similar to the second, but it specifically identifies the PBO as a regulatory bypass. Regulatory bypasses are generally mandatory operating conditions, whereas the bypass for the PBO will be voluntary. Bypasses for the PBO that does not paper fill the storage right will represent an enlargement on the historic operation of the right, and will injure upstream rights and likely injure any junior right in the basin. For these two reasons a regulatory bypass under the PBO will be administered as a paper filling of a storage right. Noted – clarification will be made. Is it certain that CFOPS will be voluntary?

My third comment relates to releases of storage for peak flow support. If a storage decree includes piscatorial or fishery uses, and these uses were clearly to include not only use within the reservoir, but also releases below the reservoir, it is the opinion of the Division of Water Resources that this use includes storage released to the 15-mile reach for peak flow support. Noted –will this affect administration?

I have recently discussed both of these issues, bypass of storable inflow and release of storage for peak flow support, with the State Engineer and the Attorney Generals office. I have the concurrence of both for these positions. I am sure the AG's office would want me to add this disclaimer; this is not an official determination of the Attorney General and is based on the issue only as I have presented it to them.

Thanks for the opportunity to provide some input,

Alan

Burec A2 Comments

COMMENTS ON
DRAFT
PHASE 2 COORDINATED FACILITIES
WATER AVAILABILITY STUDY FOR THE
ENDANGERED FISHES OF THE UPPER
COLORADO RIVER
DATED JANUARY 2003

1) The Executive Summary should clearly acknowledge the limitations of the modeling effort. Specifically, that the period of record modeled does not include a long term drought period or even one as long as we are currently experiencing nor does the model accurately depict the exchanges between reservoirs. Additionally, the limitations that using a monthly model, with perfect hind sight and operational response, attempting to analyze an operation that requires changes and responses on a daily basis lends a much more positive picture of what reservoirs could do than reality bears out. In actual practice operators are going to be much more conservative with releasing water for peak flow augmentation and will be looking for assurances from forecasts, and perhaps an insurance pool, that they will be able to recover water released for peak flow augmentation before they do so. As a result of this, the reality is that the estimates in the evaluation of all of the different alternatives lead the reader to believe that much more can be done with the existing systems than will be the case.

This should also be reflected in the Conclusions and Recommendations chapter.

Time period for study was agreed upon by all involved at the start of the study, as well as the selection of StateMod. We believe that the tools and data used in this analysis adequately determines the feasibility of supplying the 20,000 acre-feet. The final recommendation and "rules" governing CFOPS should have drought provisions, but the findings of this study clearly indicate that enhancement of peak flows, during wet years, is feasible.

2) Executive Summary, page 5, second paragraph under "feasibility of Efficiencies . . ."; "Analysis of this alternative indicated that diverting to storage under the Green Mountain refill priority was a more efficient way to replace the 20,000 acre-feet supplied...". It is unclear what measure of "efficiency" is being judged here. 'Suggest the term "efficiency" be replaced with "less costly" or something that more accurately defines a real measure. This comment also applies to the body of the report and the Conclusions and Recommendations chapter. Noted. Revision will be made to be more clear about what the measure of efficiency is meant by here.

3) Section 1.3.1, page 10, second bulleted paragraph, 1st line: Suggest replacing "occurring" with "accruing". Noted – correction will be made.

4) Section 1.3.1, page 11, first bulleted paragraph, 3rd line: ". . .pursuant to the Ruedi Reservoir Round II Water Sales Biological Opinion." Noted – correction will be made.

5) Section 1.3.1, page 11, third bulleted paragraph, 3rd line: Suggest the first sentences of the paragraph be changed as follows:

> "An additional 10,825 acre-feet per year from Ruedi Reservoir delivered to the 15-Mile Reach under the terms of a short and/or long term lease(s) through the year 2012. In the past, Reclamation had provided 21,650 acre-feet of water annually from the unsold regulatory capacity as referred to in the Ruedi Reservoir Round II Water Sales Amended Biological Opinion (January 6, 1999). This 21,650 acre-feet annual commitment, contained in the Ruedi Reservoir Biological Opinion, will be replaced by the long term lease of 10,825 acre-feet from Ruedi Reservoir and a . . . "Noted – correction will be made.

6) Section 1.3.1, page 12, numbered paragraph 2, the following sentences should be changed as follows, "In order to work within the confines of State of Colorado water law a municipal recreation contract with the City of Grand Junction, City of Fruita and Town of Palisade has been entered into.". and "This contract would protect releases of surplus water from the Green Mountain HUP in excess of the capacity of the Orchard Mesa Power Plant to and through the 15-Mile Reach for municipal recreational purposes." Noted – correction will be made.

7) Section 1.3.2, page 12, last sentence: Should be changed as follows: "No CROP activities were conducted in 2000 and 2001 due to low snow pack and concerns about reservoir storage, although a peak in the range of 13,500 cfs did occur in 2000 because of rapid snow melt." Noted – correction will be made.

8) Section 2.3.2, Page 18, first paragraph, last sentence: Use of the term "replacement" here confuses the purpose of the 52 kaf CBT replacement pool and the 100 kaf compensatory pool of which the HUP is part. This sentence should be replaced with the following: "HUP surplus is that water which is determined to be in excess of the HUP beneficiaries needs and can be released for authorized purposes. The determination is an ongoing process during the irrigation season and surpluses are typically not available or released until late summer." Noted – correction will be made.

9) Section 2.3.2.2, page 18, second bulleted paragraph: should read ". . . water in storage on April 1st of each year is credited to the CBT replacement pool and any remaining water is credited to the sub-pools of the 100,000 acre-foot power pool in order of priority; the Silt pool, the HUP and the Contract pool." I trust the modeling was conducted this way. Noted – correction will be made.

10) Section 2.3.2.2, page 18, Third bulleted paragraph: The initial implication is that no reservoir refill rights were in the original C1 data set. Then mention is made of inserting the correct priority number for the Ruedi refill right. Were correct priorities of Green Mountain and any other reservoirs' refill rights also inserted and if so, it should be noted. Only Ruedi refill was wrong – correction will be made.

11) Section 2.3.6, page 21, change the last sentence as follows, "The Service's priority is to increase spring peak flows when the peak runoff is expected to be in the range of 12,900 to 26,600 cfs at the head of the 15-Mile Reach or approximately 15,000 to 29,000 cfs at the Cameo Gage...". Noted – correction will be made.

12) Section 2.3.8, page 23, change the last sentence as follows, "The necessity and frequency of obtaining such a junior water right must be determined...". Noted – correction will be made.

13) Section 2.3.11, page 24, change the last sentence of the first paragraph in this section as follows, "The units are not normally worked on at the same time thus maintaining capacity to deliver water through at least one unit.". Noted – correction will be made.

14) Section 2.3.13, page 25 & 26, Second bulleted paragraph: The heading for this paragraph should read "Division 5 Fill". If it is necessary to add more definition of what that means, the following could be added "or reservoir fill as against all water rights in the basin except those of Denver Water and Colorado Springs as adjudicated in the Blue River Decrees"

Similarly, the first bulleted paragraph on page 26 should read "Blue River Decree Fill" or if further definition is needed, the following may be added "or reservoir fill as against the rights of Denver Water and Colorado Springs as adjudicated in the Blue River Decrees." Noted – correction will be made.

15) Section 2.3.13, page 26, third full paragraph: Both the Div. 5 fill and Blue River fill may be 'paper' fills. It should be specified in this paragraph that it is the Div. 5 Fill that is being discussed. Is the erroneous modeling of the Div. 5 fill being corrected or was it determined to inconsequential to the results of the Phase 2 analyses? Additional discussion and or clarification would be helpful. Noted – additional clarification will be added to final report

16) Section 2.3.13, page 26, Fourth full paragraph: Suggest the first sentence be reworded as follows: "Power releases made under the direct flow power right are debited in the accounting against the "Blue River Fill" specified in the Blue River Decrees which define the obligations of Denver Water and Colorado Springs in relationship to Green Mountain Reservoir." Noted – correction will be made.

17) Section 3.3.2, page 39, second full paragraph, Figure 14 actually indicates that less water was released from Ruedi Reservoir under the GMR 20kAF Release than the Revised StateMod and C1 Data Set (Fifth Revision) baseline. Therefore the assertion that reduced HUP Surplus availability was made up from Ruedi Reservoir appears to be erroneous. Noted – correction will be made.

18) Section 3.4.1, page 39, last paragraph, the reference to Figure 3 in third sentence of this paragraph should be changed to "Figure 30". Additionally, it appears that Figure 32 actually indicates that releases from Ruedi Reservoir are reduced under the Revised StateMod and C1 Data Set (Fifth Revision) with 110kAF Future Demand than the Revised StateMod and C1 Data Set (Fifth Revision) baseline. Therefore the assertion that reduced HUP Surplus availability was made up from Ruedi Reservoir again appears to be erroneous. Noted – correction will be made.

19) Section 3.4.5, page 41 and 42, while the modified Share the Pain Alternative With CROP Alternative appears to be feasible with perfect hindsight, in actual practice it would be very problematic to determine the allocation of the 20,000 acre-foot releases presented in Table 11 under real time operations. This limitation should be acknowledged. Noted – will be acknowledged.It would also be interesting and informative to develop comparison graphs of the Modified Share The Pain Alternative With CROP and 110kAF Demand and Revised StateMod

and C1 Data Set (Fifth Revision) with 110kAF Future Demand baseline. This will be considered for the final report.

20) Section 3.4.6, page 42, first paragraph in this section, the third sentence references "43 occasions of decreased diversions" which appears to be in conflict with the reference to "47 occasions" in the fourth sentence. Noted – correction will be made.

21) Table 14: Suggest that the signs for the figures in the 'Difference' column be reversed to indicate that the augmentation is an increase in volume (positive) and the recovery of the augmentation releases results in a lesser (negative) volume of flow in the month. This will be considered for the final report.

22) Figures 55 through 63: Identify these as representing the 'Modified' Share the Pain alternative. Noted – correction will be made.

February 18, 2003

Randy Seaholm
Colorado Water Conservation Board
1313 Sherman Street, Room 721
Denver, CO 80203

Dear Randy:

Subject: Phase 2 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado River, Draft, January 2003.

The following comments are in response to the above-referenced report and the January 17, 2003 meeting at Denver Water.

General

The report should clearly acknowledge that STATEMOD has inconsistencies and limitations. Report will acknowledge limitations, not inconsistencies. As implied on page 41, using STATEMOD with a monthly time step is insufficient to simulate both CROP bypasses/releases and CFOPS bypasses/releases. It is our understanding that the state plans to update STATEMOD to a daily model to more correctly simulate operations. The daily time step problem is especially apparent in attempting to simulate Denver's exchange and substitution operations. Although STATEMOD was modified to more correctly model exchange and substitution operations, problems are still apparent. For example, on page 40 (and Figure 34) the report states that with 110,000 af of future demands (50,000 af of which is increased demand on Dillon Reservoir), Williams Fork Reservoir would have greater contents in dry periods such as 1977-78 and 1981-82. However, with a higher demand, Williams Fork Reservoir is more fully used for exchanges and substitution in dry years – and therefore the contents should be lower, not higher. We believe that during dry years with increased demand, GMR does not achieve a fill, therefore there can not be an exchange between WRF and Dillon because GMR is still filling. This is why WFR has higher contents. Appendix N (Table N-2) shows the STATEMOD-generated exchanges from Williams Fork Reservoir to Dillon Reservoir. This should be compared with Table N-3 that shows the exchanges based on PACSM. What is clear is that STATEMOD is not allowing exchanges each winter and throughout dry years. This results in higher contents in Williams Fork Reservoir, especially in dry periods, than what should be simulated. Also, for some reason, the STATEMOD-generated exchanges from Williams Fork Reservoir are unrealistic during March (Table N-2). It is also unclear whether the exchanges to the ski areas (Clinton Agreement) are being performed. We do not know how PACSIM defines a fill of GMR – using Division 5 rules or Senate Bill 80 rules. During initial modeling, we realaized that the Williams

Fork exchange was not being modeled correctly by StateMod. In order to more closely match PACSIM results we split the Williams Fork exchange into two rights, a senior right for winter (Jan-March) and a junior right for summer (April-Dec). For some years in which run-off occurred in March, Williams Fork was operating with a senior exchange right. The important point is that this is not a fatal flaw for CFOPS. In comparison to PACSIM, the yearly results are more accurate than for the individual months.

Likewise, with the 110,000 af of future demands (50,000 af of which is increased demand on Dillon Reservoir), the substitution requirements of Denver's pool in Wolford will be greater, and the contents of Wolford Mountain Reservoir (Figure 36) should be much lower in 1977, not higher as shown in STATEMOD. Same story as WRF, Green Mountain does not fill in dry years with increased demand and so exchange can not take place.

Other limitations include the modeled period of 1975-1991, which doesn't include the mid-1950's critical drought period. This time period was agreed to at the start of the study.

The lack of daily routing of reservoir releases also minimizes the real-time problem of dealing with lag times and overestimates the efficiency of making the correct amount of reservoir release at the right time. Monthly model, StateMod was chosen and agreed to by everyone at beginning of study.

The modeling includes the operation of 5,412 af fish pool in Williams Fork (p. 20). This is a temporary arrangement which should not have been assumed in the Baseline hydrology. We used C1 dataset as it was given to us by the State.

Page 30 states that because the 20,000 af does not have to be supplied in dry years, the effects on reservoir firm yield are minimized or eliminated. While this is true for individual dry years, it is important to note in the report that reservoir operators usually don't know when a drought has begun. If water is released from a reservoir in an average year preceding a drought, and the reservoir doesn't subsequently fill, then firm yield has been lost. Another concern is a year such as 1978 that follows the severe dry year of 1977. In 1978, the 20,000 af for flows in the 15-Mile Reach are required even though reservoirs such as Williams Fork have not refilled. Until the reservoirs completely refill, the reservoir operators have no way of knowing when the critical drought period is over. The report incorrectly assumes that water would be released in a year such as 1978. It was not in the scope of work to define the operating rules for CFOPS, nor predict future flows. The study focuses on what was feasible historically. USFWS will have to ultimately define the operating/participation rules and hopefully include drought provisions to avoid the above described scenario. It needs to be decided if CFOPS will be mandatory or voluntary.

The goal of an additional 20,000 af is an average volume to enhance spring peak flows in the 15-Mile Reach. In some years more water is available, and in other years less is available. If the junior Green Mountain Reservoir refill right is aggressively used for CFOPS, it could preclude Douglas County from getting much water under a new junior water right at Dillon Reservoir. Being able to derive new yield from a junior water right at Dillon Reservoir is critical for success of a cooperative arrangement among Douglas County, the River District, and Denver Water. Success on this cooperative effort is important to harmony between the east and the west. It was

not within the scope of work to derive junior yields for specific projects other than the potential new reservoir sites.

Project Alternatives

For the Webster Hill alternative, the report should clearly state that not only could this option provide 20,000 af or more every year on a firm yield basis, this alternative could also be used to meet the 10,825 af goal for fall releases. The report should also clearly state that only the main stem storage and new tributary storage alternatives can meet the goal of the project sponsors which is "to secure a firm water supply for project purposes" (p. 10) while also meeting the 10,825 af RIPRAP goal for late summer and fall base flow releases. We can not guarantee a CFOPS release in every year for this alternative, we did not model this.

Another benefit of the Webster Hill alternative that should be pointed out is that it is relatively close to the 15 Mile Reach and the problem of river travel time is greatly diminished (i.e., the 3-day travel time from Green Mountain Reservoir). It should be noted in the report that the Webster Hill alternative would inundate a few miles of marginal T&E habitat. Noted and will be included.

On page 6 the report states that tributary storage alternatives are all costly and the consultant team recommends that there be "no further consideration" of these alternatives. However, tributary storage may be the most practicable, least environmentally damaging alternative to meet the project purpose. Concluding that tributary storage is too expensive ignores the economic realities of what is required to develop water supply for new purposes. There is no easy or cheap fix. For example, Colorado water users are pursuing the Sulphur Gulch Reservoir option to develop up to 10,825 af of water for late summer and fall base flow releases. While costly, this project is being pursued because it may be the most feasible alternative to meet the project purpose. Another tributary alternative is the Eagle-Colorado Reservoir. Momentum is building between numerous water users to cooperatively developing this multi-purpose reservoir. This project could be sized to accommodate the 20,000 af spring peak water as well as the 10,825 af fall base flow water. Noted.

Use of Existing Reservoirs (i.e., Green Mountain or "Share the Pain" alternatives)

Under real-time operations, the managers of existing reservoirs would need to designate how much water could be available for the spring release based on their ability to forecast that their reservoirs would fill and then spill. In reality, operators of Williams Fork and Wolford reservoirs and the CBT project would not allow releases from those projects until the operators are sure that the facilities' yield will not be impacted, regardless of what the modeling for this study shows. For example, in the last several years (prior to 2002) the operators have made limited CROP releases due to imperfect ability to forecast the peak flows, and the uncertainty of filling once releases are made. It should be noted that CROP is voluntary, but it is unknown if CFOPS will be mandatory. This all depends on the participation/operating rules that the USFWS imposes.

This more realistic expectation of reservoir operations must be accurately reflected in the report. Since project operators will only release water once they are sure the reservoirs will fill, it is critical to draw a distention between the unreliable water source that could be provided by existing reservoirs and the highly reliable water sources provided by options like Webster Hill Reservoir and new tributary storage. Denver would like the opportunity to review and comment on draft language for this conclusion to assure this type of realistic expectation is included in the final report. This will be considered while drafting the Executive Committee Recommendation.

Other operating consequences are as follows:

1. To make CFOP releases, the probability of filling the reservoirs must be high. For example, under current demands for Denver in the CROS program, the probability of filling the reservoirs must be at least 90% after the releases are made. As demand increases and approaches existing supply, operators such as Denver may require more than a 90% fill probability. Why 90%? It is beyond the scope of the study to predict a fill.
2. The possible impacts on the trout fisheries (e.g., below Williams Fork Reservoir), which are an important issue, would need to be considered. Beyond scope.
3. The impact of this option on power generation at Williams Fork Reservoir, Dillon Reservoir, and the East Portal should at least be mentioned, if not quantified. Noted. Our scope specified only looking at GMR, Ruedi and Shoshone power generation.

Williams Fork Reservoir

On page 32 it is stated that "Williams Fork Reservoir is not a direct water supply for Denver." This is inadequate reasoning. Williams Fork Reservoir is a direct supply in the sense that it enables diversion of significant amounts of municipal water supply at numerous locations that otherwise would not be directly diverted. Noted.

On page 33, the text for the results of Alternative 1e, Denver Water System Operations, should state that under this operation, Williams Fork Reservoir does not fill in 1975, 1980, 1982; and there is a 19,000 af deficit in 1978. As stated previously, in a year such as 1978, 20,000 af for flows in the 15-Mile Reach are required, but Williams Fork has not refilled from the severe dry year of 1977. Until the reservoirs completely refill, the reservoir operators have no way of knowing when the critical drought period is over. Water would not be released in a year such as 1978, unless there is some kind of payback "insurance" from another reservoir or a reduction in the river calls. As described in a January 22, 2002 letter to you, CROS releases from Williams Fork would occur in four of the eight designated years under existing levels of demand and releases would be less and may approach zero as demand on Denver's existing system approaches that system's capabilities to supply water. After CROS releases are made, even less water would be available for CFOPS. We believe that CFOPS will supersede CROS releases.

Also on page 33, the report states that Williams Fork Reservoir refilled eventually and was never completely drawn down. First, don't all reservoirs eventually refill? If so, what is the point of this statement? Noted. Secondly, it should be clearly explained that in STATEMOD Williams Fork Reservoir was never completely drawn down because (1) only existing demands are modeled, we did model future demands (2) the model doesn't include the mid-1950's critical

drought, not in scope, we used time period agreed to by everyone and (3) STATEMOD is not correctly simulating exchanges and substitution. We do not agree.

Finally, we are concerned that a perception could be constructed that Denver's reservoirs have unused future capacity to accomplish a significant portion of the 20,000 af CFOPS goal. This perception is based upon a monthly model that does not adequately model Denver's substitution with Green Mountain Reservoir, Wolford Mountain Reservoir, and Williams Fork Reservoir, or Denver's exchange operations using Williams Fork Reservoir. While we understand and support the use of STATEMOD, the analysis greatly overestimates the present and future ability of Denver's facilities to assist in the CFOPS solution. The shortcomings of the analysis must be included at numerous locations throughout the report so that the information is clear. Denver would like to review and comment on the qualifying language prior to finalizing the report. If it is decided to not include those qualifiers, Denver would like the time and opportunity to meet and discuss the issue prior to finalizing the report. We believe that the findings in this study support the conclusion that several reservoirs have excess capacity during wet years. This is why many alternatives are feasible for providing the 20,000 acre-feet.

Denver remains willing to explore the use of any flexibility in its system that could be used for the benefit of the fish. However, the amount of flexibility available must be accurately portrayed to assure that expectations remain reasonable. Noted.

Sincerely,

Steve Schmitzer
Chief of Water Resource Planning

cc: Leo Eisel
Bruce Rindahl
Eric Wilkinson
Malcolm Wilson
George Smith
Dan Luecke
Ray Tenney

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COLORADO RIVER WATER CONSERVATION DISTRICT

Protecting Western Colorado Water Since 1937

MEMORANDUM
February 14, 2003

TO: Randy Seaholm

FROM: Ray Tenney

SUBJECT: Comments on Behalf of West Slope Water Users on the Coordinated Facilities Operations Studies - Implementation and January 2003 DRAFT Report

General

Thank you for the opportunity to review the subject DRAFT report and provide comments on behalf of western slope water users. These comments are intended to reflect potential implementation of CFOPS, deficiencies in the report, and the general concerns of western slope water users impacted by the considered alternatives. The comments are not intended to represent any water user's specific comments unless noted. These comments may not be completely endorsed by all affected western slope water users.

Implementation of Peak Flow Augmentation

The west slope water users offer the following comments on the implementation of the Coordinated Facilities Operations of Division 5 Reservoirs (CFOPS) for augmentation of peak flows for the benefit of endangered fishes. These comments are intended to provide input to the Executive Committee's recommendation to the Recovery Program. The comments are formulated considering the content of the "Phase 2 Coordinated Facilities Water Availability Study for the Endangered Fishes of the Upper Colorado ", draft January 2003, the Executive Committee discussions and discussions with interested west slope water users. The comments are intended to contribute to the advancement of the process and are not to be considered to be comments about the subject report, which are included below.

Coordinated Facilities Operations (CFOPS) should be conducted in addition to the already occurring Coordinated Reservoir Operations activities as follows:

All participating reservoirs will bypass inflow in the support of CROS as outlet structure limitations and drought provisions allow.

The CFOPS releases of 20,000 acre feet or 1,008 cfs (on average of occurrences), will be provided when the flow triggers of 12,900 cfs to 26,400 cfs at the Palisade gage are realized.

Planning for the implementation of CFOPS must begin with the March 1 forecast of available water supply for the various contributing reservoirs and the estimate of potential runoff at the Palisade gage.

Implementation of the CFOPS efforts will be through the existing CROS working group.

CFOPS peak flow augmentation will be provided on an equal basis from Green Mountain Reservoir, Granby Reservoir and Williams Fork Reservoir (6,667 acre feet each on average).

Green Mountain Reservoir will participate to the extent that the sum of CROS inflow bypasses and CFOPS releases can be passed through the outlet works (turbines and bypass tubes) and over the spillway. Or as limited by USBOR for dam safety purposes.

The contribution from Green Mountain Reservoir will come from the 100,000 acre foot pool and any portion not used for CFOPS will be considered to be in the 100,000 acre foot pool for previously identified purposes, not carried over into another year for CFOPS releases.

The ability of Green Mountain Reservoir to participate will be ascertained at the adjusted start of fill date.

Drought provisions must be included in the rules under which CFOPS releases and CROS bypasses are made, which recognize the potential problems related to making fish bypasses and releases following dry years. Triggers will include: forecast storable inflow, reservoir contents (in individual pools) and peak flow forecast.

CFOPS releases and CROS bypasses are voluntary.

The Recovery Program and USFWS must verify and demonstrate a measurable positive fish population response from peak flow augmentation activities, beyond reporting increases in gaged flows. If CROPS and CROS operations are not shown to contribute to populations necessary for recovery they will be discontinued.

Reduced reservoir levels which do not impact a reservoir's ability to meet its intended purposes are not to be considered an impact on facility firm yield.

An insurance pool must be included to meet obligations of participating reservoirs should they not refill the "fish hole" created through peak flow releases. The insurance pool obligation will be met through use of the USFWS' environmental pools, first from Ruedi Reservoir and second from Wolford Mountain Reservoir. All exchanges necessary to implement the use of Ruedi and Wolford reservoir waters to meet the delivery obligations of the participating reservoirs will be the responsibility of the USFWS.

CFOPS operations will not injure junior water users. (e.g. If Green Mountain Reservoir makes a fish release and uses its refill right to refill the space created, use of the refill right will not cause the curtailment of storage in Wolford Mountain Reservoir, in favor of the Green Mountain Reservoir refill right, to satisfy a Shoshone (or other downstream) call.)

Recommendations included by the River District in this section will be taken into consideration during the drafting of the CFOPS Executive Committee Recommendation, to be submitted to the Water Acquisition Committee.

The Executive Committee should make a decision on whether or not CFOPS is a voluntary program, and whether or not it supersedes CROS.

Comments on the January 2003 DRAFT Report

The DRAFT report suffers a need for significant revision as it is the record of the process and the alternatives considered. The implied precision in the portrayal of hydrology related to demands and facility operations may over estimate facility flexibility and the potential augmentation opportunities. Further modeling with the available tools does not seem warranted. The results presented suggest ranges of potential which should be considered in the implemention of the recommendations above. Revisions are necessary to avoid portrayal of potential which does not really exist.

Phase 2 report, technical memoranda (appendices) and Phase 1 Report in total are meant to provide the record of the process and alternatives considered. What further documentation is needed? What is meant by "revisions are necessary to avoid portrayal of potential which does not really exist"?

We understand the potentially viable options to be:

Release of 20,000 acre feet from Green Mountain Reservoir (GMR) to be replaced under an existing refill right.

Release of 20,000 acre feet from Granby Reservoir (GR/CBT) to refill when hydrology permits

"Share the Pain" consisting of:

1) 6,667 acre feet from each of GR/CBT, GMR and Williams Fork Reservoir (WFR)

2) or, proportional deliveries from GMR, GR/CBT, Ruedi, WFR and Wolford Mountain Reservoir (WMR)

3) or, as much of the of the 20,000 acre feet from GMR with that portion limited by outlet capacity made up by Ruedi, WMR, WFR and GR/CBT

Up to 7,000 acre feet from Ruedi Reservoir (due to downstream channel limitations)

New Storage at Webster Hill on the mainstem Colorado River

Elimination of the Shoshone Call - use of resulting stored water savings and increased diversions to storage for later release

The utilization of an insurance pool was included in the discussion and presumably part of any alternative.

Your understanding of the feasible alternatives is correct.

Specific Comments

Executive Summary

Ref. pg. 3, No. 8 line 3 should read "...four times..."

Editorial comments are noted and will be addressed in the revision of the draft report.

Ref. pg. 4 para. 3 The reason Granby Reservoir does not refill the fish "hole" created in the same year it is made has nothing to do with the lack of a refill decree as cited. The replacement pool in GMR enables Granby to store everything available to it hydrologically, except for minimum stream flows. The only time Granby would need a refill right is if the 52,000 acre foot replacement pool was exhausted and there were still storable inflow above Granby. This is an accurate statement. We agree, the problem is caused by limited physical availability in some years.

Ref. pg. 4 para. 5 It is possibly questionable that the refill rights for the various reservoirs included peak flow augmentation for native fishes in their decreed purposes. It would be better to use a junior water right for the fish release holes. The sensitivity analysis which showed little impact on junior water users suggests that the junior decrees would yield fish peak flow augmentation water. This would avoid any impact to junior water users. Response: This a legal question. This was not modeled with a junior decree; it was modeled with existing refill rights.

Ref. pg. 6 para 3 and 4 Does the model allow diversions through the Adams Tunnel in excess of the annual supplemental supply deliveries (i.e. non-charge water) in CROS/CFOPS or near CROS/CFOPS years? How much? No water in addition to those amounts specified in the demand files was diverted and pumped through the Adams Tunnel. Those demand amounts were provided to the State for the original C1 data set by NCWCD. It is unknown if "Non-Charge" water was included in those original demand files.

Ref. pg. 7, para 1 Xcel has advised that removal of the Shoshone Call is not an option for consideration for CFOPS and has insisted that all references to Shoshone be removed from this report and other documentation. If this is not achievable based on these comments I will so advise Xcel so they may take whatever action they deem necessary. Excerpt from Xcel communication:

> "Xcel should not be treated any different than any other water right holder. If individual water rights need to be taken for the endangered species recovery program, it should be done under the Colorado Doctrine of Prior Appropriations, meaning the water right at Shoshone is last in line, not first."

Ground rules for CFOPS study stated that all alternatives would be considered for the feasibility study. This alternative has been found to be a feasible source for the 20,000 acre-feet release based on engineering analysis, and so has been included in this report.

Chapter 1 - Introduction and Purpose

Please remove all reference to Shoshone Power Plant call reduction per Xcel as noted above.

Executive Committee should make the call.

Ref. pg. 9 Section 1.2 para 3 The quotation from the 15 Mile Reach PBO is taken out of context and without the references to the USFWS objective of providing additional peak flow enhancement in only those years in which the current CROS activity is undertaken and the triggers at the Palisade gage are realized. This report suggests throughout that the provision of 20,000 acre feet is to be made on the **average of all years** (e.g. average annual) not just the triggered years. See nos. 1, 2, 3 on page 2 and the first full paragraph of page 22 , also page 30 Section 3.2.1 bullets 1, 2 and 3. for correct portrayal of the objectives of CFOPS. **Please correct at all occurrences**. Please verify that the analyses were not undertaken to achieve an average annual delivery of 20,000 acre feet as the triggers were only realized in 6 of the 17 modeled years. Thank you. Noted – correction will be made.

Ref. pg. 11, para 2 The additional 5,000 acre feet 4 out of 5 years can be delivered either from Ruedi or GMR. Noted – correction will be made.

Ref. pg. 11 para 5 Delivery of 5,412.5 acre feet from WMR is subject to drought provisions which should be noted. Noted – correction will be made.

Ref. pg. 11 para 5 Delivery of 5,412.5 acre feet from WFR is subject to drought provisions which should be noted. (Different provisions than WMR) Noted – correction will be made.

Ref. pg. 12 para 1.3.2 Did the peak of 17,000 cfs occur in both 2000 and 2001 as stated? Was the CROS trigger exceeded in both years? The trigger of 12,900 cfs was not reached in 2001. The consultant team will check 2000 hydrology and determine what the peak flow in 2000 was and correct this paragraph.

Chapter 2 - Ground Rules, Assumptions and Analysis Procedures

Please remove all reference to Shoshone Power Plant call reduction per Xcel as noted above.

Executive Committee should make the call

West Slope Comments

Ref. pg. 15 para 2 The CFOPS alternatives were analyzed to provide an average of 20,000 acre feet in the years where the triggers a the Palisade gage were realized, **not** "...average annual 20,000 acre feet." Noted – correction will be made.

Ref. pg. 20 para 2.3.3 2nd bullet The additional 5,000 acre feet 4 out of 5 years can come from Ruedi or GMR Noted – correction will be made.

Ref. pg. 20 para 2.3.3 5th bullet Wolford Mountain Reservoir provides up to 6,000 acre feet of water per year for fish releases depending on pool contents and storable inflow. The FWS controls 6,000 acre feet of storage which benefits from 10% of the storable inflow. For example in 2002 the 6,000 acre foot fish pool received about 345 acre feet. Suggest revise to read "Up to..." Noted – correction will be made.

Ref. pg. 20 Section 2.3.4 para 3 delete "...average annual..." The provision of 20,000 acre feet is an average of 20,000 acre feet only counting those years in which release triggers at the Palisade gage are realized. Noted – correction will be made.

Ref. pg. 21 para 3 #5 and #6 What is the temporal distribution of the 14, 000 acre feet of depletions for the west slope reflected in these nodes? The Consultant Team will provide the temporal distribution. Does the modeling reflect some diversion to storage and later use totaling 14, 000 acre feet of depletion after inclusion of return flows or just 14, 000 acre feet of depletion from the hydrograph? An additional municipal diversion was added at the Roaring Fork node and the node near Grand Junction and 14,000 acre-feet was diverted at these nodes depending on physical and legal availability. Diversions to storage less return flows would result in significantly greater alteration of the hydrograph, at the Palisade gage especially on the peak, than 100 percent consumptive use totaling 14,000 acre feet. Diversions were not made to storage, but were diverted directly for municipal use with 100% consumptive use.

Ref. pg. 21 para 4 Why is only 110,000 acre feet of new depletions included in the analyses? The 15 MR PBO recognizes 120,000 acre feet of new depletions. The individual future depletions cited by the report total 111,000 acre feet. What is the effect of the additional 10,000 (or 9,000) acre feet of depletions if they are used on the west slope through diversions to storage less return flows when used? Significant to the estimate of peak flow at the Palisade gage? Effect is not known because demands submitted to Brown and Caldwell for the modeling effort only totaled 111,000 acre-feet, not 120,000 acre-feet as specified in the PBO. We chose to model the exact projected demand provided by the modeled entities.

Ref. pg. 21 Section 2.3.6 para 1 The 20,000 acre feet is not provided "...on an average annual basis." The 20,000 acre feet is to be provided on average based on the years which the triggers at the Palisade gage are realized. Noted – correction will be made.

Ref. pg. 22 para 1 The 20,000 acre feet will **not** be determined "...as an average annual volume..." but rather on an average of the years when the triggers at the Palisade gage are realized. The first reference in this paragraph is incorrect (similar to the other examples cited in these comments) with respect to the objective of CFOPS . The second reference in this paragraph correctly states the objective of CFOPS:

> "In the years when flows in the Colorado River at the top of the 15-Mile Reach are less than 12,900 cfs or greater than 26,600 cfs, no water will be provided. For those years when the flow is between 12,900 and 26,600 cfs, an average of 20,000 acre-feet will be provided, and in some years less."

Please correct all the other references to the provision of 20,000 acre feet to be consistent with this objective statement. Noted – correction will be made.

Ref. pg. 23 para 1, and Section 2.3.7 #2, and para 4 the portrayal of the objective of CFOPS to deliver "average annual 20,000 acre-feet" is incorrect. The statement in paragraph 4: "Throughout this report, the term "average annual 20,000 acre-feet" will be used to indicate the target for this program." is incorrect. The remainder of the paragraph provides a correct characterization of the objective of CFOPS. Please correct all occurrences. Noted – correction will be made.

Ref. pg. 23 Section 2.3.8 Are there any cases water where stored under first fill rights which do not allow piscatorial purposes for peak flow augmentation is released for CFOPS? How can this occur? The refill rights which recognize piscatorial purposes were decreed without the contemplation of releases for peak flow augmentation for native fishes. How would the analyses be altered by use of junior water rights for the CFOPS operations? It does not seem "The necessity and frequence of obtaining such a junior *(water right?)* must be determined before implementing any of the alternatives." was ever explored or discussed. This was included in the SOW and is a critical part of the consideration of alternatives. The report is incomplete and the SOW unfulfilled without this work. The modeling was based on diverting water to storage under the priorities of any of the decrees and making releases for the endangered species from this stored water. Determining the feasibility of diverting to storage for purposes of making releases to the endangered species has been discussed by the Executive Committee on several occasions. Resolution of this matter is beyond the scope of this present study.

Ref. pg. 26 first full para The CROS bypasses will also count against the first fill of GMR and should be considered in the analyses. Why is the effect of the refill of a reservoir any different than the effect of a first fill? This paragraph does not make sense. The Consultant Team thinks this paragraph does make sense, but we are willing to further discuss this matter.

Ref. pg. 26 paras 2 and 3 change "Power releases made ..." To Power generation effected by ..." to reflect direct flow power generation which does not count against the "Division 5" fill of GMR. Change "...are..." to "...is..." Noted – correction will be made.

Ref. pg. 27 Section 2.3.16, second bullet Why would reservoir release capacity be maximum capacity? This will over estimate the potential release for any reservoir which has not reached full head by the time a CROS bypass and CFOPS release is calculated. Were "maximum release rates" in the model adjusted accordingly? The effects of hydraulic on release capacity were not considered for any of the reservoirs. See Tables 5 through 9 for the release capacities used. For Green Mountain reservoir, the one year in the study period in which the spillway could not be used was 1979 because the pool was below the spillway level.

Chapter 3 - Results

Ref. pg. 30 Section 3.2.1 No CD-ROM was received with the DRAFT report under review. Please provide after modeling corrections made. CD-ROM will be provided with Final Report

Ref. pg. 31 Section 3.2.3 3rd bullet, If there is "...no disruption to releases from Green Mountain Reservoir under the Check Settlement." why are releases made from Ruedi Reservoir to "cover" the resulting less water in the HUP surplus pool? (See pg. 39 para 2) In the C1 data set, there is a fish pool account in both Green Mountain and Ruedi used to supplement fish flows in late summer in the 15-Mile Reach. If the 20,000 acre-feet release in any given year reduces the amount available in that fish pool account in GMR such that the minimum flow targets cannot be covered by that account, then increased demand is made on Ruedi Reservoir fish pool account.

Ref. pg. 32 Section 3.2.4 para 3 Is the "No reduction in power revenues at Green Mountain Reservoir, Shoshone Power Plant or Orchard Mesa Power Plant ..." considering the 13,000 acre feet of CFOPS releases which must come from somewhere other than Ruedi Reservoir? The analysis for obtaining releases for the endangered fish from Ruedi Reservoir concluded that up to 7,000 acre-feet could be released from Ruedi without exceeding downstream channel constraints. We did not investigate where the remaining 13,000 acre-feet would come from.

Ref. Pg. 33 Section 3.2.6 The curtailment of diversions to storage in Division 5 facilities unfairly allows the continuation of direct flow transmountain diversions to storage or other uses. The inflow to transmountain diversion forebays located on the west slope can conveniently be excluded from this alternative. This is unacceptable to the west slope. Alternatives 1f and 1g were modeled relatively early in this investigation. After completing the modeling of additional alternatives, it was apparent that some of the procedures used in some of the alternatives were not necessary in order to produce 20,000 acre-feet for release/bypass to the endangered fish. Modeling of the alternatives indicated that some combination of reservoirs could make this release and then refill under existing priorities. Therefore, the procedures detailed for cessation of storage to the inbasin reservoirs were not necessary.

Ref. pg. 35 para 5 The firm yield of Webster Hill was characterized as 10x greater in the first draft report. Is this estimate correct? The term, " firm yield" should not probably have been used in this paragraph. What is meant in this paragraph is that the 20,000-40,000 acre-feet could be released for the endangered fish in the required years depending on the total storage capacity of the proposed Webster Hill reservoir.

Ref. pg. 37 Section 3.2.11 How is having more reservoirs participate an insurance pool? The reservoirs which are participating will not be backed up by any other source if all are participating. This is just another "share the pain" alternative. This is true.

Ref. pg. 37 Section 3.2.11 Remove the reference to the Shoshone call reduction. This is not an insurance pool. See Xcel comments above.

Executive Committee should make the call on this.

Ref. pg. 39 para 1 Why does GMR need to use its refill right in the Spring of 1979? If GMR is storing in the fill season it would be using its first fill right. Correct. "refill right" should be first fill right.

Ref. pg. 39 para 2 The amount of surplus HUP water is a function of GMR operations and has nothing to do with Ruedi Reservoir. True. If there is less HUP surplus as a result of CFOPS operations there is less HUP surplus available to serve those identified purposes. True. Late summer releases from the HUP surplus which might have been possible without CFOPS should not be made up from Ruedi Reservoir. It is not possible to model this situation. The consultant Team compared two model runs (with and without CFOPS). The comparison between these two runs shows, just as is stated here, that there is an impact to Ruedi Reservoir from CFOPS operation at GMR. Maybe what is going on here is the low flow period is being more heavily augmented by Ruedi Reservoir due to GMR's reduced capability. True. This is an impact either in reduced low flow augmentation capability under the HUP surplus rules or an increased draw on Ruedi Reservoir and should be portrayed as such. Agreed.

Ref. pg 39 Section 3.3.3 para 2 The ground rules include the provision that yield shall not be adversely impacted. The analyses do not show an impact to yield in GMR, GR/CBT or WFR from having lower storage levels carry over between years. The report should note that while lower levels are carried over the reservoirs the analyses never show a reduction in deliveries or yield. Noted – correction will be made.

Ref. pg. 39 Section 3.4.1 para 1 The reduced availability of GMR HUP surplus is just that. There is no commitment or reason for Ruedi Reservoir to make up HUP surplus obligations. If additional low flow augmentation from Ruedi Reservoir is necessary to achieve USFWS flow targets due to reduced HUP surplus then it should be shown as an impact to Ruedi Reservoir from CFOPS operations at GMR. Agreed. See comments above.

Ref. pg. 40 Section 3.4.3 For the modified share the pain alternative, where GR/CBT, GMR and WFR contribute 6,667 acre feet each, described in this section a table of contributions (like that shown in Table 11) should be generated. Is GMR participation limited by the analyses limiting releases to the turbine capacity? Noted – correction will be made.

Ref. Pg. 41 Section 3.4.4 The potential for contribution by GMR should not be limited to turbine capacity. If it is necessary to limit the contribution of GMR to turbine capacity that is all that can be expected from GMR. No releases from other reservoirs should be expected to "make up" for the limited release capacity of GMR. It is not acceptable to the River District Enterprise for Wolford Mountain Reservoir to "make up" releases "expected" from GMR but limited by turbine capacity.
The only year in which the 20,000 acre-feet release was required and Green Mountain Reservoir could not make the total 20,000 acre-feet by itself due to limited release capacity was 1985 (see Table 5). This was a big water year with a C1 Baseline release of 104, 470 acre-feet. The Executive Committee would need to review this situation and determine what its policy would be in situations such as this.

Ref. pg. 42 Section 3.4.6 Shortages to junior water rights resulting from CFOPS activities and increase in exercise of more senior refill rights is unacceptable in any amount. Is the average portrayed computed on a monthly basis? What are the extremes? We suggest that the Consultant add a table which would indicate the maximum shortage to junior water rights in any month and for any year. The Executive Committee can then review these data and determine an appropriate policy.

Ref. pg. 42, Section 3.4.7 Consideration of removal of the Shoshone call is unacceptable to Xcel. Xcel has requested that any references to removal of the Shoshone call be purged from this report. Please advise if this is possible or if I should advise Xcel otherwise. Thank you. One of the principal Ground Rules was that all alternatives could be investigated. Nothing was to be initially taken off the table. However, the Executive Committee needs to decide if it wants to change the Ground Rules or not.

~~Executive Committee should make the call.~~

In this analysis it is unclear if the analyses includes removal of the Shoshone call for the entire year, every year. The Shoshone call was removed in every year and in every month. What the effects of the increased storage realized in the benefiting reservoirs would be. See Technical Memorandum No. 9 for the effects on reservoir storage. What happens to the increased storage realized if the CFOPS triggers are not tripped. This analysis was not done.

Chapter 4 - Conclusions and Recommendations

19 conclusions are included in this section. No recommendations were found. What is the recommendation of the study team? I believe we are entitled to recommendations of the study team based on our SOW. This particular study team was selected on the basis of superior ability to provide recommendations considering more than just numerical and technical analyses. **Please provide recommendations. Executive Committee to Draft.**

Tables

Tables 5, 6, 7, 8, 9 The characterization of CROS (CROP) inflow bypasses as releases is incorrect and mis-leading. Correct, CROS/CROP inflow bypasses are bypasses. These cannot be modeled as bypasses in StateMod and have to be modeled as releases. These will be released in the same month as the inflow. What is a C1 Baseline release? A contract delivery? The C1 Baseline release indicated in Tables 5-9 is the amount of reservoir release from the C1 data set without CROS/CROP. This title is also misleading. Please use titles which are correct to the actual operation occurring. Noted – correction will be made. We will explain the column headings in footnotes in Tables 5-9.

Appendices

The appendices must be included in the final report. Noted – correction will be made.

DRAFT
March 3, 2003

Mr. Randy Seaholm
Colorado Water Conservation Board
1313 Sherman Street, Room 719
Denver, CO 80203

Dear Randy:

The Recovery Program Director=s office and U.S. Fish and Wildlife Service (Service), Water Resources staff have reviewed the Draft Final Report for Phase 2 Coordinated Facilities Water Availability Study for the Endangered Fish of the Upper Colorado River (CFOPS). However, before commenting on the report, we wish to clarify the respective roles of the Service and the Recovery Program in the CFOPS process.

I have represented the Service on the Executive Committee, which also includes representatives of other Recovery Program participants. My role on the Committee largely has been to provide information as requested by the Executive Committee and CFOPS contractor and to remain informed as to the status of the CFOPS process. Completion of the CFOPS study and ultimately the implementation of a strategy to augment spring peak flows in the Colorado River are part of the proposed action on which the Service consulted in 1999; the product of that consultation was the Service=s programmatic biological opinion (PBO) for the Colorado River. Page 11 of the PBO identifies the purpose of the CFOPS as follows:

> *The* [CFOPS] *study is intended to assess water management facilities and operations that can be coordinated to benefit fish habitat primarily during the spring peak. The goal is for project sponsors to satisfy project purposes, but to utilize any flexibility that may exist to enhance spring flows for endangered fish. Possible options include new projects, long- and short-term leases or delivery agreements and using or moving winter water in excess of fish needs to meet water demand or fish needs during the spring. The intent is to provide an additional 20,000 acre-feet/year of water for spring peak flow enhancement, without diminishing useable project yield or causing project sponsors to incur significant costs.*

Under the PBO, the Recovery Program is responsible to ensure that certain recovery actions specified in the PBO, such as selective fish passage, Grand Valley Project water conservation measures and water leases, are implemented in a timely manner. The Recovery Program also initiated and funded the CFOPS. The PBO directs water users to Aassess water management facilities and operations@ and to augment peak flows by A[utilizing] any flexibility that may exist [in these facilities and operations] to enhance spring flows for endangered fish.@ The Service=s role in the process should not be construed as that of a decision-maker or facilitator. Once a decision is made as to whether and by what means 20,000 AF would be delivered to

enhance peak flows, the Service, in cooperation with the Recovery Program, will determine if the proposal satisfies the requirements of the PBO. Although the Service can provide technical assistance to the Executive Committee, it would be inappropriate for the Service to specify which alternative(s) should be selected for detailed analysis. .

Absent specific guidance from the study, I offer some suggestions for completing the CFOPS study process and developing an adaptive-management process to implement the best features of selected alternatives. The following suggestions should be considered only as the beginning of a negotiation process.

1) The Phase 2 Report should be finalized by the consultant, incorporating appropriate comments from the Executive Committee and the Recovery Program Water Acquisition Committee.

2) The Executive Committee is the appropriate forum for an interdisciplinary review of the study=s results and subsequent identification and formulation of an augmentation proposal. The Committee should follow an adaptive-management process similar to the current coordinated reservoir operations (CROS) process to monitor river flows and coordinate reservoir releases to augment flows. Using this model, some combination of the AShare the Pain@/Modified AShare the Pain@ and AInsurance Pool@ alternatives appear to provide the best solutions to meet short-term objectives. However, no reasonable alternative should be eliminated before the Committee has adequately assessed its individual merits and evaluated it against other options. For example, the proposal set forth by the Ray Tenney on behalf of the west slope water users appears to have merit and should be considered by the Executive Committee.

3) The Executive Committee should begin discussions and hold several work sessions to identify the most feasible alternatives or portions of these alternatives and use them as sideboards for an adaptive-management process. Once identified, an agreement should be negotiated among affected parties to implement the alternative(s) identified.

4) Any new projects (including all feasibility studies, engineering design and construction) would be funded outside the Recovery Program, similar to that which East Slope water users are carrying out on Sulfur Gulch Reservoir.

5) The Service recognizes that providing 20,000 acre-feet of water for peak augmentation will be difficult and will take a great deal of cooperation and trust, which has been demonstrated so far in the existing CROS and late summer flow augmentation efforts undertaken by the Recovery Program. We have all learned hard lessons during the current drought, which were expressed at the last Executive Committee meeting. A major concern that was not addressed in the Phase 2 Report is a situation where an above -average water year occurs after a period of drought. A situation could occur where un-augmented flows in the target range of 12,900 to 26,000 cfs would trigger peak-flow augmentation. However, reservoir operators would be reluctant to bypass inflow because reservoir levels are low due to the preceding drought. I believe that the Service would

have no problem with language in any agreement worked out to allow reservoirs to opt out of participating in peak-flow augmentation under these conditions.

6) When the Executive Committee has had an opportunity to review comments and develop a recommendation for a action, the Committee needs to present their recommendation to the Recovery Program Management Committee. The Management Committee will act as the arbiter/referee to ensure that all parties are cooperating and sharing the Apain@ equally.

In conclusion, the implementation of a peak-flow augmentation strategy is an expectation of the PBO and, as such, should be coordinated with the Recovery Program Management Committee and the Service to ensure that it meets PBO objectives. The appropriate Service contact for this purpose would be our Grand Junction Ecological Services Field Office. However, I will continue to serve as the Service liaison to the Executive Committee and we all look forward to the next phase of this process.

George Smith

Dan Luecke's Comments

Randy -- I've read the draft of the Final Phase 2 CFOPS Report. The message in this draft is loud and clear -- there are a host of options for supply 20,000 acre-feet to enhance the peak in the 15-Mile Reach except in dry years. I support the concept and think that the Modified "Share the Pain" alternative is the most sensible. In fact, I would also be willing to consider most other feasible options as possibilities, with the exception of the Webster Hill reservoir. I think I would choke on this one as would most of the environmental community.

1. OUTLET CAPACITY

All reservoirs have UNLIMITED outlet capacity in the C1 run.
Any reservoir's releases can be limited to 1 maximum outlet flow using the FLOMAX variable in the .res file.
To limit a reservoir's releases, go to the bottom of the .res file and find the info for the reservoir in question. The FLOMAX variable is the 3rd variable of the 2nd row of reservoir data. [2nd row is min storage (AF), max storage (AF), max outflow (CFS), dead storage (AF), # evap stations, # precip stations, etc.]
Change the FLOMAX variable from 0 (unlimited) to the maximum outlet capacity you desire, in CFS.

2. WOLFORD Outlet Capacity

I haven't found information in our database on Wolford's outlet capacity. I've asked the Division 5 office to provide me with any data they have and will pass that along to you.

3. WILLIAMS FORK Exchange and Substitution

It appears the the Williams Fork Exchange and Substitution accounts and rules are functioning. All 5 substitution pools exist, have correct volumes, have operational rules, and do provide water. However, they provide much less water than historically was required. Denver Water believes StateMod is underestimating the amount needed for substitution by overestimating the amount of water in/available to Green Mountain Reservoir. One reason they suspect is that the USBR filling targets for April 1, as per USBR operating policy, are in Denver's opinion overoptimistic and do not reflect actual storage operations. Therefore Green Mountain goes into every fill season more full than is realistic and needs less water during substitution years. Others factors including power releases from Green Mountain being described only through EOM contents could also play a factor (i.e. if the reservoir is already drawn down below the EOM content, that historic release for power is not made. In some cases that may be fair if during the same month, other releases were made that passed through the turbines, but in other cases there may be less power releases modeled). I'll be trying to test this issue Friday through some work with Denver, some comparison of USBR targets to historic values and by making 1 - 2 model runs and will keep you posted as to the results.

4. RIPRAP Information

Please refer to Ross Bethel's LR-2 memo for further information and some prose that might be useful to the CFOPS writeup. Hard copies of this memo were provided to you in March 1999, January 2001 and again in December 2001 so hopefully you have a hard copy available in your office. In December only the RIPRAP portion of the memo was distributed to the CFOPS executive committee, but the memo contains other useful information as well. The entire memo is available in Appendix D, section 13 of the Colorado River Basin Documentation on our web site: http://cdss.state.co.us/ftp/products/statemod/app_reports/coloupT_pdf/coloreport.pdf
Appendix C section 8 also contains detailed language about the Orchard Mesa Check Settlement and other special operations throughout the basin that might also be useful to the CFOPS final report.

I will address the RIPRAP issues in the same order they appear in the LR-2 memo.

A. Orchard Mesa Check Settlement – Reduced USA Grand Valley Power Plant summer call

To reflect the agreement to subordinate the power right in the summer, the US GVPP rights were split into two parts. The part representing the subordinated summer right was given a junior priority. These two rights replace the one original full right.

To implement this in StateMod:

Structures **950007** USA_PP-Winter-OM_Stipulation and
950008 USA_PP-Winter-OM_Stipulation represent the winter and summer rights, respectively.
They are already correctly turned on in the .dds file.

TURN ON:

Direct diversion rights **950007.01** USA_PP_Winter_OM-Stip and
950008.01 USA_PP_Summer_OM-Stip
in .ddr file, last field. #> ID Name Struct App Dat Admin# Right On/Off
This turns on the diversion rights for the GVPP according to the OM settlement.

Operational rights **7206460.10** Opr GVP-Power, winter un 30895.21241 0. **0** 950007 1 720646.05 1 0 0 11 and
7206460.11 Opr GVP-Power, summer un 99999.90010 0. **0** 950008 1 950008.01 1 0 0 11

in .opr file, 5th full field.
ID Name (empty) AdminDat.Adm# # Str On/Off Dest Id Dest Ac Sou1 Id Sou1 Ac Sou2 Id Sou2 Ac Type
This turns on the operational rules to release from Green Mountain to the power plant.
NOTE: I rechecked, and these two operational rights are OFF in every run (a,b,d,e,f,etc) in the CFOPS files Bruce sent me, so they do need to be turned on for the base run.

***TURN OFF**:*

Operational right ***7206460.05*** Opr GVP - USA Power in .opr file, 5th full field.
which releases from Green Mountain to the OLD power plant rights.
Ross also suggests turning off direct diversion right ***950002.01***, USA_POWER_PLANT, which you have already done.

B. Orchard Mesa Check Settlement – HUP pool operation

As part of the Orchard Mesa Check Settlement, it was agreed that the HUP pool would be operated to provide late summer flow augmentation to benefit the 15-Mile Reach and the Grand Valley irrigators. Operation of the HUP pool is discussed by the HUP Managing Entities and bounded by operational rule curves. If there is sufficient water, Green Mountain releases surplus water from the HUP pool to the available capacity in the Grand Valley Power Plant (replacing the subordinated power right). This water then flows into the 15-Mile Reach to help meet the USFWS flow recommendations. If the flow recommendations in the 15-Mile Reach are not being met and there is additional surplus HUP water available, Green Mountain releases water according to a Municipal Recreation contract with the cities of Grand Junction, Palisade, and Fruita. The contract allows legal protection for the release of the water, which then flows through the 15-Mile Reach.

In the model, this is handled as follows:
A separate pool is created for HUP Surplus. Water is transferred from the HUP pool to the HUP surplus pool in July. While the HUP operating rule curves could not be incorporated, there is a limit to how much water can be placed into the HUP surplus pool. Only the amount of HUP water not needed to meet the other HUP demands throughout that summer is transferred to the HUP surplus pool. Operating rules allow the HUP surplus pool to release water to the 15-Mile Reach. While the two explicit releases to the GVPP capacity and the muni rec contract are not handled separately, the total amount released to attempt to meet the flow recommendations should be reasonable.
At the end of the summer, any unused HUP surplus water is transferred back to the original HUP pool.

To implement in Statemod:

TURN ON:

Direct diversion rights — You have already turned on right **952002.01** USFWS_Recomm._Fish_Flow in the .ddr file.

Operational rights

3635430.27 Trans surplus HUP to Surplus - moves water of HUP pool in excess of HUP demands into surplus pool
3635430.28 Opr Surplus to Fish Flow - releases water from surplus pool to node 952002, USFWS Recommended Fish Flows
3635430.29 Trans Surplus fish back to HUP - moves unused surplus water at end of summer back to HUP pool

Ignore 3635430.31 Opr Surplus to reduced usfws. Throughout the model, we are using the USFWS Recommended Fish Flows at node 952002 and not using the reduced usfws demands at node 952004.

***TURN OFF**:*

Ross' memo suggests turning off Operational right 3635430.14, but I believe the corresponding rule in your C1 data set is 3635430.12, which releases water to node 952001. Now that you have changed the unnecessary node 952001 to other demands for your modeling purposes, you should continue to use operational right 3635430.12 if you need it to serve your purposes at node 952001, or leave it off if you don't need it to serve your new demands at 952001.

Ross also suggests using node 950584 and operating right 9505840.01 to model additional HUP demand beyond explicitly modeled rights. Those nodes and rights have already been removed from your data set and more demands and rights are modeled explicitly in the C1 data set you have, so you can ignore the text in the LR-2 memo regarding this issue.

C. Reduced Diversion Demands Under Grand Valley Project

Ross created two sets of structures and associated demands and rights for the Grand Valley Project. The first was the Grand Valley structure and its demands and rights based on historical record. That was the one originally turned on in the model. The second set of structures, demands, and rights relate to Reduced Irrigation Demands of the Grand Valley Project. Ross suggests turning OFF the original structure, rights, and demands (structure 950001 and right 950001.01) and turning ON the reduced demands using structure 950009 and diversion right 950009.01.
However, I believe Reduced Diversion Demands is NOT part of the agreed upon baseline for CFOPS. I also believe Bruce modeled this as part of one of the alternatives. Therefore please ignore the suggestions in the LR-2 Memo for this issue.

D. Ruedi Reservoir Endangered Fish Pool Operations

Several changes have been made to the data set at Ruedi since the LR-2 memo was written, so while the ideas are correct, the rules and rule numbers are not.
In addition, the amount of water dedicated to the USFWS from Ruedi and other reservoirs has changed. Also, modeling of the 5000 AF in 4 of 5 years was added.
Below is a summary of the fish pools for ALL participating reservoirs.

ORIGINALLY			NOW	
Ruedi	10,825 AF		Ruedi	10,825 AF
	10,825 AF	-2nd 10,825 AF responsibility now shared by E&W Slope:	Williams Fork	5,412.5 AF
			Wolford	5,412.5 AF
	5,000 AF		Ruedi	5,000 AF
	26,650 AF	lumped together in the C1 data set		
Ruedi	5,000 AF	4 of 5 years	Ruedi	5,000 AF 4 of 5 years
Wolford	5,992 AF		Wolford	5,992 AF

CURRENT TOTALS:

Ruedi	15,825 AF annually (10,825 + 5,000)	+	5000 AF 4 of 5 years
Williams Fork	5,412.5 AF annually		
Wolford	11,405 AF annually (5,992 + 5412.5)		

The C1 run contained a fish pool of 26,650 AF at Ruedi and a fish pool of 5,992 AF at Wolford. Both also had operating rules to release water from those pools to the 15-Mile Reach. In your baseline, those rules are not turned on. To model RIPRAP, they need to be turned on. However, this is a good time to alter the fish pools in the various reservoirs to reflect current agreements. Therefore I suggest the following changes to the files for the fish pools:

- Change Ruedi 26,650 AF fish pool volume to 15,825 AF and adjust other Ruedi pool volumes if necessary. Leave 5000 4/5 yr pool as currently modeled, where 2 pools are used to transfer water in and out of this intermittent pool. Turn existing rules to release from Ruedi fish pools to USFWS Recommended Flows.
- Change Wolford 5,992 AF fish pool volume to 11,405 AF to reflect both the 5,992 AF pool and the 5,412.5 pool and adjust other Wolford pool volumes if necessary. Turn on existing operating rule to release from Wolford fish pool to USFWS Recommended Flows.
- Add fish pool at Williams Fork for 5413 AF and adjust other WF pool volumes if necessary. Add operational right to release from Williams Fork fish pool to USFWS Recommended Flows.

I'LL ADD THE DETAILS FOR THIS ON THURSDAY MORNING. They'll include lists of changes to make to the .res, .rer, and .opr files.

E. Ruedi Reservoir Water Sales

Ross gives a list of 4 sets of nodes and rights for Ruedi Round 1 and 2 Water Sales for municipal and industrial purposes. All those were already turned ON in the C1 data set you received, so all of those demands are already being modeled in your CFOPS baseline. No changes are necessary.

F. Wolford Mountain Reservoir - Endangered Fish Releases

Covered under Ruedi fish release discussion.

G. USFWS/CWCB 15-Mile Reach Instream Flow Demands

Ross suggests turning ON structure 952002 and direct diversion right 952002.01, which you have already done. He suggests turning off structure 952001 and its rights, which you have done by using it for other purposes. He also suggests turning off 952003, which has already been deleted from the C1 runs as an extraneous node. No changes are necessary.

Many of the operational rules related to RIPRAP are intermittent. Examples are the transfer of water into and out of the HUP surplus pool, the releases from the fish pools only in the summer, etc. All of these operational rules have the second line with the monthly on/off switch. Bruce indicated his version of the StateMod GUI might not be reading these operational rules correctly. If that is the case, I will work with Bruce on this problem. Once he has confirmed that the GUI is not reading the files properly, I'd be happy to take one of his scenarios and run it on my machine. I have several versions of StateMod available on my machine and can run any of them using the command line in DOS, so I'd try the version closest to his first and we could go forward from there.

SUMMARY OF CHANGES TO FILES FOR REVISED CFOPS BASE RUN

- if the text says REPLACE, I have provided the old information plus corrected lines that can be substituted for the existing lines.
- if the text says CHANGE or TURN ON or TURN OFF, I show the line as it appears NOW, not as it will appear after you make the change(s).

.dds file - no changes needed

950007	USA_PP-Winter-OM_Stip	correctly on
950008	USA_PP-Summer-OM_Stip	correctly on
952001	15-MILE_FISH_REQUIREMENT	not needed for C1, being used for other purposes in the CFOPS modeling
952002	USFWS_Recomm._Fish_Flow	correctly on
952004	Reduced_USFWS_Fish_Req	extraneous node

.ddr file changes

Orchard Mesa Check Case Settlement, summertime subordination of 310 cfs USA power right.
Add winter, summer sr and summer jr rights for USA power plant using carrier structure 720646, Grand Valley Canal.
Any rights input for the structures themselves (950007.01, 950008.01) are overwritten by the operating rules which use the Grand Valley Canal carrier to serve those demands.
These new rights allow the winter diversions under the entire 800 cfs sr right, while the summer rights are split into a senior 490 and a junior (subordinated) 310 (here unlimited) as per the Check Case Settlement.

#> ID	Name	Struct	App Dat	Admin#	Right	On/Off
ADD:						
720646.08	USA_PP_Winter_OM-Stip	720646	30895.21241		800.00	1
720646.09	USA_PP_Summer_OM-Stip	720646	30895.21241		490.00	1
720646.10	USA_PP_Summer_OM-Stip	720646	100000.1000		999.00	1
TURN OFF						
720646.05	USA_POWER_PLANT	720646	30895.21241		800.00	1

Right 950002.01 already correctly turned off.
Right 952002.01 already correctly turned on.

.res file changes

RUEDI RESERVOIR

Replace the existing Ruedi information:

```
383713      RUEDI_RESERVOIR          383713             1      4.
                           0. 102373. 999999.      0.       6       1       0      14
            Rnd_1&2_Cont  24850.  21955.       0       1
            CWCB_Fish     26650.      0.       0       1
            Unalloc/Dead  17873.  17873.       0       1
            Replacement   28000.  24740.       0       1
            Unalloc/5k     5000.   5000.       0       1
            USFWS_5k_4/5   5000.      0.       0       1
            Evaporation 10006           100.
```

With this new Ruedi information:

```
383713      RUEDI_RESERVOIR          383713             1      4.
                           0. 102373. 999999.      0.       6       1       0      14
            Rnd_1&2_Cont  24850.  21955.       0       1
            Replacement   28000.  24740.       0       1
            Unalloc/Dead  28698.  28698.       0       1
            CWCB_Fish     15825.   2000.       0       1
            Unalloc/5k     5000.      0.       0       1
            USFWS_5k_4/5   5000.      0.       0       1
            Evaporation 10006           100.
```

WOLFORD MOUNTAIN RESERVOIR

Replace the existing Wolford information:

```
503668      WOLFORD_MOUNTAIN_RES     503668             1      4.
                           0.  65985. 999999.      0.       4       1       0      10
            West_Slope    35996.  25530.       0       1
            Denver1        5000.   5000.       0       1
            Denver2       18997.  12020.       0       1
            Fish_Account   5992.      0.       0       1
            Evaporation 10008           100.
```

With this new Wolford information:

```
503668      WOLFORD_MOUNTAIN_RES     503668             1      4.
                           0.  65985. 999999.      0.       5       1       0      10
            West_Slope    35996.  25530.       0       1
```

```
            Denver1        5000.   5000.       0       1
            Denver2       18997.  12020.       0       1
            Fish_Account   6000.      0.       0       1
            WM_Fish_Temp   5413.      0.       0       1
            Evaporation 10008           100.
```

WILLIAMS FORK RESERVOIR

Replace the old WF information:

```
513709      WILLIAMS FORK RESERVOIR 513709            1      4.
                          0.  96822. 999999.      0.       3       1       0      14
            Denver        84622.  59566.       0       1
            Denver_Gen1   10000.  10000.       0       1
            Henderson      2200.   2073.       0       1
            Evaporation 10008           100.
```

With this new WF information:

```
513709      WILLIAMS FORK RESERVOIR 513709            1      4.
                          0.  96822. 999999.      0.       4       1       0      14
            Denver        84622.  59566.       0       1
            Denver_Gen1   10000.  10000.       0       1
            Henderson      2200.   2073.       0       1
            WF_Fish_Temp   5413.      0.       0       1
            Evaporation 10008           100.
```

.rer file changes

RUEDI RESERVOIR

CHANGE the owner variable from -4 to a -3 to fill one less pool with Ruedi's refill right because none of the fish pools should refill.
If fish pools refill during the late summer, they overrelease to the USFWS.

```
#> ID        Name                    Struct          Admin #      Right   On/Off    Owner   Type    Fill#
```

```
383713.02   RUEDI_RESERVOIR-refill  383713          47869.00000   101280       1      -4       1       2


WOLFORD MOUNTAIN RESERVOIR

CHANGE the 5992 to 6000 AF fill right in 503668.02 to reflect corrected pool size and corrected fill right
of 6000 AF
#> ID        Name                    Struct          Admin #      Right   On/Off    Owner   Type    Fill#
503668.02   WOLFORD_MOUNTAIN_RES    503668          52976.00000     5992       1       4       1       1


CHANGE the Owner variable to -3 to not refill the 6000 AF fish pool.
#> ID        Name                    Struct          Admin #      Right   On/Off    Owner   Type    Fill#
503668.03   WOLFORD_MTN_RES-refill  503668          99999.99999    65985       1      -4       1       2

Note:  The 59993 AF fill right remains unchanged, giving them 8 AF more fill rights than decreed capacity.
Note:  Wolford obtained a separate right for the 6000 AF pool, hence the separate fill right.


WILLIAMS FORK RESERVOIR - CORRECT AS WRITTEN. No changes needed to .rer file for Williams Fork.
513709.01   WILLIAMS FORK RESERVOIR 513709          31359.00000    93637       1      -3       1       1

513709.02   WILLIAMS FORK RESERVOIR 513709          39095.38998    93637       1      -2       1       2




.opr file changes
-----------------


RUEDI RESERVOIR

CHANGE the source accounts in Ruedi's operational rights to reflect that the fish pool is now pool #4
instead of #2, and the Replacement pool is now #2 instead of #4:
#> ID        Name                    NA          AdminDat  Admin#   #Str  On/Off Dest Id       DestAc
Sou1Id      Sou1Act Sou2Id        Sou2Ac     Type
CHANGE Source 1 Account from 4 to 2:
3837130.01  Opr Ruedi exch Hunter                   39291.00001      0.       0 3815940.01         1 383713
            4 0                   0       7
3837130.02  Opr Ruedi exch Boustead                 39291.00001      0.       0 3846250.01         1 383713
            4 0                   0       7
3837130.03  Opr Ruedi exch Boustead                 48577.39292      0.       0 3846250.02         1 383713
            4 0                   0       7
```

```
3837130.04  Opr Ruedi exch Boustead                  39291.00001      0.       1 3815940.02          1 383713
            4 0                    0       7
3837130.05  Opr Ruedi exch Boustead                  39291.00001      0.       1 3846250.03          1 383713
            4 0                    0       7
3837130.06  Opr Ruedi exch Boustead                  48577.39292      0.       1 3846250.04          1 383713
            4 0                    0       7

CHANGE Source 1 Account from 2 to 4:
3837130.07  Opr Ruedi-15 Mile Fish                   99999.91001      0.       0 952001              1 383713
            2 0                    0       2
3837130.13  Opr Ruedi Res to USFWS Fish              99999.93000    -12.       0 952002              1 383713
            2 0                    0       2
                                     1 1 1 1 1 1 0 0 0 0 1 1
3837130.14  Opr Ruedi Res to Reduced USFWS           99999.93000    -12.       0 952004              1 383713
            2 0                    0       2
                                     1 1 1 1 1 1 0 0 0 0 1 1
3837130.15  Opr Ruedi add depletion                  99999.92500      0.       0 953005              1 383713
            2 0                    0       2


CHANGE On/Off Switch to 1 to TURN ON RIPRAP releases from Ruedi fish pools to USFWS:
#> ID        Name                    NA           AdminDat Admin#   #Str  On/Off Dest Id       DestAc
Sou1Id      Sou1Act Sou2Id        Sou2Ac     Type
3837130.13  Opr Ruedi Res to USFWS Fish              99999.93000    -12.       0 952002              1 383713
            2 0                    0       2
                                     1 1 1 1 1 1 0 0 0 0 1 1

3837130.16  Opr Ruedi 5k Res to USFWS Fish           99999.92800    -12.       0 952002              1 383713
            6 0                    0       2
                                     1 1 1 1 1 1 0 0 0 0 1 1

3837130.17  Trans Ruedi Unallocated to 5k Pool       99999.92000    -12.       0 383713              6 383713
            5 953006               0       6
                                     0 0 0 0 0 0 0 0 1 1 1 0

3837130.18  Trans 5k Ruedi back to unallocated       99999.92000    -12.       0 383713              5 383713
            6 0                    0       6
                                     0 0 1 0 0 0 0 0 0 0 0 0


These RIPRAP rules are not needed and are correctly turned off:
3837130.14  Opr Ruedi Res to Reduced USFWS           99999.93000    -12.       0 952004              1 383713
            2 0                    0       2
3837130.15  Opr Ruedi add depletion                  99999.92500      0.       0 953005              1 383713
            2 0                    0       2                                 1 1 1 1 1 1 0 0 0 0 1 1
```

REPLACE the second lines of 3837130.13, .14, and .16: 1 1 1 1 1 1 0 0 0 0 1 1
WITH: 1 1 1 0 0 1 1 0 0 1 1 1

This more accurately represents the late summer augmentation in July, August, September, October, and November and also allows (if there is any water left in the pools) releases in March and April to augment the 15-Mile Reach when the Grand Valley canals come online for the season and create a hole in the river.

CHANGE Struct # from -12 to 12 as type 6 operating rules require a positive value:

```
3837130.17  Trans Ruedi Unallocated to 5k Pool       99999.92000    -12.       0 383713            6 383713
            5 953006             0       6
                                    0 0 0 0 0 0 0 0 1 1 1 0

3837130.18  Trans 5k Ruedi back to unallocated       99999.92000    -12.       0 383713            5 383713
            6 0                  0       6
                                    0 0 1 0 0 0 0 0 0 0 0 0
```

WOLFORD MOUNTAIN RESERVOIR

```
#> ID        Name                    NA            AdminDat Admin#   #Str  On/Off Dest Id       DestAc
Sou1Id      Sou1Act Sou2Id        Sou2Ac     Type
```

CHANGE On/Off Switch to 1 for existing fish release rule:

```
5036680.01  Opr Wolford Mtn Res to USFWS Fish        99999.94000    -12.       0 952002            1 503668
            4 0                  0       2
                                    1 1 1 1 1 1 0 0 0 0 1 1
```

REPLACE the second line of 5036680.01 and .07: 1 1 1 1 1 1 0 0 0 0 1 1
WITH: 1 1 1 0 0 1 1 0 0 1 1 1

Leave rule 5036680.07 turned off.

ADD the following NEW OPERATING RULES to the file immediately after 5036880.07:

```
5036680.08  Transfer W Slope to temp 5413            99999.95000     12.       1 503668            5 503668
            4 0                  0       6
                                    0 0 0 0 0 0 0 0 1 0 0 0

5036680.09  Opr Wolford temp 5413 to USFWS           99999.95000    -12.       1 952002            1 503668
            5 0                  0       2
                                    1 1 1 0 0 1 1 0 0 1 1 1
```

WILLIAMS FORK RESERVOIR:

ADD the following NEW OPERATING RULES to the file immediately after 5137090.16:

```
5137090.17  Transfer WF Denver to temp 5413          99999.95000     12.       1 513709            4 513709
            1 0                  0       6
                                    0 0 0 0 0 0 0 0 1 0 0 0

5137090.18  Opr WFRes temp 5413 to USFWS             99999.95000    -12.       1 952002            1 513709
            4 0                  0       2
                                    1 1 1 0 0 1 1 0 0 1 1 1
```

GRAND VALLEY POWER PLANT:

```
#> ID        Name                    NA            AdminDat Admin#   #Str  On/Off Dest Id       DestAc
Sou1Id      Sou1Act Sou2Id        Sou2Ac     Type
REPLACE:
7206460.10  Opr GVP-Power, winter under stip         30895.21241      0.       0 950007            1
720646.05          1 0                  0      11
7206460.11  Opr GVP-Power, summer under stip         99999.90010      0.       0 950008            1
950008.01          1 0                  0      11

WITH:
7206460.10  Opr GVP-Power, winter under stip         30895.21241      0.       1 950007            1
720646.08          1 0                  0      11
7206460.11  Opr GVP-Power, summer stip sr            30895.21241      0.       1 950008            1
720646.09          1 0                  0      11
7206460.12  Opr GVP-Power, summer stip jr            99999.90010      0.       1 950008            1
720646.10          1 0                  0      11
```

This more correctly covers the split of the GVP power plant rights and references the correct water rights added to the .ddr file.

TURN OFF:

```
7206460.05  Opr GVP - USA Power                      30895.21241      0.       1 950002            1
720646.05          1 0                  0      11
```

GREEN MOUNTAIN RESERVOIR
TURN ON:

#> ID	Name	NA	AdminDat	Admin#	#Str	On/Off	Dest Id	DestAc
Sou1Id	Sou1Act	Sou2Id	Sou2Ac	Type				
3635430.27	Trans surplus HUP to Surplus Fish		48962.00002		12.	0	363543	6 363543
	1 950061	99	6					
		0 0 0 0 0 0 0 0 0 1 0 0						
3635430.28	Opr Surplus to Fish Flow		99999.95000		-12.	0	952002	1 363543
	6 0	0	2					
		1 1 1 1 1 1 0 0 0 0 1 1						
3635430.29	Trans Surplus fish back to HUP		99999.96000		-12.	0	363543	1 363543
	6 0	0	6					
		0 0 1 0 0 0 0 0 0 0 0 0						

Leave Off:

3635430.31	Opr Surplus to reduced usfws		99999.95000		-12.	0	952004	1 363543
	6 0	0	2					
		1 1 1 1 1 1 0 0 0 0 1 1						

CHANGE months of operation:

3635430.27	Trans surplus HUP to Surplus Fish		48962.00002		12.	0	363543	6 363543
	1 950061	99	6					
		0 0 0 0 0 0 0 0 0 1 0 0						
REPLACE	0 0 0 0 0 0 0 0 0 1 0 0							
WITH	0 0 0 0 0 0 0 0 1 0 0 0							
3635430.28	Opr Surplus to Fish Flow		99999.95000		-12.	0	952002	1 363543
	6 0	0	2					
		1 1 1 1 1 1 0 0 0 0 1 1						
REPLACE	1 1 1 1 1 1 0 0 0 0 1 1							
WITH	1 1 1 0 0 1 1 0 0 1 1 1							

CHANGE #Str from -12 to 12 as positive numbers are used for operating rule type 6

3635430.29	Trans Surplus fish back to HUP		99999.96000		-12.	0	363543	1 363543
	6 0	0	6					
		0 0 1 0 0 0 0 0 0 0 0 0						

Table O-1 Exchange to Dillon Reservoir as calculated by Revised StateMod and C1 Data Set

Operational Right Summary af Base Run

Name = Opr WFRes - Dillon Exch ID = 5137090.20 Admin # = 31257.99999 & 49500.00002 On(1)/Off(0) = 1

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOT
1975	7962	0	0	0	0	1222	0	0	0	0	1011	7968	18163
1976	3851	0	0	0	0	1453	0	0	0	0	5571	7960	18835
1977	5714	0	0	0	0	788	0	0	4647	8623	5363	2940	28075
1978	6979	0	0	0	0	1479	0	0	0	0	10854	6994	26306
1979	3450	0	0	0	0	1962	0	0	0	0	1011	6856	13279
1980	3472	0	0	0	0	1765	0	0	0	0	6976	6445	18658
1981	3776	0	0	0	0	592	1182	0	0	8745	7607	7258	29160
1982	3121	0	0	0	0	1067	0	0	0	0	982	5249	10419
1983	5000	877	0	0	386	3953	2593	0	0	0	1011	822	14642
1984	1007	562	155	0	0	264	306	0	0	0	1011	822	4127
1985	696	931	413	0	0	2683	0	0	0	0	1011	5187	10921
1986	3642	564	0	0	0	2803	0	0	0	0	1011	8613	16633
1987	7647	817	0	0	0	1676	0	0	0	0	10267	6012	26419
1988	2807	0	0	0	0	1647	0	0	0	0	10809	5528	20791
1989	3080	0	0	0	0	1653	0	0	0	0	10012	4977	19722
1990	2543	0	0	0	0	1839	0	0	0	0	11120	5934	21436
1991	5298	0	0	0	0	1339	0	0	0	0	5882	7221	19740
AVG	4120	221	33	0	23	1658	240	0	273	1022	5383	5693	18666

Table O-2 Exchange to Dillon Reservoir as calculated by Revised StateMod and C1 Data Set with 110kAF of Additional Future Demand

Operational Right Summary af Base Run + 110k

Name = Opr WFRes - Dillon Exch ID = 5137090.20 Admin # = 31257.99999 & 49500.00002 On(1)/Off(0) = 1

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOT
1975	7962	0	0	0	0	1222	0	0	0	0	980	8876	19040
1976	3851	0	0	0	0	1453	0	0	0	0	15911	7960	29175
1977	5714	0	0	0	0	788	0	0	0	7333	5363	2940	22138
1978	6979	0	0	0	0	1479	0	0	0	0	0	6994	15452
1979	3450	0	0	0	0	1962	0	0	0	0	0	6856	12268
1980	3472	0	0	0	0	1765	0	0	0	0	7131	6445	18813
1981	3776	0	0	0	0	592	1280	0	0	0	7607	7258	20513
1982	5149	0	0	0	0	1067	0	0	0	0	1921	10756	18893
1983	7271	877	0	0	386	3953	3700	0	0	0	1011	822	18020
1984	7699	443	155	0	0	2614	0	0	0	0	1011	822	12744
1985	696	444	413	0	0	2684	0	0	0	0	1011	5386	10634
1986	4234	564	0	0	0	2803	0	0	0	0	1011	8613	17225
1987	7647	817	0	0	0	1676	0	0	0	6326	11176	6015	33657
1988	2807	0	0	0	0	1647	0	0	0	0	11147	5531	21132
1989	3080	0	0	0	0	1653	0	0	0	14171	12101	4980	35985
1990	2543	0	0	0	0	1839	0	0	0	4443	11124	5937	25886
1991	5298	0	0	0	0	1339	0	0	0	3338	11451	7422	28848
AVG	4802	185	33	0	23	1796	293	0	0	2095	5880	6095	21202

Denver Water's 58,000 AF/year of additional demand on the Roberts Tunnel is included in the 110kAF demand

Table O-3 Exchange to Dillon Reservoir as calculated by Denver Water's PACSIM with 58,000 AF of additional Roberts Tunnel demand for Denver Water.

BASELINE 316.2 DEM 30 CFS CHAT PMP TO MAR AUG- MAR 12.2 CFS CITY DTCH RT
Exchange Inflow

WATER YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	MINIMUM	TOTAL
1975	3,734	1,600	1,050	835	645	534	0	0	0	0	2,868	6,939	0	18,204
1976	3,444	1,414	662	909	644	507	0	0	0	219	7,302	6,972	0	22,073
1977	**5,657**	**1,691**	**433**	**485**	**453**	**587**	**1,051**	**242**	**3,425**	**7,325**	**4,308**	**2,471**	**242**	**28,128**
1978	4,471	1,273	1,677	1,171	686	958	0	0	0	0	7,647	5,542	0	23,425
1979	3,465	1,286	1,113	1,247	1,030	1,419	534	0	0	0	4,148	5,400	0	19,643
1980	3,538	2,465	1,115	2,219	1,410	727	0	0	0	336	7,795	5,943	0	25,549
1981	**3,576**	**1,610**	**1,033**	**381**	**348**	**485**	**1,534**	**423**	**226**	**4,271**	**5,940**	**5,848**	**226**	**25,676**
1982	2,611	678	547	753	328	954	1,162	0	0	0	2,209	7,871	0	17,113
1983	6,116	2,562	2,164	2,100	3,177	1,893	0	0	0	0	0	3,655	0	21,667
1984	5,265	2,894	2,192	2,242	749	144	0	0	0	0	0	0	0	13,485
1985	115	0	8	658	1,216	651	0	0	0	0	3,377	5,896	0	11,921
1986	3,398	1,349	2,104	2,176	1,462	0	0	0	0	0	3,259	6,462	0	20,211
1987	5,152	1,594	1,580	1,682	1,543	1,661	569	0	0	5,117	9,025	5,367	0	33,291
1988	3,119	2,042	1,812	2,634	1,581	1,379	0	0	0	5,202	9,921	4,592	0	32,281
1989	3,122	1,684	724	701	771	966	554	0	0	4,549	8,220	5,247	0	26,539
1990	2,957	1,528	1,893	1,149	841	1,958	3,374	1,638	0	3,782	8,242	5,850	0	33,211
1991	5,666	2,562	1,089	909	773	1,621	1,989	1,002	0	411	9,067	6,660	0	31,750
VERAGE:	3,847	1,661	1,247	1,309	1,039	967	633	194	215	1,836	5,490	5,336	28	23,774
INIMUM:	115	0	8	381	328	0	0	0	0	0	0	0	0	11,921
AXIMUM:	6,116	2,894	2,192	2,634	3,177	1,958	3,374	1,638	3,425	7,325	9,921	7,871	242	33,291

NOTE:

The sum of the Critical Period (August 1953 - April 1957) is 84,766 AcFt

Table O-4
Comparison of Estimated Exchange to Dillon Reservoir and Calculated by:

1) StateMOD/C1
2) StateMOD/C1 with additional 110kAF of Demand
3) Denver's PACSIM

Month	Year	Date	Revised Base	Revised Base + 110k	Denver's PACSIM
OCT	1975	10/1/1974	7962	7962	3734
NOV	1975	11/1/1974	0	0	1599.8
DEC	1975	12/1/1974	0	0	1049.8
JAN	1975	1/1/1975	0	0	834.8
FEB	1975	2/1/1975	0	0	644.9
MAR	1975	3/1/1975	1222	1222	534.3
APR	1975	4/1/1975	0	0	0
MAY	1975	5/1/1975	0	0	0
JUN	1975	6/1/1975	0	0	0
JUL	1975	7/1/1975	0	0	0
AUG	1975	8/1/1975	1011	980	2867.9
SEP	1975	9/1/1975	7968	8876	6938.5
OCT	1976	10/1/1975	3851	3851	3443.6
NOV	1976	11/1/1975	0	0	1414.2
DEC	1976	12/1/1975	0	0	662.4
JAN	1976	1/1/1976	0	0	909.4
FEB	1976	2/1/1976	0	0	643.9
MAR	1976	3/1/1976	1453	1453	507.1
APR	1976	4/1/1976	0	0	0
MAY	1976	5/1/1976	0	0	0
JUN	1976	6/1/1976	0	0	0
JUL	1976	7/1/1976	0	0	218.8
AUG	1976	8/1/1976	5571	15911	7301.8
SEP	1976	9/1/1976	7960	7960	6972
OCT	1977	10/1/1976	5714	5714	5657
NOV	1977	11/1/1976	0	0	1691.3
DEC	1977	12/1/1976	0	0	432.7
JAN	1977	1/1/1977	0	0	484.8
FEB	1977	2/1/1977	0	0	452.6
MAR	1977	3/1/1977	788	788	587.4
APR	1977	4/1/1977	0	0	1050.9
MAY	1977	5/1/1977	0	0	242.2
JUN	1977	6/1/1977	4647	0	3425.2
JUL	1977	7/1/1977	8623	7333	7325
AUG	1977	8/1/1977	5363	5363	4308
SEP	1977	9/1/1977	2940	2940	2470.8
OCT	1978	10/1/1977	6979	6979	4470.5
NOV	1978	11/1/1977	0	0	1273.3
DEC	1978	12/1/1977	0	0	1676.5
JAN	1978	1/1/1978	0	0	1170.7
FEB	1978	2/1/1978	0	0	686.4
MAR	1978	3/1/1978	1479	1479	958.2
APR	1978	4/1/1978	0	0	0
MAY	1978	5/1/1978	0	0	0

Table O-4
Comparison of Estimated Exchange to Dillon Reservoir and Calculated by:

1) StateMOD/C1
2) StateMOD/C1 with additional 110kAF of Demand
3) Denver's PACSIM

Month	Year	Date	Revised Base	Revised Base + 110k	Denver's PACSIM
JUN	1978	6/1/1978	0	0	0
JUL	1978	7/1/1978	0	0	0
AUG	1978	8/1/1978	10854	0	7647.3
SEP	1978	9/1/1978	6994	6994	5542.1
OCT	1979	10/1/1978	3450	3450	3465.1
NOV	1979	11/1/1978	0	0	1286.2
DEC	1979	12/1/1978	0	0	1113
JAN	1979	1/1/1979	0	0	1247
FEB	1979	2/1/1979	0	0	1029.8
MAR	1979	3/1/1979	1962	1962	1419.4
APR	1979	4/1/1979	0	0	534.4
MAY	1979	5/1/1979	0	0	0
JUN	1979	6/1/1979	0	0	0
JUL	1979	7/1/1979	0	0	0
AUG	1979	8/1/1979	1011	0	4147.5
SEP	1979	9/1/1979	6856	6856	5400.1
OCT	1980	10/1/1979	3472	3472	3538.1
NOV	1980	11/1/1979	0	0	2465.3
DEC	1980	12/1/1979	0	0	1115
JAN	1980	1/1/1980	0	0	2219
FEB	1980	2/1/1980	0	0	1410.1
MAR	1980	3/1/1980	1765	1765	726.7
APR	1980	4/1/1980	0	0	0
MAY	1980	5/1/1980	0	0	0
JUN	1980	6/1/1980	0	0	0
JUL	1980	7/1/1980	0	0	336.1
AUG	1980	8/1/1980	6976	7131	7795.4
SEP	1980	9/1/1980	6445	6445	5942.9
OCT	1981	10/1/1980	3776	3776	3576.2
NOV	1981	11/1/1980	0	0	1609.7
DEC	1981	12/1/1980	0	0	1033.1
JAN	1981	1/1/1981	0	0	381
FEB	1981	2/1/1981	0	0	347.7
MAR	1981	3/1/1981	592	592	485.3
APR	1981	4/1/1981	1182	1280	1533.8
MAY	1981	5/1/1981	0	0	423.1
JUN	1981	6/1/1981	0	0	226.3
JUL	1981	7/1/1981	8745	0	4271.4
AUG	1981	8/1/1981	7607	7607	5940
SEP	1981	9/1/1981	7258	7258	5848.3
OCT	1982	10/1/1981	3121	5149	2610.5
NOV	1982	11/1/1981	0	0	677.8
DEC	1982	12/1/1981	0	0	547.4
JAN	1982	1/1/1982	0	0	752.6

Table O-4
Comparison of Estimated Exchange to Dillon Reservoir and Calculated by:

1) StateMOD/C1
2) StateMOD/C1 with additional 110kAF of Demand
3) Denver's PACSIM

Month	Year	Date	Revised Base	Revised Base + 110k	Denver's PACSIM
FEB	1982	2/1/1982	0	0	327.5
MAR	1982	3/1/1982	1067	1067	954.4
APR	1982	4/1/1982	0	0	1161.8
MAY	1982	5/1/1982	0	0	0
JUN	1982	6/1/1982	0	0	0
JUL	1982	7/1/1982	0	0	0
AUG	1982	8/1/1982	982	1921	2209.2
SEP	1982	9/1/1982	5249	10756	7871.3
OCT	1983	10/1/1982	5000	7271	6116
NOV	1983	11/1/1982	877	877	2562.4
DEC	1983	12/1/1982	0	0	2164.4
JAN	1983	1/1/1983	0	0	2100.3
FEB	1983	2/1/1983	386	386	3176.6
MAR	1983	3/1/1983	3953	3953	1892.5
APR	1983	4/1/1983	2593	3700	0
MAY	1983	5/1/1983	0	0	0
JUN	1983	6/1/1983	0	0	0
JUL	1983	7/1/1983	0	0	0
AUG	1983	8/1/1983	1011	1011	0
SEP	1983	9/1/1983	822	822	3654.8
OCT	1984	10/1/1983	1007	7699	5264.5
NOV	1984	11/1/1983	562	443	2893.5
DEC	1984	12/1/1983	155	155	2192.4
JAN	1984	1/1/1984	0	0	2241.5
FEB	1984	2/1/1984	0	0	748.9
MAR	1984	3/1/1984	264	2614	144.4
APR	1984	4/1/1984	306	0	0
MAY	1984	5/1/1984	0	0	0
JUN	1984	6/1/1984	0	0	0
JUL	1984	7/1/1984	0	0	0
AUG	1984	8/1/1984	1011	1011	0
SEP	1984	9/1/1984	822	822	0
OCT	1985	10/1/1984	696	696	115.3
NOV	1985	11/1/1984	931	444	0
DEC	1985	12/1/1984	413	413	7.9
JAN	1985	1/1/1985	0	0	658.2
FEB	1985	2/1/1985	0	0	1216.2
MAR	1985	3/1/1985	2683	2684	650.6
APR	1985	4/1/1985	0	0	0
MAY	1985	5/1/1985	0	0	0
JUN	1985	6/1/1985	0	0	0
JUL	1985	7/1/1985	0	0	0
AUG	1985	8/1/1985	1011	1011	3376.6
SEP	1985	9/1/1985	5187	5386	5896.1

Table O-4
Comparison of Estimated Exchange to Dillon Reservoir and Calculated by:

1) StateMOD/C1
2) StateMOD/C1 with additional 110kAF of Demand
3) Denver's PACSIM

Month	Year	Date	Revised Base	Revised Base + 110k	Denver's PACSIM
OCT	1986	10/1/1985	3642	4234	3398.4
NOV	1986	11/1/1985	564	564	1349.2
DEC	1986	12/1/1985	0	0	2104.4
JAN	1986	1/1/1986	0	0	2175.6
FEB	1986	2/1/1986	0	0	1461.9
MAR	1986	3/1/1986	2803	2803	0
APR	1986	4/1/1986	0	0	0
MAY	1986	5/1/1986	0	0	0
JUN	1986	6/1/1986	0	0	0
JUL	1986	7/1/1986	0	0	0
AUG	1986	8/1/1986	1011	1011	3259.3
SEP	1986	9/1/1986	8613	8613	6462.3
OCT	1987	10/1/1986	7647	7647	5152.3
NOV	1987	11/1/1986	817	817	1594.2
DEC	1987	12/1/1986	0	0	1580.1
JAN	1987	1/1/1987	0	0	1682.2
FEB	1987	2/1/1987	0	0	1543
MAR	1987	3/1/1987	1676	1676	1660.8
APR	1987	4/1/1987	0	0	569.4
MAY	1987	5/1/1987	0	0	0
JUN	1987	6/1/1987	0	0	0
JUL	1987	7/1/1987	0	6326	5117.3
AUG	1987	8/1/1987	10267	11176	9024.9
SEP	1987	9/1/1987	6012	6015	5366.6
OCT	1988	10/1/1987	2807	2807	3118.8
NOV	1988	11/1/1987	0	0	2042.3
DEC	1988	12/1/1987	0	0	1811.5
JAN	1988	1/1/1988	0	0	2633.6
FEB	1988	2/1/1988	0	0	1581.3
MAR	1988	3/1/1988	1647	1647	1378.8
APR	1988	4/1/1988	0	0	0
MAY	1988	5/1/1988	0	0	0
JUN	1988	6/1/1988	0	0	0
JUL	1988	7/1/1988	0	0	5201.6
AUG	1988	8/1/1988	10809	11147	9920.5
SEP	1988	9/1/1988	5528	5531	4592.4
OCT	1989	10/1/1988	3080	3080	3122.4
NOV	1989	11/1/1988	0	0	1683.7
DEC	1989	12/1/1988	0	0	724.1
JAN	1989	1/1/1989	0	0	701
FEB	1989	2/1/1989	0	0	771.4
MAR	1989	3/1/1989	1653	1653	965.8
APR	1989	4/1/1989	0	0	554.2
MAY	1989	5/1/1989	0	0	0

Table O-4
Comparison of Estimated Exchange to Dillon Reservoir and Calculated by:

1) StateMOD/C1
2) StateMOD/C1 with additional 110kAF of Demand
3) Denver's PACSIM

Month	Year	Date	Revised Base	Revised Base + 110k	Denver's PACSIM
JUN	1989	6/1/1989	0	0	0
JUL	1989	7/1/1989	0	14171	4549.4
AUG	1989	8/1/1989	10012	12101	8219.8
SEP	1989	9/1/1989	4977	4980	5247
OCT	1990	10/1/1989	2543	2543	2956.5
NOV	1990	11/1/1989	0	0	1528.1
DEC	1990	12/1/1989	0	0	1892.8
JAN	1990	1/1/1990	0	0	1148.6
FEB	1990	2/1/1990	0	0	841.4
MAR	1990	3/1/1990	1839	1839	1958.4
APR	1990	4/1/1990	0	0	3373.7
MAY	1990	5/1/1990	0	0	1637.9
JUN	1990	6/1/1990	0	0	0
JUL	1990	7/1/1990	0	4443	3781.6
AUG	1990	8/1/1990	11120	11124	8241.8
SEP	1990	9/1/1990	5934	5937	5850.4
OCT	1991	10/1/1990	5298	5298	5665.8
NOV	1991	11/1/1990	0	0	2562.4
DEC	1991	12/1/1990	0	0	1089.1
JAN	1991	1/1/1991	0	0	908.9
FEB	1991	2/1/1991	0	0	773.3
MAR	1991	3/1/1991	1339	1339	1621.3
APR	1991	4/1/1991	0	0	1989.3
MAY	1991	5/1/1991	0	0	1001.9
JUN	1991	6/1/1991	0	0	0
JUL	1991	7/1/1991	0	3338	411.3
AUG	1991	8/1/1991	5882	11451	9067
SEP	1991	9/1/1991	7221	7422	6660.1