White River Basin, Arkansas, Minimum Flows
Project Report

Economics

APPENDIX A

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1. INTRODUCTION

1.1 <u>General</u>. The Federal objective of water and related land resources project planning is to contribute to National Economic Development (NED) consistent with protecting the nation's environment. To that end, this Appendix addresses the NED contributions of potential alternatives to maintain the minimum flows to improve trout fishing on the White and North Fork Rivers. This is a significant difference from the draft economic appendix from the White River Minimum Flow, Reallocation Study, Arkansas and Missouri, July 2004, which examined the NED contributions of improved trout fishing on the White, North Fork, and Little Red Rivers. The current economic appendix and the 2004 draft economic appendices differ in that the 2004 appendix examined five lakes, and this appendix will only examine the two lakes that were authorized for implementation of minimum flows in the Energy and Water Development Appropriations Act of 2006. NED contributions are defined as "increases in the net value of the national output of goods and services, expressed in monetary units. Contributions to NED are the direct net benefits that accrue in the planning area and the rest of the nation. Contributions to NED include increases in the net value of those goods and services that are marketed, and also those that might not be marketed." (*Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies,* p. 1, March 1983.)

1.2 <u>Study Constraints and Assumptions</u>.

- All NED costs and benefits are expressed in FY 2009 price levels;
- Resources have alternative uses and, consequently, opportunity costs;
- Individuals are risk neutral and rational economic agents;
- The project life and period of analysis is 50 years with the appropriate operation, maintenance, replacements, and interest during construction; and
- The project interest rate used to discount future NED benefits and costs is 4.625 percent with a project base year of 2010.

2. EXISTING CONDITIONS

2.1 <u>Location</u>. Bull Shoals and Norfork Lakes and their tailwater trout habitat are located in north central Arkansas in the heart of the Ozarks.

2.2 <u>Existing Projects</u>. The existing lake projects were authorized by the Flood Control Act of 1938. The Bull Shoals and Norfork authorizations were amended by the Flood Control Act of 1954. Table A-1 displays some of the pertinent characteristics of the existing projects.

TABLE A-1 EXISTING LAKE CHARACTERISTICS				
Lake	**Year Completed[1]**	**Surface Acres[2]**	**Shoreline in Miles[3]**	**Project Purposes**
Bull Shoals	1951	45,400	740	FC,R,HP,RP,O
Norfork	1944	22,000	380	FC,R,HP,RP,O
FC = Flood Control HP = Hydropower R = Recreation RP = Mitigation and Public Use O= Other Beneficial Purposes 1 Based on completion of main dam. 2 & 3 are referenced to top of the conservation pool.				

Table A-2 shows the most recent accounting of project benefits for the two multipurpose lakes.

TABLE A-2 PROJECT BENEFITS – 2008				
Lake	**Flood Damages Prevented[1]**	**Recreation Visitors[2]**	**Water Supply[3]**	**Hydropower Generation[4]**
Bull Shoals	$189,983,600	3,028,080	880	518,284
Norfork	$59,373,000	1,423,857	2,400	184,000
1 Cumulative damages prevented through FY 2008 in 2008 dollars 2 FY 2008 recreation visitation data 3 Acre-feet storage allocation with an estimated additional 19,200 acre-feet allocation pending for all reservoirs, FY 2008 4 FY08 generation (MWh)				

3. AUTHORIZATION

3.1 Legislation. Studies for the White River Minimum Flows Project were originally authorized by Section 374 of the Water Resources Development Act of 1999 (WRDA 1999), and Section 304 of WRDA 2000. Simply stated, the U.S. Army Corps of Engineers was directed to provide minimum flows subject to the following principles "... that the work is technically sound, environmentally acceptable, and economically justified." This direction resulted in the White River Minimum Flow, Reallocation Study, Arkansas and Missouri, July 2004. Section 132 of the Energy and Water Development Appropriations Act of 2006 authorized and directed the Secretary to implement alternatives BS-3 and NF-7 of the aforementioned report and repealed the Section 374 of WRDA 1999 and Section 304 of WRDA 2000.

3.2 Problems and Opportunities. The White River Basin, Arkansas, Minimum Flows Project examines both the beneficial and the adverse effects that could result from reallocating storage in Bull Shoals and Norfork lakes to maintain minimum flows for the purpose of improving tailwater trout fishing. In order to accomplish the maintenance of tailwater flow, existing reservoir storage allocations must be altered. Storage allocations studied were:

- 3.5 feet in Norfork Lake,
- 5 feet in Bull Shoals Lake

The stored water currently allocated to other uses (see Table A-1) would be reallocated for the Minimum Flows Project and released during periods when hydropower is not being generated and floodwater releases are not being made. In order to meet the technical, environmental, and economic legislative mandates, detailed evaluations must be made of existing operational parameters to define beneficial and adverse effects of any change in operation of the reservoirs.

4. METHODOLOGY

4.1 **<u>Evaluation Parameters</u>**. The following paragraphs briefly describe the various effect categories and individual parameters.

4.2 **<u>Lake Operations and Flood Control</u>**. The two lakes under examination are operated under individual and system-wide regulation plans. To that end, almost forty years ago the Southwestern Division, U. S. Army Corps of Engineers began developing a computer modeling system known as SUPER, a simulation model that currently operates on 64 years of record (1940-2003). In its purest form, the model is a historical simulation of what has happened in the basin over the period of record of the reservoirs. Details of the SUPER model and other pertinent hydraulic and hydrologic information are presented in APPENDIX B of the Project Report.

The SUPER model performs the following functions.

- Evaluate flood control, recreation, and hydropower effects due to alternative regulation plans for multiple and individual lakes;
- Evaluate the effects caused by deviations from existing regulation plans;
- Evaluate risk in emergency situations;
- Hydrologic analysis and economic screening of storage reallocations at existing lakes; and
- Determination of critical data for evaluating hydropower.

A water-accounting algorithm was added to the SUPER Model to track the daily "fishwater" (Target) releases and remaining "fishwater" storage volume. The algorithm allows for fishwater releases to be halted when the allocated storage is depleted, and to be resumed when the increased inflows recharge the target "fish" storage, see APPENDIX B of the Project Report.

4.3 **<u>Hydroelectric Power</u>**. The analysis of hydropower effects was performed by the Southwestern Power Administration, in accordance with Sections 132(a)(3) and 132(a)(4) of the Energy and Water Development Appropriations Act of 2006. SWPA’s report, "White River Minimum Flows Study, Determination of Offset to the Federal Hydropower Purpose and Impacts on Non-Federal Project", dated June 2008 is presented as APPENDIX C of the Project Report. Briefly, the report describes the relevant hydropower characteristics including:

- Energy and Capacity Losses,
- Replacement Costs,
- Additional Losses, i.e. Increased Maintenance, Carbon Dioxide Tax, etc., and
- Operational Considerations.

4.4 **<u>Tailwater Recreation</u>**. The evaluation of tailwater recreation benefits was performed by means of a contingent value method (CVM) analysis. The original "willingness to pay" evaluation contained an "existence value", which is a non-use value attributed merely to the existence, in this case, of enhanced trout fishing. Non-use values are not in accordance with current Corps policy. ATTACHMENT 1 to this Appendix displays the procedures to remove existence value from the CVM analysis.

4.5 Plan for Economic Updates. The White River Basin, Arkansas, Minimum Flows Project may require an economic update if implementation of the recommended plan does not occur expeditiously. In this event the economics of the study could be updated using sampling and limited indexing. Monitoring of the study area could be used to determine if the tailwater is still being utilized for trout fishing and a determination could be presented as to the robustness of the use relative to when the study was originally done. Sampling of the study area could also be done. Survey responses could collected and analyzed to determine if a commensurate willingness to pay still exists within the confines of the project. This data plus the existing spreadsheet analysis should be sufficient for any economic update.

5. TROUT FISHING

5.1 Historical Significance. Although trout habitat in the White River Basin exists in numerous spring-fed tributaries to Table Rock and Bull Shoals Lakes, tailwater areas provide the bulk of the trout fishing and the best year round quality. There are approximately 66 miles of tailwater trout habitat on the White River – below Bull Shoals Lake. An additional 29 miles of tailwater trout habitat are located on the North Fork and White Rivers below Norfork Lake. The tailwater trout fisheries date back to the stocking of rainbow trout in 1948. In addition to rainbow, there are cutthroat, brook, and brown trout. The current record for a brown trout on the North Fork tailwater is over 35 pounds. The record brown on the White River is in excess of 33 pounds with rainbows in the 19-pound range and cutthroats in excess of 9 pounds.

5.2 Anecdotal Evidence. Trout fishing, primarily fly fishing, has long been associated with western, northeastern, and mountain states. However, habitat creation, stocking programs, and ultra-light spinning tackle have spurred a wider geographic interest in trout fishing, especially in the south/southeast.

According to the Oregon Department of Fish and Wildlife, April 9,1996 – "...last national survey of fishing and hunting, trout fishing attracted 9.1 million freshwater anglers on 81 million activity days in 1991. This makes trout fishing second in importance to warm water fishing."

In an untitled press release, the U. S. Fish and Wildlife Service estimated southeast direct trout fishing expenditures at more than $107 million per year. These relatively recent trout fishing areas are due to stocking at dams of the U. S. Army Corps of Engineers and Tennessee Valley Authority that have converted the warm water fisheries to cold-water fisheries.

An Associated Press posting of June 14, 2003 compares Kentucky's burgeoning trout fishing to the "good old days" by saying there is no comparison. Kentucky has no native trout population. Trout anglers ante up $10 dollars per year for the permit to fish for stocked trout.

It is important to note that although anecdotal expressions can give a feel for economic effects associated with trout fishing, they are not necessarily NED benefits.

5.3 <u>Government Studies</u>. Though not meeting the test of NED benefit quantification, an August 2001 study by the U. S. Fish and Wildlife Service, "Economic Effects of Trout Production by National Fish Hatcheries in the Southeast," identified several characteristics of Arkansas trout anglers. Based on 1995 data, there were 140,000 trout permit holders. Furthermore, they estimated 4.2 trout angling days per angler with a per day expenditure of $28.07.

An addendum to the 1996 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation by the U. S. Fish and Wildlife Service dated August 1998 presented an analysis titled, "1996 Net Economic Values for Bass, Trout and Walleye Fishing, Deer, Elk and Moose Hunting, and Wildlife Watching." Although the trout state species designation consisted of the extreme northeast and the western one-third of the United States, the study was based on "consumer willingness to pay" and employed a contingent value bidding procedure. Net economic values ranged from a low of $6 per angler day to a high of $38 per angler day in Alaska.

Though not the recommended procedure, the unit day values for specialized fishing and hunting for fiscal year 2008 are presented in Economic Guidance Memorandum 08-02. There are eleven point categories ranging from zero to 100 points with increasing unit day values. The unit day values range from a minimum of $23.81 to a maximum of $40.38. These values have not been published yet for fiscal year 2009.

5.4 <u>White River Contingent Value Method</u>. Engineer Regulation (ER) 1105-2-100, referred to as "the planning guidance notebook," specifically defines the analytical method of estimating NED recreation benefits. The benefit is measured as the willingness of the consumer to pay. This willingness to pay includes any entry or use fees actually paid for site use plus any unpaid value (consumer surplus) enjoyed by the consumer. Since most recreation is publicly provided, it is not possible to estimate demand directly from observed price-consumption data. There are three Corps methodologies for evaluating recreation benefits. The Unit Day Value (UDV) is the least suitable in that "expert" judgment is used to estimate willingness to pay. The Travel Cost Method (TCM) uses the cost of travel and the value of time as proxies for price in the creation of the demand curve. Finally, the Contingent Valuation Method (CVM) uses surveys to directly ask households their willingness to pay for changes in recreation opportunities at a given site. CVM Analysis was used to conduct the study effort for the White River Minimum Flow, Reallocation Study, Arkansas and Missouri, July 2004.

5.4.1 <u>Relevant Range.</u> The contingent value literature describes a concept called part-whole bias. This bias arises when survey respondents have difficulty valuing the good the same way depending on whether the good is presented as an individual good or as part of a set of choices. In this study, sample members are asked to value the benefit of increasing minimum flows at a specific dam. Their responses, however, may instead represent their actual valuation of increasing minimum flows at all dams across the State, or of improving trout fishery in any way. Table A-3 displays two sets of aggregated willingness to pay values – the lower and upper bound. The first set of values assumes the survey respondents based their values on a valuation of improvement to only one of the projects. These values would represent a lower bound of the benefit. The second set of values assumes the survey respondents based their values on a valuation of improvements at both projects. Therefore, the benefits would be extended to both lakes within the study area. A value at one lake would be equal to the value at another lake. These values would represent an upper bound to the benefit.

TABLE A-3 LOWER – UPPER BOUND CONTINGENT VALUE		
Trout Permit Holder Benefits	**Lower Bound**	**Upper Bound**
-Study Area (17 Counties)		
-Resident Trout Permit Holders	$ 257,442	$ 391,837
-Non-Resident Trout Permit Holders	$ 10,808	$ 12,387
-Remaining Resident Trout Permit Holders	$ 697,712	$ 697,712
-Remaining Non-Resident Trout Permit Holders	$ 656,477	$ 656,477
Total Trout Permit Holders	$ 1,622,439	$ 1,758,413
NEW- Use Benefits		
-Study Area (17 Counties)		
-Resident Non-Trout Permit Holders	$ 57,597	$ 110,251
-Non-Resident Non-Trout Permit Holders	$ 19,047	$ 23,407
-Remaining Resident Non- Trout Permit Holders	$ 1,473,154	$ 1,473,154
Total New-Use Benefits	$ 1,549,798	$ 1,606,812
TOTAL BENEFITS	$ 3,172,237	$ 3,365,225

5.4.2 <u>Diminishing Returns.</u> Implementing Minimum Flows to the Bull Shoals and Norfork project sites will likely yield benefits at each project. To what degree then will benefits be experienced after the first project is implemented, as well as each succeeding project? Table A-4 and Table A-5 below display the diminishing returns to project benefits for the lower and upper bound values.

TABLE A-4 PROJECT BENEFITS DIMINISHING RETURNS							
	Part-Whole Bias – Lower Bound Diminishing Returns Range 100% - 0% per Successive Project Implemented						
Project	**100 %**	**75 %**	**67 %**	**50 %**	**33 %**	**25 %**	**0 %**
1st	$ 64,277,455	$ 64,277,455	$ 64,277,455	$ 64,277,455	$ 64,277,455	$ 64,277,455	$ 64,277,455
2nd	64,277,455	48,208,091	43,065,895	32,138,727	21,211,560	16,069,364	-
Total	$128,554,909	$112,485,546	$107,343,349	$ 96,416,182	$ 85,489,015	$ 80,346,818	$ 64,277,455

TABLE A-5 PROJECT BENEFITS DIMINISHING RETURNS							
	Part-Whole Bias – Upper Bound Diminishing Returns Range 100% - 0% per Successive Project Implemented						
Project	**100 %**	**75 %**	**67 %**	**50 %**	**33 %**	**25 %**	**0 %**
1st	$ 68,187,874	$ 68,187,874	$ 68,187,874	$ 68,187,874	$ 68,187,874	$ 68,187,874	$ 68,187,874
2nd	68,187,874	51,140,906	45,685,876	34,093,937	22,501,999	17,046,969	-
Total	$136,375,749	$119,328,780	$113,873,750	$102,281,811	$ 90,689,873	$ 85,234,843	$ 68,187,874

Using the lower bound and assuming a 50% decrease for each succeeding project, we would experience total benefits of $96,416,182.

5.5 NED Tailwater Recreation Benefit. Based on the data presented in the forgoing Tables, what is the relevant benefit? Economic theory, the law of diminishing returns, rules out the largest values. Clearly, the smallest values are not relevant. The $96,416,182 value for total benefits was chosen. This value is conservative in that it represents the lower bound value, in regards to part-whole bias, and accounts for a substantial, 50%, diminishing returns to project benefits. The average annual equivalent benefit expected, when amortized over a 50-year period at 4.625%, is approximately $4,978,400.

5.6 Benefit Allocation. Since the CVM focused only on Bull Shoals Lake, it was necessary to allocate the benefits to Norfork Lake. This was accomplished by assigning the aggregate benefit according to the miles of downstream trout fishery. The trout stream miles below Bull Shoals and Norfork Lakes are shared and were computed by splitting the river miles below the confluence of the North Fork and White Rivers. Table A-6 below displays the miles of tailwater, the percentage allocation applied, and the average annual benefit.

TABLE A-6 BENEFIT ALLOCATION			
Project	**Downstream Trout Fishery Miles**	**Percent of Total Fishery**	**Benefits**
Bull Shoals Lake	66	0.695	3,458,678
Norfork Lake	29	0.305	1,519,722
Total	95	1.000	$ 4,978,400

6. SUPER MODEL

6.1 Hydrology and Hydraulics. Details of the hydrologic modeling are described in APPENDIX C of the Project Report. However, some discussion of the intersection of hydrologic data and the determination of economic effects is necessary. The following paragraphs discuss the operation of SUPER with respect to the evaluation of alternative plans to the current storage allocations and lake operations. The details of the alternative SUPER model runs in Excel format are shown in ATTACHMENT 2 to this Appendix. The data are also incorporated in ATTACHMENT 3 describing the alternative plan benefit-cost summary.

6.2 Existing Condition. The existing condition provides the baseline parameters by which the alternatives are evaluated. SUPER provides a hydrologic history of the daily life of the controlled segment of the White River. There are 18 downstream flood damage reaches, five reservoir flood damage areas, five reservoir recreation benefit areas, and the five-hydropower generation areas. The data represent the model results of the comparison of the existing condition and the proposed alternative withdrawals from the conservation pool, flood pool, or a 50/50 combination (see ATTACHMENT 2).

6.2.1 Downstream Flood Damages. Downstream flood damages occur primarily to crops and structures and are calculated by means of a stage/damage function for each reach. A stage versus damage relationship relates water height to the particular structure or crop damage at that elevation. Crop damage is also sensitive to time of year and prior flooding. In this manner flood damages can be estimated for a particular event or, as in this case, for the entire period of record, which provides the existing condition baseline. There are eighteen (18) downstream flood damage reaches that are allocated to the various reservoirs.

6.2.2 Lake Flood Damage Areas. Just as alternative lake operations would alter the downstream characteristics of flooding, so would the lake elevations be altered. Stage/damage functions relating to road and facility damage and cleanup activities aggregate those damage types for each lake site.

6.2.3 Lake Recreation Areas. The recreation benefit is directly related to lake elevation. Too little water or too much water has adverse effects on the recreation benefit. There is a seasonal (can also vary by day) relationship defining lake recreation benefits in dollars per day versus the simulation parameter of lake elevation.

6.3 Alternative Storage Allocations. Each lake has a different reallocation alternative. EWDAA Section 132(a) has directed implementation of Plan BS-3 at Bull Shoals and Plan NF-7 at Norfork Lake. For BS-3, the reallocation will come from the flood control pool and the main turbine will be used to make the minimum flow releases. For NF-7 reallocation shall be split evenly between the flood control pool and the conservation pool and that the releases shall be made from a new siphon in concert with the service station units. Each of the alternative routings were run through SUPER and the results are shown by reservoir in ATTACHMENT 3 – the Alternative Plans Benefit-Cost Summary.

7. HYDROELECTRIC POWER

7.1 Existing. Hydropower produced at Little Rock District lakes is marketed by the Southwest Power Administration (SWPA) in accordance with contractual and the White River Master Manual operation requirements described in the Project Report.

7.2 Hydropower Impacts. The proposed reallocation of storage and minimum flows release will reduce SWPA's ability to produce hydropower. Plans BS-3 and NF-7 have been formulated to try to minimize hydropower losses through a combination of power producing release methods and Hydropower Yield Protection Operation (HYPO) reallocation plans. The HYPO concept is fully described in Section 4.2.5.3 in the Project Report. At Bull Shoals the main turbine is used for the minimum flow releases, and at Norfork part of the minimum flow releases are made thru the station service unit. However, even with this power generation, there are still hydropower losses related to inefficient turbine operation and generation in off peak rather than peak times.

7.3 Hydropower Benefits. The hydropower benefits, or losses, derived from the SWPA analysis for each reallocation alternative is shown by lake in ATTACHMENT 3.

8. PROJECT COSTS

8.1 Project Costs. Second Generation MCACES (MII) cost estimates, displayed in ATTACHMENT 3, were prepared for alternatives BS-3 and NF-7. All NED costs are expressed in FY 2009 price levels and include a contingency factor of 25 percent. Price level escalation accounts for a 7 percent increase in project costs for BS-3 and a 12.2 percent increase in project costs for NF-7. The MII estimates relate to the modifications, relocations, dams, fish & wildlife facilities, recreational facilities, engineering & design, and supervision & administration. The calculations of average annual costs shown in ATTACHMENT 3 were based on those MII costs. Operations and maintenance and interest during construction costs are included in the average annual cost calculations.

9. PLAN EVALUATION

9.1 General. The following section presents the costs and benefits of the alternatives BS-3 and NF-7. A graphical presentation of the average annual benefits, average annual costs, and average annual net benefits is displayed in ATTACHMENT 4 to this Appendix.

9.2 NED Alternatives. The following Table displays the benefit and cost aspects of the minimum flow plans for BS-3 and NF-7.

1

TABLE 5
Lake Benefit Summary*

	First Costs	Annual Costs[2]	Annual Hydropower Benefits[3]	Annual Flood Benefits[1]	Annual Tailwater & In-Pool Rec. Benefits	Total Annual Benefits	Annual Net Benefits
BS-3	$ 12,306,600	$ 635,400	$ (1,169,100)	$ (62,000)	$ 3,441,700	$ 2,210,600	**$ 1,575,200**
NF-7	$ 10,628,596	$ 548,800	$ (977,500)	$ (6,000)	$ 1,511,700	$ 528,200	**$ (20,600)**

[1] Includes Downstream Flood Benefits Only
[2] Annual Costs are the annualized first costs. First costs are comprised of construction costs, O&M, and interest during construction.
[3] Energy and capacity losses, as calculated by SWPA. BS-3 hydropower benefit losses include hydropower losses associated with Empire Electric (FERC Lic. # 2221.)

2

ATTACHMENT 1

Non-Existence Value Willingness To Pay

LEGEND TO NON-EXISTENCE VALUE WILLINGNESS TO PAY

Column A	County
Column B-C	Lake
Column D	The number of Lake(s) the County is in proximity to.
Column E	Households per county
Column F	Households per county minus trout permit holders
Column G	Number of households in Column J that is assumed to begin trout fishing.
Column H	Number of trout permit holders
Column I	The percentage of trout permit holders in the respective county.
Column J	The percentage of nontrout permits holders in the respective county.
Column K	Void
Column L[1]	The Adjusted Average WTP for Nontrout Fishers.
Column M[1]	The Adjusted Average WTP for Trout Permit Holders.
Column N	This is the benefit of all of the households in column M. These are trout permit holding households.
Column O	This is the benefit of all of the households in column L. These are nontrout permit holding households.
Column P	This is the sum of the benefits of the households from Columns N and O multiplied by the number of Lakes the respective County is in proximity to.

[1] Columns L and M have text that is highlighted in red. The counties associated with these cells had no data collected for them. Therefore an average value was used.

REMOVING EXISTENCE VALUE WILLINGNESS TO PAY

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1		Bull Shoals	Norfork		Households	Households less TPH	Adjusted Households	Trout Permit Holders	Percent Trout	Percent Non-Trout		Adj Avg NT	Adj Avg T	Household Benefit Trout	Household Benefit NonTrout	Adjusted Household Benefit
2																
3	Baxter	1	1	2	17052	10161	1864	6891	40.4%	59.6%		9.50	8.81	60,717	17,712	156,858
4	Boone	1	1	2	13851	11895	2401	1956	14.1%	85.9%		12.25	8.69	16,996	29,410	92,812
5	Carroll	1		1	10189	8815	404	1374	13.5%	86.5%		10.00	15.00	20,610	4,044	24,654
6	Cleburne	1		1	10190	7734	568	2456	24.1%	75.9%		0.00	35.50	87,188	0	87,188
7	Fulton	1	1	2	4810	3931	144	879	18.3%	81.7%		5.00	6.33	5,566	721	12,574
8	Independence	1	1	2	13467	11327	727	2140	15.9%	84.1%		0.00	7.39	15,814	0	31,627
9	Izard	1	1	2	5440	3385	186	2055	37.8%	62.2%		13.33	3.00	6,165	2,484	17,298
10	Marion	1	1	2	6776	4225	543	2551	37.6%	62.4%		3.25	6.43	16,402	1,764	36,331
11	Newton	1		1	3500	3247	179	253	7.2%	92.8%		2.50	10.00	2,530	447	2,977
12	Searcy	1		1	3523	2855	131	668	19.0%	81.0%		1.50	10.00	6,680	196	6,876
13	Sharp	1	1	2	7211	5850	215	1361	18.9%	81.1%		1.50	2.50	3,403	322	7,449
14	Stone	1	1	2	4768	3145	144	1623	34.0%	66.0%		1.67	5.75	9,332	241	19,146
15	Van Buren	1		1	6825	6221	171	604	8.8%	91.2%		1.50	10.00	6,040	257	6,297
16																
17	Douglas	1	1	2	5201	5165	397	36	0.7%	99.3%		6.39	8.92	321	2,538	5,718
18	Howell	1		1	14762	13856	1066	906	6.1%	93.9%		6.39	8.92	8,079	6,809	14,888
19	Ozark	1	1	2	3850	3709	285	141	3.7%	96.3%		6.39	8.92	1,257	1,823	6,160
20	Taney	1		1	16158	16029	1233	129	0.8%	99.2%		6.39	8.92	1,150	7,877	9,027
21																
22											Geographic Market Benefit			344,894		537,882
23	Arkansas				1042696			103050	9.9%	90.1%	Rest of Arkansas					
24	Accounted For				107602			24811	23.1%	76.9%	-Trout Permit Holders			697,712		697,712
25	Remaining				935094	230600		78239	8.4%	91.6%	-nonTrout Permit Holders			1,473,154		1,473,154
26	Out-Of State				39971			74827			Out-of-State					
27	Accounted For							1212			-Trout Permit Holders			656,477		656,477
28	Remaining							73615			Total Benefit			3,172,238		3,365,225
29																
30																

ATTACHMENT 2

SUPER MODEL DATA

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA SUMMARY

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
SUM	TABLE ROCK OUTFLOW	FLD DMG IN ($/1000)	124.2	123.6	121.8	-0.6	-2.4	-0.46	-1.93
SUM	BULL SHOALS OUTFLOW	FLD DMG IN ($/1000)	11.6	10.6	10.3	-1.1	-1.3	-9.1	-11.15
SUM	GREERS FERRY OUTFLOW	FLD DMG IN ($/1000)	1.1	1.1	1.1	0	0	0	0
SUM	POPLAR BLUFF(UPPER)	FLD DMG IN ($/1000)	77.2	77.2	89.3	0	12.1	0	15.72
SUM	POPLAR BLUFF(LOWER)	FLD DMG IN ($/1000)	1872.2	1873.4	2006.4	1.2	134.2	0.06	7.17
SUM	CORNING	FLD DMG IN ($/1000)	824.8	824.3	827.8	-0.5	3	-0.06	0.36
SUM	POCAHONTAS	FLD DMG IN ($/1000)	949.8	950.4	952.5	0.7	2.7	0.07	0.29
SUM	BLACK ROCK (UPPER)	FLD DMG IN ($/1000)	1815.5	1815.5	1818.3	0	2.8	0	0.15
SUM	BLACK ROCK (LOWER)	FLD DMG IN ($/1000)	762.9	762.7	766.1	-0.2	3.2	-0.02	0.43
SUM	CALICO ROCK	FLD DMG IN ($/1000)	313.6	311.7	310.7	-1.8	-2.9	-0.59	-0.92
SUM	BATESVILLE (UPPER)	FLD DMG IN ($/1000)	28.8	28	28	-0.7	-0.7	-2.54	-2.49
SUM	BATESVILLE (LOWER)	FLD DMG IN ($/1000)	753.7	736.5	739.8	-17.2	-13.9	-2.28	-1.84
SUM	NEWPORT	FLD DMG IN ($/1000)	3881	3848	3850.6	-33	-30.4	-0.85	-0.78
SUM	AUGUSTA	FLD DMG IN ($/1000)	1906	1908.5	1912.6	2.5	6.6	0.13	0.35
SUM	GEORGETOWN	FLD DMG IN ($/1000)	2303.3	2299.1	2285.5	-4.1	-17.8	-0.18	-0.77
SUM	CLARENDON (UPPER)	FLD DMG IN ($/1000)	704.5	705.9	706.6	1.5	2.1	0.21	0.3
SUM	CLARENDON (MIDDLE)	FLD DMG IN ($/1000)	2855.5	2878.6	2883.1	23.1	27.6	0.81	0.97
SUM	CLARENDON (LOWER)	FLD DMG IN ($/1000)	3485.1	3497.9	3501.2	12.7	16.1	0.37	0.46
SUM			22670.7	22653.2	22812	-17.5	141.2	-0.08	0.62

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA SUMMARY

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
SUM	BEAVER RES AREA	FLD DMG IN ($/1000)	30	30.2	30	0.1	0	0.39	-0.09
SUM	TABLE ROCK RES AREA	FLD DMG IN ($/1000)	76	75.8	75.5	-0.2	-0.5	-0.31	-0.67
SUM	BULL SHOALS RES AREA	FLD DMG IN ($/1000)	79.2	64.4	64.2	-14.8	-15	-18.74	-18.93
SUM	NORFORK RES AREA	FLD DMG IN ($/1000)	79.6	72.5	72.4	-7.2	-7.3	-8.98	-9.12
SUM	GRERS FERRY RES AREA	FLD DMG IN ($/1000)	92	93.3	93.7	1.4	1.7	1.49	1.87
SUM	CLEARWATER RES AREA	FLD DMG IN ($/1000)	18.6	18.5	18.1	0	-0.5	-0.09	-2.62
SUM			375.5	354.7	353.9	-20.8	-21.6	-5.53	-5.74

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
SUM	BEAVER LAKE	REC BENEFITS($/1000)	6190.1	6186.8	6184.7	-3.3	-5.4	-0.05	-0.09
SUM	TABLE ROCK LAKE	REC BENEFITS($/1000)	5775.7	5778.7	5779.9	2.9	4.2	0.05	0.07
SUM	BULL SHOALS LAKE	REC BENEFITS($/1000)	9529.8	9663.3	9664.8	133.5	135	1.4	1.42
SUM	NORFORK LAKE	REC BENEFITS($/1000)	4683.6	4717.6	4716.4	34	32.9	0.73	0.7
SUM	GREERS FERRY LAKE	REC BENEFITS($/1000)	11221.3	11219.5	11214.1	-1.8	-7.2	-0.02	-0.06
SUM	CLEARWATER LAKE	REC BENEFITS($/1000)	806.8	806.7	805.9	0	-0.8	0	-0.1
SUM			38207.2	38372.6	38365.9	165.4	158.7	0.43	0.42

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA SUMMARY

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
SUM	BEAVER POWER	TOTAL ENERGY IN GWH	127.5	127.4	123.5	-0.1	-4.1	-0.08	-3.2
SUM	NORFORK POWER	TOTAL ENERGY IN GWH	169.1	181.2	182.2	12.1	13	7.13	7.7
SUM	GREERS FERRY POWER	TOTAL ENERGY IN GWH	172.2	172.8	175.7	0.5	3.5	0.31	2.04
SUM	TABLE ROCK POWER	TOTAL ENERGY IN GWH	474.6	474.2	470	-0.4	-4.6	-0.08	-0.96
SUM	BULL SHOALS POWER	TOTAL ENERGY IN GWH	654.8	696.5	694.7	41.7	40	6.37	6.1
SUM			1598.2	1652.1	1646.1	53.8	47.9	3.37	2.99

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
SUM	BEAVER POWER	ON LOAD IN GWH	45.1	45.1	45.1	0	0	0	0
SUM	NORFORK POWER	ON LOAD IN GWH	91.8	91.9	91.9	0.1	0.2	0.14	0.19
SUM	GREERS FERRY POWER	ON LOAD IN GWH	72.4	72.4	72.4	-0.1	-0.1	-0.09	-0.08
SUM	TABLE ROCK POWER	ON LOAD IN GWH	207	207	207	0	0	0	0
SUM	BULL SHOALS POWER	ON LOAD IN GWH	274.2	275.1	275.4	0.9	1.2	0.34	0.42
SUM			690.5	691.5	691.8	1	1.3	0.14	0.18

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA SUMMARY

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
SUM	BEAVER POWER	DUMP ENERGY IN GWH	82.4	82.3	78.3	-0.1	-4.1	-0.12	-4.96
SUM	NORFORK POWER	DUMP ENERGY IN GWH	77.4	89.3	90.2	11.9	12.9	15.43	16.61
SUM	GREERS FERRY POWER	DUMP ENERGY IN GWH	99.8	100.4	103.4	0.6	3.6	0.6	3.59
SUM	TABLE ROCK POWER	DUMP ENERGY IN GWH	267.6	267.2	263	-0.4	-4.6	-0.15	-1.7
SUM	BULL SHOALS POWER	DUMP ENERGY IN GWH	380.6	421.3	419.4	40.8	38.8	10.72	10.19
SUM			907.7	960.5	954.3	52.8	46.6	5.82	5.13

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
SUM	BEAVER POWER	THERMAL BUY IN GWH	0	0	0	0	0	-	-
SUM	NORFORK POWER	THERMAL BUY IN GWH	5.9	5.8	5.8	-0.1	-0.2	-2.15	-2.88
SUM	GREERS FERRY POWER	THERMAL BUY IN GWH	0.8	0.9	0.9	0.1	0.1	7.93	7.53
SUM	TABLE ROCK POWER	THERMAL BUY IN GWH	0	0	0	0	0	-	-
SUM	BULL SHOALS POWER	THERMAL BUY IN GWH	11.6	10.7	10.4	-0.9	-1.2	-7.94	-10.03
SUM			18.3	17.4	17.1	-1	-1.3	-5.36	-6.94

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA ITEM SUMMATION

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
1	TABLE ROCK OUTFLOW	STAGE-DAMAGE	124.2	123.6	121.8	-0.6	-2.4	-0.46	-1.93
SUM	TABLE ROCK OUTFLOW	FLD DMG IN ($/1000)	124.2	123.6	121.8	-0.6	-2.4	-0.46	-1.93

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
2	BULL SHOALS OUTFLOW	STAGE-DAMAGE	10.9	9.9	9.6	-1.1	-1.3	-9.67	-11.86
3	BULL SHOALS OUTFLOW	IMPROVED PASTURE	0.6	0.6	0.6	0	0	0.06	0.12
4	BULL SHOALS OUTFLOW	UNIMPROVED PASTURE	0.1	0.1	0.1	0	0	0.06	0.12
SUM	BULL SHOALS OUTFLOW	FLD DMG IN ($/1000)	11.6	10.6	10.3	-1.1	-1.3	-9.1	-11.15

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
5	GREERS FERRY OUTFLOW	STRUCTURES	0	0	0	0	0	-	-
6	GREERS FERRY OUTFLOW	CORN	0.2	0.2	0.2	0	0	0	0
7	GREERS FERRY OUTFLOW	COTTON	0.4	0.4	0.4	0	0	0	0
8	GREERS FERRY OUTFLOW	IMPROVED PASTURE	0.1	0.1	0.1	0	0	0	0
9	GREERS FERRY OUTFLOW	UNIMPROVED PASTURE	0.1	0.1	0.1	0	0	0	0
10	GREERS FERRY OUTFLOW	SOYBEANS	0.2	0.2	0.2	0	0	0	0
11	GREERS FERRY OUTFLOW	DOUBLE CROP SOYBEANS	0	0	0	0	0	0	0
12	GREERS FERRY OUTFLOW	DOUBLE CROP WHEAT	0.1	0.1	0.1	0	0	0	0
SUM	GREERS FERRY OUTFLOW	FLD DMG IN ($/1000)	1.1	1.1	1.1	0	0	0	0

ECONOMIC DATA ITEM SUMMATION

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
13	POPLAR BLUFF(UPPER)	STRUCTURES	13.6	13.6	13.6	0	0	0.07	0.3
14	POPLAR BLUFF(UPPER)	CORN	8	8	8.8	0	0.9	-0.04	10.71
15	POPLAR BLUFF(UPPER)	GRAIN SORGHUM	15.7	15.7	17.3	0	1.5	-0.04	9.72
16	POPLAR BLUFF(UPPER)	IMPROVED PASTURE	10.3	10.3	14.6	0	4.3	0	41.76
17	POPLAR BLUFF(UPPER)	UNIMPROVED PASTURE	1.9	1.9	2.8	0	0.9	0	45.73
18	POPLAR BLUFF(UPPER)	SOYBEANS	11.7	11.7	14.5	0	2.8	-0.03	23.41
19	POPLAR BLUFF(UPPER)	DOUBLE CROP SOYBEANS	1.1	1.1	1.7	0	0.6	0	61.15
20	POPLAR BLUFF(UPPER)	DOUBLE CROP WHEAT	14.9	14.9	16	0	1.1	0	7.69
SUM	POPLAR BLUFF(UPPER)	FLD DMG IN ($/1000)	77.2	77.2	89.3	0	12.1	0	15.72

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
21	POPLAR BLUFF(LOWER)	STRUCTURES	708.8	710.9	710.7	2.2	1.9	0.31	0.27
22	POPLAR BLUFF(LOWER)	RICE	648.8	648.1	706.9	-0.7	58.1	-0.1	8.96
23	POPLAR BLUFF(LOWER)	CORN	71.3	71.2	78.8	-0.1	7.5	-0.09	10.56
24	POPLAR BLUFF(LOWER)	GRAIN SORGHUM	210.9	210.7	231.4	-0.2	20.5	-0.09	9.71
25	POPLAR BLUFF(LOWER)	UNIMPROVED PASTURE	4	4.1	5.4	0.1	1.4	2.46	35.04
26	POPLAR BLUFF(LOWER)	SOYBEANS	161.5	161.3	198.8	-0.2	37.3	-0.1	23.12
27	POPLAR BLUFF(LOWER)	DOUBLE CROP SOYBEANS	4.5	4.5	7.1	0	2.6	0	57.67
28	POPLAR BLUFF(LOWER)	DOUBLE CROP WHEAT	62.5	62.5	67.3	0	4.8	0	7.67
SUM	POPLAR BLUFF(LOWER)	FLD DMG IN ($/1000)	1872.2	1873.4	2006.4	1.2	134.2	0.06	7.17

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
29	CORNING	TREE DAMAGE	218.3	217.9	215.3	-0.4	-3.1	-0.18	-1.4
30	CORNING	STRUCTURES	321.8	321.6	323.3	-0.2	1.5	-0.07	0.47
31	CORNING	RICE	108.7	108.8	110.7	0.1	2.1	0.12	1.91
32	CORNING	CORN	20.7	20.7	20.9	0	0.2	-0.05	1.2
33	CORNING	COTTON	35.2	35.3	35.9	0	0.7	0.04	1.97
34	CORNING	GRAIN SORGHUM	28	28	28.4	0	0.3	-0.04	1.22
35	CORNING	SOYBEANS	53.2	53.1	53.8	0	0.6	-0.05	1.13
36	CORNING	DOUBLE CROP SOYBEANS	6.1	6.1	6.1	0	0	-0.07	-0.05
37	CORNING	DOUBLE CROP WHEAT	32.8	32.8	33.4	0	0.6	0	1.82
SUM	CORNING	FLD DMG IN ($/1000)	824.8	824.3	827.8	-0.5	3	-0.06	0.36

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
38	POCAHONTAS	STRUCTURES	0.2	0.2	0.2	0	0	0	4.6
39	POCAHONTAS	RICE	451.7	452.2	453.4	0.5	1.6	0.11	0.36
40	POCAHONTAS	CORN	42.9	42.9	42.9	0	0	0.06	0.02
41	POCAHONTAS	GRAIN SORGHUM	82.5	82.6	82.6	0.1	0	0.06	0.05
42	POCAHONTAS	SOYBEANS	91.9	91.9	91.6	0.1	-0.3	0.09	-0.28
43	POCAHONTAS	DOUBLE CROP SOYBEANS	24.2	24.2	24.1	0	-0.1	0.13	-0.46
44	POCAHONTAS	DOUBLE CROP WHEAT	256.3	256.3	257.7	0	1.4	0	0.54
SUM	POCAHONTAS	FLD DMG IN ($/1000)	949.8	950.4	952.5	0.7	2.7	0.07	0.29

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	 SWPA CC PLAN B	 SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	 PLAN (C-A)	% DIFFERENCE PLAN (B/A)	 PLAN (C/A)
45	BLACK ROCK(UPPER)	STRUCTURES	1.8	1.8	1.8	0	0	0.07	0
46	BLACK ROCK(UPPER)	RICE	850.1	849.8	850	-0.3	-0.1	-0.04	-0.02
47	BLACK ROCK(UPPER)	GRAIN SORGHUM	188.8	189	189.8	0.2	1	0.11	0.5
48	BLACK ROCK(UPPER)	IMPROVED PASTURE	45.9	46.1	46	0.2	0.1	0.36	0.12
49	BLACK ROCK(UPPER)	UNIMPROVED PASTURE	13.6	13.7	13.6	0.1	0	0.42	0.19
50	BLACK ROCK(UPPER)	SOYBEANS	266.2	266	268.8	-0.3	2.6	-0.11	0.97
51	BLACK ROCK(UPPER)	DOUBLE CROP SOYBEANS	43.9	44.1	45	0.2	1.1	0.37	2.49
52	BLACK ROCK(UPPER)	DOUBLE CROP WHEAT	405.1	405.1	403.3	0	-1.8	0	-0.44
SUM	BLACK ROCK (UPPER)	FLD DMG IN ($/1000)	1815.5	1815.5	1818.3	0	2.8	0	0.15

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	 SWPA CC PLAN B	 SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	 PLAN (C-A)	% DIFFERENCE PLAN (B/A)	 PLAN (C/A)
53	BLACK ROCK(LOWER)	STRUCTURES	1.1	1.1	1.1	0	0	0.05	0.01
54	BLACK ROCK(LOWER)	RICE	286.1	285.9	286.4	-0.2	0.3	-0.07	0.1
55	BLACK ROCK(LOWER)	CORN	46.9	46.9	47.1	0	0.2	0	0.49
56	BLACK ROCK(LOWER)	GRAIN SORGHUM	45.6	45.6	45.8	0	0.2	0	0.43
57	BLACK ROCK(LOWER)	UNIMPROVED PASTURE	6	6	6.1	0	0.1	0.04	1.21
58	BLACK ROCK(LOWER)	SOYBEANS	160.8	160.8	162.7	0	1.9	0.01	1.19
59	BLACK ROCK(LOWER)	DOUBLE CROP SOYBEANS	15.3	15.3	15.8	0	0.5	0.04	3.38
60	BLACK ROCK(LOWER)	DOUBLE CROP WHEAT	201.2	201.2	201.2	0	0	0	0.01
SUM	BLACK ROCK (LOWER)	FLD DMG IN ($/1000)	762.9	762.7	766.1	-0.2	3.2	-0.02	0.43

ECONOMIC DATA ITEM SUMMATION

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
61	CALICO ROCK	STRUCTURES	304.8	302.9	301.9	-1.9	-2.9	-0.62	-0.96
62	CALICO ROCK	IMPROVED PASTURE	8.2	8.2	8.2	0	0.1	0.59	0.62
63	CALICO ROCK	UNIMPROVED PASTURE	0.6	0.6	0.6	0	0	1.97	2
SUM	CALICO ROCK	FLD DMG IN ($/1000)	313.6	311.7	310.7	-1.8	-2.9	-0.59	-0.92

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
64	BATESVILLE(UPPER)	STRUCTURES	1.5	1.4	1.4	-0.1	-0.1	-6.96	-8.08
65	BATESVILLE(UPPER)	GRAIN SORGHUM	6.5	6.3	6.3	-0.2	-0.2	-2.78	-2.74
66	BATESVILLE(UPPER)	IMPROVED PASTURE	8.6	8.4	8.4	-0.1	-0.1	-1.75	-1.46
67	BATESVILLE(UPPER)	UNIMPROVED PASTURE	1.2	1.1	1.1	0	0	-1	-0.75
68	BATESVILLE(UPPER)	SOYBEANS	4	3.8	3.8	-0.1	-0.1	-3.64	-3.64
69	BATESVILLE(UPPER)	DOUBLE CROP SOYBEANS	0.5	0.5	0.5	0	0	-5.06	-5.06
70	BATESVILLE(UPPER)	DOUBLE CROP WHEAT	6.6	6.5	6.5	-0.1	-0.1	-1.73	-1.73
SUM	BATESVILLE (UPPER)	FLD DMG IN ($/1000)	28.8	28	28	-0.7	-0.7	-2.54	-2.49

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
71	BATESVILLE(LOWER)	STRUCTURES	109.7	106.1	105.5	-3.6	-4.2	-3.27	-3.78
72	BATESVILLE(LOWER)	RICE	206.6	201.3	203.3	-5.3	-3.2	-2.55	-1.56
73	BATESVILLE(LOWER)	GRAIN SORGHUM	81.8	79.8	80.2	-1.9	-1.6	-2.36	-1.91
74	BATESVILLE(LOWER)	IMPROVED PASTURE	14.2	14.2	14.2	0	0	-0.03	-0.19
75	BATESVILLE(LOWER)	UNIMPROVED PASTURE	8.3	8.3	8.3	0	0	-0.14	-0.26
76	BATESVILLE(LOWER)	SOYBEANS	146.4	141.2	141.7	-5.2	-4.7	-3.54	-3.2
77	BATESVILLE(LOWER)	DOUBLE CROP SOYBEANS	28.9	27.6	27.5	-1.4	-1.4	-4.7	-4.88
78	BATESVILLE(LOWER)	DOUBLE CROP WHEAT	157.8	158	159	0.2	1.2	0.12	0.78
SUM	BATESVILLE (LOWER)	FLD DMG IN ($/1000)	753.7	736.5	739.8	-17.2	-13.9	-2.28	-1.84

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
79	NEWPORT	STRUCTURES	1409.3	1399.5	1398.3	-9.8	-11	-0.7	-0.78
80	NEWPORT	RICE	1050	1032.3	1032.7	-17.6	-17.3	-1.68	-1.64
81	NEWPORT	GRAIN SORGHUM	132.4	130.1	130.1	-2.3	-2.3	-1.76	-1.76
82	NEWPORT	IMPROVED PASTURE	65.9	65.2	65.1	-0.8	-0.8	-1.14	-1.18
83	NEWPORT	UNIMPROVED PASTURE	19.6	19.4	19.4	-0.2	-0.2	-0.94	-0.99
84	NEWPORT	SOYBEANS	530.8	525.9	526.5	-4.9	-4.3	-0.92	-0.81
85	NEWPORT	DOUBLE CROP SOYBEANS	73.3	71.4	71.5	-1.9	-1.9	-2.61	-2.52
86	NEWPORT	DOUBLE CROP WHEAT	599.7	604.2	607	4.5	7.3	0.74	1.22
SUM	NEWPORT	FLD DMG IN ($/1000)	3881	3848	3850.6	-33	-30.4	-0.85	-0.78

ATTACHMENT 2
SUPER MODEL DATA

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ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
87	AUGUSTA	TREE DAMAGES	53	53.3	53.2	0.3	0.2	0.56	0.47
88	AUGUSTA	STRUCTURES	136.8	136.6	136.7	-0.2	-0.1	-0.12	-0.08
89	AUGUSTA	OATS	76.2	76.6	76.7	0.4	0.5	0.51	0.62
90	AUGUSTA	RICE	562.5	558.2	561.9	-4.3	-0.5	-0.76	-0.1
91	AUGUSTA	GRAIN SORGHUM	168.3	169.2	169.5	0.9	1.2	0.55	0.71
92	AUGUSTA	UNIMPROVED PASTURE	12.8	12.8	12.8	0	0	-0.28	-0.15
93	AUGUSTA	SOYBEANS	430.7	432.9	432.1	2.2	1.4	0.52	0.32
94	AUGUSTA	DOUBLE CROP SOYBEANS	73	74.1	74.6	1.1	1.6	1.48	2.18
95	AUGUSTA	DOUBLE CROP WHEAT	392.7	394.7	395.1	2	2.4	0.52	0.61
SUM	AUGUSTA	FLD DMG IN ($/1000)	1906	1908.5	1912.6	2.5	6.6	0.13	0.35

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
96	GEORGETOWN	STRUCTURES	93.5	93.1	93.2	-0.4	-0.4	-0.45	-0.38
97	GEORGETOWN	RICE	884.4	875	868.5	-9.4	-16	-1.07	-1.8
98	GEORGETOWN	GRAIN SORGHUM	106.6	105.6	104.7	-1	-1.9	-0.9	-1.82
99	GEORGETOWN	UNIMPROVED PASTURE	18.2	18.1	18	-0.1	-0.2	-0.43	-0.95
100	GEORGETOWN	SOYBEANS	571.4	574	570.4	2.6	-0.9	0.46	-0.16
101	GEORGETOWN	DOUBLE CROP SOYBEANS	83.8	86.6	84.6	2.8	0.8	3.29	0.96
102	GEORGETOWN	DOUBLE CROP WHEAT	545.4	546.7	546.1	1.3	0.8	0.25	0.14
SUM	GEORGETOWN	FLD DMG IN ($/1000)	2303.3	2299.1	2285.5	-4.1	-17.8	-0.18	-0.77

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
103	CLARENDON(UPPER)	STRUCTURES	316.8	317.4	318.9	0.6	2.1	0.18	0.65
104	CLARENDON(UPPER)	RICE	62.5	62.3	62.4	-0.2	-0.1	-0.3	-0.09
105	CLARENDON(UPPER)	IMPROVED PASTURE	21.6	21.5	21.7	0	0.1	-0.23	0.59
106	CLARENDON(UPPER)	UNIMPROVED PASTURE	3.4	3.4	3.4	0	0	-0.21	0.61
107	CLARENDON(UPPER)	SOYBEANS	76.1	75.9	75.6	-0.3	-0.5	-0.35	-0.67
108	CLARENDON(UPPER)	DOUBLE CROP SOYBEANS	21.8	22.1	21.5	0.3	-0.2	1.39	-1.11
109	CLARENDON(UPPER)	DOUBLE CROP WHEAT	202.3	203.4	203	1.1	0.7	0.53	0.37
SUM	CLARENDON (UPPER)	FLD DMG IN ($/1000)	704.5	705.9	706.6	1.5	2.1	0.21	0.3

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
110	CLARENDON(MIDDLE)	STRUCTURES	545.8	550.1	551.5	4.3	5.7	0.79	1.04
111	CLARENDON(MIDDLE)	SOYBEANS	494.3	500.5	499.6	6.2	5.3	1.25	1.06
112	CLARENDON(MIDDLE)	COTTON	155.8	158.3	158.7	2.5	2.9	1.6	1.84
113	CLARENDON(MIDDLE)	RICE	518.1	520.9	523.3	2.8	5.2	0.54	1.01
114	CLARENDON(MIDDLE)	DOUBLE CROP SOYBEANS	136.3	138.4	140.1	2.1	3.8	1.57	2.77
115	CLARENDON(MIDDLE)	DOUBLE CROP WHEAT	1005.1	1010.3	1010	5.1	4.8	0.51	0.48
SUM	CLARENDON (MIDDLE)	FLD DMG IN ($/1000)	2855.5	2878.6	2883.1	23.1	27.6	0.81	0.97

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
116	CLARENDON(LOWER)	TREE DAMAGE	403.6	406.9	406.9	3.3	3.3	0.81	0.83
117	CLARENDON(LOWER)	STRUCTURES	2795.9	2806.9	2810.3	11	14.4	0.39	0.51
118	CLARENDON(LOWER)	COTTON	104.7	103.3	103.2	-1.4	-1.6	-1.35	-1.51
119	CLARENDON(LOWER)	RICE	38.4	37.8	37.8	-0.6	-0.6	-1.56	-1.68
120	CLARENDON(LOWER)	SOYBEANS	57	57.3	57.5	0.4	0.6	0.62	0.97
121	CLARENDON(LOWER)	DOUBLE CROP SOYBEANS	15.2	15.2	15.3	0	0.1	0.17	0.47
122	CLARENDON(LOWER)	DOUBLE CROP WHEAT	70.4	70.5	70.3	0.1	0	0.14	-0.05
SUM	CLARENDON (LOWER)	FLD DMG IN ($/1000)	3485.1	3497.9	3501.2	12.7	16.1	0.37	0.46

ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
123	BEAVER LAKE	NORMAL CLEANUP	28.2	28.4	28.2	0.1	0	0.45	-0.02
124	BEAVER LAKE	CRITICAL EVENTS	1.8	1.8	1.8	0	0	-0.48	-1.25
SUM	BEAVER RES AREA	FLD DMG IN ($/1000)	30	30.2	30	0.1	0	0.39	-0.09

ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
125	TABLE ROCK LAKE	NORMAL CLEANUP	61.7	61.4	61.1	-0.2	-0.5	-0.38	-0.82
126	TABLE ROCK LAKE	CRITICAL EVENTS	14.4	14.4	14.4	0	0	0	0
SUM	TABLE ROCK RES AREA	FLD DMG IN ($/1000)	76	75.8	75.5	-0.2	-0.5	-0.31	-0.67

ATTACHMENT 2
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ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	 SWPA CC PLAN B	 SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	 PLAN (C-A)	% DIFFERENCE PLAN (B/A)	 PLAN (C/A)
127	BULL SHOALS LAKE	NORMAL CLEANUP	41	35.6	35.5	-5.3	-5.5	-13.02	-13.39
128	BULL SHOALS LAKE	CRITICAL EVENTS	38.2	28.7	28.7	-9.5	-9.5	-24.87	-24.87
SUM	BULL SHOALS RES AREA	FLD DMG IN ($/1000)	79.2	64.4	64.2	-14.8	-15	-18.74	-18.93

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	 SWPA CC PLAN B	 SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	 PLAN (C-A)	% DIFFERENCE PLAN (B/A)	 PLAN (C/A)
129	NORFORK LAKE	NORMAL CLEANUP	62.4	56.9	56.9	-5.5	-5.5	-8.86	-8.75
130	NORFORK LAKE	CRITICAL EVENTS	17.3	15.6	15.5	-1.6	-1.8	-9.43	-10.45
SUM	NORFORK RES AREA	FLD DMG IN ($/1000)	79.6	72.5	72.4	-7.2	-7.3	-8.98	-9.12

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	 SWPA CC PLAN B	 SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	 PLAN (C-A)	% DIFFERENCE PLAN (B/A)	 PLAN (C/A)
131	GREERS FERRY LAKE	NORMAL CLEANUP	80	80.8	81.2	0.8	1.2	1.05	1.49
132	GREERS FERRY LAKE	CRITICAL EVENTS	12	12.5	12.5	0.5	0.5	4.44	4.44
SUM	GRERS FERRY RES AREA	FLD DMG IN ($/1000)	92	93.3	93.7	1.4	1.7	1.49	1.87

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
133	CLEARWATER LAKE	NORMAL CLEANUP	16.3	16.3	15.9	0	-0.5	-0.1	-2.87
134	CLEARWATER LAKE	CRITICAL EVENTS	2.2	2.2	2.2	0	0	0	-0.77
SUM	CLEARWATER RES AREA	FLD DMG IN ($/1000)	18.6	18.5	18.1	0	-0.5	-0.09	-2.62

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
135	BEAVER LAKE	VISITATION	6190.1	6186.8	6184.7	-3.3	-5.4	-0.05	-0.09
SUM	BEAVER LAKE	REC BENEFITS($/1000)	6190.1	6186.8	6184.7	-3.3	-5.4	-0.05	-0.09

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
136	TABLE ROCK LAKE	VISITATION	5775.7	5778.7	5779.9	2.9	4.2	0.05	0.07
SUM	TABLE ROCK LAKE	REC BENEFITS($/1000)	5775.7	5778.7	5779.9	2.9	4.2	0.05	0.07

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ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
137	BULL SHOALS LAKE	VISITATION	9529.8	9663.3	9664.8	133.5	135	1.4	1.42
SUM	BULL SHOALS LAKE	REC BENEFITS($/1000)	9529.8	9663.3	9664.8	133.5	135	1.4	1.42

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
138	NORFORK LAKE	VISITATION	4683.6	4717.6	4716.4	34	32.9	0.73	0.7
SUM	NORFORK LAKE	REC BENEFITS($/1000)	4683.6	4717.6	4716.4	34	32.9	0.73	0.7

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
139	GREERS FERRY LAKE	VISITATION	11221.3	11219.5	11214.1	-1.8	-7.2	-0.02	-0.06
SUM	GREERS FERRY LAKE	REC BENEFITS($/1000)	11221.3	11219.5	11214.1	-1.8	-7.2	-0.02	-0.06

ATTACHMENT 2
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ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
140	CLEARWATER LAKE	VISITATION	806.8	806.7	805.9	0	-0.8	0	-0.1
SUM	CLEARWATER LAKE	REC BENEFITS($/1000)	806.8	806.7	805.9	0	-0.8	0	-0.1

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
156	BEAVER POWER	PRODUCE GWH (SYS)	127.5	127.4	123.5	-0.1	-4.1	-0.08	-3.2
SUM	BEAVER POWER	TOTAL ENERGY IN GWH	127.5	127.4	123.5	-0.1	-4.1	-0.08	-3.2

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
161	NORFORK POWER	PRODUCE GWH (SYS)	169.1	181.2	182.2	12.1	13	7.13	7.7
SUM	NORFORK POWER	TOTAL ENERGY IN GWH	169.1	181.2	182.2	12.1	13	7.13	7.7

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
166	GREERS FERRY POWER	PRODUCE GWH (SYS)	172.2	172.8	175.7	0.5	3.5	0.31	2.04
SUM	GREERS FERRY POWER	TOTAL ENERGY IN GWH	172.2	172.8	175.7	0.5	3.5	0.31	2.04

ATTACHMENT 2
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ECONOMIC DATA ITEM SUMMATION

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
171	TABLE ROCK POWER	PRODUCE GWH (SYS)	474.6	474.2	470	-0.4	-4.6	-0.08	-0.96
SUM	TABLE ROCK POWER	TOTAL ENERGY IN GWH	474.6	474.2	470	-0.4	-4.6	-0.08	-0.96

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
176	BULL SHOALS POWER	PRODUCE GWH (SYS)	654.8	696.5	694.7	41.7	40	6.37	6.1
SUM	BULL SHOALS POWER	TOTAL ENERGY IN GWH	654.8	696.5	694.7	41.7	40	6.37	6.1

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
158	BEAVER POWER	ON LOAD GWH (SYS)	45.1	45.1	45.1	0	0	0	0
SUM	BEAVER POWER	ON LOAD IN GWH	45.1	45.1	45.1	0	0	0	0

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
163	NORFORK POWER	ON LOAD GWH (SYS)	91.8	91.9	91.9	0.1	0.2	0.14	0.19
SUM	NORFORK POWER	ON LOAD IN GWH	91.8	91.9	91.9	0.1	0.2	0.14	0.19

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
168	GREERS FERRY POWER	ON LOAD GWH (SYS)	72.4	72.4	72.4	-0.1	-0.1	-0.09	-0.08
SUM	GREERS FERRY POWER	ON LOAD IN GWH	72.4	72.4	72.4	-0.1	-0.1	-0.09	-0.08

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
173	TABLE ROCK POWER	ON LOAD GWH (SYS)	207	207	207	0	0	0	0
SUM	TABLE ROCK POWER	ON LOAD IN GWH	207	207	207	0	0	0	0

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
178	BULL SHOALS POWER	ON LOAD GWH (SYS)	274.2	275.1	275.4	0.9	1.2	0.34	0.42
SUM	BULL SHOALS POWER	ON LOAD IN GWH	274.2	275.1	275.4	0.9	1.2	0.34	0.42

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
159	BEAVER POWER	DUMP GWH (SYS)	82.4	82.3	78.3	-0.1	-4.1	-0.12	-4.96
SUM	BEAVER POWER	DUMP ENERGY IN GWH	82.4	82.3	78.3	-0.1	-4.1	-0.12	-4.96

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
164	NORFORK POWER	DUMP GWH (SYS)	77.4	89.3	90.2	11.9	12.9	15.43	16.61
SUM	NORFORK POWER	DUMP ENERGY IN GWH	77.4	89.3	90.2	11.9	12.9	15.43	16.61

ATTACHMENT 2
SUPER MODEL DATA

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ECONOMIC DATA ITEM SUMMATION

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
169	GREERS FERRY POWER	DUMP GWH (SYS)	99.8	100.4	103.4	0.6	3.6	0.6	3.59
SUM	GREERS FERRY POWER	DUMP ENERGY IN GWH	99.8	100.4	103.4	0.6	3.6	0.6	3.59

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
174	TABLE ROCK POWER	DUMP GWH (SYS)	267.6	267.2	263	-0.4	-4.6	-0.15	-1.7
SUM	TABLE ROCK POWER	DUMP ENERGY IN GWH	267.6	267.2	263	-0.4	-4.6	-0.15	-1.7

			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
179	BULL SHOALS POWER	DUMP GWH (SYS)	380.6	421.3	419.4	40.8	38.8	10.72	10.19
SUM	BULL SHOALS POWER	DUMP ENERGY IN GWH	380.6	421.3	419.4	40.8	38.8	10.72	10.19

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
160	BEAVER POWER	PURCHASE GWH (SYS)	0	0	0	0	0	-	-
SUM	BEAVER POWER	THERMAL BUY IN GWH	0	0	0	0	0	-	-

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
165	NORFORK POWER	PURCHASE GWH (SYS)	5.9	5.8	5.8	-0.1	-0.2	-2.15	-2.88
SUM	NORFORK POWER	THERMAL BUY IN GWH	5.9	5.8	5.8	-0.1	-0.2	-2.15	-2.88

ITEM	REACH	KIND	AVERAGE ANNUAL VALUES SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	VALUE DIFFERENCE PLAN (B-A)	PLAN (C-A)	% DIFFERENCE PLAN (B/A)	PLAN (C/A)
170	GREERS FERRY POWER	PURCHASE GWH (SYS)	0.8	0.9	0.9	0.1	0.1	7.93	7.53
SUM	GREERS FERRY POWER	THERMAL BUY IN GWH	0.8	0.9	0.9	0.1	0.1	7.93	7.53

ATTACHMENT 2
SUPER MODEL DATA

No Dependable Yield
Mitigation Storage

ECONOMIC DATA ITEM SUMMATION

ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
175	TABLE ROCK POWER	PURCHASE GWH (SYS)	0	0	0	0	0	-	-
SUM	TABLE ROCK POWER	THERMAL BUY IN GWH	0	0	0	0	0	-	-

ITEM	REACH	KIND	SWPA MF PLAN A	SWPA CC PLAN B	SWL CC PLAN C	PLAN (B-A)	PLAN (C-A)	PLAN (B/A)	PLAN (C/A)
			AVERAGE ANNUAL VALUES			VALUE DIFFERENCE		% DIFFERENCE	
180	BULL SHOALS POWER	PURCHASE GWH (SYS)	11.6	10.7	10.4	-0.9	-1.2	-7.94	-10.03
SUM	BULL SHOALS POWER	THERMAL BUY IN GWH	11.6	10.7	10.4	-0.9	-1.2	-7.94	-10.03

ATTACHMENT 3

ALTERNATIVE PLANS BENEFIT - COST SUMMARY

Bull Shoals Option Costs - First Costs

BS-3: Use Main Turbine	Relocations	Dams	Fish & Wildlife Facilities	Recreational Facilities	Engineering & Design	Supervision & Adminstration	Interest During Construction	Total Costs
100% Flood Pool								
BS-3	$ 1,875,100	$ 213,900	$ -	$ 6,384,200	$ 1,928,500	$ 846,800	$ 1,058,100	$ 12,306,600

Bull Shoals Option Benefits

BS-3: Use Main Turbine	TW Rec.Benefits (from Contingent Value) (1)	Power Benefits (from SWPA)	Rec. Benefits (from SUPER)	In Pool Flood Benefits (from SUPER)	Down Stream Flood Benefits (from SUPER)	Total Benefits Gained
100% Flood Pool						
BS-3	$ 3,458,700	$ (1,169,100)	$ -	$ (17,000)	$ (62,000)	$ 2,210,600

Note (1) Tailwater Recreation Benefits are reduced to reflect the reliability of the authorized storage to provide the proposed minimum flows.

Bull Shoals Option Costs - Annual Costs

BS-3: Use Main Turbine	Relocations	Dams	Fish & Wildlife Facilities	Recreational Facilities	Engineering & Design	Supervision & Adminstration	O&M	Total Costs
100% Flood Pool								
BS-3	96,800	11,000	-	329,600	99,600	43,700	-	635,400

Bull Shoals Option Benefits

BS-3: Use Main Turbine	TW Rec.Benefits (from Contingent Value) (1)	Power Benefits (from SWPA)	Rec. Benefits (from SUPER)	In Pool Flood Benefits Foregone (from SUPER)	Down Stream Flood Benefits (from SUPER)	Total Benefits Gained	Net Annual Benefits
100% Flood Pool							
BS-3	$ 3,458,700	$ (1,169,100)	$ -	$ (17,000)	$ (62,000)	$ 2,210,600	$ 1,575,200

Note (1) Tailwater Recreation Benefits are reduced to reflect the reliability of the authorized storage to provide the proposed minimum flows.

Bull Shoals Summary

BS-3: Use Main Turbine	First Costs	Annual Total Costs	Annual Hydropower Benefits	Annual Downstream Flood Control Benefits	Annual Total Benefits	Benefits - Costs	B/C Ratio
100% Flood Pool							
BS-3	$ 12,306,600	$ 635,400	$ (1,169,100)	$ (62,000)	$ 2,210,600	**$ 1,575,200**	**3.48**

First time costs estimates as shown in MCASES cost estimate.

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	Project Cost
Bid Schedule Items			8,892,453	0	2,356,000	0	11,248,453
02: Relocations	**EA**	1.0	1,482,075	0	393,000	0	1,875,075
04: Dams	**EA**	1.0	168,868	0	45,000	0	213,868
06: Fish and Wildlife Facilities	**EA**	1.0	0	0	0	0	0
14: Recreational Facilities	**EA**	1.0	5,047,170	0	1,337,000	0	6,384,170
30: E&D	**EA**	1.0	1,524,528	0	404,000	0	1,928,528
31: S&A	**EA**	1.0	669,811	0	177,000	0	846,811

Norfork Option Costs - First Costs

NF-7: Existing SS Units	Relocations	Dams	Fish & Wildlife Facilities	Recreational Facilities	Engineering & Design	Supervision & Adminstration	Interest During Construction	Total Costs
50/50 Storage								
NF-7	$ -	$ 3,374,925	$ 710,321	$ 3,710,019	$ 1,600,094	$ 779,038	$ 454,200	$ 10,628,596

Norfork Option Benefits

NF-7: Existing SS Units	TW Rec. Benefits (from Contingent Value) (1)	Power Benefits (from SWPA)	Rec. Benefits (from SUPER)	In Pool Flood Benefits (from SUPER)	Down Stream Flood Benefits (from SUPER)	Total Benefits Gained
50/50 Storage						
NF-7	$ 1,519,700	$ (2,000)	$ -	$ (8,000)	$ (6,000)	$ 1,503,700

Note (1) Tailwater Recreation Benefits are reduced to reflect the reliability of the authorized storage to provide the proposed minimum flows.

Norfork Option Costs - Annual Costs

NF-7: Existing SS Units	Relocations	Dams	Fish & Wildlife Facilities	Recreational Facilities	Engineering & Design	Supervision & Adminstration	O&M	Total Costs
50/50 Storage								
NF-7	-	174,300	36,700	191,600	82,600	40,200	-	548,800

Norfork Option Benefits

NF-7: Existing SS Units	TW Rec. Benefits (from Contingent Value) (1)	Power Benefits (from SWPA)	Rec. Benefits (from SUPER)	In Pool Flood Benefits (from SUPER)	Down Stream Flood Benefits (from SUPER)	Total Benefits Gained	Net Annual Benefits
50/50 Storage							
NF-7	$ 1,519,700	$ (977,500)	$ -	$ (8,000)	$ (6,000)	$ 528,200	$ (20,600)

Note (1) Tailwater Recreation Benefits are reduced to reflect the reliability of the authorized storage to provide the proposed minimum flows.

Norfork Summary

NF-7: Existing SS Units	First Costs	Annual Total Costs	Annual Hydropower Benefits	Annual Downstream Flood Control Benefits	Annual Total Benefits	Benefits - Costs	B/C Ratio
Reallocate 50/50 NF-7	$ 10,628,596	$ 548,800	$ (977,500)	$ (6,000)	$ 528,200	**$ (20,600)**	**0.96**

First time costs estimates as shown in MCASES cost estimate.

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	Project Cost
Bid Schedule Items			8,043,396	0	2,132,000	0	10,175,396
04: Dams	**EA**	1.0	2,667,925	0	707,000	0	3,374,925
06: Fish and Wildlife Facilities	**EA**	1.0	561,321	0	149,000	0	710,321
14: Recreational Facilities	**EA**	1.0	2,933,019	0	777,000	0	3,710,019
30: E&D	**EA**	1.0	1,265,094	0	335,000	0	1,600,094
31: S&A	**EA**	1.0	616,038	0	163,000	0	779,038

Tailwater Recreation Benefits are distributed to reflect the total miles of Arkansas Trout streams.

Aggregate Tailwater Recreation Benefits calculated by the Contingent Value Method is $4,978,400 state wide.

SITE	Downstream Trout Fishery (miles)	% Total Trout Fishery
Bull Shoals	66	0.694736842
Norfork	29	0.305263158
Total Gain	95	1

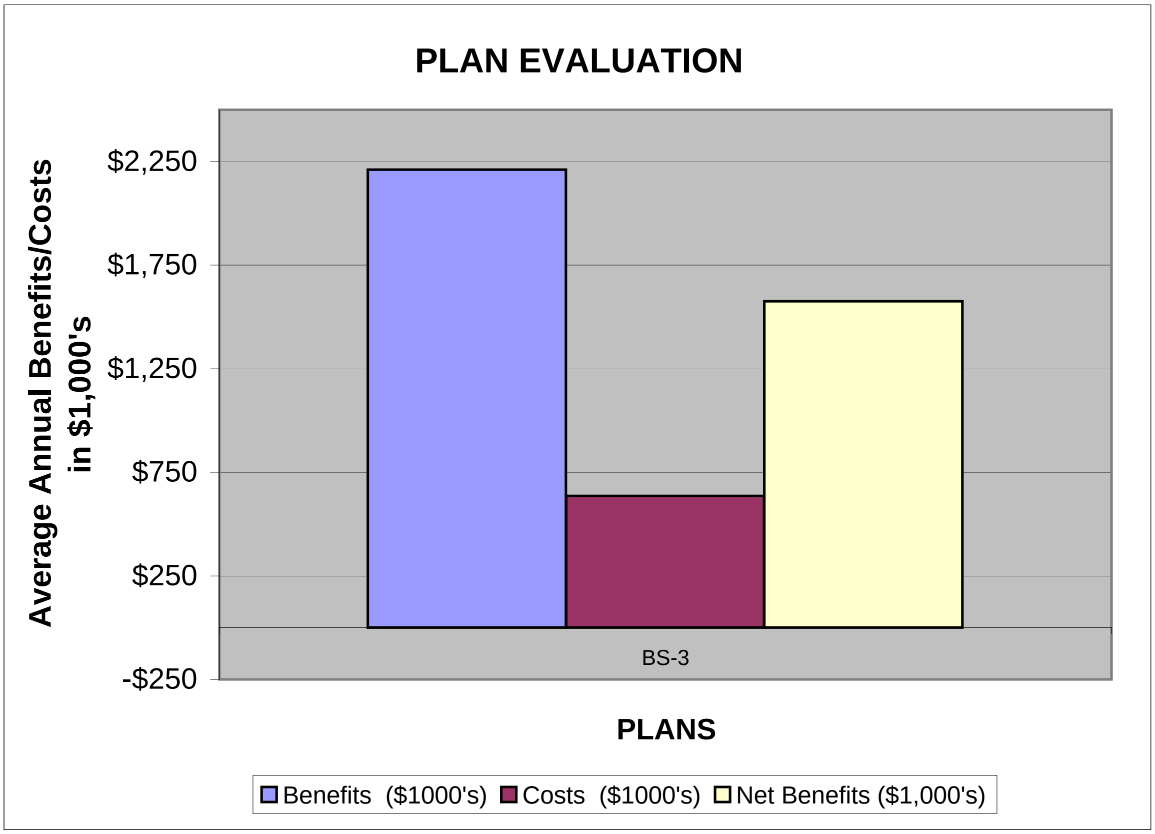
SITE	Tailwater Rec. Benefit per mile	100% Reliability Benefits
Bull Shoals	$ 3,458,678	$ 3,458,700
Norfork	$ 1,519,722	$ 1,519,700
Total Gain	$ 4,978,400	$ 4,978,400

ATTACHMENT 4

ALTERNATIVE PLANS

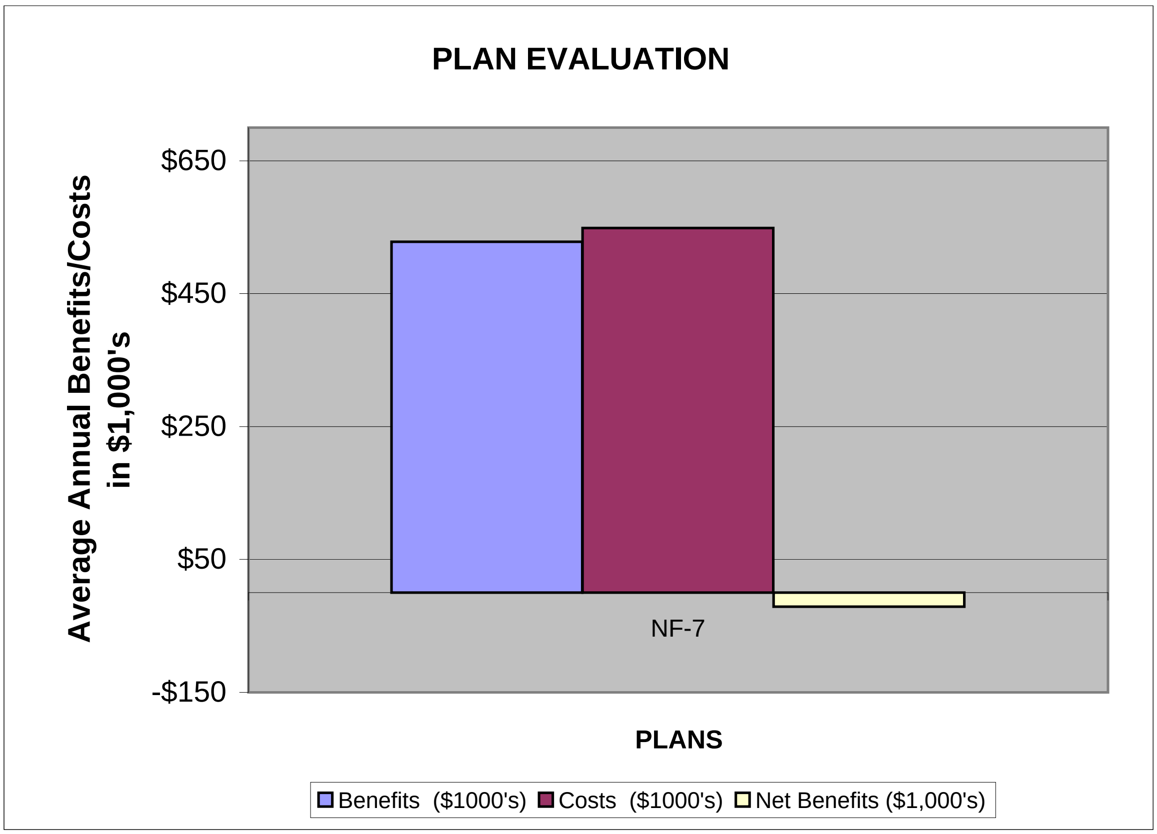
Plan: Bull Shoals Lake Options
Tailwater benefits are discounted 50% for each succeeding site and to the 100% reliability factor. Total tailwater recreation benefit distributed is $4,978,400

Measure	Average Annual Benefits ($1000's)	TOTAL Average Annual Costs ($1000's)	Average Annual Net Benefits ($1,000's)
BS-3	$2,211	$635	$1,576



Plan: Norfork Lake Options
Tailwater benefits are discounted 50% for each succeeding site and to the
100% reliability factor. Total tailwater recreation benefit distributed is $4,978,400

		TOTAL	
Measure	Average Annual Benefits ($1000's)	Average Annual Costs ($1000's)	Average Annual Net Benefits ($1,000's)
NF-7	$528	$549	-$21



White River Basin, Arkansas, Minimum Flows
Project Report

Hydraulics and Hydrology

APPENDIX B

US Army Corps
of Engineers

Little Rock District

WHITE RIVER MINIMUM FLOW FEASIBILITY STUDY

HYDROLOGIC AND HYDRAULIC REPORT WITH ADDENDUM

NOVEMBER 2006

CESWL-EC-HH

CESWL-EC-H 13 September 2006

MEMORANDUM FOR Ch, Planning Office, Attn: Mr. Mike Rodgers

SUBJECT: Review Comments of the Draft EIS for the White River Minimum Flow Reallocation Study, Project No. 102515.

1. Please include the attached comments and summary in the final EIS for the White River Minimum Flow Reallocation Study.

2. Certain aspects of the technical data were not sufficiently represented in the Executive Summary. While it is difficult to summarize all of the data for this complex project, that presented must more thoroughly reflect the findings. Review the wording in the Executive Summary along with our specific comments and summary to ensure the data is best represented. Similarly, we have provided comments regarding the body of the report. Several of the points made in the text require substantiation. In other, cases, our comments reflect what we believe to be a better representation of the data.

3. POC for H&TS Branch is Mr. Glen Raible or Mr. John Kielczewski.

Encls

HENRY HIMSTEDT, P.E.
Chief, H&TS Branch

Additional Hydrology and Hydraulic Summary for the Draft EIS for the White River Minimum Flow Reallocation Study to be included in the Executive Summary

Comparison of Extreme Events.

a. Flood Events. When considering the impacts of the proposed project, it is prudent to review the impacts upon operations at each project for extreme flood events. When annualized during the period of record, the single event impacts can be spread out and seem less significant. Impacts at Bull Shoals and Norfork were analyzed based upon SUPER model runs W01X01R for existing conditions and W06X03 for the proposed project (BS-3 & NF-7). Five historic flood events were investigated to compare pool elevation and downstream flows: 1945, 1957, 1973, 1990, and 2002. See Table ES-1A for impacts. Also, due to the "System" operation of the White River 5-Lake System (Beaver, Table Rock, Bull Shoals, Norfork and Greers Ferry Lakes), impacts at all the lakes were investigated. There were some minor impacts to the other lakes for the proposed plan (BS-3 & NF-7), but these impacts are not shown as they were deemed insignificant.

(1) At Bull Shoals, the proposed plan increased the pool elevation for each event. The increase ranged from 0.01 feet for the 1957 event to 0.88 feet for the 2002 event. None of the maximum pool elevations exceeded top of dam, although three events did exceed the flood pool for both existing and plan. The duration of storage in flood pool either had no change or the number of days above conservation pool was reduced. For the 1957 and 1973 events simulating the proposed project, the number of days above conservation pool was reduced by 10 and 15 days respectively. The impact of the proposed project on pool elevation for these events is that there will be an expected increase in the maximum pool for the extreme events but no increase in the duration that the pool is above conservation pool.

(2) At Norfork, the proposed plan increased the pool elevation for four of the five events. The increase ranged from 0.01 feet for the 1945 event to 1.26 feet for the 1990 event. For the 1957 event, the maximum pool elevation was 0.25 feet lower than the existing conditions simulation. None of the maximum pool elevations exceeded top of dam, although three events exceeded the flood pool under existing conditions and two events exceeded the flood pool under the plan. The duration of storage in flood pool was reduced slightly for the 1990 and 2002 events for the simulated proposed project, but for the 1945, 1957 and 1973 events, the number of days above conservation pool was increased by 2, 30, and 2 days respectively. In other words, if the 1957 flood event were to occur again when operating the project according to the proposed reallocation plan, Norfork Lake would be in flood control operations for approximately an additional month. The impact of the proposed project on pool elevation for these events is that there will be an expected increase in the maximum pool for the extreme events and some increase in the duration that the pool is above conservation pool.

(3) The 1945 event represented the greatest impacts above flood stage for the simulation period 1940-2003. See Table ES-1A for impacts. Simulating the proposed reallocation project using the 1945 event, the maximum discharge from Bull Shoals and Norfork lakes would have increased and the maximum stage at four downstream regulation stations investigated would have increased. At Bull Shoals the maximum outflow would have increased about 3% from

approximately 127,000 cfs to 131,000 cfs. At Norfork the maximum outflow would have increased less than 1% from approximately 42,400 cfs to 42,750 cfs. The increase in outflow would have increased the elevation in the vicinity of the dams by about 0.1 feet and would have increased the stage by 0.5 feet at Calico Rock, 0.3 feet at Batesville, 0.1 feet at Newport, and 0.3 feet at Georgetown. Each location would have exceeded flood stage under existing conditions and under the proposed plan. The increase in elevation would have caused no increase in the number of days that the White River would have exceeded flood stage at any of the gaging stations. Visual examination of the 1957, 1973, 1990, and 2002 events showed less impacts that the 1945 event for the maximum flows. The impact of the proposed project for these events is that there would be an expected increase in the maximum stages downstream for extreme events but that there is no expected increase in the duration of the events above flood stage.

b. Drought Events. Similar to flood events, the impacts of the proposed project should be analyzed for impacts upon operations at each project for drought events. For this study, four time periods were analyzed: 1953-1957, 1962-1965, 1980-1982, and 1999-2002. See Table ES-1A for impacts. Again, the impacts to Beaver, Table Rock, and Greers Ferry Lakes were investigated and deemed to be insignificant.

(1) For Bull Shoals Lake simulating the proposed plan for the 1953-1957 drought would have increased the number of days that the pool elevation remained below conservation pool by more than two months, but the lake level would not have reached as low an elevation as it did under simulated existing conditions. This drought period produced the lowest elevation and longest duration below top of conservation pool for both existing conditions and the proposed project. The 1999-2002 drought would have produced a lower elevation than existing conditions had the proposed plan been in operation; however, the lowest elevation would have been higher than the 1953-1957 drought. The proposed plan would have increased the number of days the lake was below top of conservation pool by about two months. The impact of the proposed project on pool elevation and duration for these events is that that although the minimum pool elevation may not be as severe; it would be expected to take about 6 percent longer to refill the lake to conservation pool.

(2) For Norfork Lake, the 1953-1957 drought would have had similar impacts. Simulating the proposed project increased the number of days that the pool elevation remained below conservation pool by about two months, but the lake level would not have reached as low an elevation as it did under simulated existing conditions, ending about 0.15 higher. Likewise, this drought period produced the lowest elevation and longest duration below top of conservation pool. The 1999-2002 drought would have produced a lower elevation, about -0.33 feet, than existing conditions had the proposed plan been in operation, but the lowest elevation would have been about 4.25 feet higher than the 1953-1957 drought. The 1962-1965 drought showed a lower minimum pool with the proposed plan by 2.64 feet, but still above the 1953-1957 minimum pool. The proposed plan would not have significantly increased the number of days the lake was below top of conservation pool for the 1980s or 1990s drought. The impact of the proposed project on pool elevation and duration for these events is that the minimum pool may be lower and will take about 3 percent longer to refill the lake to conservation pool.

c. Summary. In summary from a hydrologic and hydraulic perspective, the proposed project would have slightly higher flood pool elevations with minimum impacts to the duration that the pools are above conservation pool at both Bull Shoals and Norfork Lakes when considering operations during extreme events. During droughts it would be expected that Bull Shoals would have less severe minimums and Norfork would have slightly lower minimum pool elevations. At both lakes it would be expected that it will take longer to refill the lakes to conservation pool. It is expected that the increase in the maximum stages downstream from the lakes for extreme events will be minor, but there is no expected increase in the duration of the events above flood stage.

Table ES-1A
Impacts on Bull Shoals and Norfork Lake Pool Elevations and Downstream Flows
based on SUPER Model Runs W01X01R (Existing) and W06X03 (Proposed) for the Period of Simulation 1940-2003

The Current Operation Plan and the Minimum Flow Plan
BS-3 (5-ft with 100% from flood pool: new Cons Pool @ 659) and NF-7 (3.5 ft - with 50% from flood pool: new Cons Pool @ 553.75)

FLOOD EVENTS	BULL SHOALS LAKE					
	Pool Elevation W01X01R Max Pool EL Top of FCP 695 feet	Pool Elevation W06X03 Max Pool EL Top of FCP 695 feet	Pool Elev Plan Change Difference feet	No. of Days W01X01R Cons Pool Above 654	No. of Days W06X03 Cons Pool Above 659	No. of Days Plan Change Above Cons Pool
1945	697.37	697.40	0.03	288	288	0
1957	695.88	695.89	0.01	216	206	-10
1973	695.31	695.54	0.23	245	230	-15
1990	694.06	694.75	0.69	212	212	0
2002	690.02	690.90	0.88	211	205	-6
	NORFORK LAKE					
	Pool Elevation W01X01R Max Pool EL Top of FCP 580 feet	Pool Elevation W06X03 Max Pool EL Top of FCP 580 feet	Pool Elev Plan Change Difference feet	No. of Days W01X01R Cons Pool Above 552	No. of Days W06X03 Cons Pool Above 553.75	No. of Days Plan Change Above Cons Pool
1945	580.94	580.95	0.01	286	288	2
1957	580.09	579.84	-0.25	217	247	30
1973	580.38	580.43	0.05	253	255	2
1990	577.88	579.14	1.26	221	220	-1
2002	575.38	576.33	0.95	214	212	-2
DROUGHT EVENTS	**BULL SHOALS LAKE**					
	Pool Elevation W01X01R Min Pool EL Bot. Power Pool 628.5 feet	Pool Elevation W06X03 Min Pool EL Bot. Power Pool 628.5 feet	Pool Elev Plan Change Difference feet	No. of Days W01X01R Cons Pool Below 654	No. of Days W06X03 Cons Pool Below 659	No. of Days Plan Change Below Cons Pool
1953-1957	642.11	642.94	0.83	1148	1221	73
1962-1965	642.79	644.88	2.09	657	647	-10
1980-1982	643.62	644.21	0.59	577	607	30
1999-2002	644.86	644.37	-0.49	800	857	57
	NORFORK LAKE					
	Pool Elevation W01X01R Min Pool EL Bot. Power Pool 510 feet	Pool Elevation W06X03 Min Pool EL Bot. Power Pool 510 feet	Pool Elev Plan Change Difference feet	No. of Days W01X01R Cons Pool Below 552	No. of Days W06X03 Cons Pool Below 553.75	No. of Days Plan Change Below Cons Pool
1953-1957	529.63	529.78	0.15	1308	1363	55
1962-1965	534.91	532.27	-2.64	1032	1059	27
1980-1982	535.84	536.50	0.66	612	615	3
1999-2002	534.37	534.04	-0.33	949	957	8

CONTROL POINTS	Downstream Impacts for the Maximum Flood Event (1945)*									
	Flow in cfs		Plan Change	Max Stage	Max Stage	Stage Diff	Flood Stage		No. Days	
	W01X01R	W06X03	cfs	W01X01R	W06X03	feet	Stage (feet)	Flow (cfs)	Above Flood Stage	
Bull Shoals Outflow	127,053	130,905	3,852	455.67	455.78	0.1	N/A	N/A	N/A	N/A
Norfork Outflow	42,395	42,747	352	390.05	390.15	0.1	N/A	N/A	N/A	N/A
Calico Rock	249,831	255,292	5,461	43.1	43.6	0.5	19	62,150	9	9
Batesville	299,823	305,574	5,751	28.7	29.0	0.3	15	62,500	9	9
Newport	312,533	318,360	5,827	33.7	33.8	0.1	26	74,000	19	19
Georgetown	253,968	259,120	5,152	32.7	33.0	0.3	21	60,200	96	96

*The 1945 event represented the greatest impacts above flood stage for the simulation period 1940-2003 and
visual examination of the 1957, 1973, 1990 and 2002 events showed less impacts than 1945 event for the maximum flows.

US Army Corps
of Engineers

Little Rock District

DRAFT

WHITE RIVER MINIMUM FLOW FEASIBILITY STUDY

HYDROLOGIC AND HYDRAULIC REPORT

JULY 2003

CESWL-EC-HH

I have independently technically reviewed the Hydrology and Hydraulics Report to be included in the White River Minimum Flows Feasibility Study in the White River Basin, Arkansas, done by Catherine Funkhouser, Greg Mattson, and Chris Reicks. This work was based on the SWD SUPER model modified and updated by Ron Hula for a POR of 1940-1992. The work is technically correct but not to the level of detail needed to optimize the reallocation of storage necessary to provide the requested target minimum flows.

Glen A. Raible, P.E.
Hydrology and Hydraulics Engineer
CESWL-EC-HH

22 July 2003
Date

WHITE RIVER MINIMUM FLOW FEASIBILITY STUDY

HYDROLOGIC AND HYDRAULIC REPORT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICES

1. **General**

This study will investigate the feasibility of alternate White River Lakes control plans that would provide target minimum flows to benefit the downstream fisheries while minimizing impacts to flood control, hydropower, lake fisheries and recreation. A comparative analyses on the duration and frequency of alternative plans to existing conditions for the White River Lakes and the White River at certain downstream control points were performed. Backwater models were used for specified lake tailwaters and specified reaches of the White River to determine wetted area and water surface area for existing minimum flows and for proposed target minimum flows. The control points analyzed are: Calico Rock, Batesville, Newport, Augusta, Georgetown and Clarendon gages. The White River Lakes are: Beaver, Table Rock, Bull Shoals, Norfork and Greers Ferry. In order to increase the duration and frequency of target minimum flows on the White River, the reallocation of storage in the White River Lakes is proposed. The alternatives are for the reallocation of this storage to come from the conservation pool only, the flood pool only, and 50% from conservation and 50% from flood pools to come up with three alternative solutions. The four plans explored in this study are henceforth referred to as; Current, Conservation, Flood, and Split; where Current is the existing or no action plan.

1.1 Scope of Work

Hydrologic and hydraulic studies were performed to determine, frequency and duration for pool outflow, pool elevation, river stage, and river discharge for each of the respective alternative plans. Existing HEC-2 and HEC-RAS models were used to determine the wetted area and water surface area for specified flows for Beaver Tailwater to Hwy 62 bridge, for Greers Ferry tailwater to Hwy 305 bridge, and for the White River from the confluence of the North Fork River to Guion Ferry. Two high flow events and one low flow event were compared to show the impacts of the alternatives to the Current poolelevation and pool releases.

1.2 Methods and Procedures

Basic hydrologic and hydraulic data for each alternative were assembled in order to make the necessary comparisons of each alternative to the current plan. This data was used to develop annual pool elevation-frequency, pool elevation-duration, annual pool discharge-frequency and pool discharge-duration for each of the White River Lakes. The data was also used to develop annual stage-frequency, stage-duration, annual discharge-frequency and discharge-duration for the specified control points along the White River. The duration analysis was performed for annual, monthly, and seasonal (J-M, A-J, J-S, O-D) time periods. Target pool releases and critical pool elevations were used to compare the durations of the three (3) alternatives with the current plan. The target releases are listed in Table 1 and the critical pool elevations are listed in Table 2. Existing backwater models were used to determine the wetted area and water surface area for dam tailwaters and for several reaches of the White River.

Table 1
Current and Target Releases

PROJECT	CURRENT RELEASE	TARGET RELEASE
BEAVER	55	136
BULL SHOALS	210	800
NORFORK	115	300
GREERS FERRY	70	200

Table 2
Critical Pool Elevations

PROJECT	CRITICAL POOL ELEVATIONS
BEAVER	1110, 1120.43, 1121, 1121.18, 1121.93, 1130, 1140
TABLE ROCK	915, 916, 917, 931, 940, 960, 1100
BULL SHOALS	654, 656.5, 657, 659, 670, 675, 690, 695, 780
NORFORK	552, 553.75, 555, 555.5, 580, 600, 640
GREERS FERRY	461.26, 462, 462.76, 464.26, 480, 487, 490, 500

2. Hydrologic Analysis

The basic hydrologic data used for this study were developed using the White River Basin hydrologic routing model "SUPER", which was developed by Southwestern Division. The model was calibrated to documented historical events at specific control points. The calibrated model was then used to simulate the 1940-1992 period of record flows, stages and pool elevations for current conditions and for each respective alternative reservoir regulation plan of operation. These simulations resulted in continuous 53-year period of record daily flows, stages and pool elevations for current conditions and for each respective alternative at the White River Lakes specific control points along the White River. A water accounting algorithm was added to the SUPER Model to track daily fishwater (Target) releases and remaining fishwater storage volume. The algorithm allows for fishwater releases to be halted when the allocated storage is depleted, and to be resumed when increased inflows recharge the "fish" storage. The percentage of inflow that is allocated to "fish" storage is the ratio of the total fishwater storage volume to the total conservation pool volume. Fishwater releases occur when no hydropower generation is taking place.

The SUPER Model run for each alternative and the current plan is listed in Table 3 along with a brief description for each run.

Table 3
SUPER MODEL RUNS

ALTERNATIVE PLANS	SUPER RUN ID	DESCRIPTION
Current	W01X01	No Reallocation
Alternative 1 - Conservation	W01X02	Reallocation From Conservation Pool
Alternative 2 - Flood	W01X08A	Reallocation From Flood Pool
Alternative 3 - Split	W01X09A	50% of Reallocation from Conservation Pool and 50% Reallocation from Flood Pool

2.1 Frequency Data

The daily river flows, river stages, pool outflows, and pool elevations resulting from the SUPER model simulations were used in developing the annual series discharge-frequency curves at each lake and control point for current conditions and for each alternative reallocation plan.

2.2 Duration Data

The daily river flows, river stages, and pool elevations resulting from the SUPER model simulations were used to develop pool elevation-duration and river stage-duration data at each lake and control point for current conditions and for alternative reallocation plans based on daily values. For the pool outflows, the duration that the target flows were met was based on the modifications to SUPER as described in Section 2, Hydrologic Analysis, and reflect an hourly computation. Therefore, the pool outflow-durations reflect the modified SUPER model output on an hourly basis. That is, target flows for Current conditions are only met when hydropower releases are being made which is based on the "power operation-factor". The power operation-factor is the calculated percent of time in a 24 hour period that power is generated based on the plant's capacity. For the alternatives, target flows are met when hydropower releases are being made and the re-allocated storage is sufficient to meet the target release. See Appendix A for pool outflow-duration.

3. Hydraulic Analysis

3.1. Backwater Models

Existing HEC-2 backwater models for the White River Lakes tailwaters and along the White River were converted from HEC-2 to HEC-RAS 3.1.1 models. Bridge geometry requirements for HEC-2 and HEC-RAS differ slightly, so the bridges were removed from the HEC-RAS models after conversion since bridges have minimal to no effect on the low flows that were being modeled for this study. The top width, wetted perimeter and downstream reach lengths for each cross section were extracted from HEC-RAS and used to calculate the wetted area and the water surface area for the specified reaches.

4. **Results and Conclusions**

4.1. White River Lakes

4.1.1. Duration

Although the alternatives were close to being equivalent in duration for pool elevation, the pool outflow-duration analysis of the target flows for each of the lakes showed that the reallocation from the flood pool would provide the highest percentage of times that the target flows are met for annual, monthly and seasonal time periods. Reallocation from the conservation pool decreases the duration of a given pool elevation more than the other reallocations from the lake for annual, monthly and seasonal time periods.

See Appendix A for pool outflow-duration results and Appendix B for pool conservation elevation-duration results.

4.1.2. Frequency

The outflow-frequency curves for each of the alternatives for each of the lakes shows an increase in exceedance probability for the lower flows than the current plan. See Appendix C for pool outflow-frequency curves. The pool elevation-frequency alternative curves show little to no effect in the maximum pool elevation frequencies for the longer recurrence intervals, but shows significant impact on the minimum pool elevation-frequencies. The conservation reallocation causes the greatest decrease in minimum pool elevation followed by the split reallocation. Reallocation from the flood pool actually produces a higher minimum pool elevation frequency than the current plan for all lakes with the exception of Beaver Lake. See Appendix D for pool elevation-frequency curves.

4.2. White River

4.2.1. Duration

The impacts to the flood stage-duration at the control points are shown in Appendix E.

4.2.2. Frequency

All three alternatives show no increase in flood frequency at the control points along the White River. See Appendix F for stage-frequency and Appendix G for discharge-frequency curves.

4.3. Backwater Models

See Appendix H for wetted area and water surface area for selected reaches of the White River

4.4. Flood Flow and Low Flow Events

Two historic flood flow events and one low historic flood event were used to compare the impacts of the alternative plans with the current plan. The split reallocation was determined to provide similar impacts on flood flows and flood stages as the current plan while the conservation plan usually lowered the flood flows and stages. Since reallocation from the flood pool would reduce the reservoirs ability to hold back flood waters, the flood reallocation would increase flood flows and stages. Again, the current and the split plans provided similar impacts on the reservoir during drought conditions. It took a longer period of time to refill the reservoirs to the conservation pool elevation during drought conditions, using the conservation reallocation alternative. Reallocation from the flood pool decreased the period of time to refill the reservoirs to conservation pool elevation. See Appendix I for reallocation impacts on reservoirs for two flood events and one drought event.

Appendix A

Pool Outflow-Duration

Beaver Lake				
Target Flow (cfs)	Percentage of time the target is met or exceeded (Pool Outflow - Duration)			
136	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	11.2%	79.7%	85.8%	82.8%
JANUARY	11.1%	66.0%	87.2%	79.1%
FEBRUARY	9.5%	66.0%	88.9%	75.2%
MARCH	10.7%	79.7%	87.0%	83.4%
APRIL	14.8%	82.9%	90.0%	86.7%
MAY	20.2%	87.5%	92.4%	88.8%
JUNE	15.0%	85.1%	85.8%	84.2%
JULY	16.5%	83.0%	82.8%	82.1%
AUGUST	14.8%	83.2%	81.5%	81.4%
SEPTEMBER	6.8%	82.8%	81.0%	81.0%
OCTOBER	2.8%	83.6%	82.3%	82.0%
NOVEMBER	3.0%	82.9%	85.6%	85.4%
DECEMBER	8.7%	72.4%	85.7%	84.1%
JANUARY - MARCH	10.5%	70.7%	87.7%	79.4%
APRIL - JUNE	16.7%	85.2%	89.5%	86.6%
JULY - SEPTEMBER	12.8%	83.0%	81.8%	81.5%
OCTOBER - DECEMBER	4.8%	79.6%	84.5%	83.8%

Beaver Lake		
Differences in Pool Outflow-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
68.5%	74.7%	71.6%
54.9%	76.0%	68.0%
56.5%	79.4%	65.7%
69.0%	76.4%	72.7%
68.1%	75.2%	71.9%
67.3%	72.2%	68.5%
70.2%	70.9%	69.2%
66.5%	66.3%	65.5%
68.4%	66.7%	66.6%
76.1%	74.3%	74.3%
80.8%	79.5%	79.2%
80.0%	82.6%	82.4%
63.7%	77.0%	75.4%
60.2%	77.2%	68.9%
68.5%	72.7%	69.9%
70.2%	69.0%	68.7%
74.8%	79.7%	79.0%

Table Rock Lake

Target Flow (cfs)	Percentage of time the target is met or exceeded (Pool Outflow - Duration)			
400	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	23.5%	83.0%	88.3%	86.1%
JANUARY	22.3%	68.3%	83.6%	76.2%
FEBRUARY	22.5%	66.8%	78.8%	73.5%
MARCH	32.0%	81.6%	83.8%	83.9%
APRIL	39.3%	89.8%	89.8%	90.1%
MAY	30.5%	90.7%	92.7%	91.6%
JUNE	27.7%	92.0%	92.8%	92.5%
JULY	28.2%	89.2%	91.1%	90.0%
AUGUST	22.7%	90.8%	91.0%	90.9%
SEPTEMBER	9.2%	87.6%	89.4%	88.5%
OCTOBER	5.9%	86.7%	88.6%	88.5%
NOVEMBER	16.4%	79.0%	89.0%	85.9%
DECEMBER	25.0%	72.4%	87.9%	80.8%
JANUARY - MARCH	25.7%	72.4%	82.2%	78.0%
APRIL - JUNE	32.5%	90.8%	91.8%	91.4%
JULY - SEPTEMBER	20.2%	89.2%	90.5%	89.8%
OCTOBER - DECEMBER	15.8%	79.4%	88.5%	85.1%

Table Rock Lake

Differences in Pool Outflow-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
59.5%	64.8%	62.6%
46.0%	61.3%	53.9%
44.3%	56.3%	51.0%
49.6%	51.8%	51.9%
50.5%	50.5%	50.8%
60.2%	62.2%	61.1%
64.3%	65.1%	64.8%
61.0%	62.9%	61.8%
68.1%	68.3%	68.2%
78.4%	80.2%	79.2%
80.8%	82.7%	82.5%
62.6%	72.6%	69.5%
47.3%	62.9%	55.8%
46.7%	56.5%	52.3%
58.4%	59.3%	58.9%
69.0%	70.4%	69.6%
63.6%	72.7%	69.2%

Bull Shoals Lake				
Target Flow (cfs)	Percentage of time the target is met or exceeded (Pool Outflow - Duration)			
800	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	20.5%	97.2%	97.7%	97.3%
JANUARY	20.8%	96.2%	96.2%	95.9%
FEBRUARY	17.6%	97.1%	96.9%	97.0%
MARCH	26.7%	98.4%	98.4%	98.4%
APRIL	21.1%	100.0%	100.0%	100.0%
MAY	15.9%	97.0%	99.0%	98.9%
JUNE	26.7%	95.3%	98.3%	95.4%
JULY	30.3%	97.3%	97.3%	97.3%
AUGUST	25.9%	99.7%	99.7%	99.7%
SEPTEMBER	19.2%	97.9%	97.6%	97.8%
OCTOBER	9.3%	96.4%	96.4%	96.4%
NOVEMBER	9.5%	95.6%	96.3%	96.3%
DECEMBER	22.6%	95.0%	96.2%	94.8%
JANUARY - MARCH	21.8%	97.3%	97.2%	97.1%
APRIL - JUNE	21.2%	97.4%	99.1%	98.1%
JULY - SEPTEMBER	25.2%	98.3%	98.2%	98.2%
OCTOBER - DECEMBER	13.9%	95.7%	96.3%	95.8%

Bull Shoals Lake		
Differences in Pool Outflow-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
76.7%	77.2%	76.8%
75.5%	75.5%	75.1%
79.5%	79.4%	79.4%
71.7%	71.7%	71.7%
78.9%	78.9%	78.9%
81.1%	83.1%	83.1%
68.6%	71.6%	68.7%
66.9%	66.9%	66.9%
73.8%	73.8%	73.8%
78.8%	78.5%	78.6%
87.1%	87.1%	87.1%
86.0%	86.8%	86.8%
72.4%	73.6%	72.2%
75.4%	75.4%	75.3%
76.2%	77.9%	77.0%
73.1%	73.0%	73.0%
81.8%	82.4%	82.0%

Norfork Lake

Target Flow (cfs)	Percentage of time the target is met or exceeded (Pool Outflow - Duration)			
300	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	24.1%	86.6%	92.6%	89.9%
JANUARY	25.4%	83.8%	90.1%	89.8%
FEBRUARY	21.4%	80.8%	94.7%	91.6%
MARCH	29.7%	84.4%	97.4%	90.5%
APRIL	22.8%	89.4%	98.2%	91.6%
MAY	19.6%	94.1%	98.1%	96.7%
JUNE	30.6%	90.6%	95.6%	94.6%
JULY	35.9%	91.6%	95.4%	93.5%
AUGUST	28.7%	85.5%	94.2%	89.6%
SEPTEMBER	24.4%	83.9%	88.6%	84.0%
OCTOBER	14.5%	84.9%	86.7%	85.4%
NOVEMBER	9.6%	84.6%	86.0%	85.1%
DECEMBER	26.0%	85.1%	86.9%	86.3%
JANUARY - MARCH	25.7%	83.1%	94.1%	90.6%
APRIL - JUNE	24.3%	91.4%	97.3%	94.3%
JULY - SEPTEMBER	29.7%	87.0%	92.8%	89.1%
OCTOBER - DECEMBER	16.8%	84.9%	86.5%	85.6%

Norfork Lake

Differences in Pool Outflow-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
62.5%	68.6%	65.8%
58.4%	64.7%	64.3%
59.4%	73.3%	70.1%
54.6%	67.7%	60.8%
66.6%	75.4%	68.8%
74.5%	78.5%	77.1%
60.0%	65.0%	64.0%
55.6%	59.5%	57.6%
56.9%	65.5%	60.9%
59.5%	64.2%	59.7%
70.3%	72.1%	70.8%
75.0%	76.4%	75.5%
59.1%	60.9%	60.3%
57.4%	68.4%	64.9%
67.1%	73.0%	70.0%
57.3%	63.1%	59.4%
68.1%	69.7%	68.8%

Greers Ferry Lake

Target Flow (cfs)	Percentage of time the target is met or exceeded (Pool Outflow - Duration)			
200	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	19.5%	99.0%	99.7%	99.4%
JANUARY	23.3%	97.5%	98.8%	98.0%
FEBRUARY	23.9%	99.4%	99.4%	99.4%
MARCH	33.3%	100.0%	100.0%	100.0%
APRIL	33.3%	100.0%	100.0%	100.0%
MAY	23.5%	100.0%	100.0%	100.0%
JUNE	20.6%	100.0%	100.0%	100.0%
JULY	15.8%	100.0%	100.0%	100.0%
AUGUST	13.2%	100.0%	100.0%	100.0%
SEPTEMBER	10.2%	100.0%	100.0%	100.0%
OCTOBER	5.7%	98.2%	100.0%	100.0%
NOVEMBER	10.0%	96.8%	99.7%	97.9%
DECEMBER	21.3%	96.7%	98.3%	97.3%
JANUARY - MARCH	26.9%	99.0%	99.4%	99.1%
APRIL - JUNE	25.8%	100.0%	100.0%	100.0%
JULY - SEPTEMBER	13.1%	100.0%	100.0%	100.0%
OCTOBER - DECEMBER	12.4%	97.2%	99.3%	98.4%

Greers Ferry Lake

Differences in Pool Outflow-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
79.5%	80.2%	79.9%
74.2%	75.4%	74.7%
75.5%	75.5%	75.5%
66.7%	66.7%	66.7%
66.7%	66.7%	66.7%
76.5%	76.5%	76.5%
79.4%	79.4%	79.4%
84.2%	84.2%	84.2%
86.8%	86.8%	86.8%
89.8%	89.8%	89.8%
92.5%	94.3%	94.3%
86.7%	89.7%	87.8%
75.3%	76.9%	76.0%
72.0%	72.4%	72.2%
74.2%	74.2%	74.2%
86.9%	86.9%	86.9%
84.8%	86.9%	86.0%

Appendix B

Pool Elevation-Duration
at Conservation Elevation

Beaver Lake				
Target Elevation (feet)	Percentage of time the target is met or exceeded (Pool Elevation - Duration)			
1110	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	91.20	86.65	86.92	86.74
JANUARY	80.89	76.05	76.49	76.05
FEBRUARY	85.36	81.01	81.62	81.08
MARCH	89.64	86.66	86.66	86.66
APRIL	92.31	90.06	90.06	90.06
MAY	98.57	96.40	96.71	96.59
JUNE	99.62	96.35	96.92	96.47
JULY	96.46	96.15	96.15	96.15
AUGUST	96.15	94.91	95.16	95.10
SEPTEMBER	94.49	88.97	89.55	89.42
OCTOBER	89.45	83.75	83.87	83.87
NOVEMBER	87.88	74.87	75.26	74.87
DECEMBER	83.31	74.26	74.26	74.19
JANUARY - MARCH	85.30	81.25	81.59	81.27
APRIL - JUNE	96.85	94.29	94.59	94.40
JULY - SEPTEMBER	95.71	93.39	93.67	93.60
OCTOBER - DECEMBER	86.87	77.65	77.82	77.68

Beaver Lake		
Differences in Pool Elevation-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-4.54	-4.28	-4.45
-4.84	-4.40	-4.84
-4.36	-3.74	-4.29
-2.98	-2.98	-2.98
-2.24	-2.24	-2.24
-2.17	-1.86	-1.99
-3.27	-2.69	-3.14
-0.31	-0.31	-0.31
-1.24	-0.99	-1.05
-5.51	-4.94	-5.06
-5.71	-5.58	-5.58
-13.01	-12.63	-13.01
-9.06	-9.06	-9.12
-4.05	-3.71	-4.03
-2.56	-2.26	-2.45
-2.32	-2.05	-2.11
-9.22	-9.05	-9.20

Table Rock Lake				
Target Elevation (feet)	Percentage of time the target is met or exceeded (Pool Elevation - Duration)			
915	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	56.66	45.02	69.92	61.41
JANUARY	38.83	20.16	59.37	50.74
FEBRUARY	48.67	24.17	67.05	56.84
MARCH	68.42	43.05	83.06	75.99
APRIL	77.69	57.12	87.95	84.04
MAY	88.34	85.48	92.56	88.83
JUNE	92.76	88.65	95.45	92.69
JULY	80.02	71.65	95.16	86.91
AUGUST	36.60	33.00	61.35	43.24
SEPTEMBER	27.50	24.23	38.14	28.97
OCTOBER	31.70	25.37	44.98	33.93
NOVEMBER	44.10	36.86	54.29	45.38
DECEMBER	45.10	29.53	59.31	49.07
JANUARY - MARCH	52.08	29.28	69.91	61.33
APRIL - JUNE	86.28	77.18	91.99	88.52
JULY - SEPTEMBER	48.27	43.16	65.18	53.30
OCTOBER - DECEMBER	40.26	30.52	52.84	42.77

Table Rock Lake		
Differences in Pool Elevation-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-11.64	13.26	4.74
-18.67	20.53	11.91
-24.51	18.38	8.17
-25.37	14.64	7.57
-20.58	10.26	6.35
-2.85	4.22	0.50
-4.10	2.69	-0.06
-8.37	15.14	6.89
-3.60	24.75	6.64
-3.27	10.64	1.47
-6.33	13.28	2.23
-7.24	10.19	1.28
-15.57	14.21	3.97
-22.80	17.84	9.25
-9.11	5.71	2.24
-5.10	16.91	5.04
-9.74	12.58	2.51

Bull Shoals Lake				
Target Elevation (feet)	Percentage of time the target is met or exceeded (Pool Elevation - Duration)			
654	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	59.92	51.39	81.96	69.60
JANUARY	46.40	40.76	72.33	60.24
FEBRUARY	57.18	46.43	77.47	65.76
MARCH	79.65	61.72	85.61	78.04
APRIL	86.47	75.00	90.26	87.31
MAY	83.00	78.66	91.44	89.21
JUNE	89.04	83.72	92.50	90.00
JULY	88.03	79.09	94.23	89.76
AUGUST	54.84	47.58	93.24	78.85
SEPTEMBER	30.58	26.79	80.13	51.67
OCTOBER	16.81	11.79	68.05	39.83
NOVEMBER	39.55	27.56	67.12	47.88
DECEMBER	47.46	37.41	70.78	56.27
JANUARY - MARCH	61.20	49.73	78.50	68.08
APRIL - JUNE	86.14	79.12	91.40	88.84
JULY - SEPTEMBER	58.11	51.42	89.30	73.66
OCTOBER - DECEMBER	34.55	25.56	68.67	47.99

Bull Shoals Lake		
Differences in Pool Elevation-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-8.53	22.03	9.68
-5.65	25.93	13.83
-10.76	20.29	8.58
-17.93	5.96	-1.61
-11.47	3.78	0.83
-4.34	8.44	6.20
-5.32	3.46	0.96
-8.93	6.20	1.74
-7.26	38.40	24.01
-3.78	49.55	21.09
-5.02	51.24	23.01
-11.99	27.56	8.33
-10.05	23.33	8.81
-11.46	17.30	6.88
-7.02	5.26	2.70
-6.69	31.19	15.55
-8.99	34.11	13.44

Norfork Lake

Target Elevation (feet)	Percentage of time the target is met or exceeded (Pool Elevation - Duration)			
552	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	51.65	40.38	68.60	57.60
JANUARY	34.68	23.64	60.48	47.83
FEBRUARY	45.41	21.92	66.51	53.71
MARCH	66.19	37.03	78.47	71.71
APRIL	79.62	54.17	89.10	82.95
MAY	86.91	81.45	92.74	85.92
JUNE	88.91	82.69	96.15	85.71
JULY	73.76	65.94	92.87	81.89
AUGUST	36.10	33.87	67.68	44.67
SEPTEMBER	24.55	23.27	40.06	26.92
OCTOBER	18.11	12.59	36.10	24.94
NOVEMBER	31.09	23.33	46.47	38.91
DECEMBER	34.49	23.76	56.33	45.84
JANUARY - MARCH	48.86	27.70	68.55	57.87
APRIL - JUNE	85.16	72.87	92.67	84.87
JULY - SEPTEMBER	45.03	41.22	67.16	51.42
OCTOBER - DECEMBER	27.86	19.86	46.30	36.54

Norfork Lake

Differences in Pool Elevation-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-11.27	16.95	5.95
-11.04	25.81	13.15
-23.49	21.10	8.30
-29.16	12.28	5.52
-25.45	9.49	3.33
-5.46	5.83	-0.99
-6.22	7.24	-3.21
-7.82	19.11	8.13
-2.23	31.58	8.56
-1.28	15.51	2.37
-5.52	17.99	6.82
-7.76	15.38	7.82
-10.73	21.84	11.35
-21.16	19.69	9.01
-12.30	7.50	-0.30
-3.80	22.14	6.40
-8.01	18.44	8.67

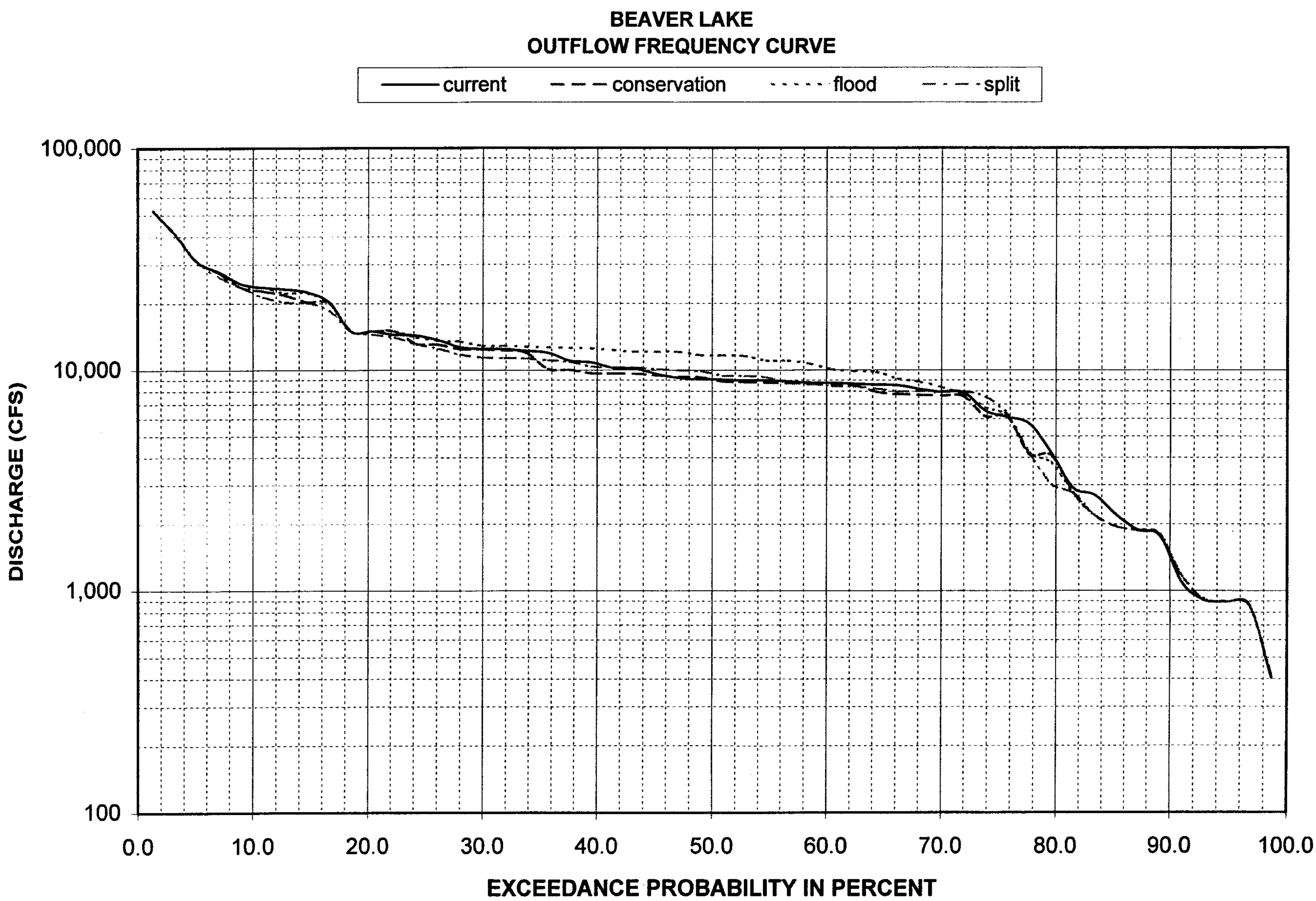
Greers Ferry				
Target Elevation (feet)	Percentage of time the target is met or exceeded (Pool Elevation - Duration)			
461.26	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	44.46	39.14	66.08	53.83
JANUARY	36.91	34.00	65.07	45.78
FEBRUARY	53.03	43.91	72.29	59.56
MARCH	74.75	64.14	89.33	80.52
APRIL	86.92	79.94	92.31	91.60
MAY	88.83	80.15	96.53	94.23
JUNE	80.13	71.28	97.88	90.96
JULY	35.11	31.70	93.30	67.62
AUGUST	10.86	9.93	53.54	22.77
SEPTEMBER	9.68	7.31	22.31	10.90
OCTOBER	9.12	6.51	21.40	16.38
NOVEMBER	19.23	16.92	34.29	25.45
DECEMBER	30.33	24.94	54.65	40.82
JANUARY - MARCH	54.95	47.45	75.67	62.03
APRIL - JUNE	85.33	77.16	95.58	92.29
JULY - SEPTEMBER	18.65	16.41	56.75	34.01
OCTOBER - DECEMBER	19.57	16.12	36.81	27.57

Greers Ferry		
Differences in Pool Elevation-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-5.32	21.61	9.37
-2.92	28.16	8.87
-9.12	19.26	6.54
-10.61	14.58	5.77
-6.99	5.38	4.68
-8.68	7.69	5.40
-8.85	17.76	10.83
-3.41	58.19	32.51
-0.93	42.68	11.91
-2.37	12.63	1.22
-2.61	12.28	7.26
-2.31	15.06	6.22
-5.40	24.32	10.48
-7.50	20.71	7.07
-8.18	10.25	6.95
-2.24	38.11	15.36
-3.45	17.24	8.01

Appendix C

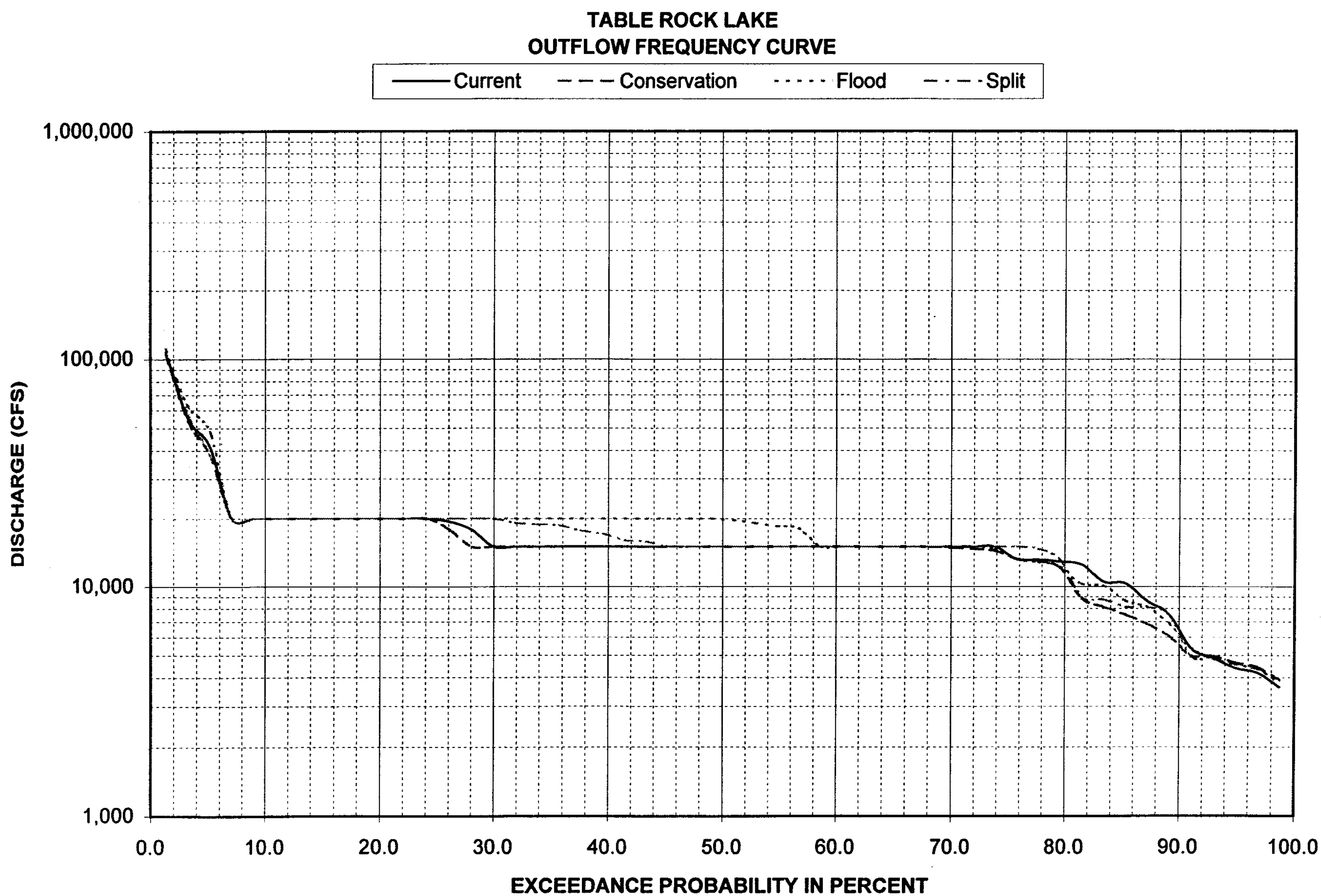
Pool Outflow-Frequency

SUMMARY CHART



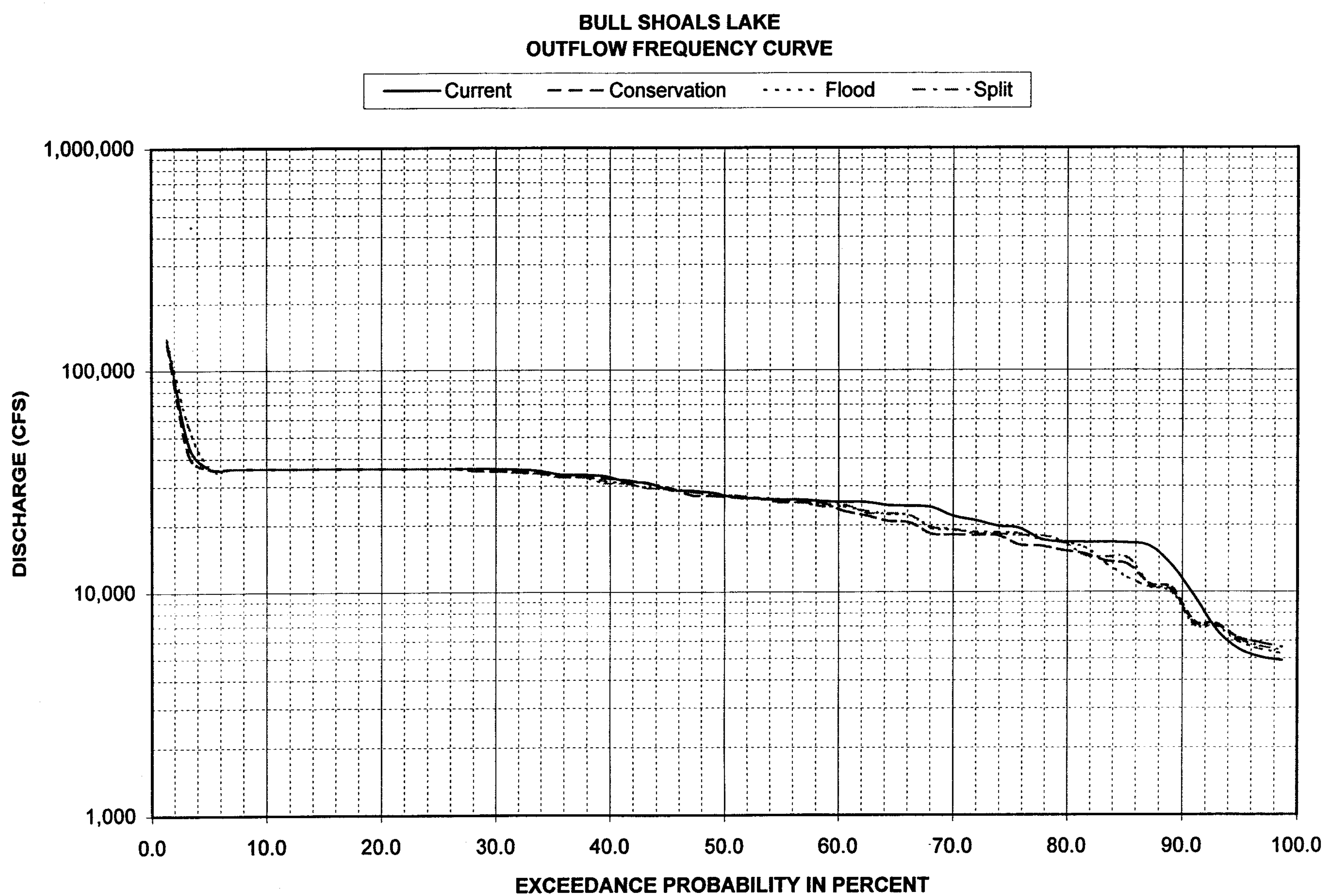
beaver_outflow_freq.xls

SUMMARY CHART



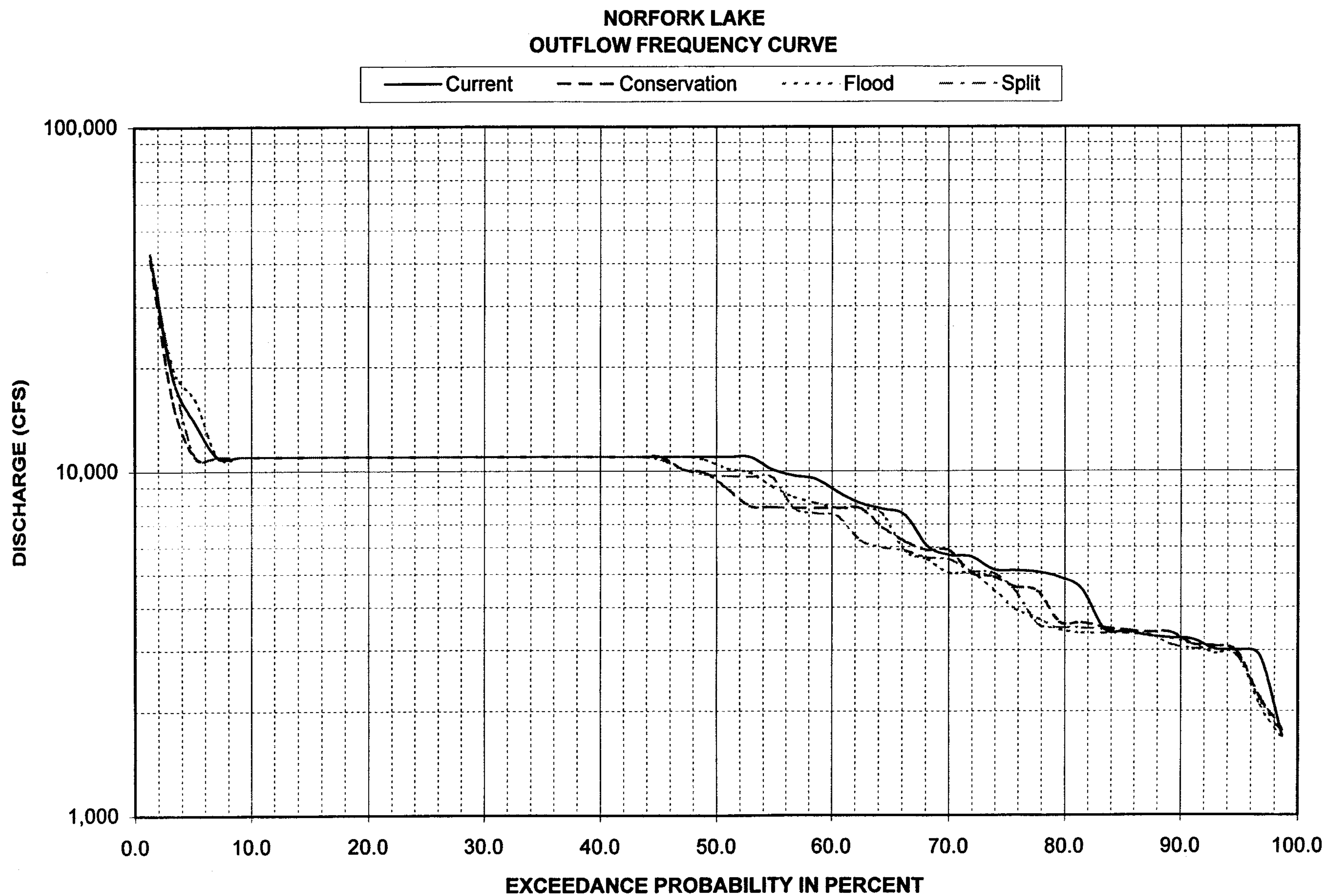
table_rock_outflow_freq.xls

SUMMARY CHART



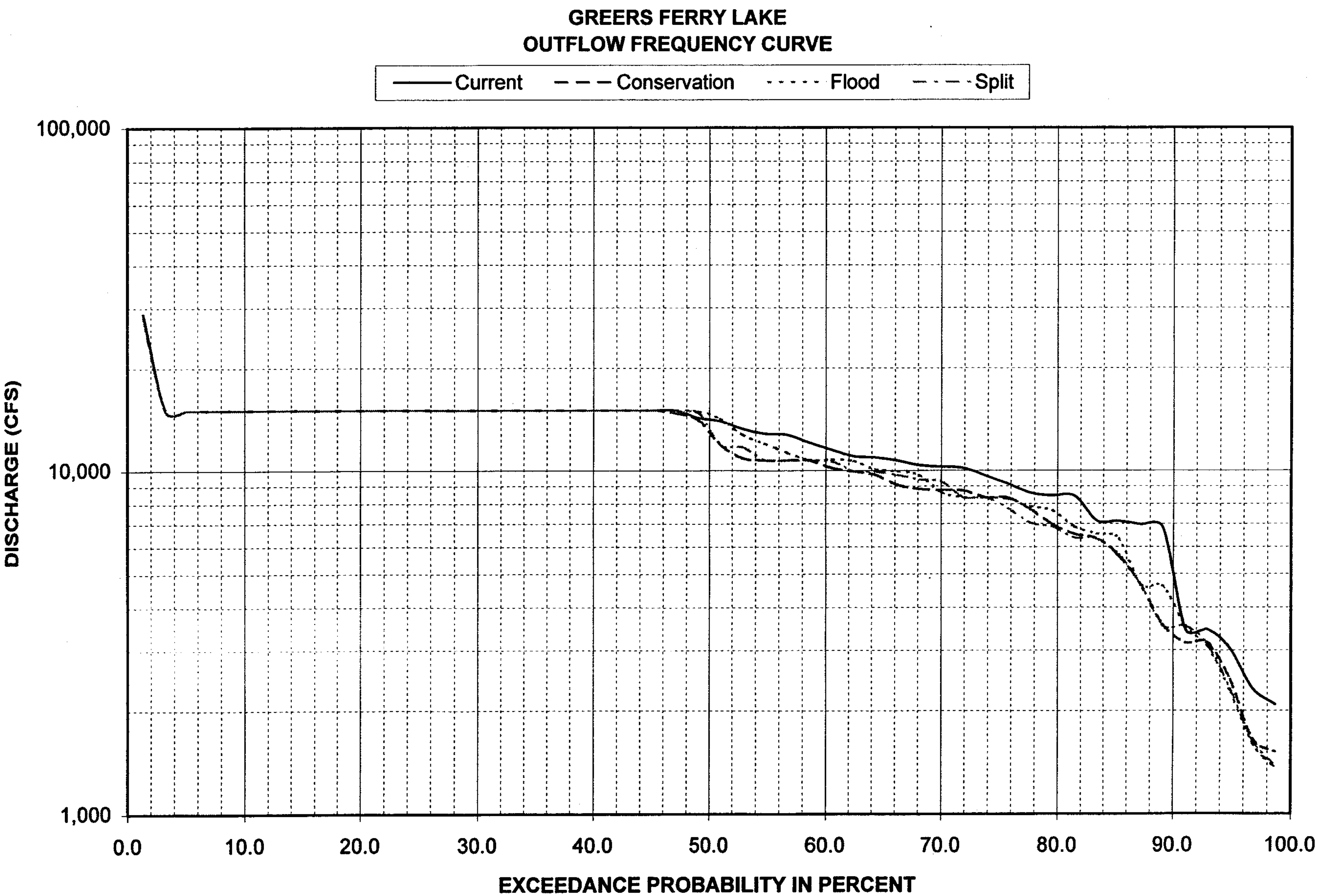
bull_shoals_outflow_freq.xls

SUMMARY CHART



norfork_outflow_freq.xls

SUMMARY CHART



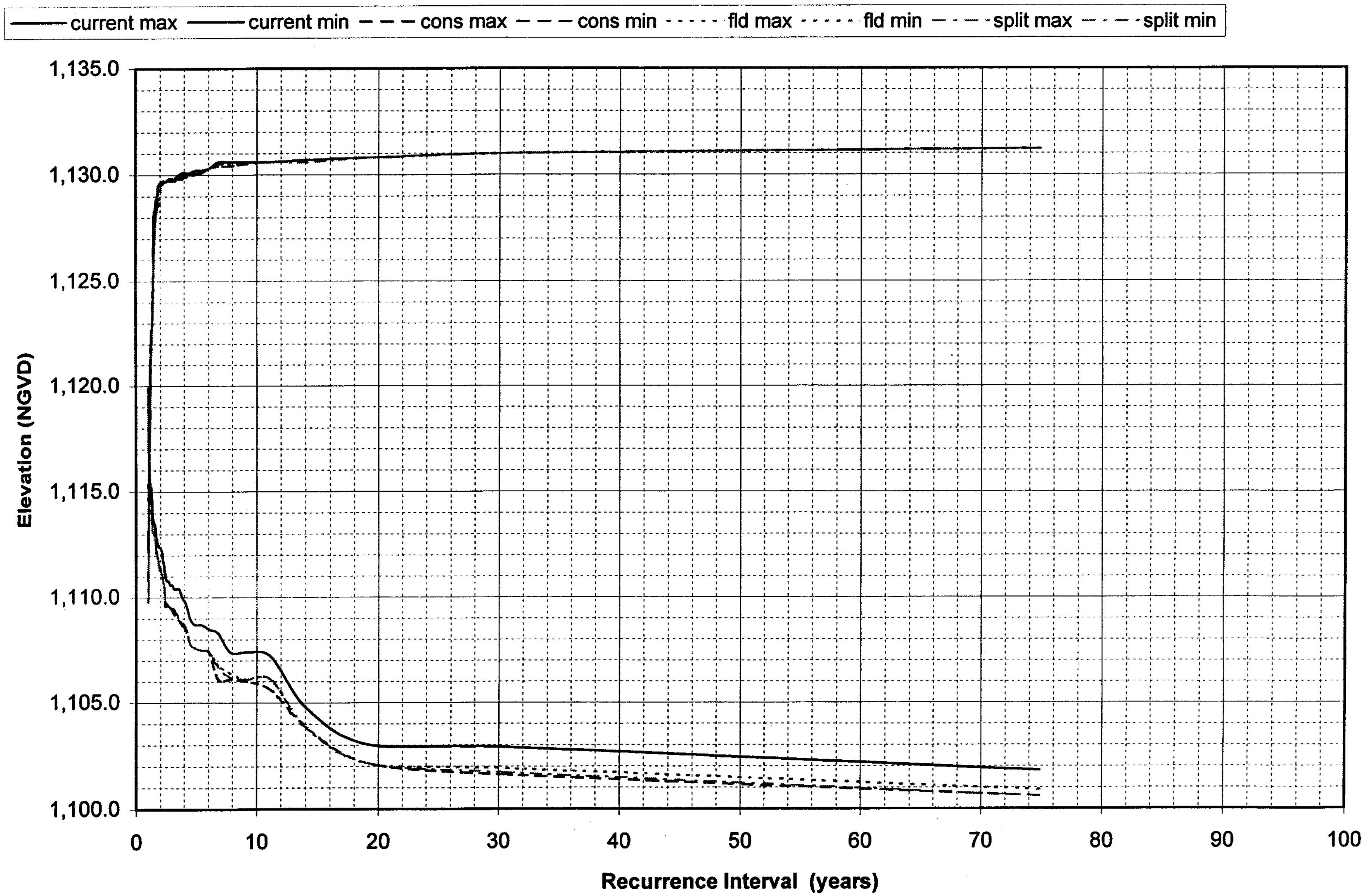
greers_ferry_outflow_freq.xls

Appendix D

Pool elevation-Frequency

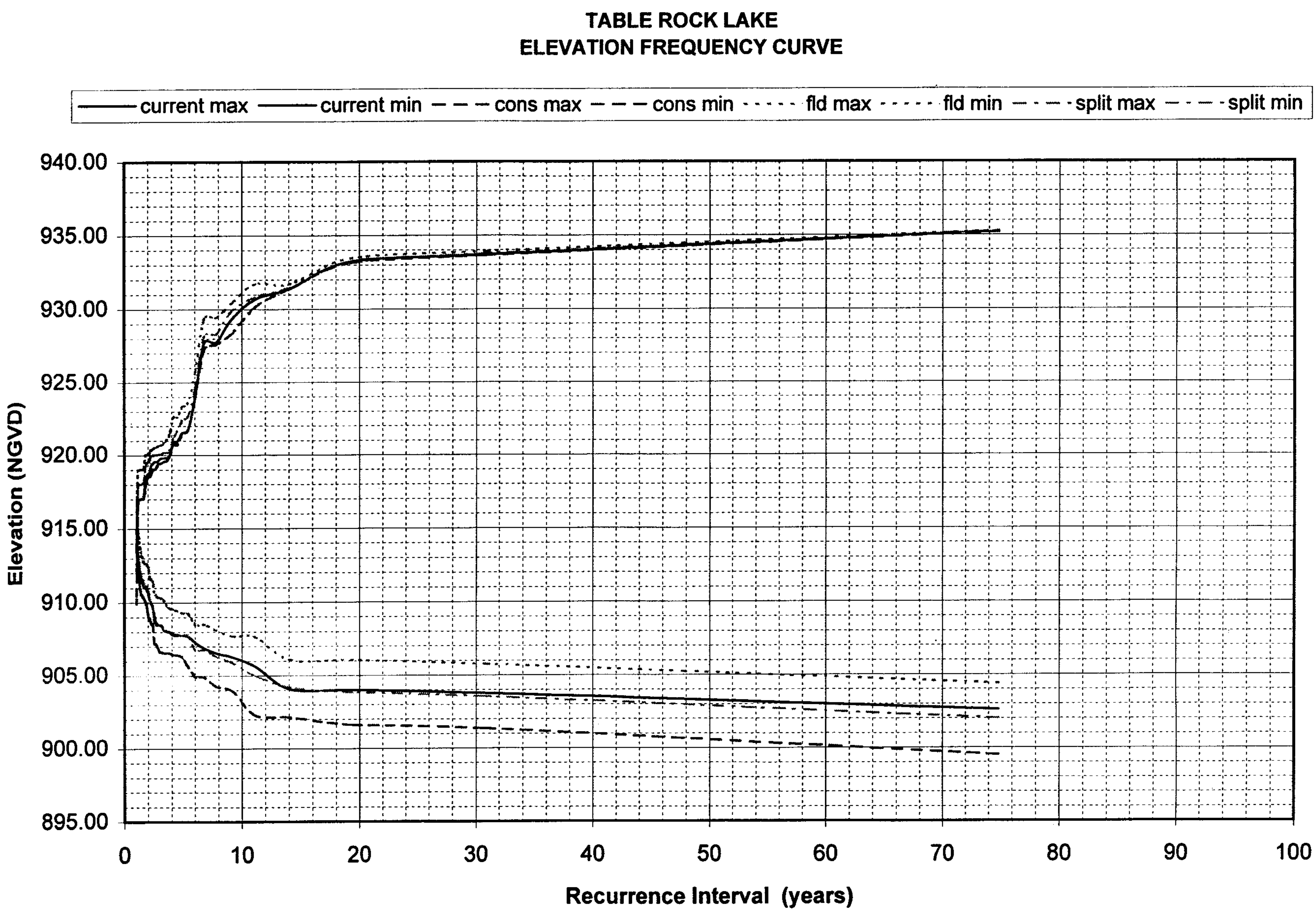
Summary chart

BEAVER LAKE
ELEVATION FREQUENCY CURVE

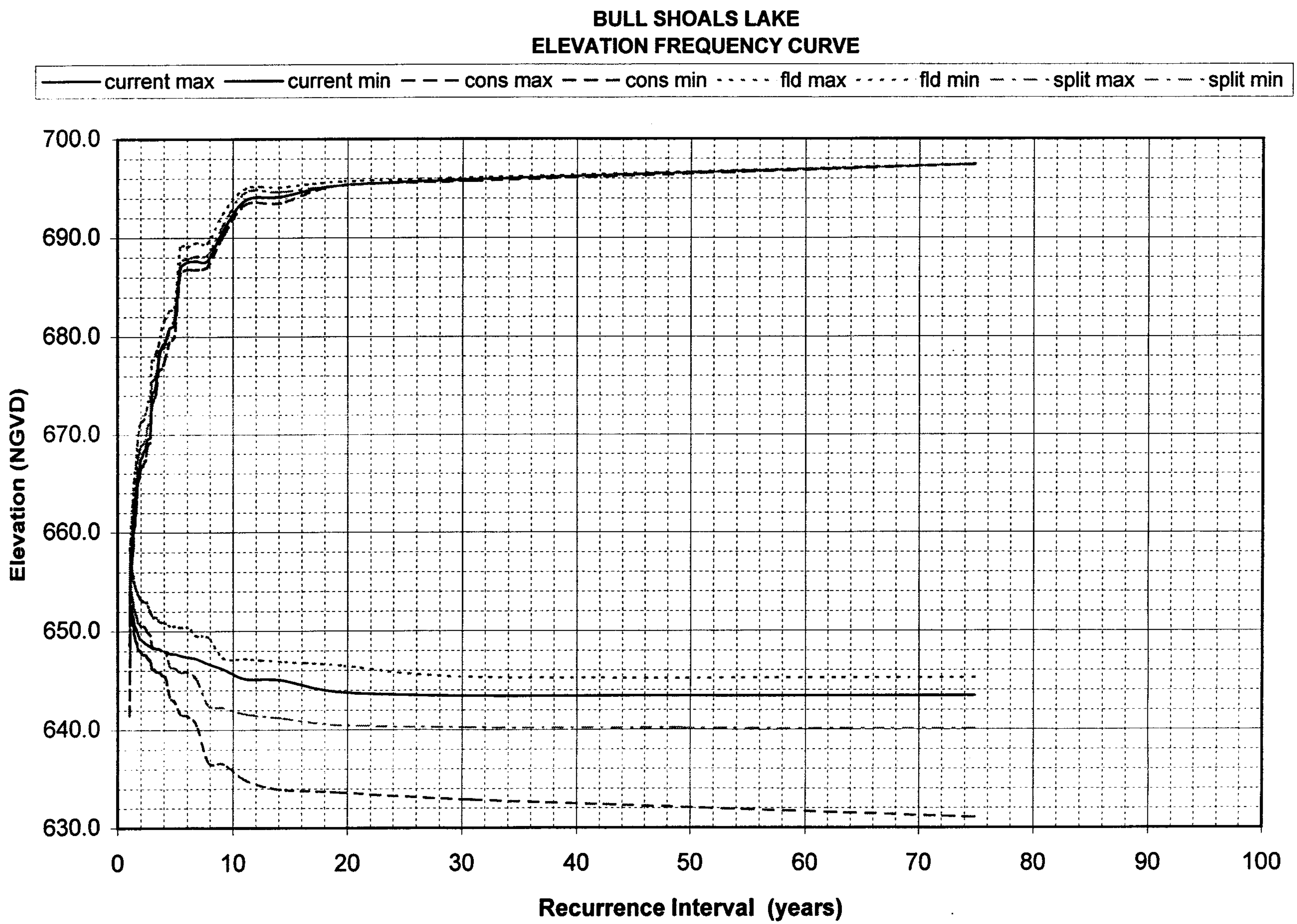


beaver_elev_freq.xls

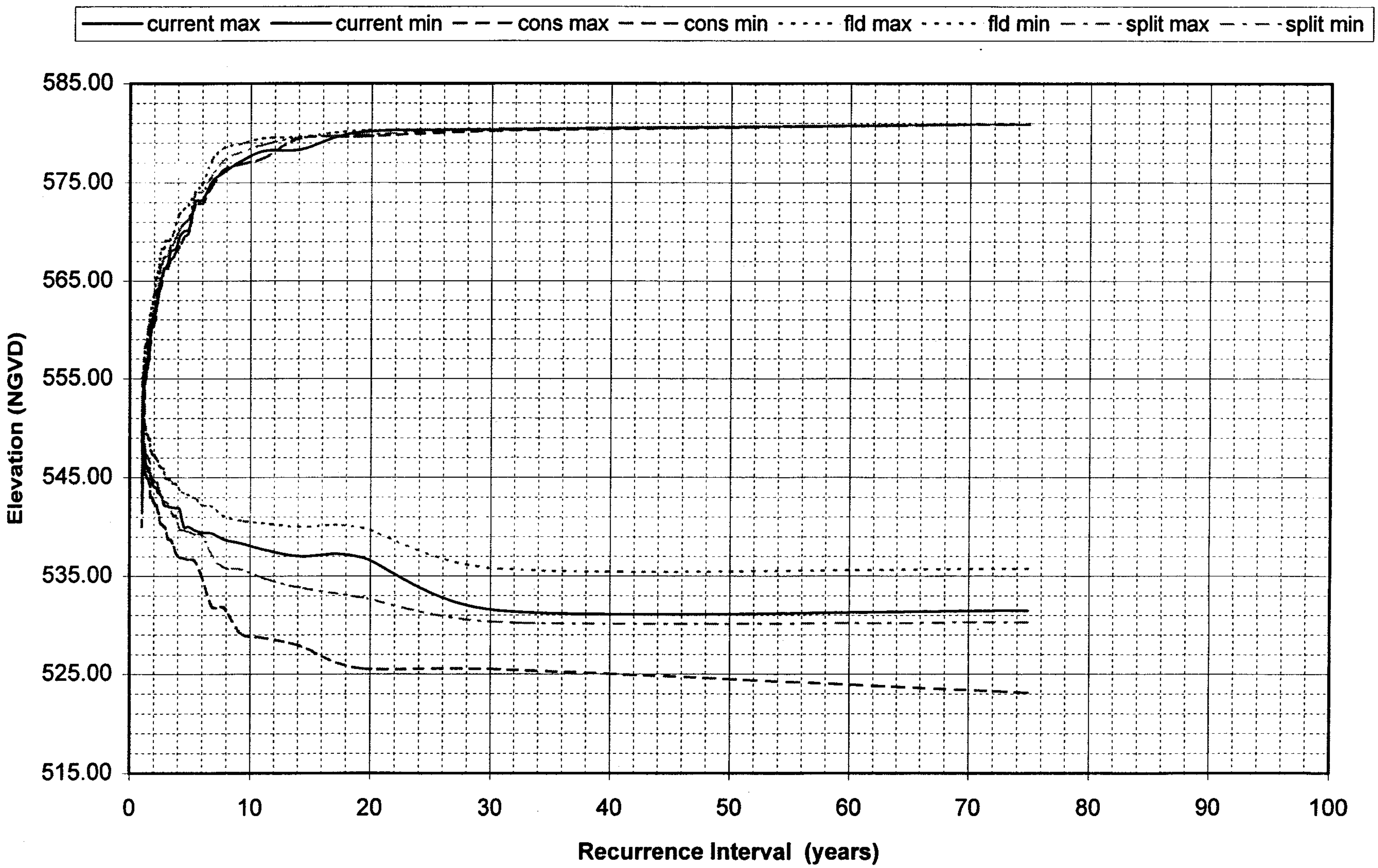
Summary chart



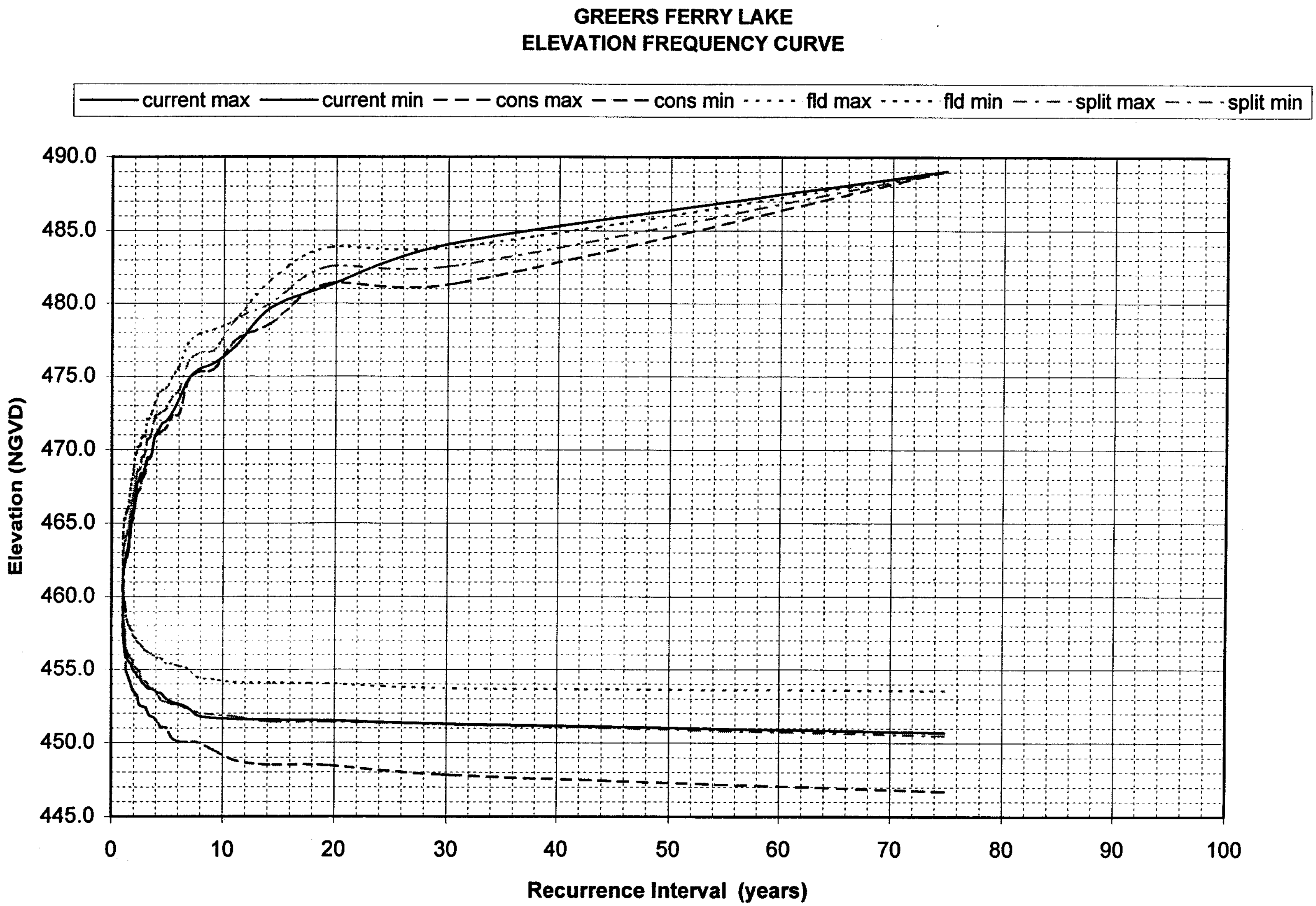
table_rock_elev_freq.xls


BULL SHOALS LAKE
ELEVATION FREQUENCY CURVE
current max
current min
cons max
cons min
fld max
fld min
split max
split min
700.0
690.0
680.0
670.0
660.0
650.0
640.0
630.0
Elevation (NGVD)
0
10
20
30
40
50
60
70
80
90
100
Recurrence Interval (years)

NORFORK LAKE
ELEVATION FREQUENCY CURVE



Summary chart



greers_ferry_elev_freq.xls

Appendix E

Stage-Duration at Flood Stage

Calico Rock

Target Stage (feet)	Percentage of time the target is met or exceeded (River Stage - Duration)			
19	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	0.25	0.23	0.28	0.24
JANUARY	0.12	0.19	0.19	0.19
FEBRUARY	0.27	0.27	0.27	0.27
MARCH	0.31	0.31	0.31	0.31
APRIL	0.77	0.77	0.77	0.77
MAY	0.56	0.31	0.87	0.37
JUNE	0.58	0.58	0.58	0.58
JULY	0.00	0.00	0.00	0.00
AUGUST	0.00	0.00	0.00	0.00
SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER	0.00	0.00	0.00	0.00
NOVEMBER	0.13	0.13	0.13	0.13
DECEMBER	0.25	0.25	0.25	0.25
JANUARY - MARCH	0.23	0.26	0.26	0.26
APRIL - JUNE	0.63	0.55	0.74	0.57
JULY - SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER - DECEMBER	0.13	0.13	0.13	0.13

Calico Rock

Differences in River Stage-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-0.02	0.03	-0.01
0.06	0.06	0.06
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
-0.25	0.31	-0.19
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.02	0.02	0.02
-0.08	0.11	-0.06
0.00	0.00	0.00
0.00	0.00	0.00

Batesville				
Target Stage (feet)	Percentage of time the target is met or exceeded (River Stage - Duration)			
15	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	0.48	0.47	0.53	0.48
JANUARY	0.56	0.56	0.56	0.56
FEBRUARY	0.75	0.75	0.75	0.75
MARCH	0.87	0.87	0.87	0.87
APRIL	1.35	1.41	1.47	1.41
MAY	0.81	0.62	1.18	0.74
JUNE	0.71	0.71	0.71	0.71
JULY	0.00	0.00	0.00	0.00
AUGUST	0.00	0.00	0.00	0.00
SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER	0.00	0.00	0.00	0.00
NOVEMBER	0.19	0.19	0.19	0.19
DECEMBER	0.62	0.62	0.62	0.62
JANUARY - MARCH	0.72	0.72	0.72	0.72
APRIL - JUNE	0.95	0.91	1.12	0.95
JULY - SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER - DECEMBER	0.27	0.27	0.27	0.27

Batesville		
Differences in River Stage-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-0.01	0.04	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.06	0.13	0.06
-0.19	0.37	-0.06
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
-0.04	0.17	0.00
0.00	0.00	0.00
0.00	0.00	0.00

Newport

Target Stage (feet)	Percentage of time the target is met or exceeded (River Stage - Duration)			
26	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	1.65	1.65	1.68	1.67
JANUARY	1.61	1.80	1.80	1.80
FEBRUARY	2.31	2.31	2.31	2.31
MARCH	2.30	2.36	2.36	2.36
APRIL	5.06	4.81	5.13	5.06
MAY	4.03	4.03	4.09	4.03
JUNE	2.12	2.12	2.12	2.12
JULY	0.00	0.00	0.00	0.00
AUGUST	0.00	0.00	0.00	0.00
SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER	0.00	0.00	0.00	0.00
NOVEMBER	0.26	0.26	0.26	0.26
DECEMBER	2.17	2.23	2.23	2.23
JANUARY - MARCH	2.07	2.15	2.15	2.15
APRIL - JUNE	3.74	3.66	3.78	3.74
JULY - SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER - DECEMBER	0.82	0.84	0.84	0.84

Newport

Differences in River Stage-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
0.01	0.04	0.03
0.19	0.19	0.19
0.00	0.00	0.00
0.06	0.06	0.06
-0.26	0.06	0.00
0.00	0.06	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.06	0.06	0.06
0.09	0.09	0.09
-0.08	0.04	0.00
0.00	0.00	0.00
0.02	0.02	0.02

Augusta				
Target Stage (feet)	Percentage of time the target is met or exceeded (River Stage - Duration)			
26	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	32.28	31.99	32.20	32.17
JANUARY	39.39	39.27	39.02	39.39
FEBRUARY	41.18	40.57	40.71	40.78
MARCH	58.06	56.02	57.01	56.39
APRIL	68.08	66.60	67.31	66.99
MAY	55.40	54.96	55.21	55.33
JUNE	31.03	31.60	32.69	31.86
JULY	18.05	18.61	19.11	18.92
AUGUST	8.50	8.68	8.75	8.87
SEPTEMBER	7.31	7.88	8.01	8.27
OCTOBER	5.09	4.90	4.65	4.78
NOVEMBER	18.21	18.27	17.95	18.01
DECEMBER	37.72	37.10	36.66	37.10
JANUARY - MARCH	46.37	45.43	45.73	45.66
APRIL - JUNE	51.54	51.10	51.78	51.44
JULY - SEPTEMBER	11.33	11.77	12.00	12.06
OCTOBER - DECEMBER	20.36	20.11	19.77	19.98

Augusta		
Differences in River Stage-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-0.29	-0.08	-0.11
-0.12	-0.37	0.00
-0.61	-0.48	-0.41
-2.05	-1.05	-1.67
-1.47	-0.77	-1.09
-0.43	-0.19	-0.06
0.58	1.67	0.83
0.56	1.05	0.87
0.19	0.25	0.37
0.58	0.71	0.96
-0.19	-0.43	-0.31
0.06	-0.26	-0.19
-0.62	-1.05	-0.62
-0.94	-0.64	-0.70
-0.44	0.23	-0.11
0.44	0.67	0.73
-0.25	-0.59	-0.38

Georgetown				
Target Stage (feet)	Percentage of time the target is met or exceeded (River Stage - Duration)			
21	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	7.26	6.97	7.03	6.98
JANUARY	15.14	14.33	14.52	14.21
FEBRUARY	10.21	8.85	9.33	9.26
MARCH	18.92	18.42	18.36	18.42
APRIL	17.63	17.18	17.18	17.12
MAY	11.85	11.85	11.97	11.85
JUNE	3.72	3.72	3.72	3.72
JULY	0.62	0.62	0.62	0.62
AUGUST	0.00	0.00	0.00	0.00
SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER	0.00	0.00	0.00	0.00
NOVEMBER	0.19	0.19	0.19	0.19
DECEMBER	8.81	8.37	8.44	8.37
JANUARY - MARCH	14.89	14.02	14.21	14.11
APRIL - JUNE	11.07	10.93	10.97	10.90
JULY - SEPTEMBER	0.21	0.21	0.21	0.21
OCTOBER - DECEMBER	3.03	2.88	2.91	2.88

Georgetown		
Differences in River Stage-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-0.29	-0.23	-0.27
-0.81	-0.62	-0.93
-1.36	-0.88	-0.95
-0.50	-0.56	-0.50
-0.45	-0.45	-0.51
0.00	0.12	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
-0.43	-0.37	-0.43
-0.87	-0.68	-0.79
-0.15	-0.11	-0.17
0.00	0.00	0.00
-0.15	-0.13	-0.15

Clarendon

Target Stage (feet)	Percentage of time the target is met or exceeded (River Stage - Duration)			
26	CURRENT	CONSERVATION	FLOOD	SPLIT 50/50
ANNUAL	17.26	16.79	17.01	16.95
JANUARY	25.93	25.43	25.81	25.81
FEBRUARY	25.94	25.19	25.05	25.53
MARCH	39.58	37.53	38.28	38.09
APRIL	47.95	45.83	46.73	46.47
MAY	29.78	30.33	30.27	30.27
JUNE	10.51	10.83	11.09	10.83
JULY	1.12	1.12	1.12	1.12
AUGUST	0.00	0.00	0.00	0.00
SEPTEMBER	0.00	0.00	0.00	0.00
OCTOBER	0.43	0.43	0.43	0.43
NOVEMBER	4.17	4.29	4.23	4.29
DECEMBER	22.27	21.03	21.59	21.15
JANUARY - MARCH	30.62	29.51	29.85	29.94
APRIL - JUNE	29.42	29.02	29.37	29.21
JULY - SEPTEMBER	0.38	0.38	0.38	0.38
OCTOBER - DECEMBER	9.01	8.63	8.80	8.67

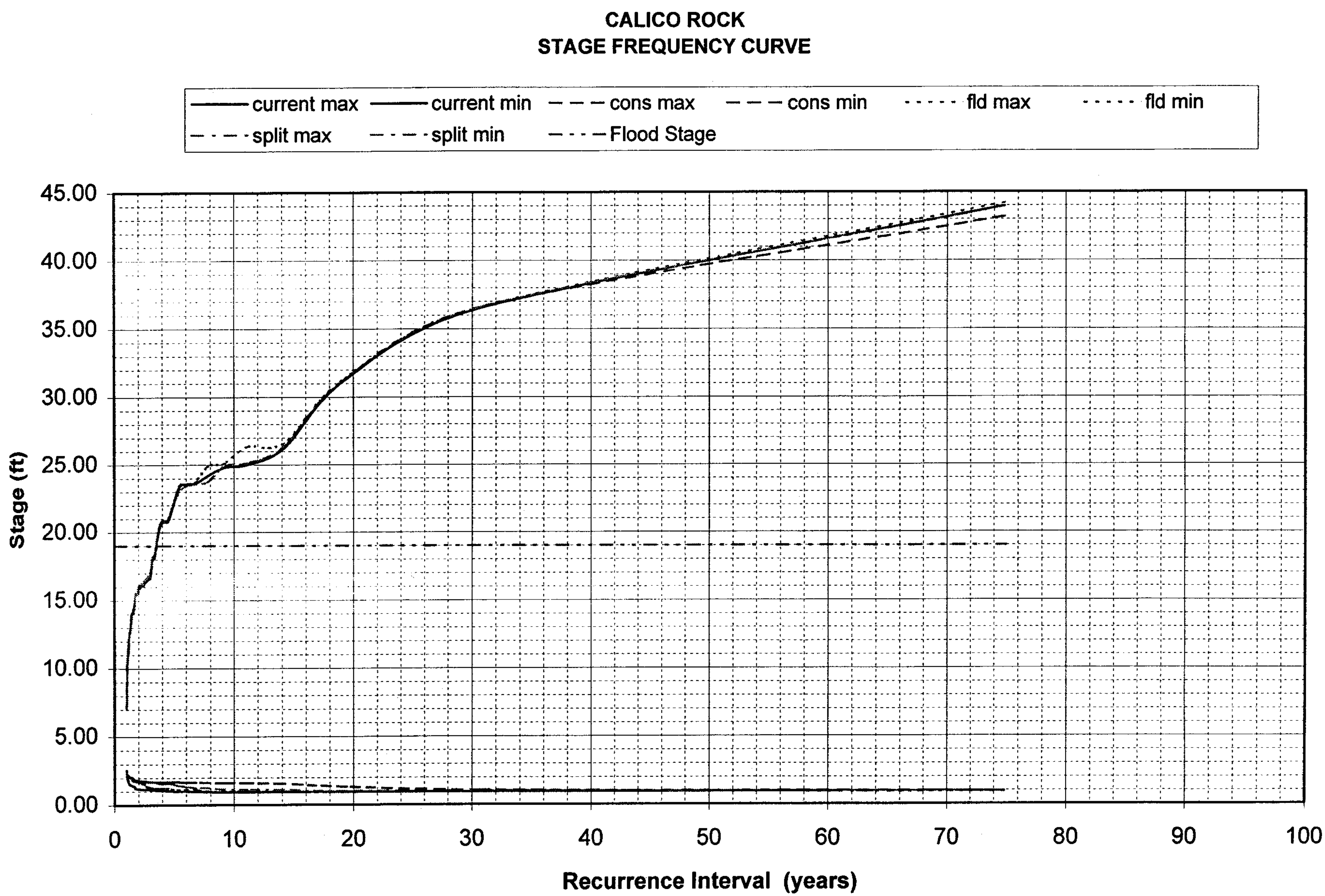
Clarendon

Differences in River Stage-Duration (Alternative minus Current)		
CONSERVATION	FLOOD	SPLIT 50/50
-0.47	-0.25	-0.31
-0.50	-0.12	-0.12
-0.75	-0.88	-0.41
-2.05	-1.30	-1.49
-2.12	-1.22	-1.47
0.56	0.50	0.50
0.32	0.58	0.32
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.13	0.06	0.13
-1.24	-0.68	-1.12
-1.11	-0.77	-0.68
-0.40	-0.04	-0.21
0.00	0.00	0.00
-0.38	-0.21	-0.33

Appendix F

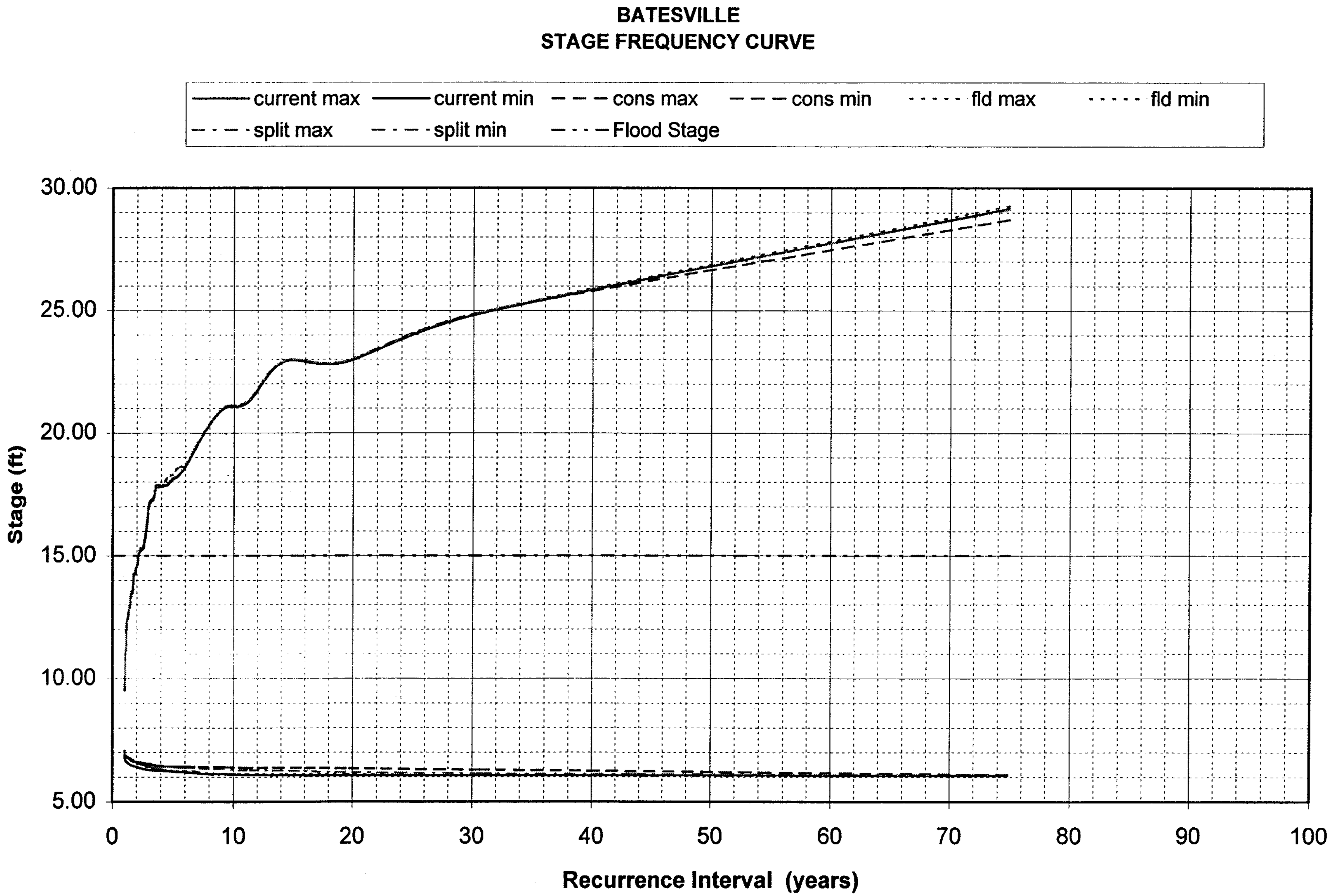
Stage-Frequency

SUMMARY CHART



calico_rock_stage_freq.xls

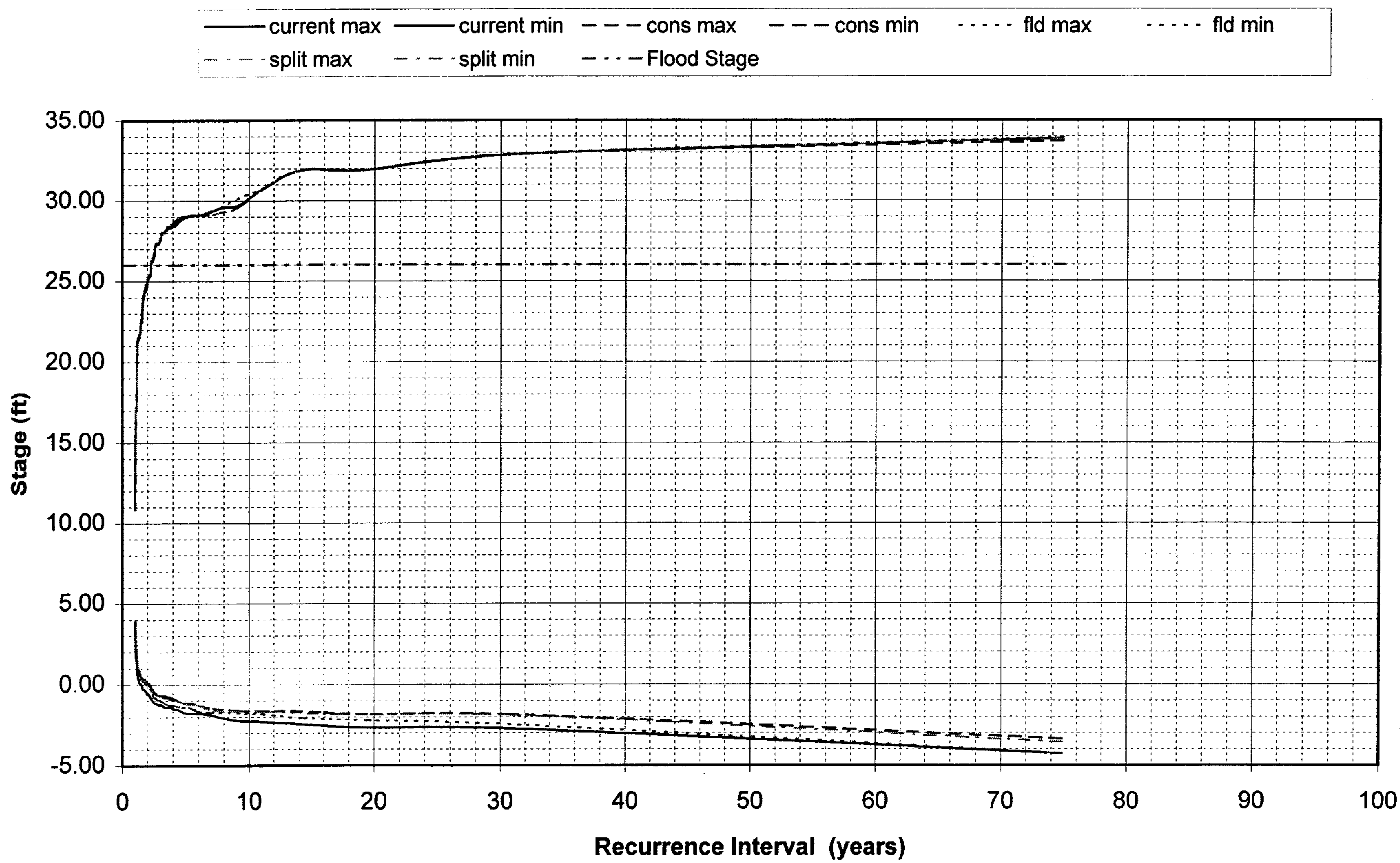
SUMMARY CHART



batesville_stage_freq.xls

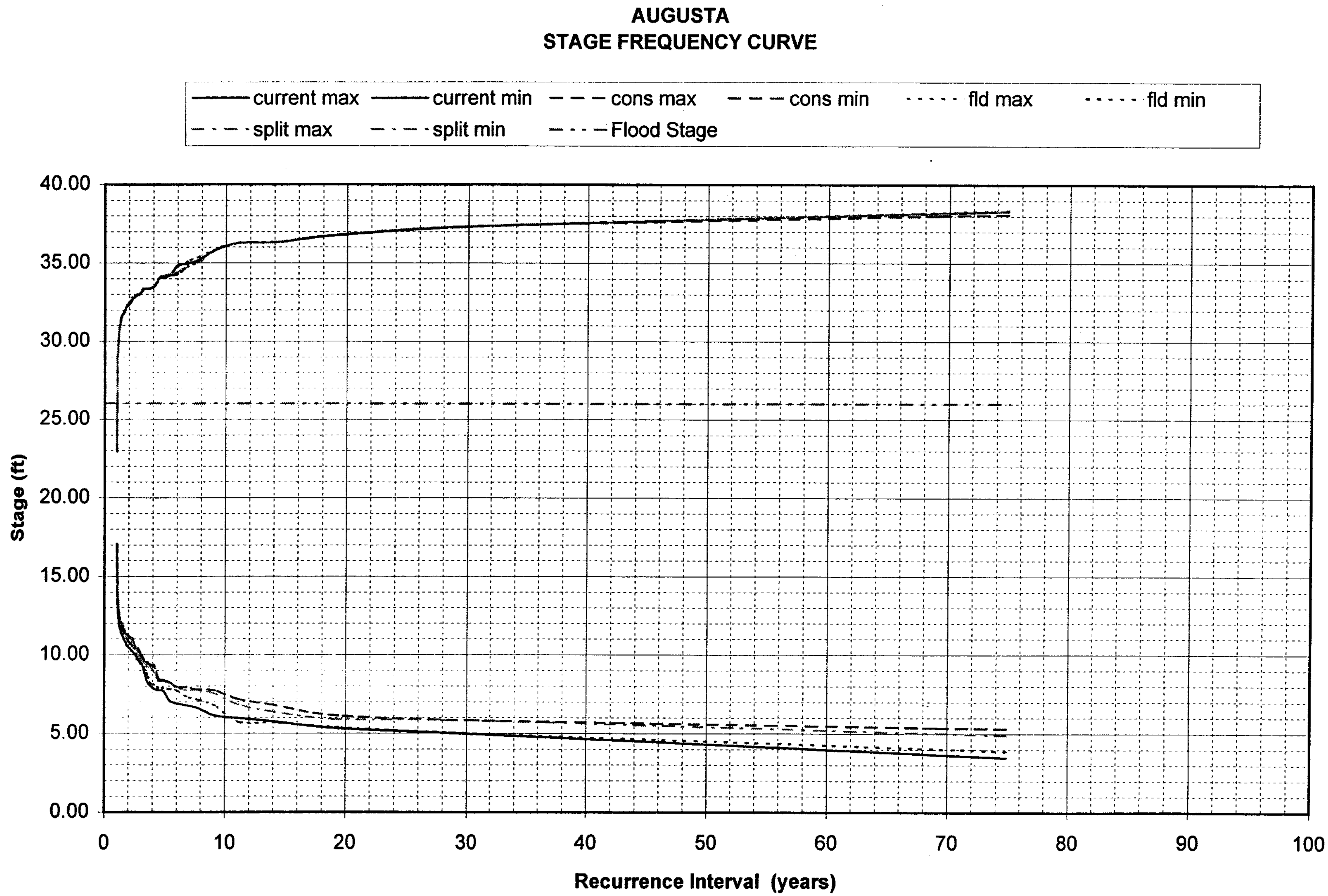
SUMMARY CHART

NEWPORT
STAGE FREQUENCY CURVE



newport_stage_freq.xls

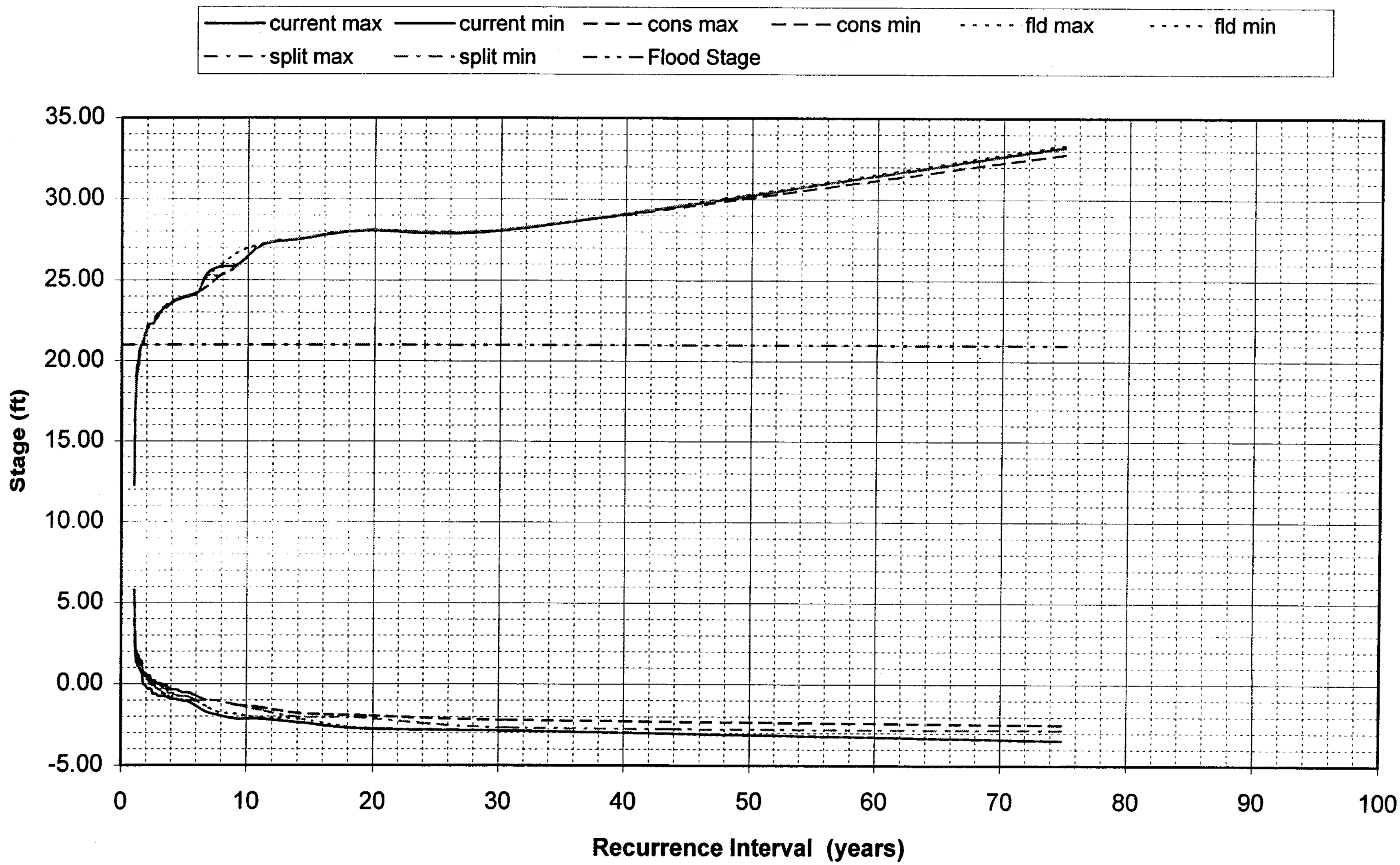
SUMMARY CHART



augusta_stage_freq.xls

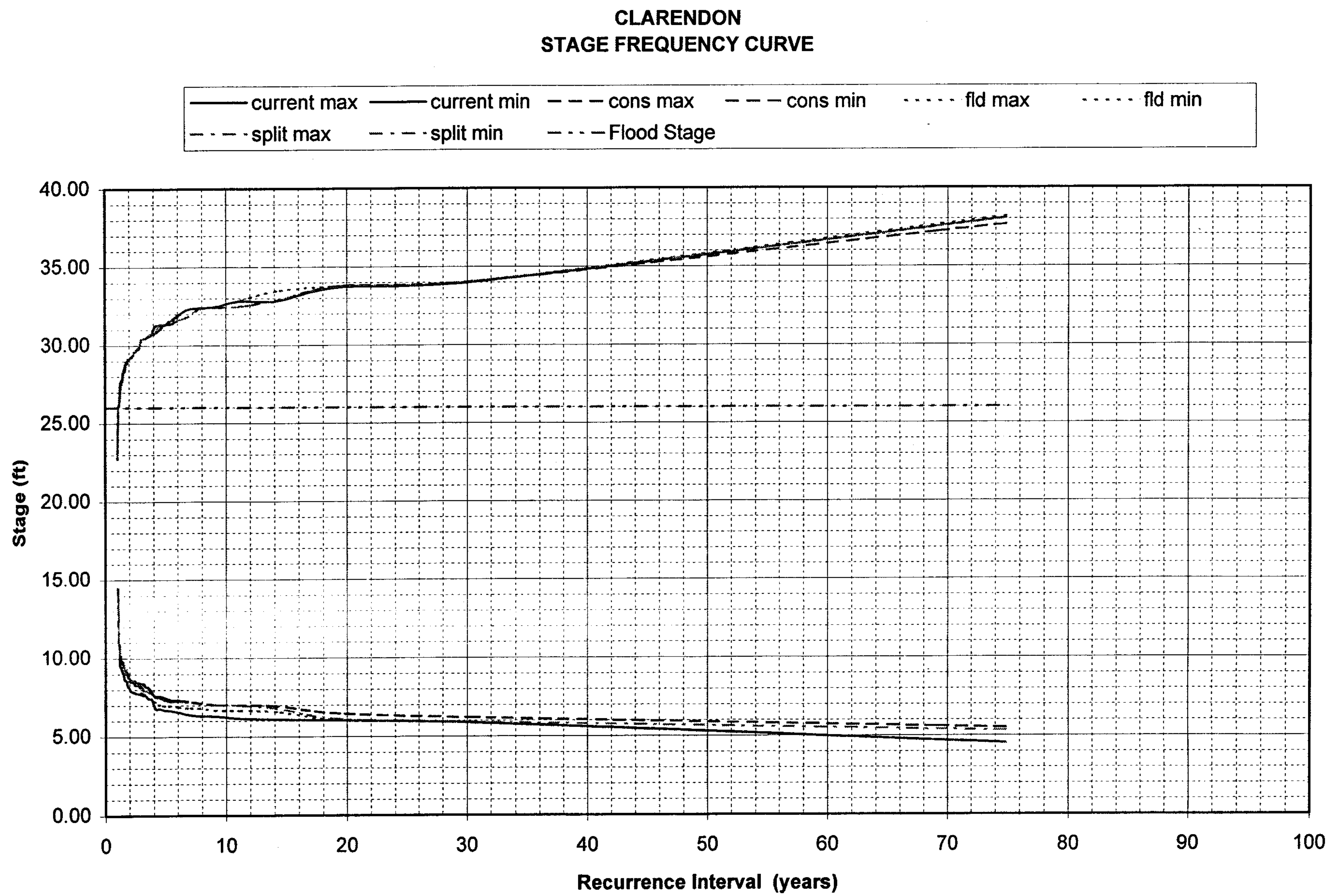
SUMMARY CHART

GEORGETOWN
STAGE FREQUENCY CURVE



georgetown_stage_freq.xls

SUMMARY CHART

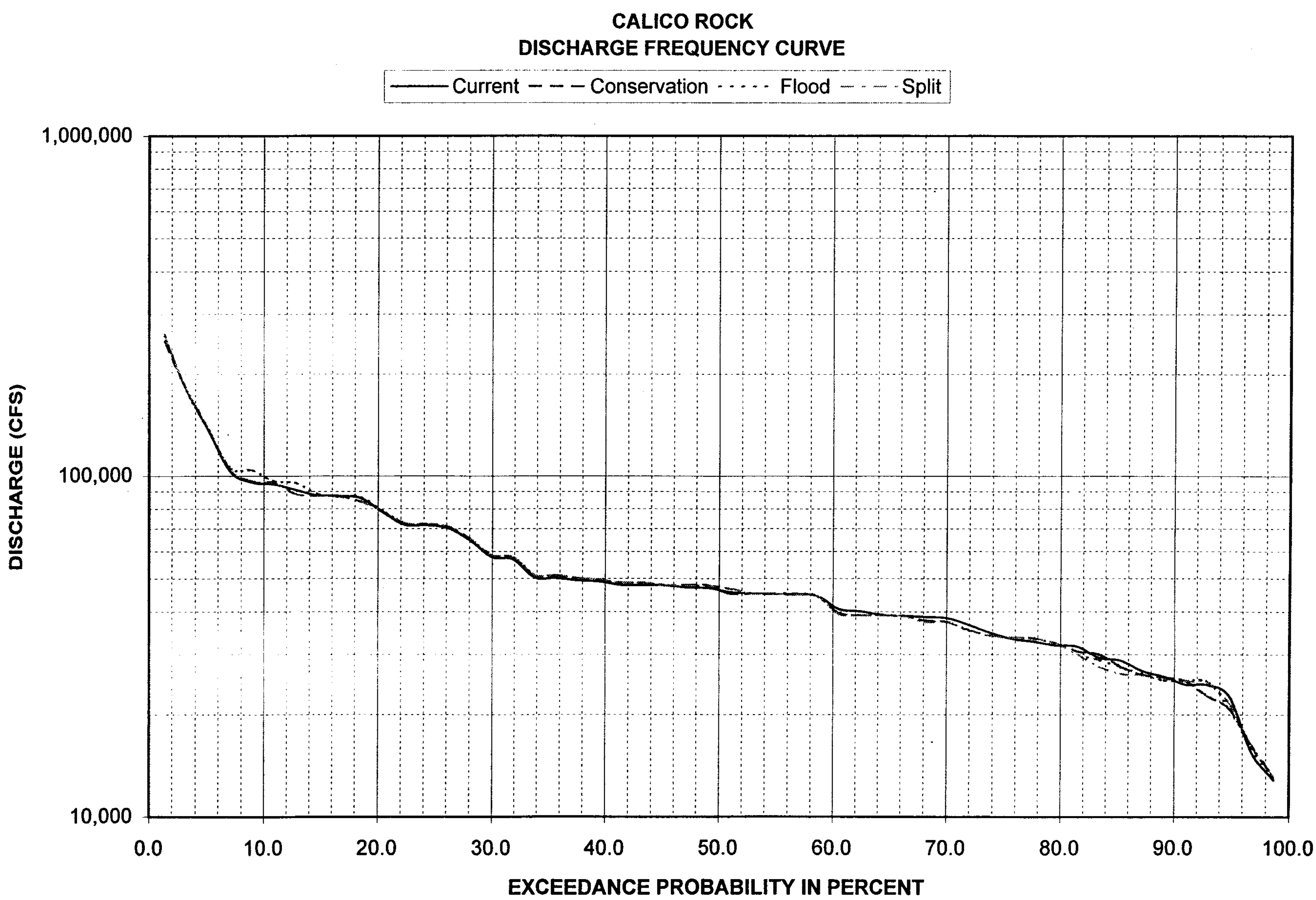


clarendon_stage_freq.xls

Appendix G

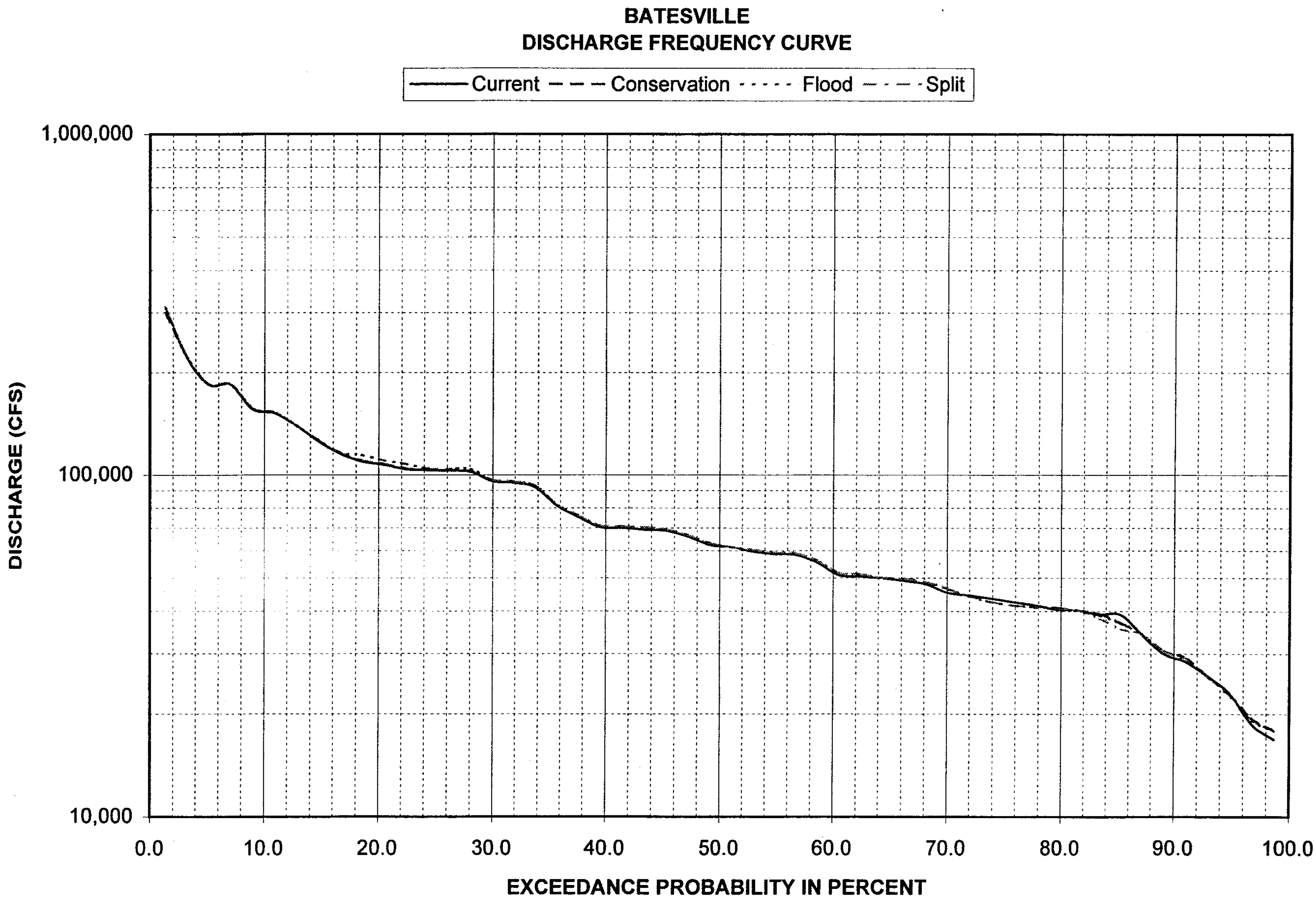
Discharge-Frequency

SUMMARY CHART



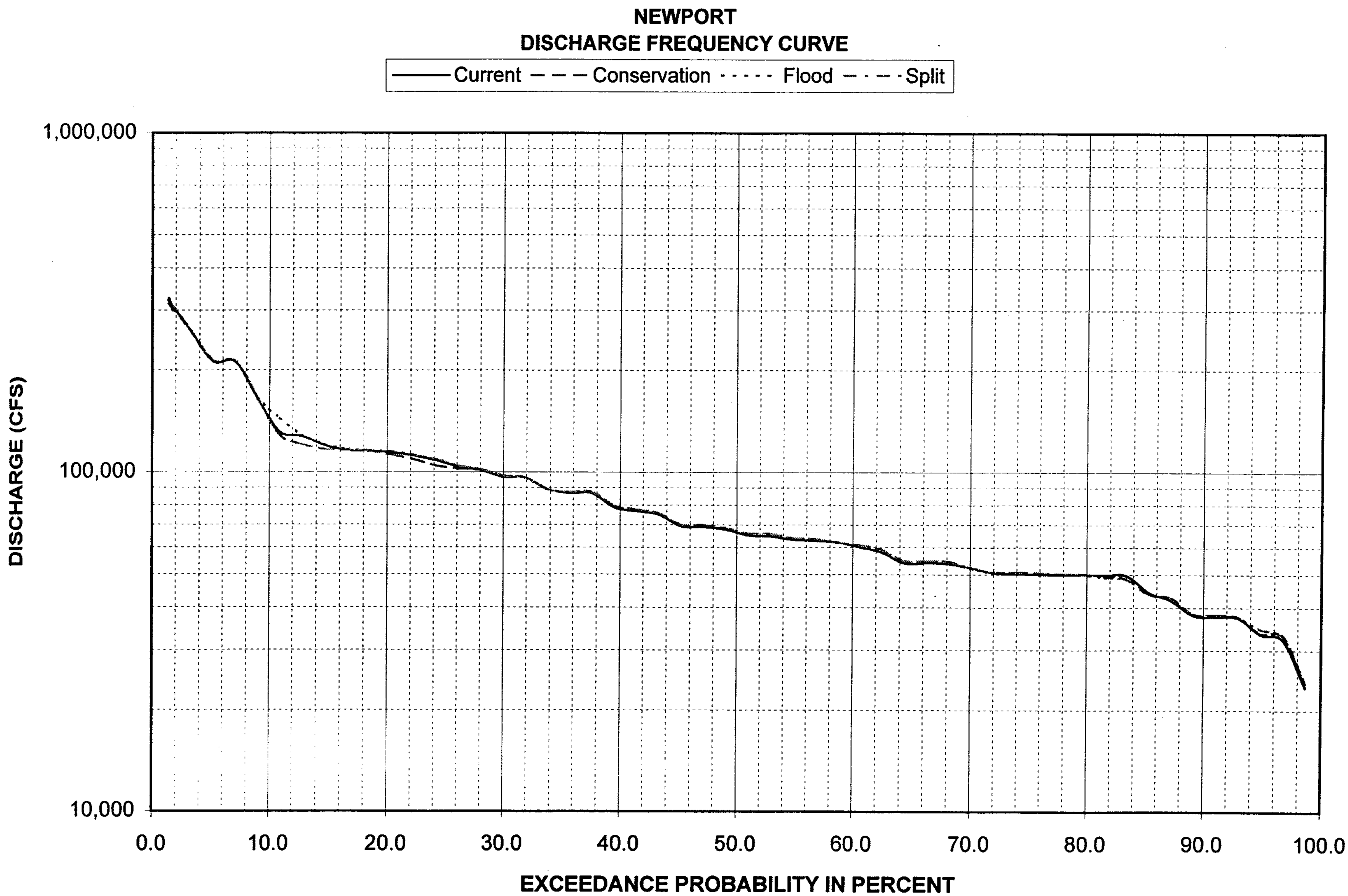
calico_rock_discharge_freq.xls

SUMMARY CHART



batesville_discharge_freq.xls

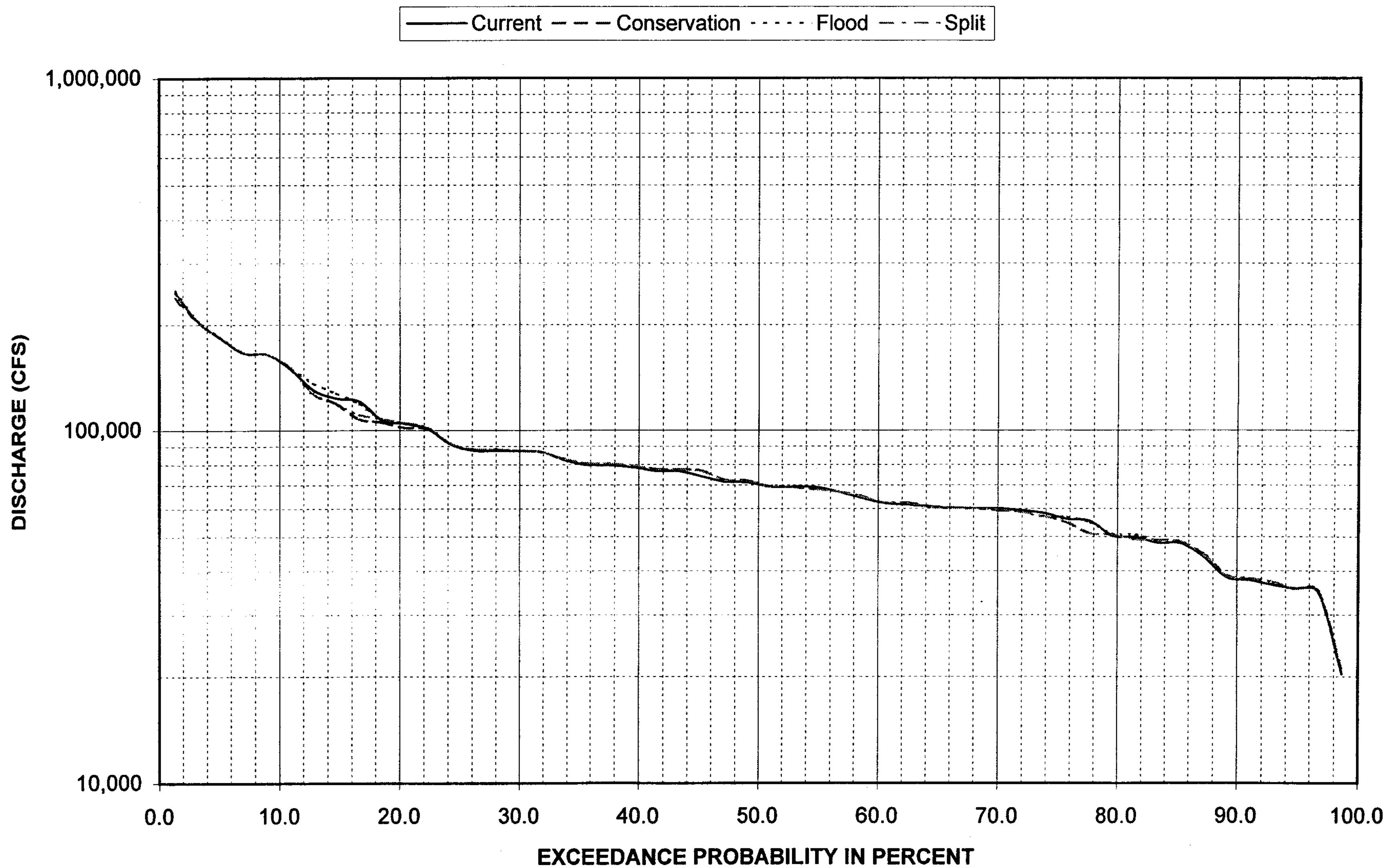
SUMMARY CHART



newport_discharge_freq.xls

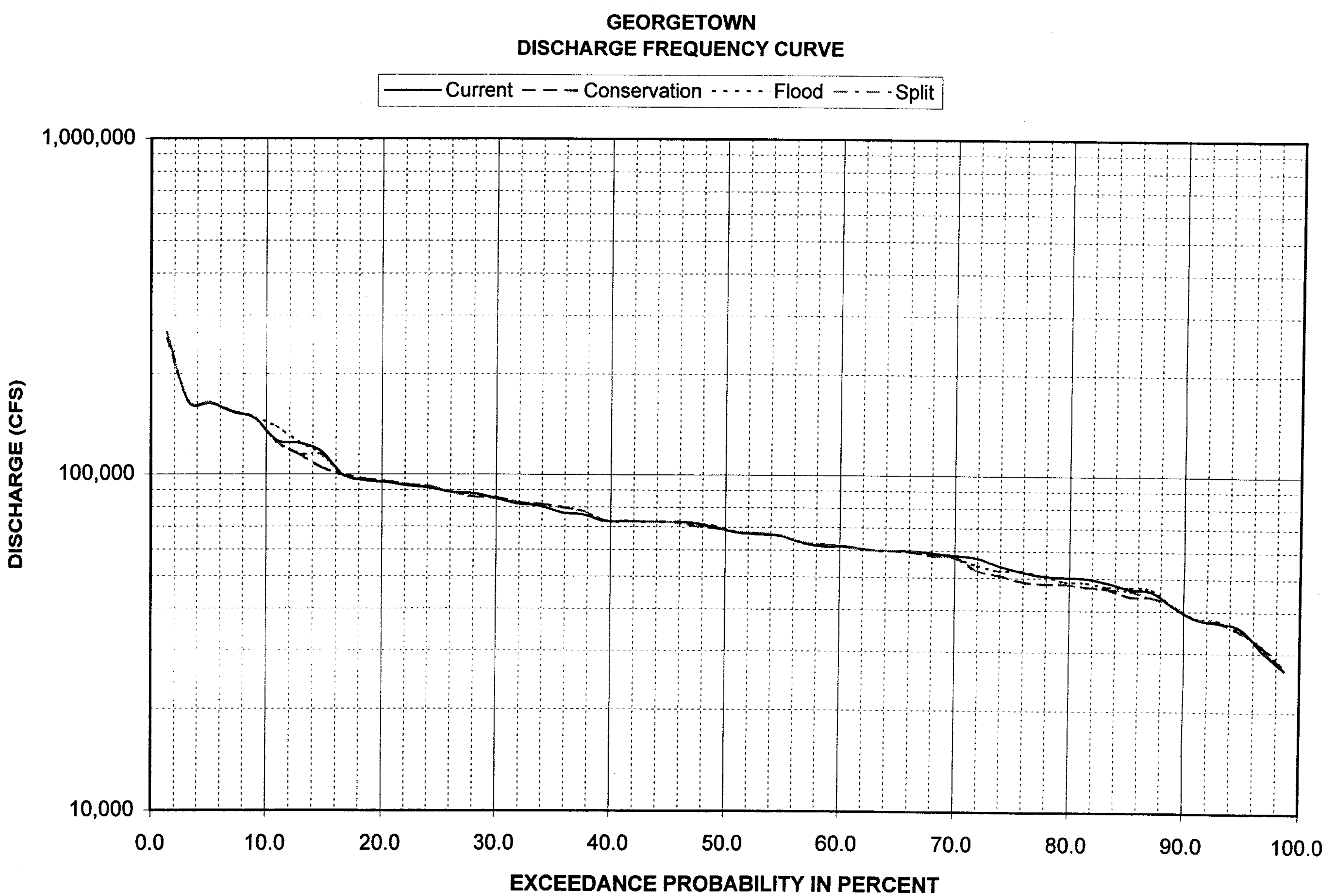
SUMMARY CHART

AUGUSTA
DISCHARGE FREQUENCY CURVE



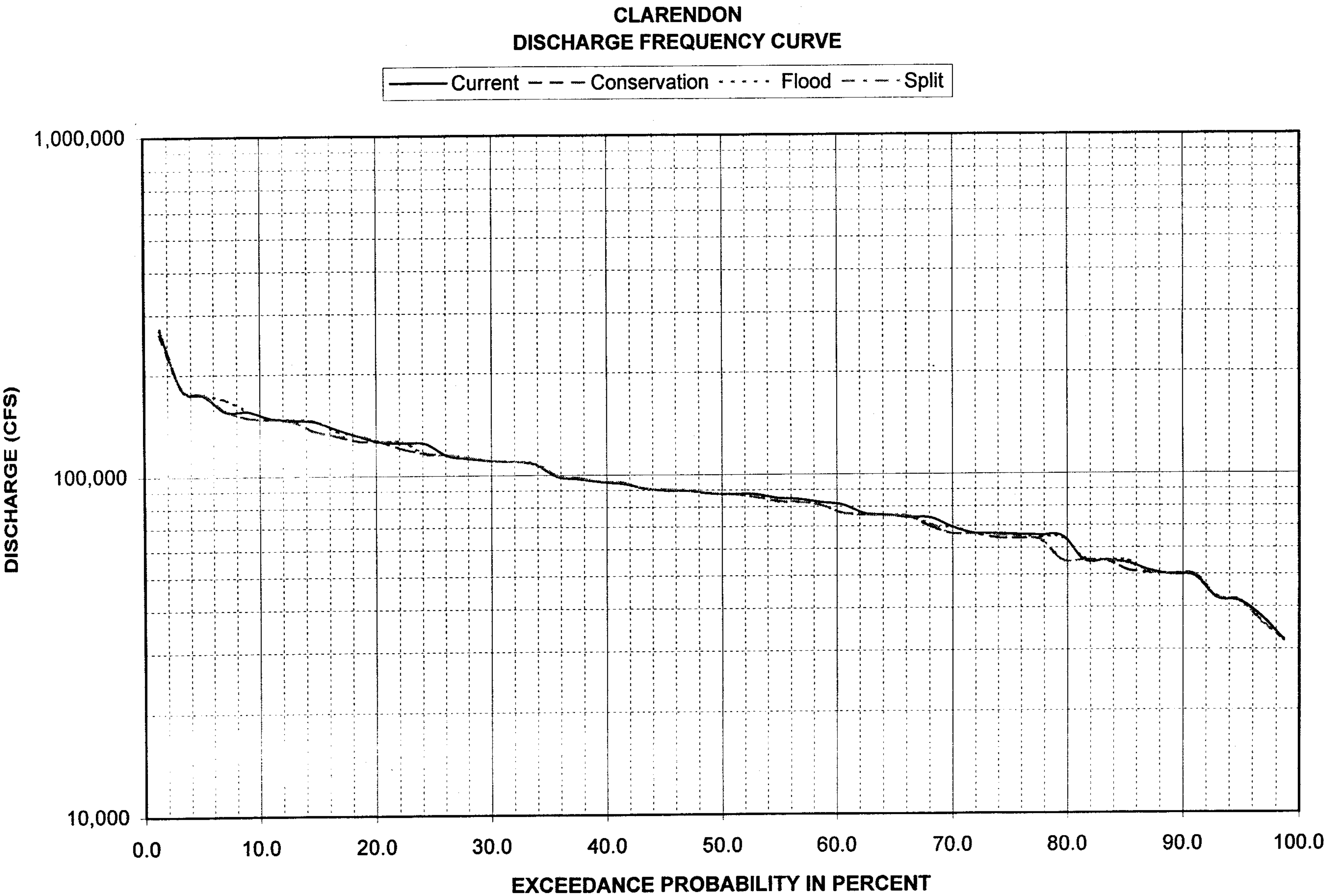
augusta_discharge_freq.xls

SUMMARY CHART



georgetown_discharge_freq.xls

SUMMARY CHART



clarendon_discharge_freq.xls

Appendix H

Backwater Models:
Wetted Area and Water Surface Area

70 cfs: Surface and Wetted Areas Between River Stations Below Greers Ferry Lake (Little Red River)				
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE*	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
78.9	72.7	127.77	128.76	
72.7	68.4	84.80	85.03	
68.4	64.7	43.80	44.40	
64.7	48.99	248.85	250.34	
78.9	48.99	505.21	508.52	Total

* User must enter exact river stations from table above in order to receive results

200 cfs: Surface and Wetted Areas Between River Stations Below Greers Ferry Lake (Little Red River)				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
78.9	72.7	142.73	143.88	
72.7	68.4	92.01	92.31	
68.4	64.7	50.21	50.92	
64.7	48.99	276.81	278.73	
78.9	48.99	561.77	565.84	Total

Differences in Surface and Wetted Areas Between River Stations (values for 200 cfs minus values for 70 cfs) Below Greers Ferry Lake (Little Red River)				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
78.90	72.70	14.96	15.12	
72.70	68.40	7.21	7.28	
68.40	64.70	6.41	6.51	
64.70	48.99	27.96	28.40	
78.90	48.99	56.55	57.32	Total

55 cfs: Surface and Wetted Areas Between River Stations Below Beaver Lake (Table Rock at 915 ft)				
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE*	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
608.8	607.1	26.96	27.06	
607.1	605.5	38.17	38.40	
605.5	604.8	22.01	22.16	
608.8	604.8	87.14	87.62	Total

* User must enter exact river stations from table above in order to receive results

136 cfs: Surface and Wetted Areas Between River Stations Below Beaver Lake (Table Rock Lake at 915 ft)				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
608.8	607.1	27.66	27.76	
607.1	605.5	38.19	38.43	
605.5	604.8	22.02	22.17	
608.8	604.8	87.87	88.36	Total

Differences in Surface and Wetted Areas Between River Stations (values for 136 cfs minus values for 55 cfs) Below Beaver Lake (Table Rock Lake at 915 ft)				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
608.80	607.1	0.70	0.71	
607.10	605.5	0.02	0.03	
605.50	604.8	0.00	0.00	
608.8	604.8	0.73	0.74	Total

55 cfs: Surface and Wetted Areas Between River Stations Below Beaver Lake (Table Rock at 917 ft)				
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
608.8	607.1	36.86	37.05	
607.1	605.5	40.07	40.47	
605.5	604.8	23.03	23.25	
608.8	604.8	99.96	100.77	Total

* User must enter exact river stations from table above in order to receive results

136 cfs: Surface and Wetted Areas Between River Stations Below Beaver Lake (Table Rock at 917 ft)				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
608.8	607.1	37.20	37.39	
607.1	605.5	40.08	40.48	
605.5	604.8	23.03	23.25	
608.8	604.8	100.30	101.11	Total

Differences in Surface and Wetted Areas Between River Stations (values for 136 cfs minus values for 55 cfs) Below Beaver Lake (Table Rock at 917 ft)				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
608.80	607.10	0.34	0.34	
607.10	605.50	0.01	0.01	
605.50	604.80	0.00	0.00	
608.80	604.80	0.34	0.35	Total

325 cfs: Surface and Wetted Areas Between River Stations White River Below the confluence of the North of the White Fork River				
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE*	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
370.9	364	207.39	207.55	
364	350.8	442.24	442.39	
350.8	341.81	300.10	300.23	
341.81	329.4	363.46	363.81	
370.9	329.4	1,313.20	1,313.98	Total

* User must enter exact river stations from table above in order to receive results

1100 cfs: Surface and Wetted Areas Between River Stations White River Below the confluence of the North of the White Fork River				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
370.9	364	251.79	252.05	
364	350.8	539.95	540.26	
350.8	341.81	371.83	372.09	
341.81	329.4	485.63	486.23	
370.9	329.4	1,649.21	1,650.64	Total

Differences in Surface and Wetted Areas Between River Stations (values for 1100 cfs minus values for 325 cfs) White River Below the confluence of the North of the White Fork River				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
370.90	364.00	44.40	44.50	
364.00	350.80	97.71	97.87	
350.80	341.81	71.74	71.86	
341.81	329.40	122.16	122.42	
370.90	329.40	336.01	336.66	Total

210 cfs: Surface and Wetted Areas Between River Stations Bull Shoals Tailwater to the North Fork of the White River			
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE*	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)
418.63	370.9	1,183.19	1,183.88

* User must enter exact river stations from table above in order to receive results

800 cfs: Surface and Wetted Areas Between River Stations Bull Shoals Tailwater to the North Fork of the White River			
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)
418.63	370.9	1,712.46	1,713.80

Differences in Surface and Wetted Areas Between River Stations (values for 800 cfs minus values for 210 cfs) Bull Shoals Tailwater to the North Fork of the White River			
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)
418.63	370.90	529.27	529.93

325 cfs: Surface and Wetted Areas Between River Stations White River from Guion to WRM 300.46			
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE*	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)
329.4	300.46	962.52	964.68

* User must enter exact river stations from table above in order to receive results

1100 cfs: Surface and Wetted Areas Between River Stations White River from Guion to WRM 300.46			
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)
329.4	300.46	1,325.68	1,328.87

Differences in Surface and Wetted Areas Between River Stations (values for 1100 cfs minus values for 325 cfs) White River from Guion to WRM 300.46			
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)
329.40	300.46	363.16	364.20

115 cfs: Surface and Wetted Areas Between River Stations Norfork Tailwater				
UP STREAM RIVER MILE*	DOWN STREAM RIVER MILE*	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
0.202	0.185	0.22	0.22	
2.164	0.202	27.95	27.99	
4.468	2.164	26.13	26.27	
4.468	0.185	54.30	54.48	Total

* User must enter exact river stations from table above in order to receive results

300 cfs: Surface and Wetted Areas Between River Stations Norfork Tailwater				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
0.202	0.185	0.31	0.31	
2.164	0.202	33.41	33.47	
4.468	2.164	48.99	49.22	
4.468	0.185	82.71	83.01	Total

Differences in Surface and Wetted Areas Between River Stations (values for 136 cfs minus values for 55 cfs) Norfork Tailwater				
UP STREAM RIVER MILE	DOWN STREAM RIVER MILE	TOTAL SURFACE AREA (acre)	TOTAL WETTED AREA (acre)	
0.202	0.185	0.09	0.09	
2.164	0.202	5.46	5.48	
4.468	2.164	22.87	22.95	
4.468	0.185	28.42	28.53	Total

Appendix I

Comparison of 2 Flood Events
and 1 Drought Event

Beaver Lake					
Top of Flood Pool: 1130.0 Conservation Pool: 1120.43	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK POOL ELEVATION (Feet)	16-Apr-45	1,131.20	1,131.20	1,131.20	1,131.20
PEAK LAKE RELEASE (cfs)	15-Apr-45	52339	52303	52303	52303
PEAK POOL ELEVATION (Feet)	25-May-57	1130.8	1130.8	1130.8	1130.8
PEAK LAKE RELEASE (cfs)	24-May-57	30,922	30,914	30,914	30,914
MINIMUM POOL ELEVATION (Feet)	1-Jan-65	1102.9	1102.1	1102.1	1102.1
DATES POOL ELEVATION LESS THAN 1120.43	Start Date	2-Jul-62	22-Jun-62	22-Jun-62	22-Jun-62
	End Date	12-Mar-66	29-Apr-66	21-Apr-66	21-Apr-66
TOTAL DAYS POOL ELEVATION LESS THAN 1120.43		1,349	1,407	1,399	1,399

Beaver Lake					
Duration in percent	**DATE**	**CURRENT**	**CONSERVATION**	**FLOOD**	**SPLIT**
POOL ELEVATION DURATION 1131.2 ft	**Annual**	0.01	0.01	0.01	0.01
	April	0.06	0.06	0.06	0.06
POOL ELEVATION DURATION 1130 ft	**Annual**	0.34	0.31	0.33	0.29
	April	1.09	1.03	1.15	0.90
	May	1.55	1.36	1.43	1.36
	December	0.25	0.06	0.12	0.06

Beaver Lake					
Duration in percent	**DATE**	**CURRENT**	**CONSERVATION**	**FLOOD**	**SPLIT**
LAKE RELEASE DURATION 52339 cfs	**Annual**	0.01	0.00	0.00	0.00
	April	0.06	0.00	0.00	0.00
LAKE RELEASE DURATION 52303 cfs	**Annual**	0.01	0.01	0.01	0.01
	April	0.13	0.06	0.06	0.06
LAKE RELEASE DURATION 40000 cfs	**Annual**	0.02	0.02	0.02	0.02
	April	0.19	0.19	0.19	0.19
	May	0.06	0.06	0.06	0.06

Table Rock Lake

Top of Flood Pool: 931.0 Conservation Pool: 915.0	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK POOL ELEVATION (Feet)	16-Apr-45	935.25	935.22	935.28	935.25
PEAK LAKE RELEASE (cfs)	15-Apr-45	107,949	104,863	110,948	107,748
PEAK POOL ELEVATION (Feet)	27-May-57	933.26			
	3-Jun-57		933.16		933.16
	26-May-57			933.48	
PEAK LAKE RELEASE (cfs)	26-May-57	41,552			
	3-Jun-57		38,119		38,120
	25-May-57			48,494	
MINIMUM POOL ELEVATION (Feet)	3-Mar-64	902.61	899.51	904.39	902.00
DATES POOL ELEVATION LESS THAN 915.0	Start Date	13-Jul-62	9-Jul-62	1-Aug-63	20-Jul-62
	End Date	3-Apr-65	5-Apr-65	3-Apr-65	4-Apr-65
TOTAL DAYS POOL ELEVATION LESS THAN 915.0		995	1,001	611	989

Table Rock Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
POOL ELEVATION DURATION 935 ft	Annual	0.01	0.01	0.01	0.01
	April	0.06	0.06	0.06	0.06
POOL ELEVATION DURATION 931 ft	Annual	0.58	0.57	0.69	0.61
	April	1.03	1.03	1.28	1.03
	May	3.10	2.92	4.09	3.41
	June	2.88	2.88	2.88	2.88

Table Rock Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 107000 cfs	Annual	0.01	0.00	0.01	0.01
	April	0.13	0.00	0.13	0.13
LAKE RELEASE DURATION 104860 cfs	Annual	0.01	0.01	0.01	0.01
	April	0.13	0.06	0.13	0.13
LAKE RELEASE DURATION 103000 cfs	Annual	0.01	0.01	0.01	0.01
	April	0.13	0.13	0.13	0.13
LAKE RELEASE DURATION 90000 cfs	Annual	0.02	0.02	0.02	0.02
	April	0.26	0.26	0.26	0.26

Bull Shoals Lake

Top of Flood Pool: 695 Conservation Pool: 654.0	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK POOL ELEVATION (Feet)	18-Apr-45	697.42	697.40	697.43	697.42
PEAK LAKE RELEASE (cfs)	18-Apr-45	136,030	129,933	138,561	135,739
PEAK POOL ELEVATION (Feet)	3-Jun-57	695.89	695.76		695.87
	27-May-57			696.08	
PEAK LAKE RELEASE (cfs)	2-Jun-57	45,772	41,401		45,162
	24-May-57			55,367	
MINIMUM POOL ELEVATION (Feet)	6-Mar-64	643.82			
	15-Nov-64		631.07	647.17	640.47
DATES POOL ELEVATION LESS THAN 654.0	Start Date	26-Jul-63	14-Aug-62	4-Sep-63	21-Jul-63
	End Date	4-Apr-65	15-Apr-65	1-Apr-65	6-Apr-65
TOTAL DAYS POOL ELEVATION LESS THAN 654.0		618	975	575	625

Bull Shoals Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
POOL ELEVATION DURATION 697 ft	Annual	0.02	0.01	0.02	0.02
	April	0.19	0.13	0.19	0.19
POOL ELEVATION DURATION 695 ft	Annual	0.57	0.46	0.61	0.54
	April	1.47	1.03	1.60	1.28
	May	2.05	1.36	2.17	1.92
	June	3.21	3.08	3.46	3.14

Bull Shoals Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 130,000 cfs	Annual	0.01	0.00	0.01	0.01
	April	0.13	0.00	0.13	0.13
LAKE RELEASE DURATION 100,000 cfs	Annual	0.03	0.03	0.03	0.03
	April	0.32	0.32	0.32	0.32
LAKE RELEASE DURATION 50,000 cfs	Annual	0.05	0.04	0.07	0.04
	April	0.51	0.51	0.51	0.51
	May	0.00	0.00	0.31	0.00
	June	0.06	0.00	0.00	0.00

Norfork Lake					
Top of Flood Pool: 580 Conservation Pool: 552.0	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK POOL ELEVATION (Feet)	15-Apr-45	580.95	580.91	580.95	580.95
PEAK LAKE RELEASE (cfs)	14-Apr-45	42,763	41,074	42,727	42,719
PEAK POOL ELEVATION (Feet)	8-May-73	580.37	580.24	580.43	580.40
PEAK LAKE RELEASE (cfs)	7-May-73	18,628	15,844	19,867	19,067
MINIMUM POOL ELEVATION (Feet)	30-Oct-64	538.73	527.89	540.65	533.82
DATES POOL ELEVATION LESS THAN 552.0	Start Date	16-Jul-62	12-Jul-62	9-Aug-62	24-Jul-62
	End Date	14-Apr-65	18-Apr-66	10-Apr-63	10-May-65
TOTAL DAYS POOL ELEVATION LESS THAN 552.0		1,003	1,376	244	1,021

Norfork Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
POOL ELEVATION DURATION 580 ft	Annual	0.07	0.06	0.07	0.06
	April	0.19	0.19	0.19	0.19
	May	0.25	0.12	0.31	0.12
POOL ELEVATION DURATION 575 ft	Annual	2.15	2.06	2.55	2.30
	March	0.12	0.00	0.12	0.06
	April	2.31	2.24	2.44	2.31
	May	5.65	5.15	7.26	5.71
	June	11.60	11.54	14.10	13.21
	July	5.65	5.33	6.20	5.83

Norfork Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 42,000 cfs	Annual	0.01	0.00	0.01	0.01
	April	0.13	0.00	0.13	0.13
LAKE RELEASE DURATION 30,000 cfs	Annual	0.02	0.01	0.02	0.02
	April	0.19	0.13	0.19	0.19
LAKE RELEASE DURATION 15,000 cfs	Annual	0.08	0.07	0.10	0.08
	April	0.32	0.32	0.32	0.32
	May	0.25	0.12	0.50	0.25
	June	0.38	0.38	0.38	0.38

Greers Ferry Lake					
Top of Flood Pool: 487.0 Conservation Pool: 461.26	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK POOL ELEVATION (Feet)	12-Jun-45	489.06	489.05	489.05	489.05
PEAK LAKE RELEASE (cfs)	12-Jun-45	28,905	28,062	28,063	28,062
PEAK POOL ELEVATION (Feet)	11-May-73	481.25	481.38	483.87	482.61
PEAK LAKE RELEASE (cfs)	7-May-73	18,628	15,844	19,867	19,067
MINIMUM POOL ELEVATION (Feet)	30-Nov-54	450.71	446.71	453.55	450.49
DATES POOL ELEVATION LESS THAN 461.26	Start Date	16-Jun-54	18-Jun-53	16-Jun-54	9-Jun-54
	End Date	19-Mar-55	22-Mar-55	7-Mar-55	20-Mar-55
TOTAL DAYS POOL ELEVATION LESS THAN 461.26		276.00	642.00	264.00	284.00

Greers Ferry Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
POOL ELEVATION DURATION 488 ft	Annual	0.03	0.03	0.04	0.03
	April	0.00	0.00	0.06	0.00
	June	0.38	0.38	0.38	0.38
POOL ELEVATION DURATION 487 ft	Annual	0.16	0.13	0.18	0.16
	April	1.03	0.71	1.28	1.03
	June	0.90	0.90	0.90	0.90
POOL ELEVATION DURATION 480 ft	Annual	0.98	0.81	1.22	0.94
	March	0.06	0.06	0.12	0.06
	April	1.92	1.92	2.12	1.92
	May	3.91	2.92	4.47	3.78
	June	3.85	3.01	4.81	3.72
	July	1.99	1.74	1.86	1.74
	December	0.00	0.00	0.43	0.06

Greers Ferry Lake

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 28,000 cfs	Annual	0.01	0.01	0.01	0.01
	June	0.13	0.06	0.06	0.06
LAKE RELEASE DURATION 20,000 cfs	Annual	0.03	0.03	0.03	0.03
	June	0.32	0.32	0.32	0.32
LAKE RELEASE DURATION 15,000 cfs	Annual	0.61	0.56	0.58	0.55
	January	1.24	1.18	1.30	1.18
	February	1.84	1.50	1.57	1.43
	April	2.05	2.12	2.05	2.05
	June	0.32	0.32	0.32	0.32
	December	1.18	0.87	0.93	0.87
LAKE RELEASE DURATION 10,000 cfs	ANNUAL	1.30	1.18	1.28	1.17
	JANUARY	2.67	2.23	2.48	2.30
	FEBRUARY	2.38	1.91	2.11	2.04
	MARCH	2.61	2.79	2.79	2.54
	APRIL	4.10	4.17	4.29	3.91
	MAY	0.43	0.19	0.56	0.31
	JUNE	0.77	0.77	0.71	0.90
	JULY	0.12	0.19	0.19	0.12
	OCTOBER	0.06	0.06	0.12	0.06
	NOVEMBER	0.13	0.19	0.19	0.19
	DECEMBER	2.36	1.74	1.92	1.67

Calico Rock

Flood Stage: 19	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK RIVER STAGE (Feet)	16-Apr-45	43.97	43.19	44.20	43.93
PEAK DISCHARGE (cfs)	16-Apr-45	259,348	250,087	262,043	258,833
PEAK RIVER STAGE (Feet)	4-Apr-57	22.86	23.00	22.99	22.99
	24-May-57	24.21	18.65	26.61	20.41
	10-Jun-57	21.58	21.45	21.59	21.59
PEAK DISCHARGE (cfs)	4-Apr-57	83,213	84,000	83,970	83,986
	24-May-57	91,003	60,405	105,605	69,638
	10-Jun-57	76,026	75,280	76,051	76,048

Calico Rock					
Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
STAGE ELEVATION DURATION 35 ft	Annual	0.03	0.02	0.03	0.03
	April	0.26	0.19	0.26	0.26
POOL ELEVATION DURATION 19 ft	Annual	0.25	0.23	0.28	0.24
	January	0.12	0.19	0.19	0.19
	April	0.77	0.77	0.77	0.77
	May	0.56	0.31	0.87	0.37

Calico Rock					
Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 250,000 cfs	Annual	0.01	0.01	0.01	0.01
	April	0.06	0.06	0.13	0.06
LAKE RELEASE DURATION 200,000 cfs	Annual	0.01	0.01	0.01	0.01
	April	0.13	0.13	0.13	0.13
LAKE RELEASE DURATION 150,000 cfs	Annual	0.03	0.03	0.03	0.03
	April	0.26	0.26	0.26	0.26

Batesville					
Flood Stage: 15	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK RIVER STAGE (Feet)	16-Apr-45	29.15	28.71	29.27	29.13
PEAK DISCHARGE (cfs)	16-Apr-45	309,221	299,463	311,775	308,684
PEAK RIVER STAGE (Feet)	4-Apr-57	17.73	17.76	17.76	17.76
	24-May-57	17.56	15.98	18.59	16.31
	11-Jun-57	15.37	15.31	15.37	15.37
PEAK DISCHARGE (cfs)	4-Apr-57	102,210	102,586	102,519	102,544
	24-May-57	99,804	78,660	114,340	82,959
	11-Jun-57	71,264	70,633	71,302	71,300

Batesville

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
STAGE ELEVATION DURATION 29 ft	Annual	0.01	0.00	0.01	0.01
	April	0.06	0.00	0.06	0.06
POOL ELEVATION DURATION 15 ft	Annual	0.48	0.47	0.53	0.48
	February	0.75	0.75	0.75	0.75
	April	1.35	1.41	1.47	1.41
	May	0.81	0.62	1.18	0.74

Batesville

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 305,000 cfs	Annual	0.01	0.00	0.01	0.01
	April	0.06	0.00	0.06	0.06
LAKE RELEASE DURATION 250,000 cfs	Annual	0.01	0.01	0.01	0.01
	April	0.06	0.06	0.06	0.06
LAKE RELEASE DURATION 175,000 cfs	Annual	0.05	0.05	0.05	0.05
	January	0.06	0.06	0.06	0.06
	April	0.38	0.32	0.38	0.38
	June	0.06	0.06	0.06	0.06
	December	0.12	0.12	0.12	0.12
LAKE RELEASE DURATION 100,000 cfs	Annual	0.19	0.19	0.19	0.19

Georgetown

Flood Stage: 21	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK RIVER STAGE (Feet)	24-Apr-45	33.22	32.78	33.35	33.19
PEAK DISCHARGE (cfs)	24-Apr-45	264,318	255,596	266,952	263,849
PEAK RIVER STAGE (Feet)	3-Jun-57	25.95		26.70	
	11-Jun-57		24.62		25.26
PEAK DISCHARGE (cfs)	3-Jun-57	126,112		138,925	
	11-Jun-57		105,113		114,833

Georgetown

	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
PEAK RIVER STAGE (Feet)	23-Jun-45	28.27	28.27	28.27	28.27
PEAK DISCHARGE (cfs)	23-Jun-45	167,178	167,106	167,106	167,106
PEAK RIVER STAGE (Feet)	30-Apr-73	28.12	28.16	28.16	28.16
	16-May-73	25.00	24.54	26.45	25.46
PEAK DISCHARGE (cfs)	30-Apr-73	164,264	165,110	165,105	165,108
	16-May-73	110,862	103,877	134,697	117,897

Georgetown

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
STAGE ELEVATION DURATION 33 ft	Annual	0.01	0.00	0.01	0.01
	April	0.13	0.00	0.13	0.13
STAGE ELEVATION DURATION 30 ft	Annual	0.03	0.03	0.03	0.03
	April	0.38	0.38	0.38	0.38
STAGE ELEVATION DURATION 28 ft	Annual	0.08	0.08	0.08	0.08
	February	0.07	0.07	0.07	0.07
	April	0.64	0.58	0.64	0.64
	May	0.06	0.06	0.06	0.06
	June	0.26	0.26	0.26	0.26
POOL ELEVATION DURATION 21 ft	Annual	7.26	6.97	7.03	6.98
	January	15.14	14.33	14.52	14.21
	February	10.21	8.85	9.33	9.26
	March	18.92	18.42	18.36	18.42
	April	17.63	17.18	17.18	17.12
	May	11.85	11.85	11.97	11.85
	June	3.72	3.72	3.72	3.72
	July	0.62	0.62	0.62	0.62
	November	0.19	0.19	0.19	0.19
	December	8.81	8.37	8.44	8.37

Georgetown

Duration in percent	DATE	CURRENT	CONSERVATION	FLOOD	SPLIT
LAKE RELEASE DURATION 260,000 cfs	Annual	0.01	0.00	0.01	0.01
	April	0.13	0.00	0.13	0.13
LAKE RELEASE DURATION 200,000 cfs	Annual	0.03	0.03	0.03	0.03
	April	0.38	0.38	0.38	0.38
LAKE RELEASE DURATION 167,000 cfs	Annual	0.05	0.04	0.05	0.05
	April	0.51	0.45	0.51	0.51
	June	0.06	0.06	0.06	0.06
LAKE RELEASE DURATION 150,000 cfs	Annual	0.13	0.13	0.14	0.13
	February	0.14	0.14	0.14	0.14
	April	0.71	0.71	0.83	0.71
	May	0.12	0.12	0.12	0.12
	June	0.45	0.45	0.45	0.45
	December	0.12	0.19	0.19	0.19

Hydrology & Hydraulics Addendum

to

White River Minimum Flow
Feasibility Study

Dated 17 July 2008

TABLES and GRAPHS

for

Bull Shoals and Norfork Lakes
(Pool Elevation Frequency and Duration)

Calico Rock, Batesville, Newport, Augusta,
Georgetown, and Clarendon
(Flow and Stage - Frequency and Duration)

changes the long-term gage records by simulating the operations of the many reservoirs in the basin and producing a modified period of record for each control point. Using this modified period of record at the control points, frequency and durations studies can be performed which conforms to the EM 1110-2-1415 guidelines.

3. GRAPHICAL FREQUENCY ANALYSIS

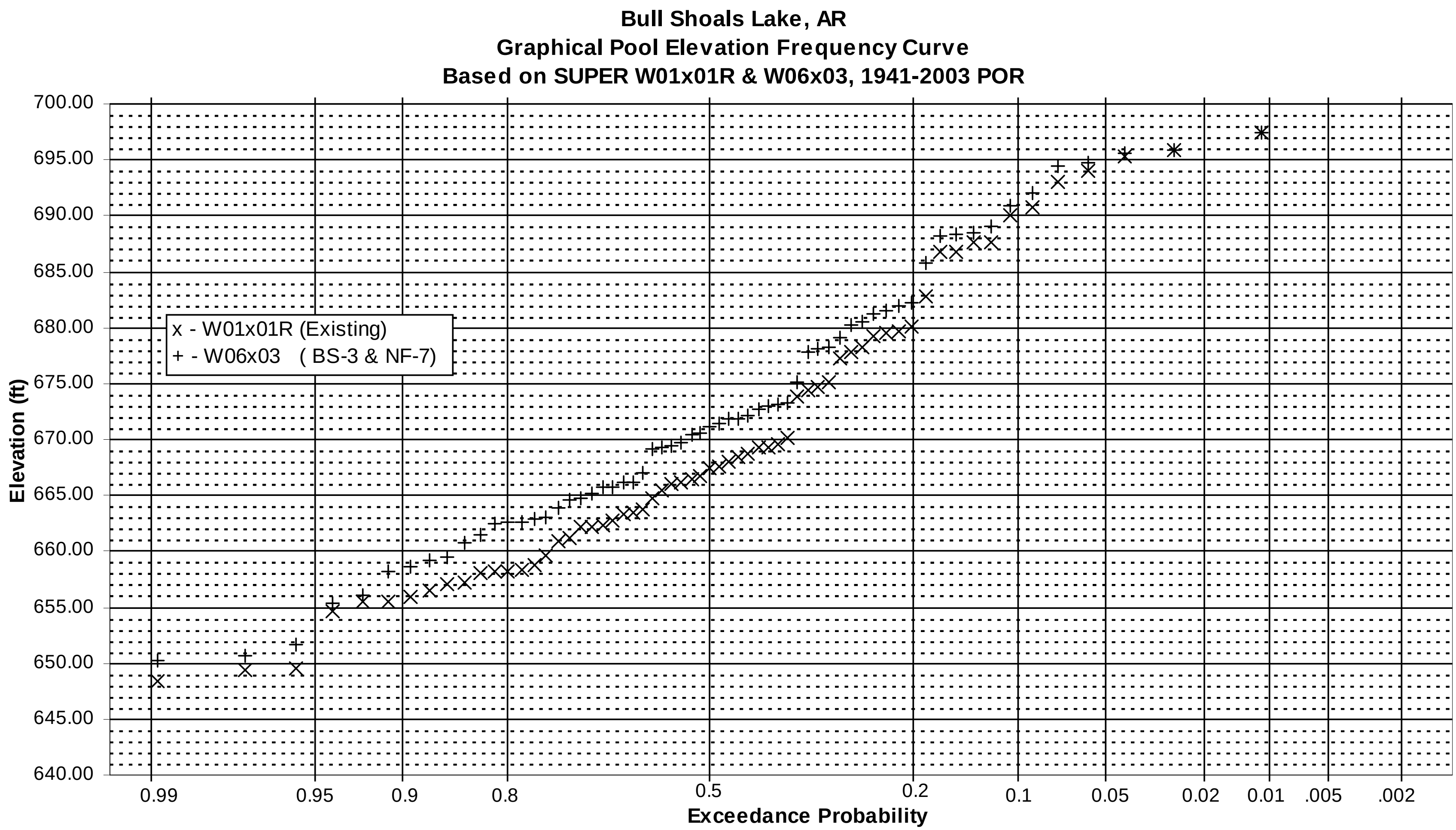
In order to use analytical methods to obtain discharge frequency relationships, the flows must be unregulated by manmade storage or diversion structure. Since the White River basin is highly regulated by several large reservoirs, analytical methods could not be used to derive discharge frequency relationships. Therefore, the graphical method was used to obtain discharge frequency curves. Using this method, the annual series discharges were graphed against the plotting positions using probability scaled graph paper. The median plotting position formula was used to compute the percent chance exceedance for each annual maximum flow and annual maximum pool elevation. Flow frequency was converted to stage frequency using the latest available rating curve at the control points. Although SUPER computes daily average flow, previous studies have shown that the peak flows varied from less than 10 percent of the daily average. Therefore, for this comparison of plans, the daily average flows were determined to be adequate for this analysis.

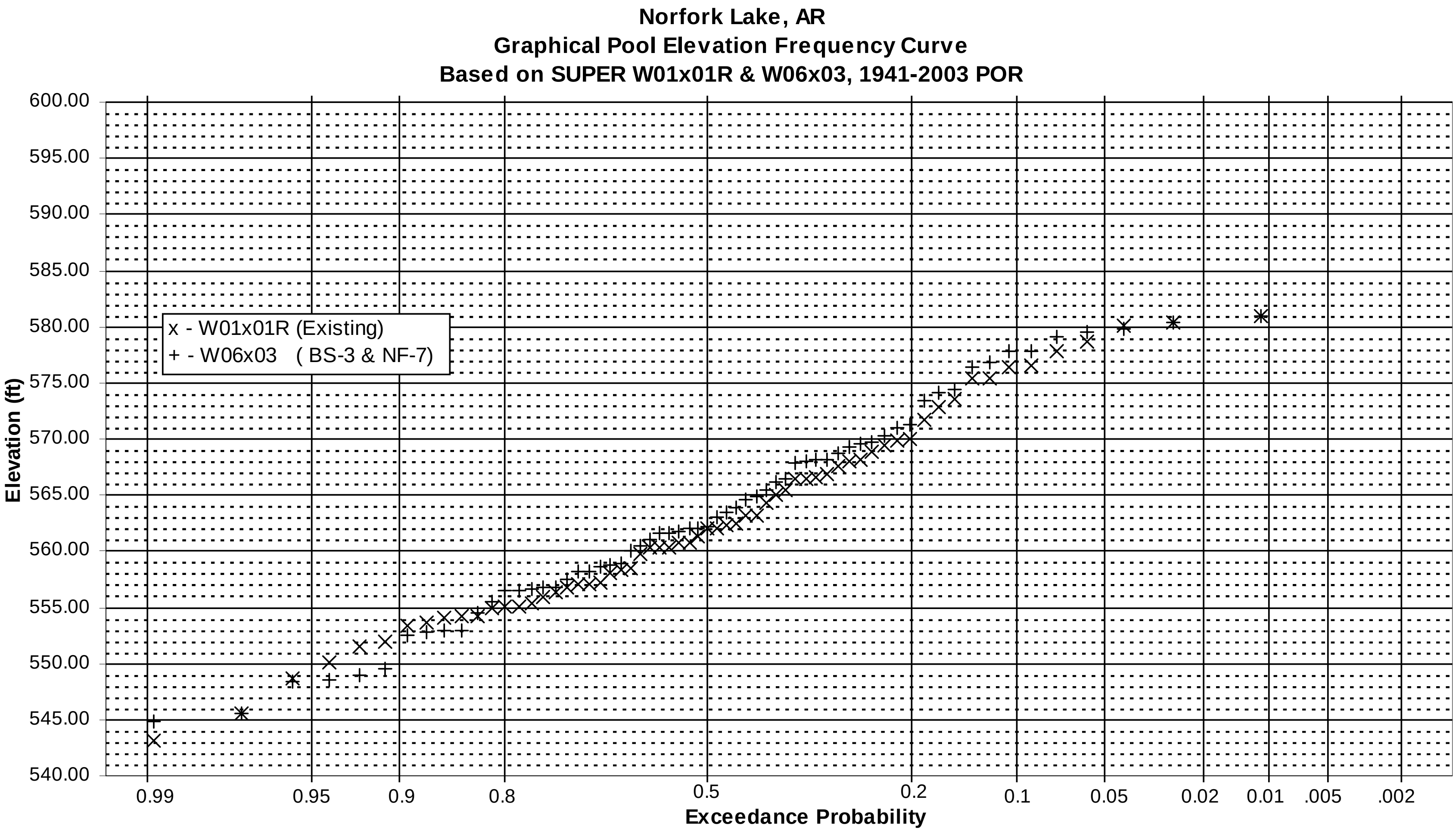
4. DURATION ANALYSIS

The daily control point (river) flows and pool elevations resulting from the SUPER model simulations were used to develop pool elevation-duration and control point flow-duration curves for SUPER Runs W01X01R and W06X03 based on the 23,010 daily values. Stage-duration was based on the latest available rating curve. The annual duration tables are interpolated values from this daily data. For the lake outflows, the duration that the target (minimum) flows were met was based on the modifications to SUPER as described in Section 2, Hydrologic Analysis, of the main H&H Report, and reflect an hourly computation. Therefore, the lake outflow-durations reflect the modified SUPER model output on an hourly basis.

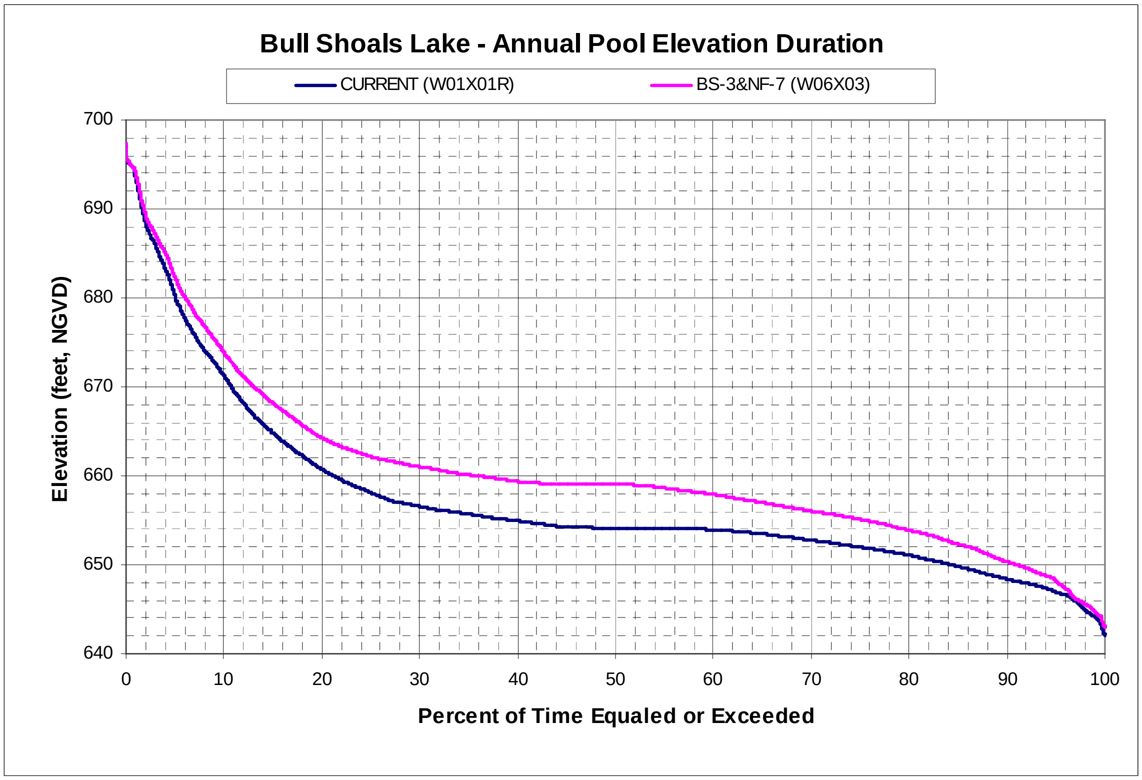
Tables and Graphs

Bull Shoals and Norfork Lakes
(Pool Elevation Frequency and Duration)

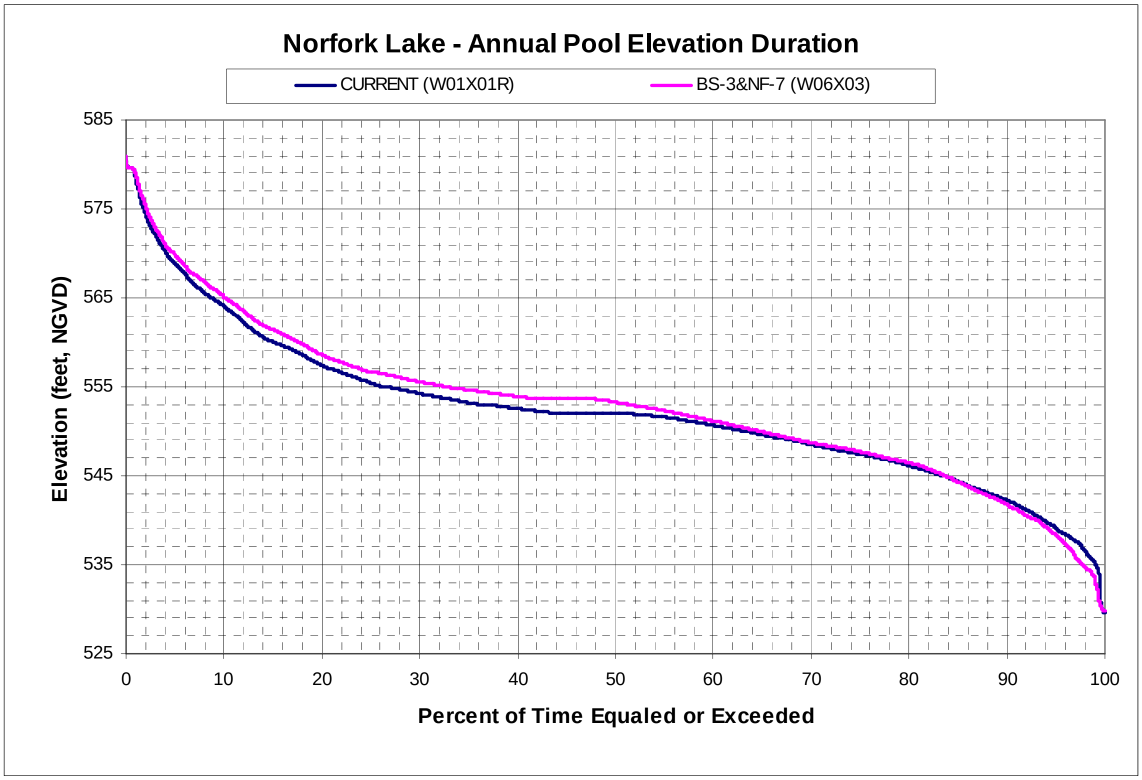

Bull Shoals Lake, AR
Graphical Pool Elevation Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Elevation (ft)
700.00
695.00
690.00
685.00
680.00
675.00
670.00
665.00
660.00
655.00
650.00
645.00
640.00
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability



Norfork Lake, AR
Graphical Pool Elevation Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Elevation (ft)
600.00
595.00
590.00
585.00
580.00
575.00
570.00
565.00
560.00
555.00
550.00
545.00
540.00
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability



Bull Shoals Lake		
Annual Pool Elevation-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	693.5	693.9
2	688.4	689.3
5	680.2	682.2
10	671.3	673.9
15	664.8	668.2
20	660.7	664.3
25	658.1	662.1
30	656.6	661.0
35	655.7	660.1
40	654.9	659.4
45	654.3	659.1
50	654.1	659.0
55	654.0	658.6
60	653.9	657.9
65	653.5	657.0
70	652.8	656.0
75	652.0	655.1
80	651.1	653.9
85	649.8	652.3
90	648.4	650.3
95	646.9	648.1
100	642.1	642.9

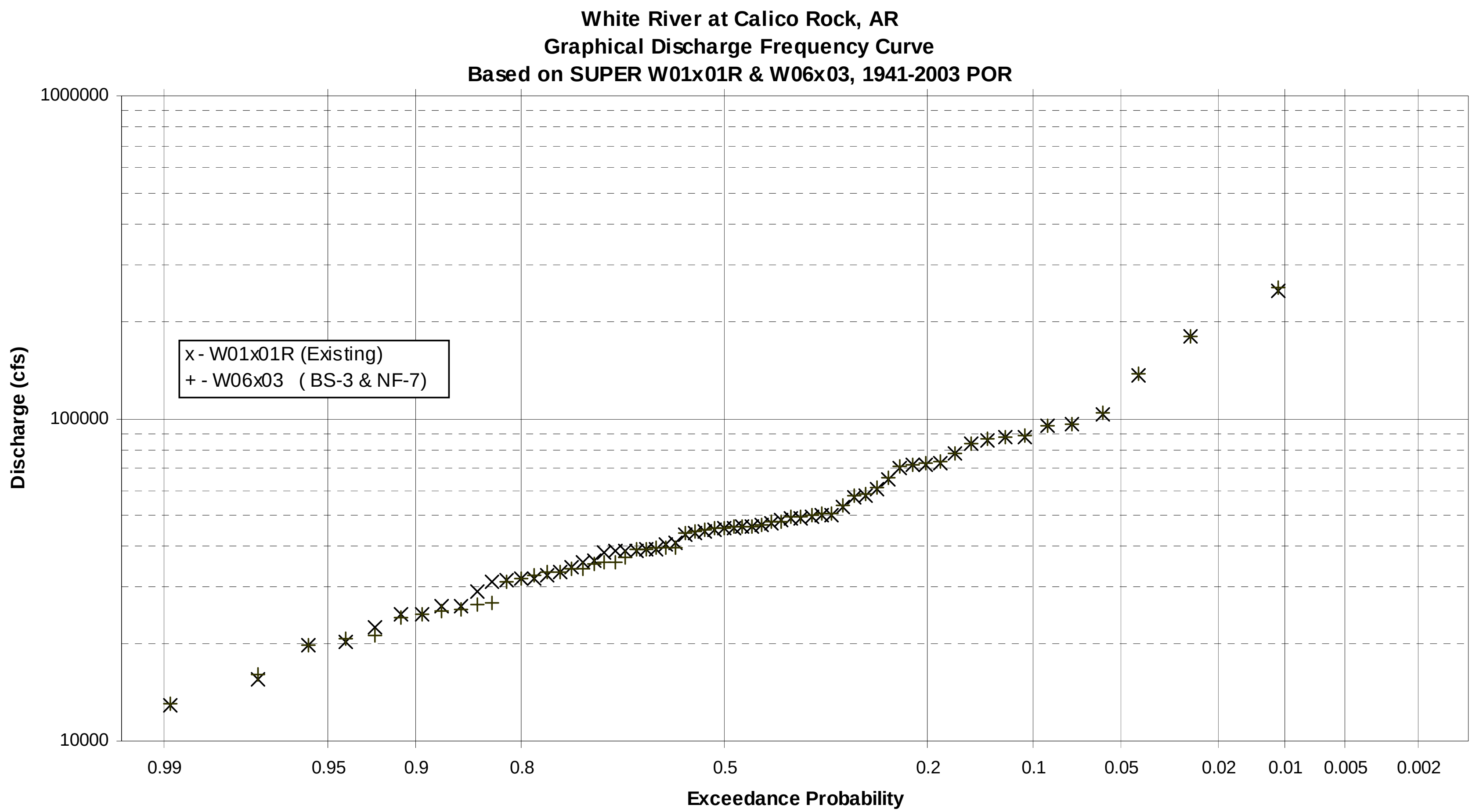


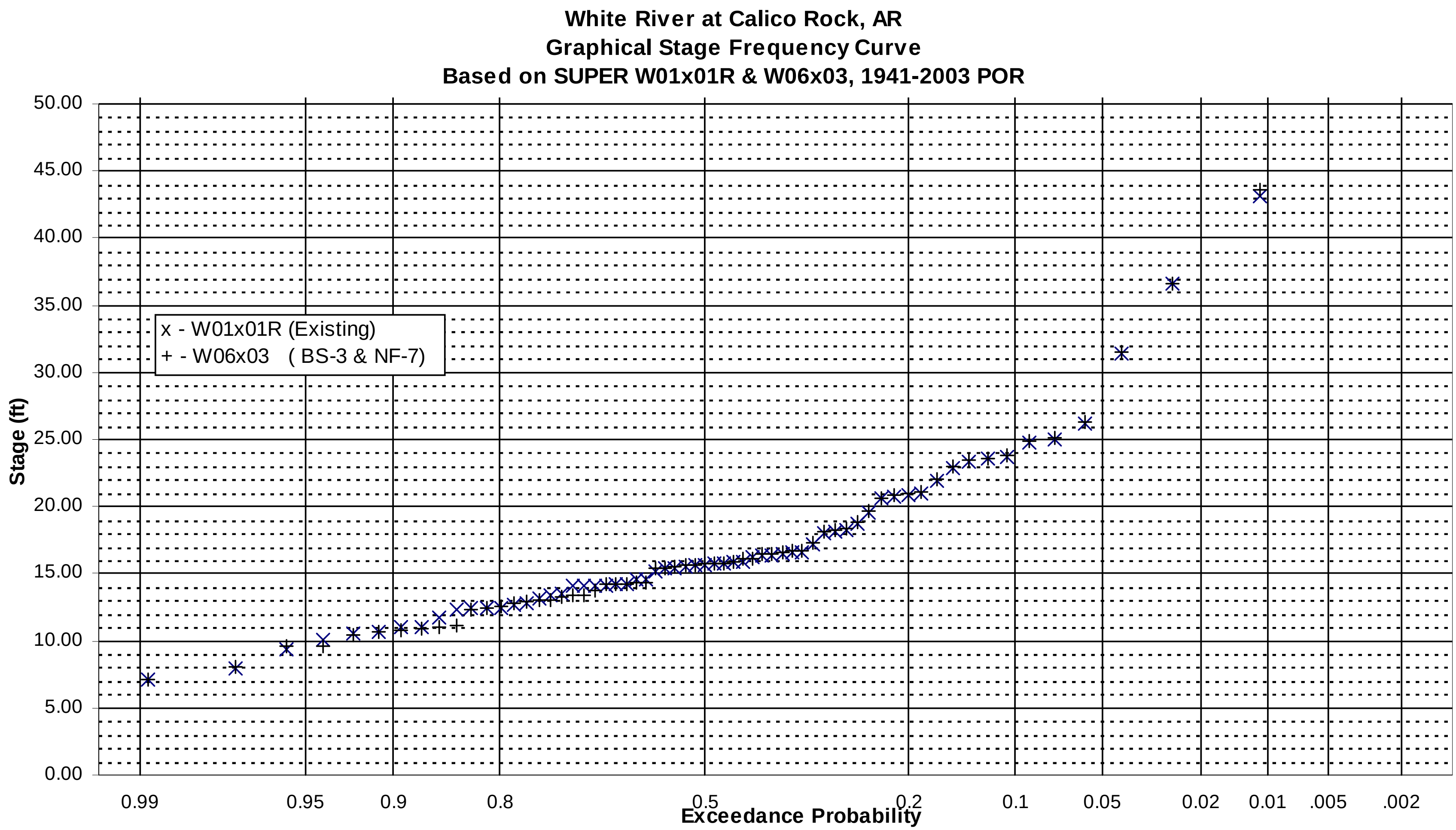
Norfork Lake		
Annual Pool Elevation-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	578.3	578.9
2	574.5	575.3
5	568.9	569.9
10	564.1	565.1
15	560.1	561.4
20	557.4	558.6
25	555.4	556.7
30	554.2	555.6
35	553.2	554.7
40	552.6	553.9
45	552.0	553.7
50	552.0	553.3
55	551.6	552.3
60	550.7	551.2
65	549.6	550.0
70	548.5	548.7
75	547.4	547.7
80	546.1	546.5
85	544.4	544.3
90	542.3	541.8
95	539.1	538.3
100	529.6	529.8

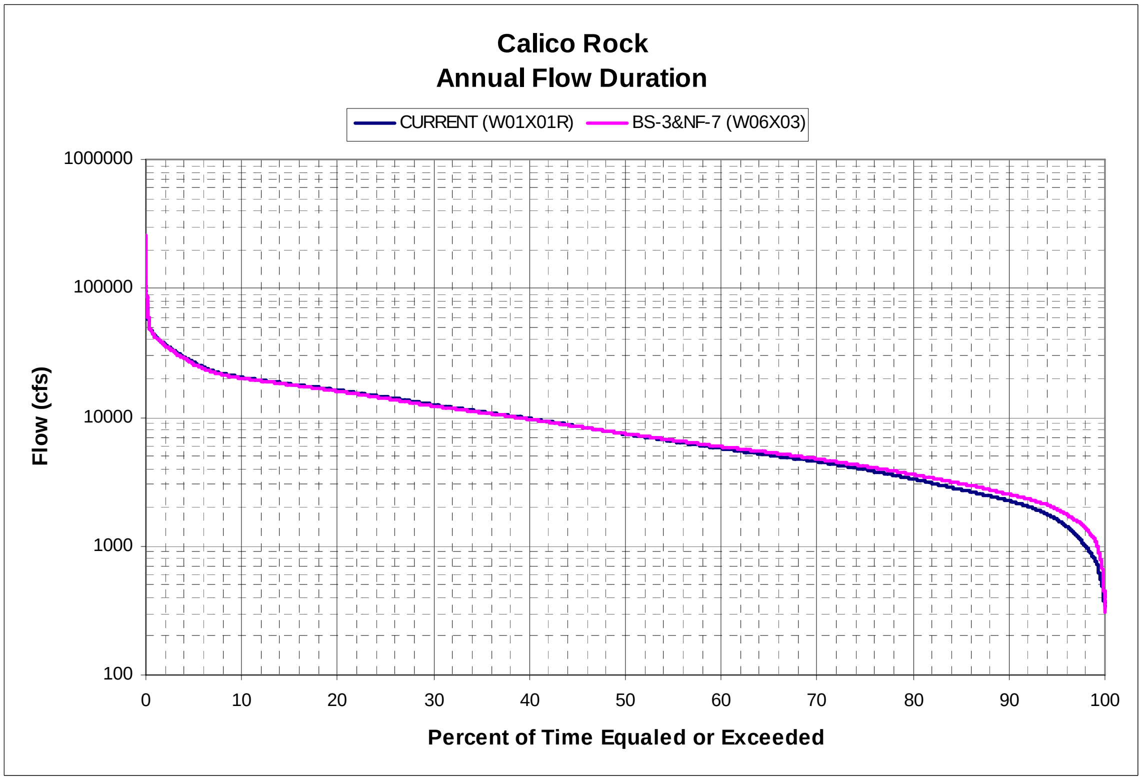
Tables and Graphs

Calico Rock, Batesville, Newport, Augusta, Georgetown, and Clarendon

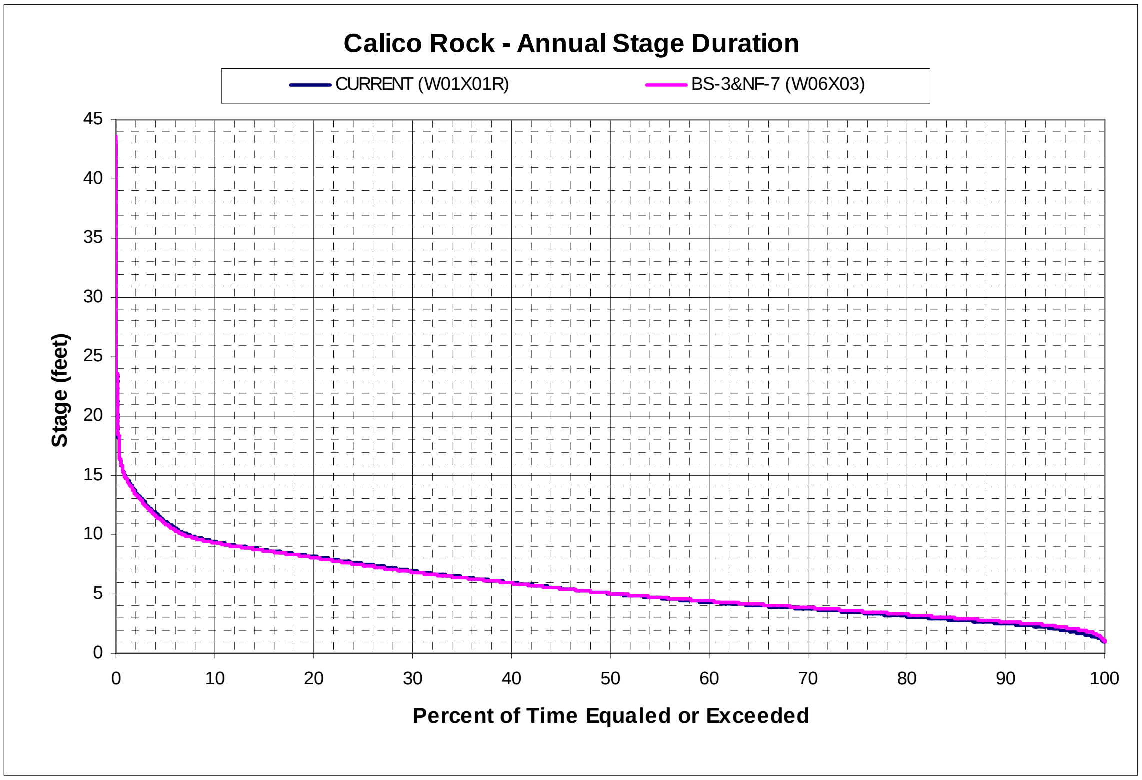
(Flow and Stage - Frequency and Duration)


White River at Calico Rock, AR
Graphical Discharge Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Discharge (cfs)
1000000
100000
10000
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
0.005
0.002
Exceedance Probability

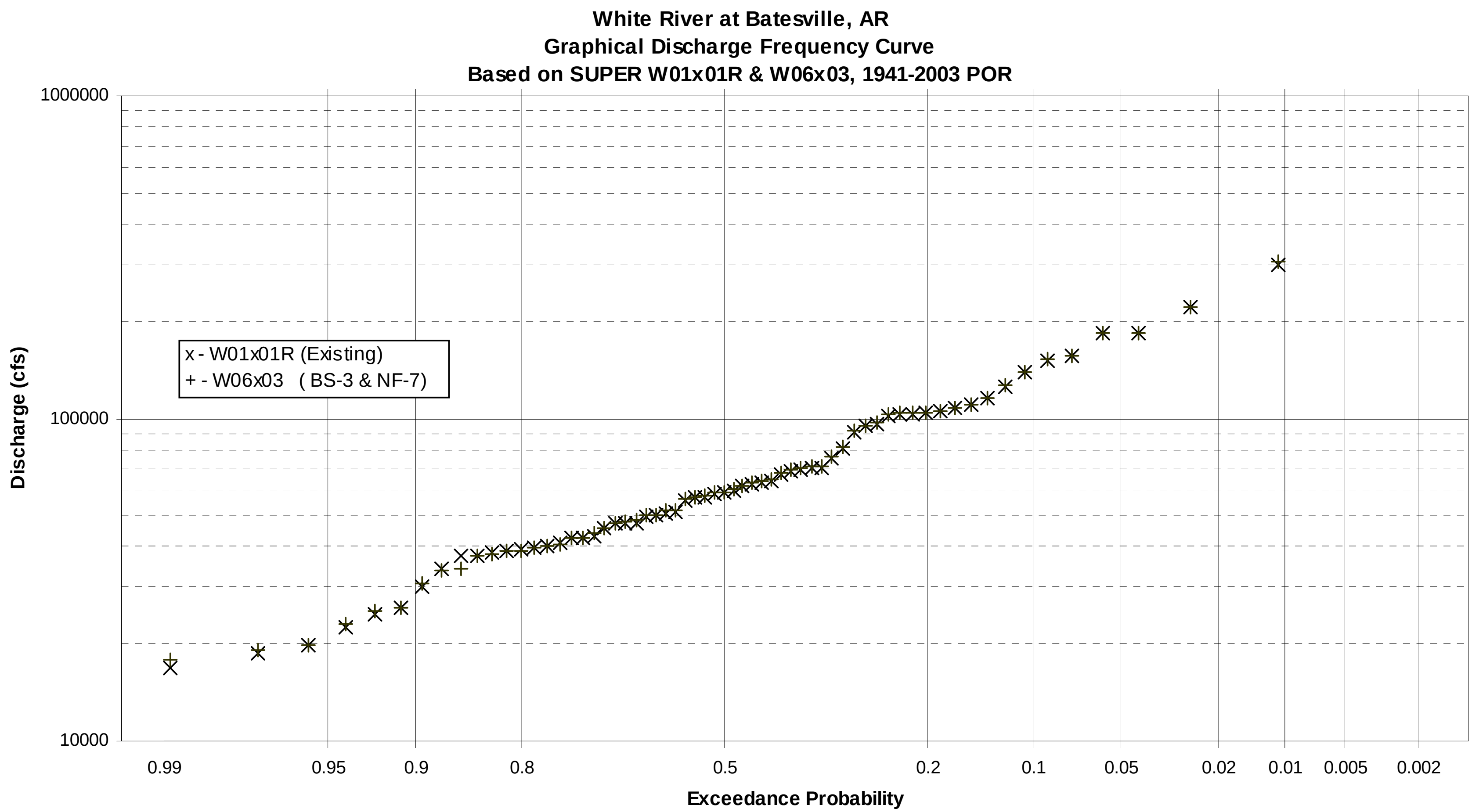

White River at Calico Rock, AR
Graphical Stage Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Stage (ft)
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability



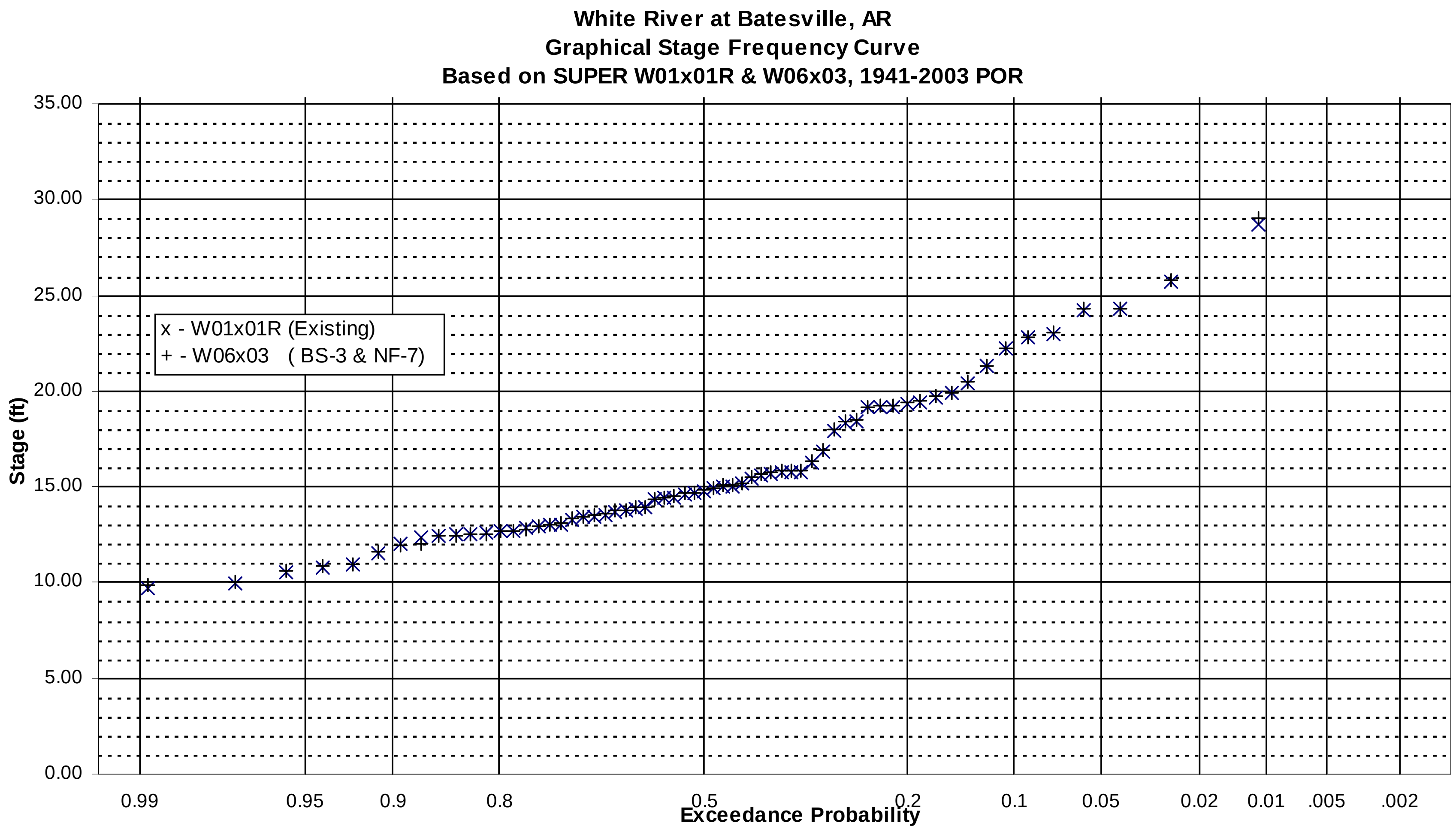
Calico Rock		
Annual Flow-Duration		
Percent Equaled or Exceeded	Current (W01X01R) (dsf)	BS-3&NF-7 (W06X03) (dsf)
1	42142	41733
2	36575	35862
5	26644	25768
10	20414	20073
15	18062	17849
20	16231	15944
25	14314	13963
30	12512	12236
35	11046	10847
40	9755	9646
45	8515	8474
50	7397	7445
55	6506	6614
60	5730	5923
65	5094	5335
70	4525	4768
75	3920	4160
80	3316	3591
85	2745	3056
90	2252	2523
95	1615	1938
100	343	308



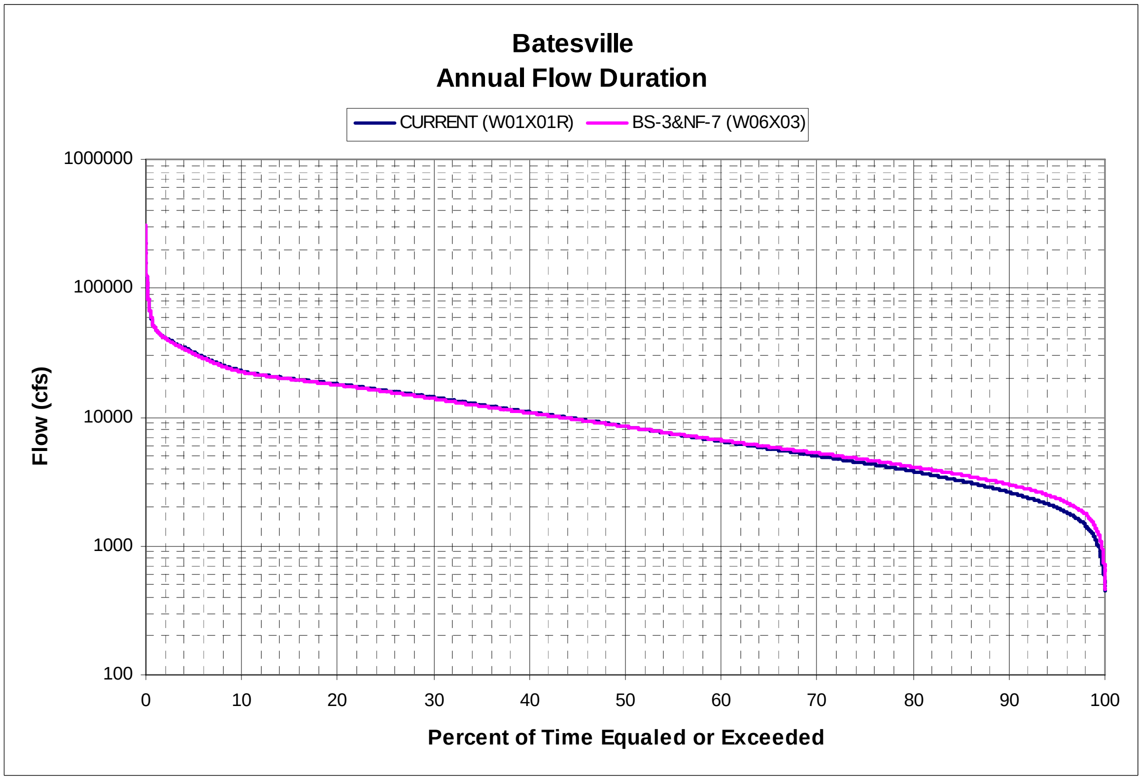
Calico Rock		
Annual Stage-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	14.9	14.8
2	13.6	13.4
5	11.1	10.9
10	9.4	9.3
15	8.7	8.7
20	8.2	8.1
25	7.5	7.4
30	7.0	6.9
35	6.4	6.4
40	6.0	5.9
45	5.5	5.5
50	5.0	5.1
55	4.7	4.7
60	4.3	4.4
65	4.0	4.1
70	3.7	3.9
75	3.4	3.6
80	3.1	3.3
85	2.8	3.0
90	2.5	2.7
95	2.1	2.3
100	1.0	0.9



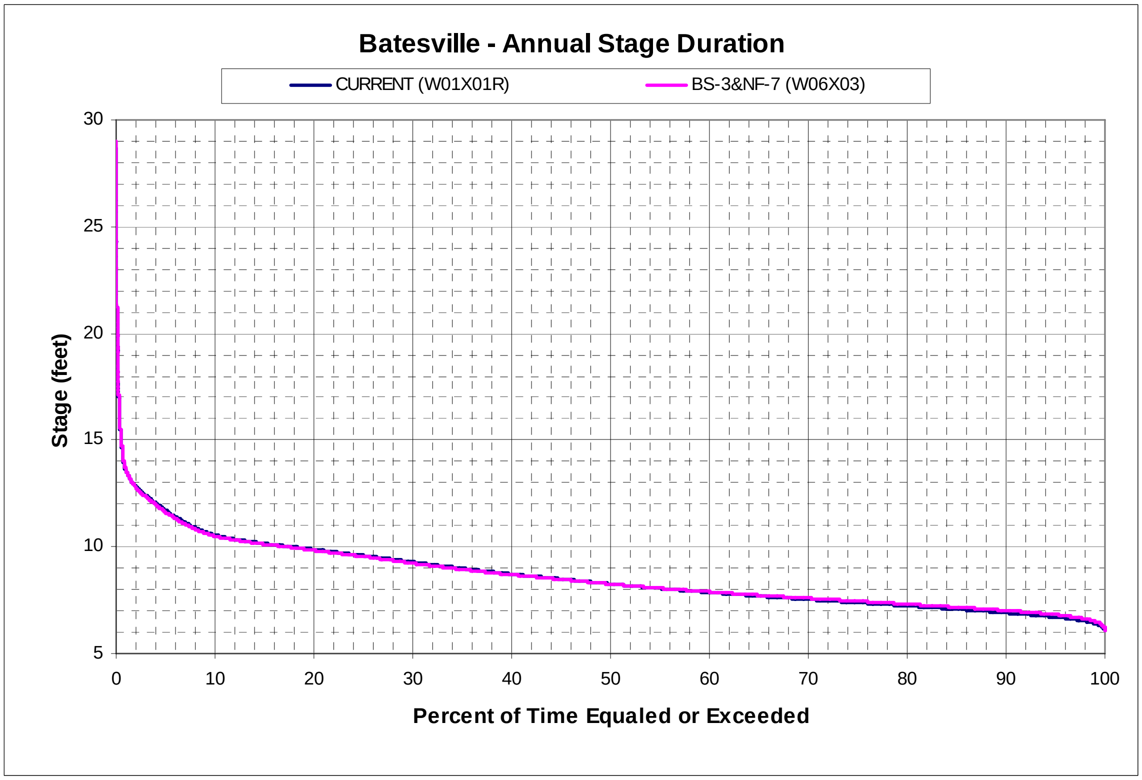
White River at Batesville, AR
Graphical Discharge Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Discharge (cfs)
1000000
100000
10000
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
0.005
0.002
Exceedance Probability



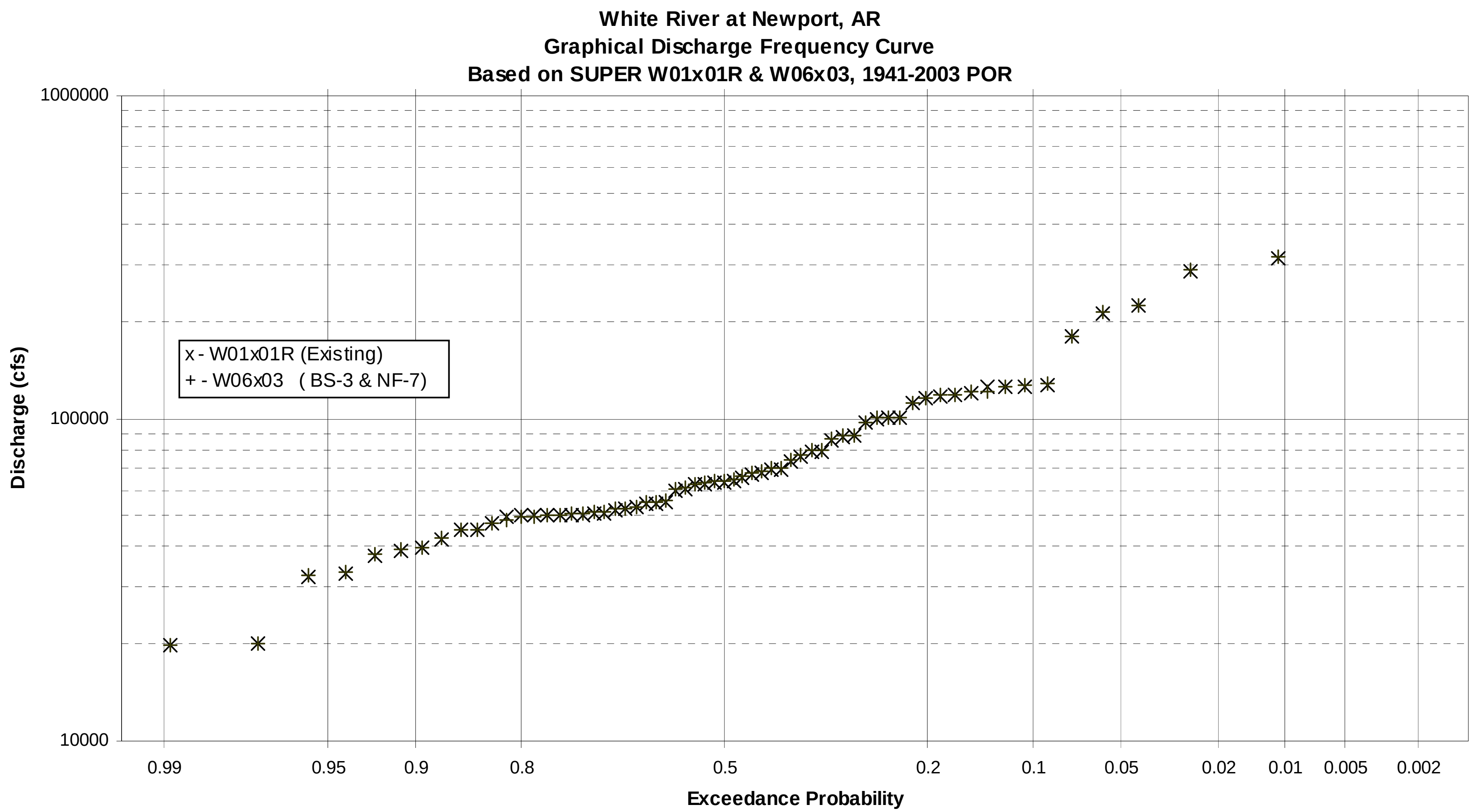
White River at Batesville, AR
Graphical Stage Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Stage (ft)
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability

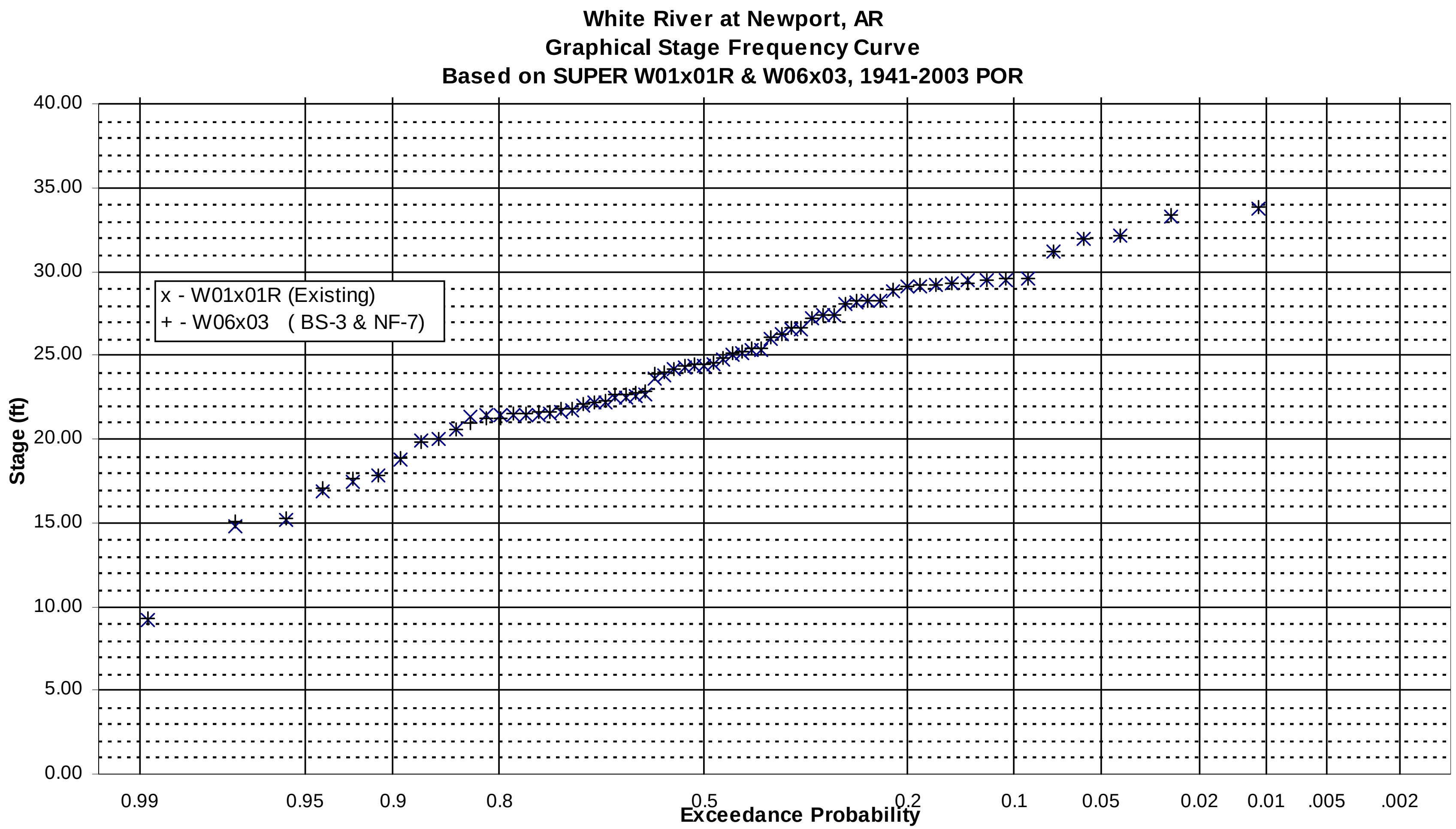


Batesville		
Annual Flow-Duration		
Percent Equaled or Exceeded	Current (W01X01R) (dsf)	BS-3&NF-7 (W06X03) (dsf)
1	48317	48457
2	41288	40999
5	31689	31074
10	22795	22381
15	19906	19711
20	18002	17714
25	16071	15835
30	14235	13874
35	12425	12152
40	10922	10754
45	9642	9550
50	8458	8444
55	7377	7419
60	6487	6619
65	5694	5887
70	5006	5259
75	4373	4683
80	3798	4110
85	3187	3571
90	2610	3004
95	1975	2352
100	448	464

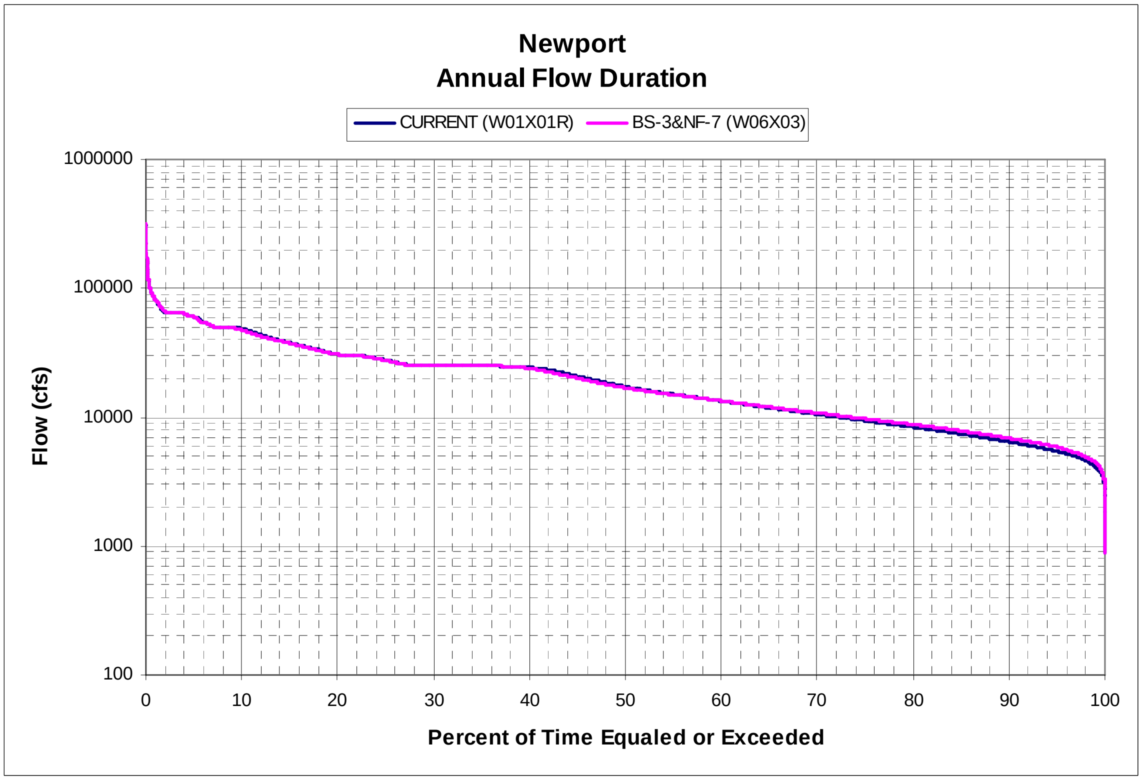


Batesville		
Annual Stage-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	13.6	13.6
2	12.8	12.8
5	11.7	11.6
10	10.6	10.5
15	10.2	10.1
20	9.9	9.8
25	9.6	9.6
30	9.3	9.2
35	9.0	8.9
40	8.7	8.7
45	8.5	8.5
50	8.3	8.3
55	8.1	8.1
60	7.9	7.9
65	7.7	7.7
70	7.5	7.6
75	7.4	7.5
80	7.2	7.3
85	7.1	7.2
90	6.9	7.0
95	6.7	6.8
100	6.1	6.1

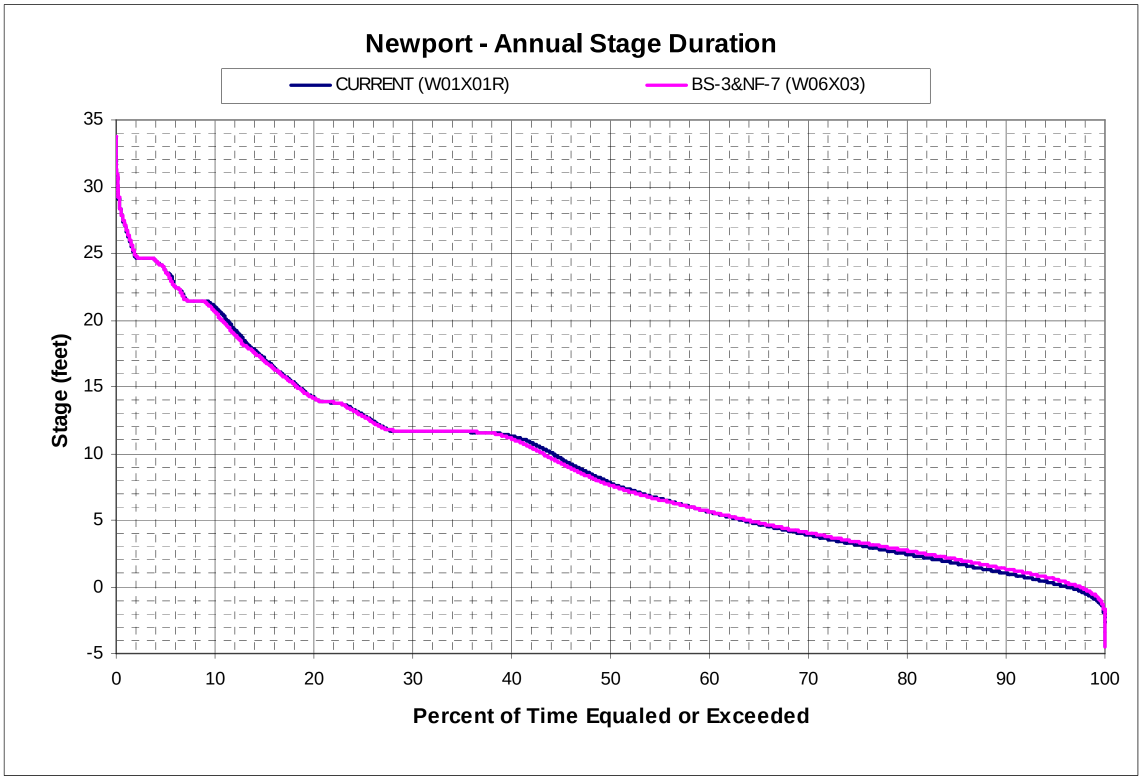

White River at Newport, AR
Graphical Discharge Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
Discharge (cfs)
1000000
100000
10000
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
0.005
0.002
Exceedance Probability



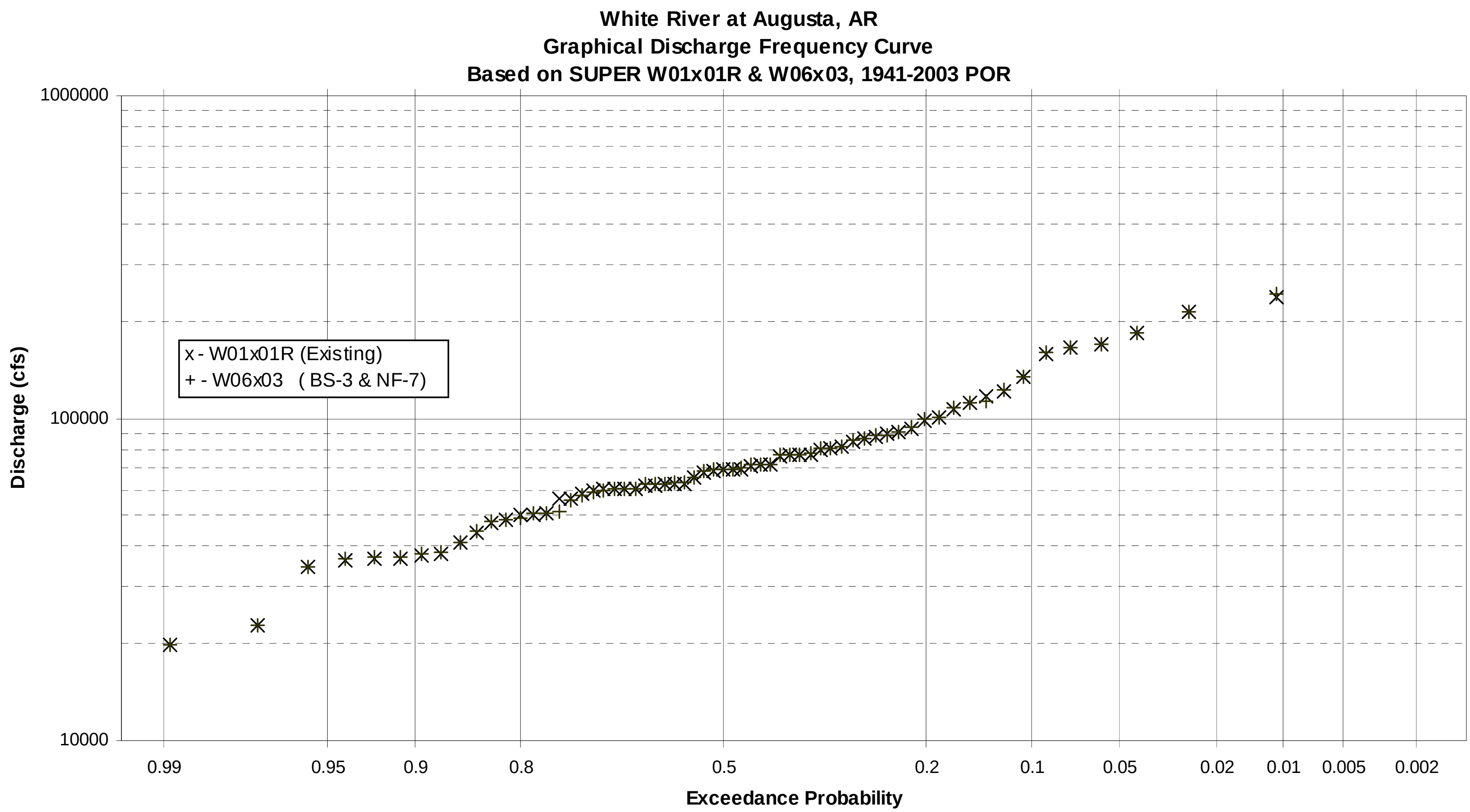
White River at Newport, AR
Graphical Stage Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Stage (ft)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability

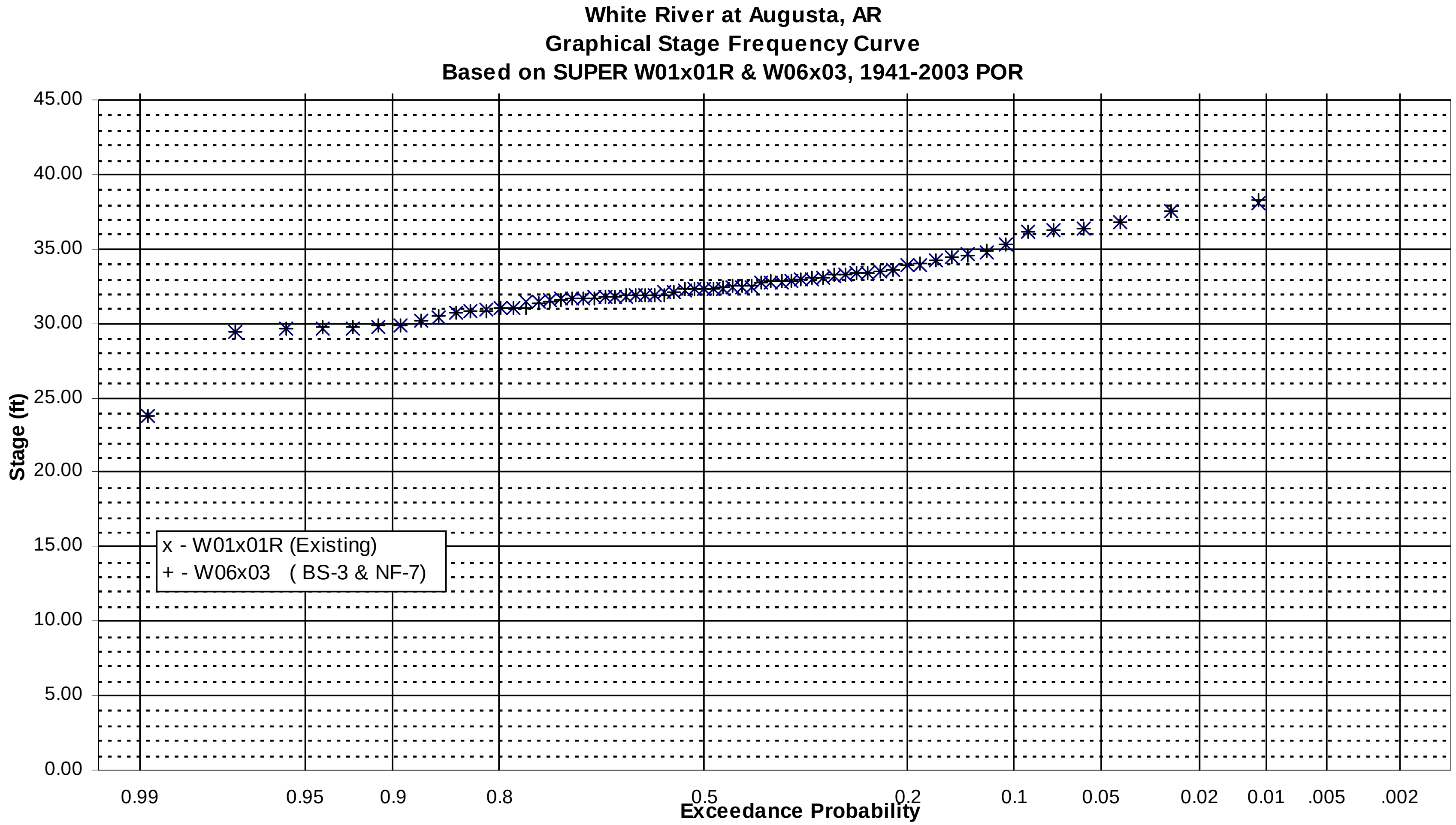


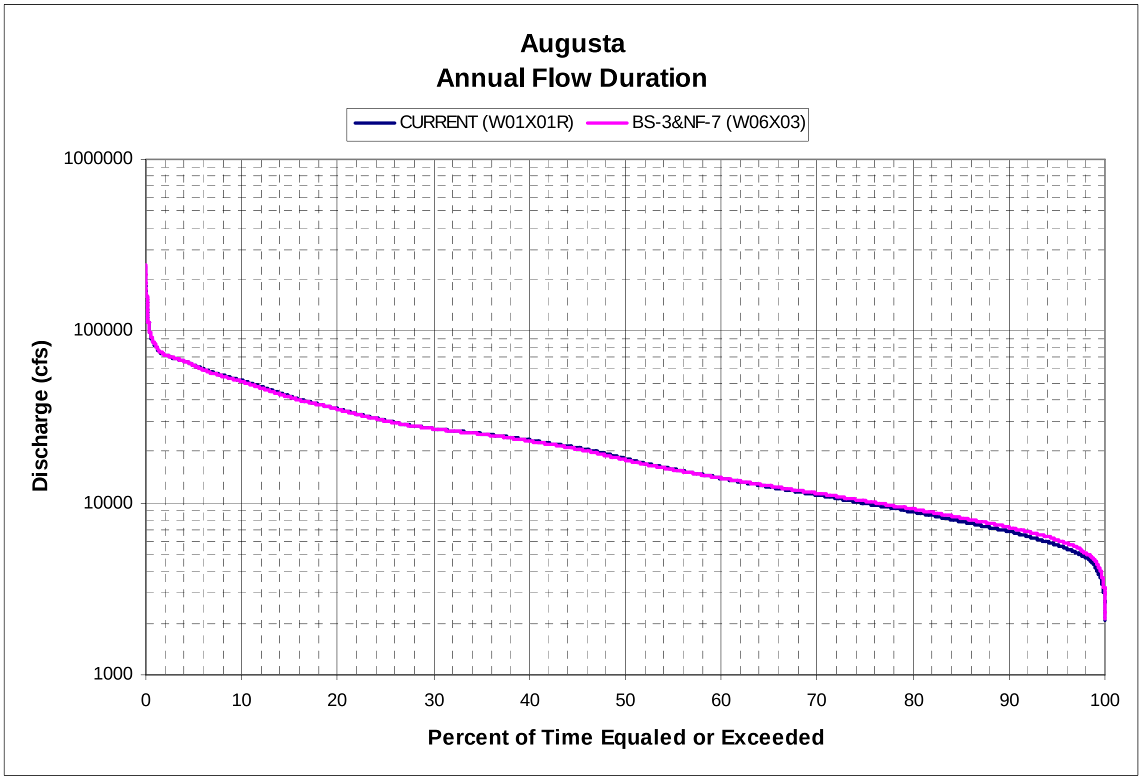
Newport		
Annual Flow-Duration		
Percent Equaled or Exceeded	Current (W01X01R) (dsf)	BS-3&NF-7 (W06X03) (dsf)
1	81327	81982
2	65206	65660
5	59506	59409
10	48435	47268
15	37873	37454
20	30691	30659
25	27722	27567
30	25000	25140
35	25000	25076
40	24335	23873
45	20785	20116
50	17216	16912
55	15065	14937
60	13345	13393
65	11826	11999
70	10522	10789
75	9395	9720
80	8383	8768
85	7406	7821
90	6417	6864
95	5436	5865
100	871	884



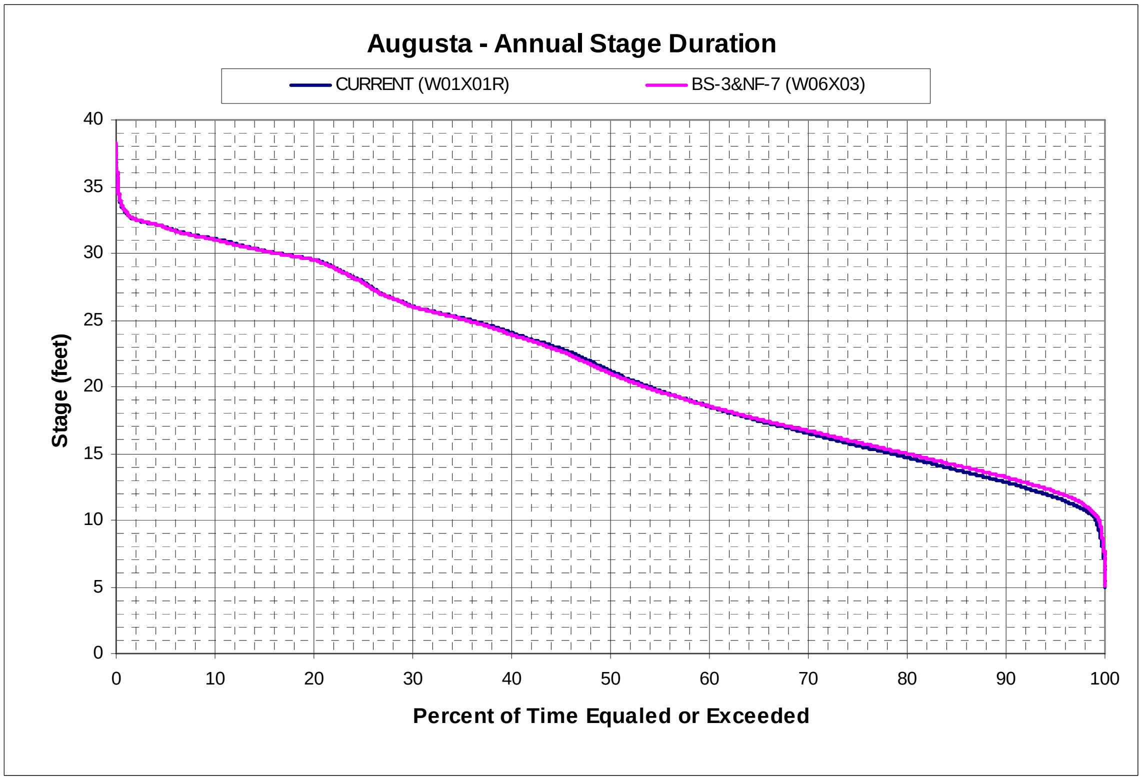
Newport		
Annual Stage-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	26.8	26.9
2	24.7	24.8
5	23.7	23.6
10	21.0	20.6
15	17.1	16.9
20	14.1	14.1
25	12.9	12.8
30	11.6	11.7
35	11.6	11.7
40	11.3	11.1
45	9.6	9.3
50	7.8	7.6
55	6.6	6.5
60	5.6	5.6
65	4.7	4.8
70	3.9	4.1
75	3.1	3.4
80	2.4	2.7
85	1.8	2.1
90	1.0	1.3
95	0.2	0.6
100	-4.5	-4.5


White River at Augusta, AR
Graphical Discharge Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Discharge (cfs)
1000000
100000
10000
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
0.005
0.002
Exceedance Probability

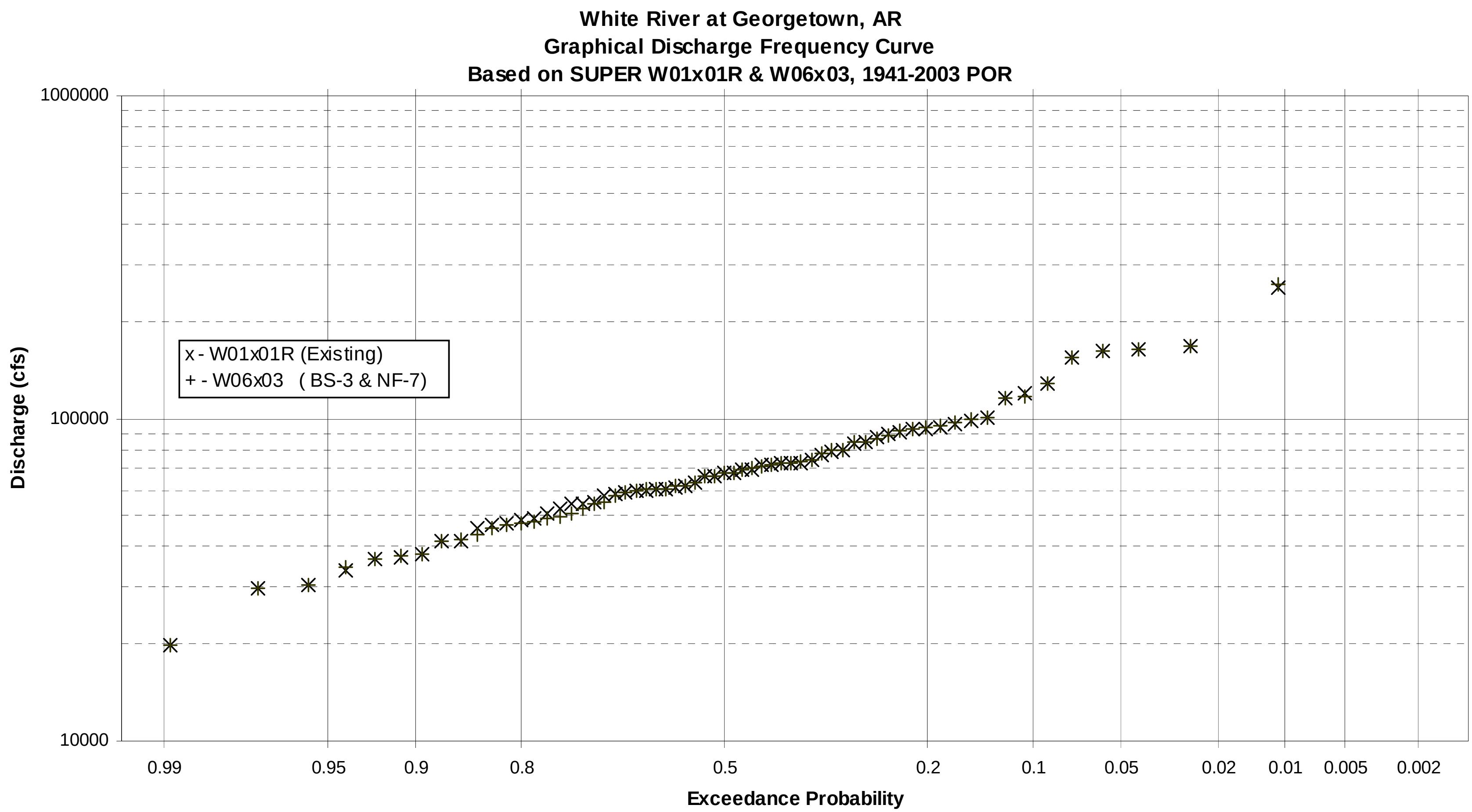

White River at Augusta, AR
Graphical Stage Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Stage (ft)
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability

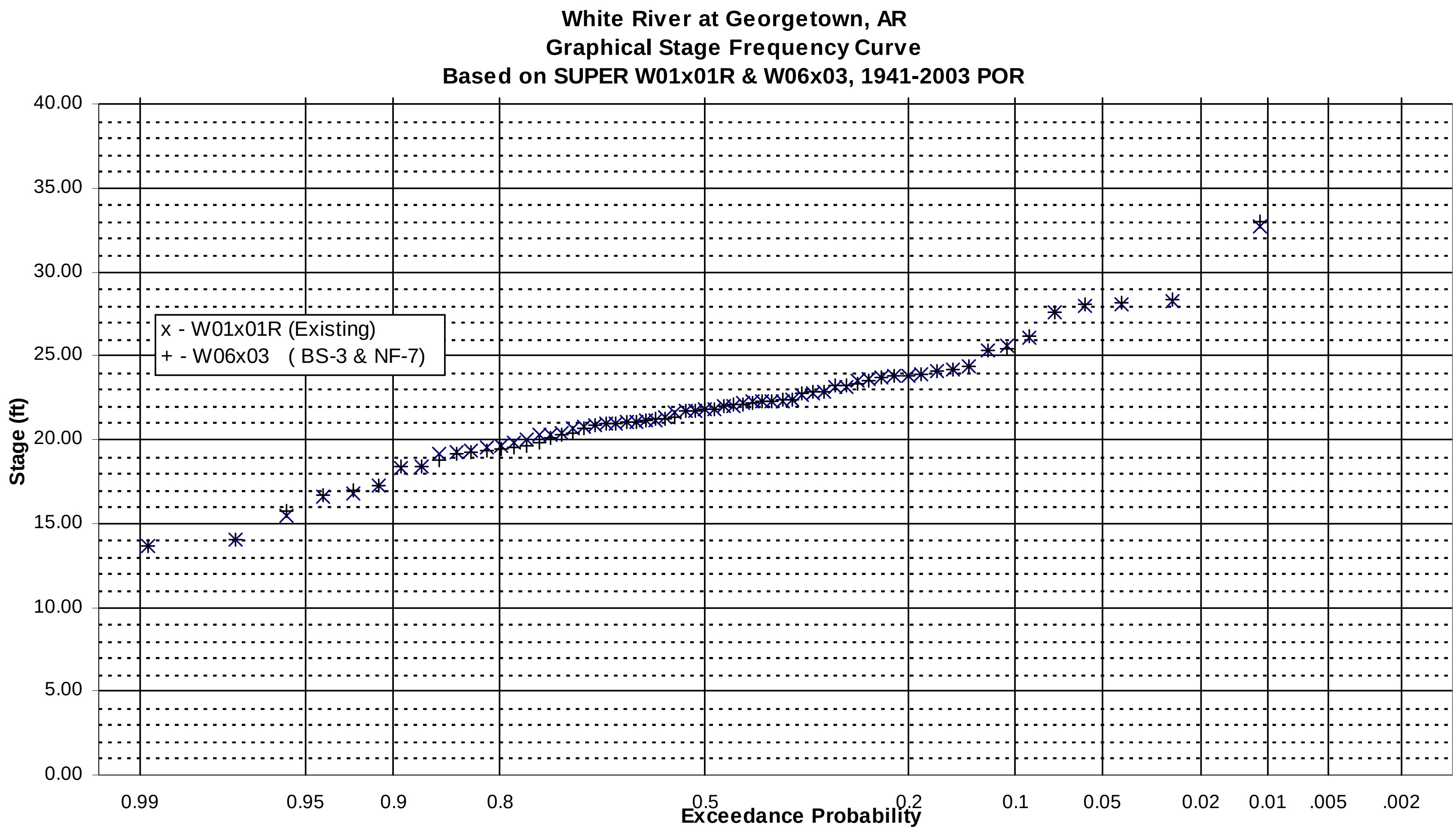


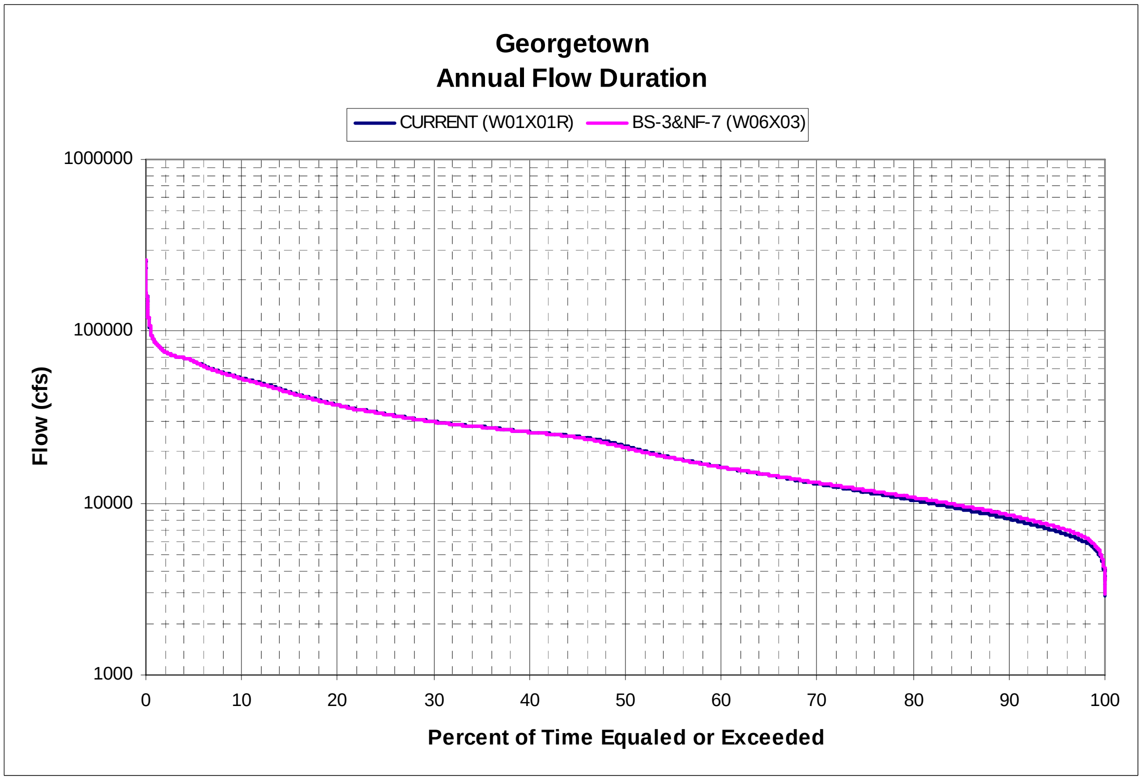
Augusta		
Annual Flow-Duration		
Percent Equaled or Exceeded	Current (W01X01R) (dsf)	BS-3&NF-7 (W06X03) (dsf)
1	81817	82550
2	72998	73005
5	63504	63034
10	51529	50744
15	41751	41345
20	35321	35144
25	30190	30102
30	27051	27012
35	25296	25150
40	23187	22934
45	20955	20636
50	18128	17813
55	15721	15598
60	13923	13969
65	12412	12567
70	11159	11405
75	9947	10272
80	8859	9219
85	7806	8205
90	6830	7221
95	5688	6108
100	2086	2106



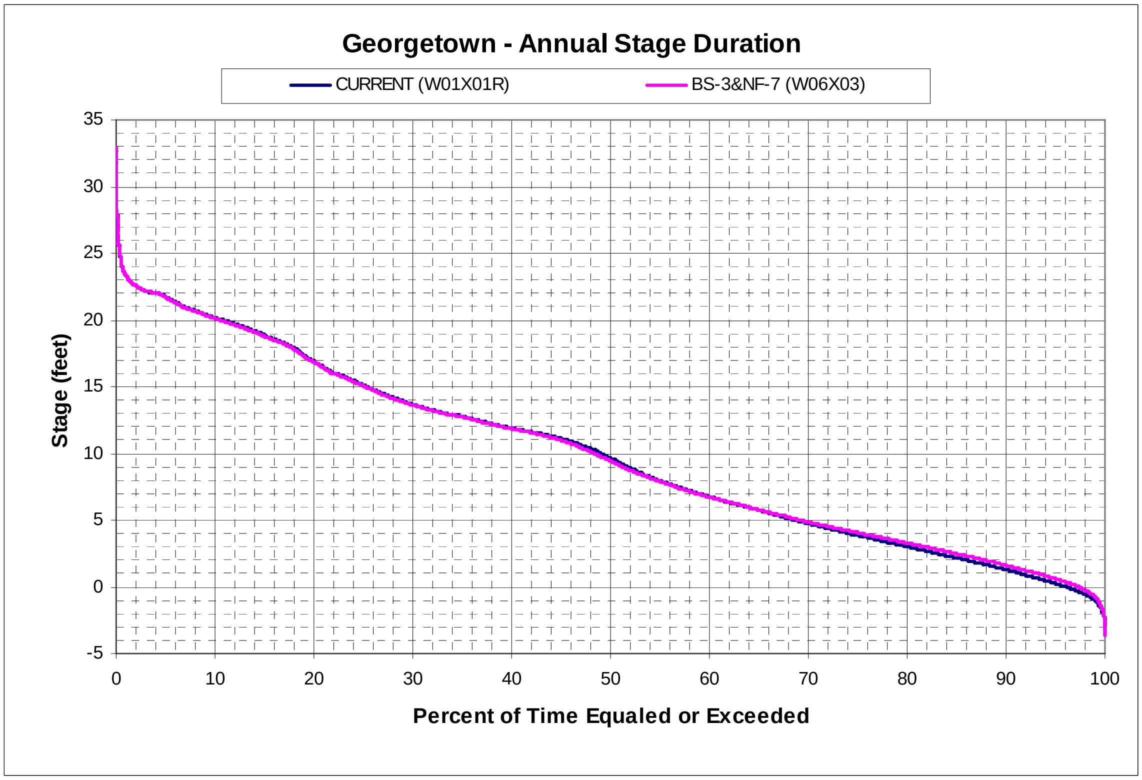
Augusta		
Annual Stage-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	33.1	33.1
2	32.5	32.5
5	32.0	31.9
10	31.1	31.0
15	30.2	30.2
20	29.5	29.5
25	27.8	27.8
30	26.0	26.0
35	25.1	25.1
40	24.0	23.9
45	22.8	22.6
50	21.2	21.0
55	19.7	19.6
60	18.5	18.5
65	17.4	17.6
70	16.5	16.7
75	15.6	15.8
80	14.7	15.0
85	13.8	14.1
90	12.8	13.2
95	11.7	12.1
100	5.0	5.0


White River at Georgetown, AR
Graphical Discharge Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
1000000
100000
10000
Discharge (cfs)
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
0.005
0.002
Exceedance Probability

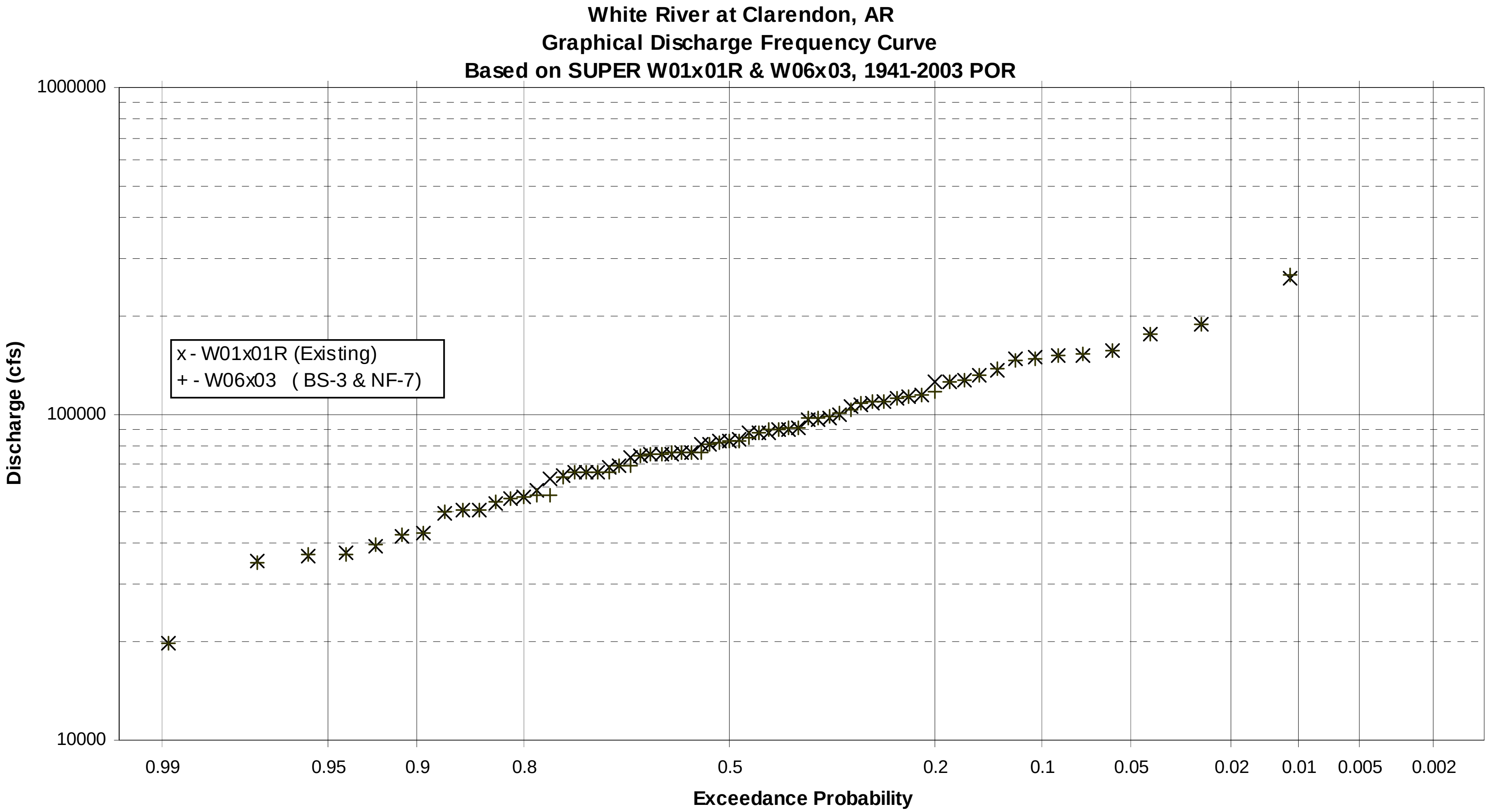

White River at Georgetown, AR
Graphical Stage Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
Stage (ft)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability



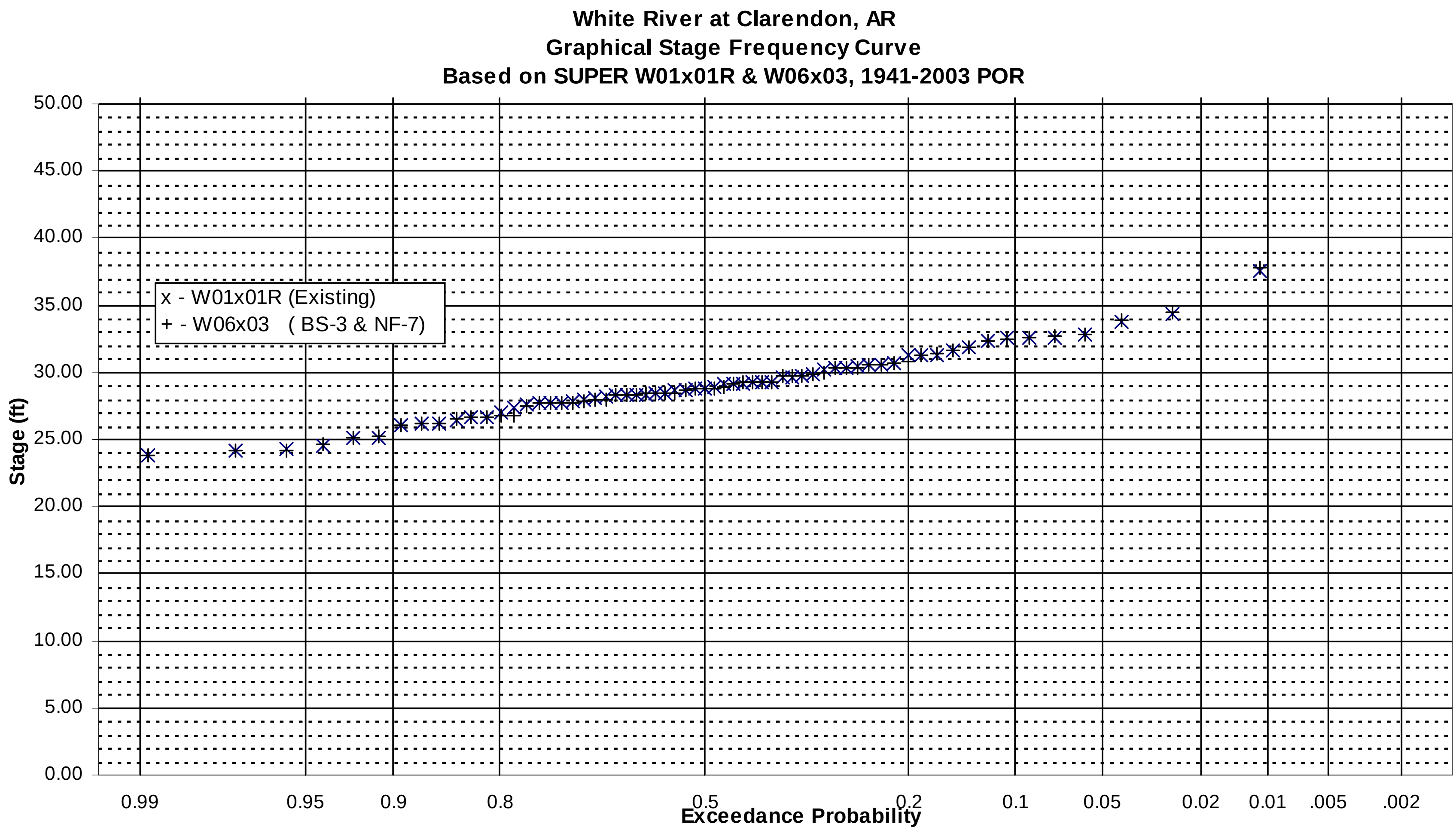
Georgetown		
Annual Flow-Duration		
Percent Equaled or Exceeded	Current (W01X01R) (dsf)	BS-3&NF-7 (W06X03) (dsf)
1	85809	86116
2	76115	76124
5	67068	66746
10	53336	52863
15	44191	43829
20	37298	37161
25	33026	32927
30	29772	29695
35	27808	27732
40	25961	25869
45	24382	24114
50	21482	21035
55	18306	18247
60	16261	16193
65	14563	14580
70	12981	13136
75	11602	11928
80	10423	10797
85	9256	9656
90	8111	8526
95	6851	7305
100	2913	2939

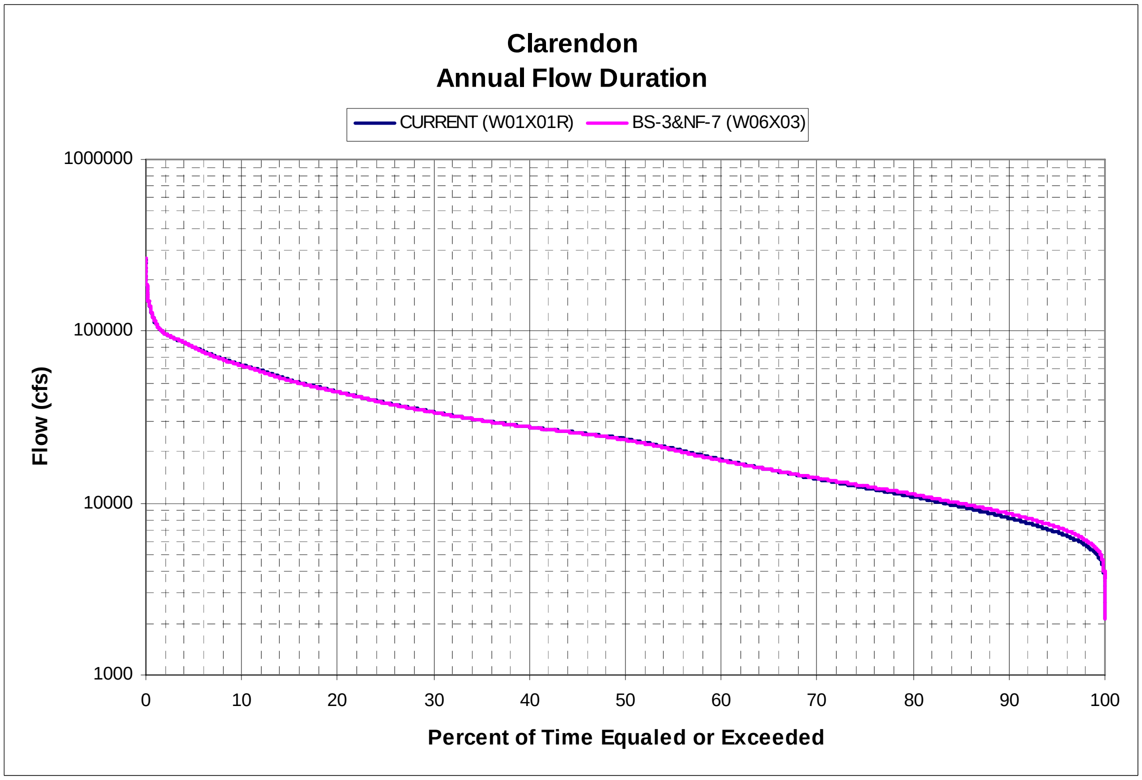


Georgetown		
Annual Stage-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	23.3	23.3
2	22.6	22.6
5	21.8	21.7
10	20.2	20.1
15	18.8	18.8
20	16.9	16.9
25	15.1	15.1
30	13.7	13.6
35	12.8	12.7
40	11.9	11.8
45	11.1	11.0
50	9.7	9.4
55	7.9	7.9
60	6.8	6.7
65	5.8	5.8
70	4.8	4.9
75	3.8	4.1
80	3.0	3.3
85	2.2	2.5
90	1.3	1.6
95	0.3	0.6
100	-3.6	-3.6

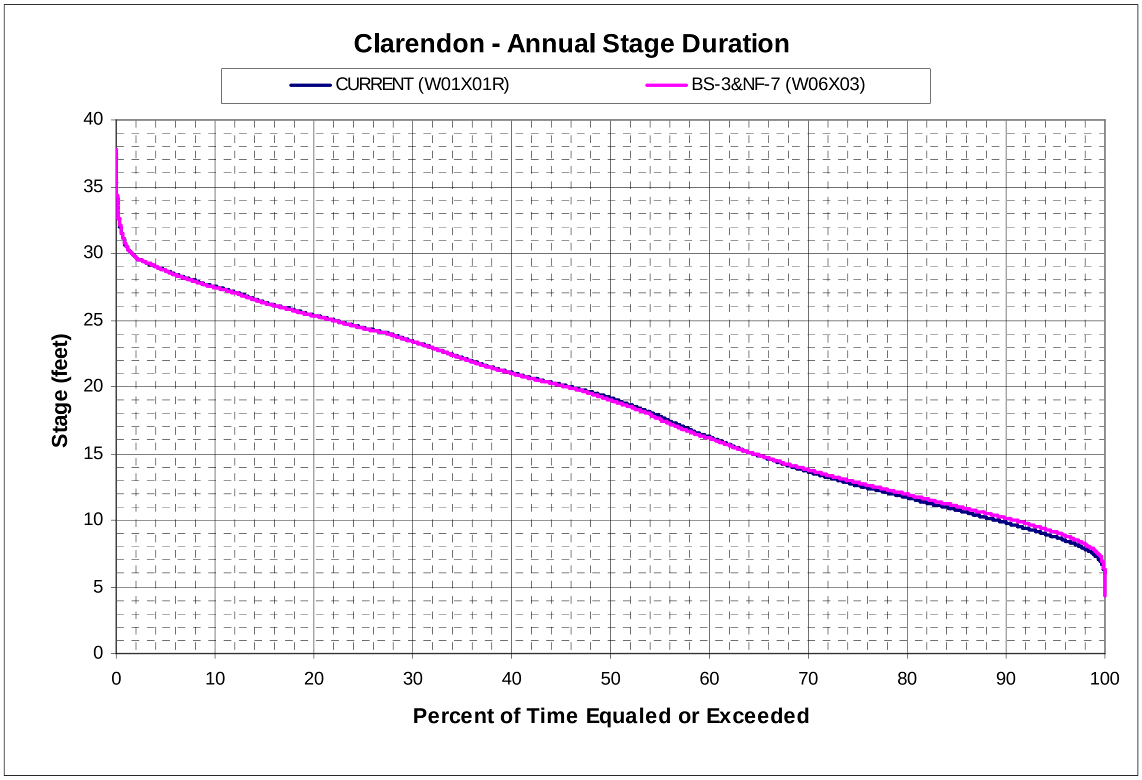


White River at Clarendon, AR
Graphical Discharge Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
Discharge (cfs)
1000000
100000
10000
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
0.005
0.002
Exceedance Probability


White River at Clarendon, AR
Graphical Stage Frequency Curve
Based on SUPER W01x01R & W06x03, 1941-2003 POR
x - W01x01R (Existing)
+ - W06x03 (BS-3 & NF-7)
Stage (ft)
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
0.99
0.95
0.9
0.8
0.5
0.2
0.1
0.05
0.02
0.01
.005
.002
Exceedance Probability



Clarendon		
Annual Flow-Duration		
Percent Equaled or Exceeded	Current (W01X01R) (dsf)	BS-3&NF-7 (W06X03) (dsf)
1	111897	112446
2	96820	97001
5	80805	80683
10	63773	63069
15	52006	51603
20	44433	44312
25	38342	38209
30	33857	33774
35	30329	30244
40	27748	27686
45	25728	25602
50	23618	23275
55	20744	20430
60	17953	17755
65	15687	15700
70	13805	14001
75	12262	12565
80	10902	11268
85	9539	9963
90	8197	8702
95	6776	7270
100	2124	2140



Clarendon		
Annual Stage-Duration		
Percent Equaled or Exceeded	Current (W01X01R)	BS-3&NF-7 (W06X03)
1	30.6	30.6
2	29.7	29.7
5	28.7	28.7
10	27.5	27.4
15	26.3	26.3
20	25.3	25.3
25	24.4	24.4
30	23.4	23.4
35	22.2	22.1
40	21.0	21.0
45	20.1	20.1
50	19.2	19.0
55	17.8	17.6
60	16.2	16.1
65	14.8	14.9
70	13.6	13.8
75	12.6	12.8
80	11.7	11.9
85	10.8	11.1
90	9.8	10.2
95	8.7	9.1
100	4.3	4.4

White River Basin, Arkansas, Minimum Flows
Project Report

HYDROPOWER EVALUATION

a. SWPA Report

b. HAC Report

APPENDIX C

PROPOSED DETERMINATION

White River Minimum Flows Study

Determination of Offset to the Federal Hydropower Purpose and Impacts on Non-Federal Project

Southwestern Power Administration

June 2008

Executive Summary

This report details the procedures used by Southwestern Power Administration (Southwestern) to determine the losses to the Federal hydropower purpose at Bull Shoals and Norfork hydroelectric projects and to the non-Federal Ozark Beach hydroelectric project in Missouri due to the implementation of White River Minimum Flows as authorized in Section 132 of Public Law 109-103 (2005). Energy and capacity losses were developed for the Federal and non-Federal projects, and additional losses related to the reallocations for minimum flows were included as appropriate. Southwestern published a "Notice of Public Review and Comment" in the Federal Register on February 5, 2008, concerning its Draft Determination Report dated January 2008. There was a 30-day public comment period which ended on March 6, 2008. The incorporation of the public comments received resulted in this Proposed Determination Report.

Currently, the calculated loss to Federal hydropower is $86,712,100, and the calculated loss to the non-Federal project is $33,935,100. The loss values were calculated on the basis of the present value of the estimated future lifetime (50 years assumed by Southwestern) replacement cost of the electrical energy and capacity assuming an implementation date of January 1, 2011, for the White River Minimum Flows project. The final calculation will depend on the official date of implementation as specified by the Corps of Engineers and the value of the specified parameters in effect at that time.

Section 132 of Public Law 109-103 (2005) authorized alternative BS–3 at Bull Shoals, as described in the White River Minimum Flows Reallocation Study Report, Arkansas and Missouri, dated July 2004. Under the authorized plan for the Bull Shoals project, five feet of storage for minimum flows will be reallocated from the flood control pool with provisions to provide a portion of the reallocated storage for hydropower's use to maintain the yield of the current hydropower storage. The current seasonal pool plan will be superimposed on the new top of conservation pool. As a result, both the conservation and seasonal pool levels at Bull Shoals will be raised five feet. The additional downstream releases for minimum flows will be accomplished by generating with one of the main units at a low, inefficient rate. Since the current hydropower yield will be maintained, there will be no loss of marketable capacity or peaking energy at Bull Shoals. The energy loss, 23,855 megawatt-hours (MWh) per year of off-peak energy, will be the result of making the required minimum downstream releases by generating energy at a much lower plant efficiency than normal generation. Since the energy that is produced from the minimum flow releases will be generated at a time when the energy is not needed to fulfill Federal peaking energy contracts, it is similar in value to the off-peak energy normally generated during flood control operations. Operating a main unit at the lower efficiency will also increase the average maintenance costs at the project by an estimated $68,000 per year.

Section 132 of Public Law 109-103 (2005) authorized alternative NF-7 at Norfork, as described in the White River Minimum Flows Reallocation Study Report, Arkansas and Missouri, dated July 2004. Under the authorized plan for the Norfork project, 3.5 feet of storage will be reallocated for minimum flows. One-half of the storage for minimum flows will be reallocated from the flood control pool and the other half from hydropower storage. The reallocation portion from the flood control storage is similar to the storage reallocation at Bull Shoals in that the hydropower storage yield for that portion will be maintained and the existing seasonal pool plan will be superimposed on the new top of conservation pool. As a result, both the conservation and seasonal pool levels at Norfork will be raised 1.75 feet. Unlike Bull Shoals, all minimum flow releases at Norfork, whether from reallocated flood or hydropower storage, will be spilled through a siphon with no energy generated from the water. Although there will be no marketable capacity loss associated with the flood control storage portion of the reallocation, there will be an off-peak energy loss. The portion of the reallocation from the hydropower storage will reduce the yield available to hydropower and will directly impact the marketable capacity and on-peak energy available at Norfork. The annual energy loss at Norfork associated with the reallocation will be 6,762 MWh of off-peak energy and 6,762 MWh of on-peak energy, for a total annual energy loss of 13,524 MWh. The marketable capacity loss will be 3.93 megawatts (MW).

Federal Energy Regulatory Commission (FERC) Project No. 2221, the non-Federal Ozark Beach hydroelectric project, will be directly affected by the authorized minimum flow plan. The implementation of the authorized plan will result in a reduction of the amount of gross head (headwater elevation minus the tailwater elevation) available for generation at the non-Federal project at Ozark Beach. The reduction in gross head will result in an annual energy loss of 6,029 MWh of on-peak energy and 2,969 MWh of off-peak energy, or an annual total energy loss of 8,998 MWh. Also associated with the loss of gross head, there will be a capacity loss of 3.00 MW at the project.

Several changes were made in the report as the result of the comments received on the draft determination report:

- The proposed determination's one-time payment to the non-Federal project licensee is $33,935,100 compared to $21,363,700 in the draft determination, an increase of $12,571,400. The hydropower impact on the Federal projects increased from $41,584,800 to $86,712,100, an increase of $45,127,300. The increases are attributable approximately to the following:
    - The amount of average annual energy lost at the non-Federal Ozark Beach project was increased by 353 MWh, 237 MWh of on-peak energy and 116 MWh of off-peak energy. The increase was in response to a comment that Southwestern had not considered the amount of intervening flow that originates from the drainage area between Table Rock dam and the Ozark Beach project. Southwestern concurred, used the additional inflow in both the base and alternative cases, and re-ran the model to get the above results. The energy increase accounted for an increase in the one-time payment for the impact to the non-Federal project of approximately $0.6 million of the $12.5

million increase. There was no change to the energy lost at the Federal projects from that correction.

- The consensus of the comments from the electrical industry indicated that the energy replacement costs used by Southwestern, especially for the value of off-peak energy, were unreasonably low. After careful evaluation, Southwestern determined that the Platts High Fuel Value energy cost forecast is more appropriate and representative of current market conditions than energy values developed using the FERC method (which was no longer being maintained by FERC) as computed by the Corps. It was previously noted that the Corps and Empire District Electric Company, the non-Federal licensee for the Ozark Beach project, had agreed to use those values prior to Southwestern's involvement. The use of the Platts forecast increased the non-Federal hydropower impact present value about $4.6 million and the Federal hydropower impact present value about $21.8 million. The Federal increase was greater because so much of the Federal energy loss was composed of the previously under-valued off-peak energy.

- The remainder of the increase is not the result of a change in methodology, but simply the result of updating the data to account for rising energy costs and lower interest rates. The rising energy costs accounted for an increase in the estimated impact on the non-Federal project of approximately $3.4 million and of $12.8 million for the Federal projects. The lower discount rate based on the 30-year U.S. Treasury rate resulted in an increase in the present value of the estimated impacts to the non-Federal project of about $3.9 million and to the Federal projects of about $10.5 million.

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White River Minimum Flows Study
Determination of Offset to the Federal Hydropower Purpose and Impacts on Non-Federal Project

1.0 Introduction

The purpose of this report is to document the procedures used by Southwestern Power Administration (Southwestern) to determine the losses to the Federal hydropower purpose at Bull Shoals and Norfork hydroelectric projects and to the non-Federal Ozark Beach hydroelectric project in Missouri due to the implementation of the White River Minimum Flows project as authorized in the Energy and Water Development Appropriations Act, 2006 (Public Law 109-103 (2005)), Section 132. The loss values were calculated on the basis of the present value of the estimated future lifetime (50 years assumed by Southwestern) replacement cost of the electrical energy and capacity assuming an implementation date of January 1, 2011, for the White River Minimum Flows project. The final calculation will depend on the official date of implementation as specified by the Corps of Engineers (Corps) and the value of the specified parameters in effect at that time.

Southwestern published a "Notice of Public Review and Comment" in the Federal Register on February 5, 2008, concerning its Draft Determination Report dated January 2008. There was a 30-day public comment period which ended on March 6, 2008. The incorporation of the public comments received resulted in this Proposed Determination Report. The public comments received are included in Appendix J, and Southwestern's responses to the public comments are included in Appendix K.

2.0 Background

The Water Resource Development Acts (WRDA) of 1999 and 2000 authorized minimum flows at five multipurpose projects in the White River Basin and directed the Corps to complete a study and report to determine if minimum flow reallocations would adversely affect other authorized purposes. Section 374 of WRDA 1999 and Section 304 of WRDA 2000 specified the following reallocations of project storage: Beaver Lake, 1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.

2.1 Section 374 of WRDA 1999.

> *SEC. 374. WHITE RIVER BASIN, ARKANSAS AND MISSOURI 1999.*
> *(a) IN GENERAL. - Subject to subsection (b), the project for flood control, power generation, and other purposes at the White River Basin, Arkansas and Missouri,*

authorized by section 4 of the Act of June 28,1938 (52 Stat. 1218, chapter 795), and modified by House Document 917, 76th Congress, 3rd Session, and House Document 290, 77th Congress, 1st Session, approved August 18, 1941, and House Document 499, 83rd Congress, 2d Session, approved September 3, 1954, and by section 304 of the Water Resource Development Act of 1996 (110 Stat. 3711) is further modified to authorize the Secretary to provide minimum flows necessary to sustain tail water trout fisheries by reallocating the following amounts of project storage: Beaver Lake, 1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.

(b) REPORT. -

(1) IN GENERAL. - No funds may be obligated to carry out work on the modification under subsection (a) until completion of a final report by the Chief of Engineers finding that the work is technically sound, environmentally acceptable, and economically justified.

(2) TIMING. - The Secretary shall submit the report to Congress not later than July 30, 2000.

(3) CONTENTS. - The report shall include determinations concerning whether-

(A) the modifications under subsection (a) adversely affects other authorized project purposes; and

(B) Federal costs will be incurred in connection with the modification.

2.2 Section 304 of WRDA 2000.

SEC. 304. WHITE RIVER BASIN, ARKANSAS AND MISSOURI 2000.

(a) IN GENERAL. - Subject to subsection (b), the project for flood control, power generation, and other purposes at the White River Basin, Arkansas and Missouri, authorized by section 4 of the Rivers and Harbors Act of June 28,1938 (52 Stat. 1218), and modified by House Document 917, 76th Congress, 3rd Session, and House Document 290, 77th Congress, 1st Session, approved August 18, 1941, and House Document 499, 83rd Congress, 2d Session, approved September 3, 1954, and by section 304 of the Water Resource Development Act of 1996 (110 Stat. 3711) is further modified to authorize the Secretary to provide minimum flows necessary to sustain tail water trout fisheries by reallocating the following recommended amounts of project storage: Beaver Lake, 1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.

(b) REPORT. -

(1) IN GENERAL. - No funds may be obligated to carry out work on the modification under subsection (a) until the Chief of Engineers, through completion of a final report, determines that the work is technically sound, environmentally acceptable, and economically justified.

(2) TIMING. - Not later than January 1, 2002, the Secretary shall transmit to Congress the final report.

(3) CONTENTS. - The report shall include determinations concerning whether-

(A) the modifications under subsection (a) adversely affects other authorized project purposes; and
(B) Federal costs will be incurred in connection with the modification.

The White River Reallocation Study, completed by the Corps in 2004, evaluated three reallocation plans at each reservoir: reallocation from the flood pool, reallocation from the conservation pool, and splitting the reallocation 50:50 from each pool. Minimum flow release alternatives studied included increased use of existing station service generating units combined with a siphon system, new station service units capable of making the entire minimum flow release, and a siphon only system. At Bull Shoals, use of one of the existing main turbines was included as a possible release alternative.

After the submittal of the 2004 reallocation study, authorization of minimum flows at Bull Shoals and Norfork Dams was included in Public Law 109-103, Section 132.

2.3 Section 132 of Public Law 109-103 (2005).

SEC. 132. WHITE RIVER BASIN, ARKANSAS.—
(a) MINIMUM FLOWS.—
(1) IN GENERAL.—The Secretary is authorized and directed to implement alternatives BS–3 and NF–7, as described in the White River Minimum Flows Reallocation Study Report, Arkansas and Missouri, dated July 2004.
(2) COST SHARING AND ALLOCATION.—Reallocation of storage and planning, design and construction of White River Minimum Flows project facilities shall be considered fish and wildlife enhancement that provides national benefits and shall be a Federal expense in accordance with section 906(e) of the Water Resources Development Act of 1986 (33 U.S.C. 2283(e)). The non-Federal interests shall provide relocations or modifications to public and private lakeside facilities at Bull Shoals Lake and Norfork Lake to allow reasonable continued use of the facilities with the storage reallocation as determined by the Secretary in consultation with the non-Federal interests. Operations and maintenance costs of the White River Minimum Flows project facilities shall be 100 percent Federal. All Federal costs for the White River Minimum Flows project shall be considered non-reimbursable.
(3) IMPACTS ON NON-FEDERAL PROJECT.—The Administrator of Southwestern Power Administration, in consultation with the project licensee and the relevant state public utility commissions, shall determine any impacts on electric energy and capacity generated at Federal Energy Regulatory Commission Project No. 2221 caused by the storage reallocation at Bull Shoals Lake, based on data and recommendations provided by the relevant state public utility commissions. The licensee of Project No. 2221 shall be fully compensated by the Corps of Engineers for those impacts on the basis of the present value of the estimated future lifetime replacement costs of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project. Such costs shall be included in the costs of

implementing the White River Minimum Flows project and allocated in accordance with subsection (a)(2)above.

(4) OFFSET.—In carrying out this subsection, losses to the Federal hydropower purpose of the Bull Shoals and Norfork Projects shall be offset by a reduction in the costs allocated to the Federal hydropower purpose. Such reduction shall be determined by the Administrator of the Southwestern Power Administration on the basis of the present value of the estimated future lifetime replacement cost of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project.

(b) FISH HATCHERY.—In constructing, operating, and maintaining the fish hatchery at Beaver Lake, Arkansas, authorized by section 105 of the Water Resources Development Act of 1976 (90 Stat. 2921), losses to the Federal hydropower purpose of the Beaver Lake Project shall be offset by a reduction in the costs allocated to the Federal hydropower purpose. Such reduction shall be determined by the Administrator of the Southwestern Power Administration based on the present value of the estimated future lifetime replacement cost of the electrical energy and capacity at the time operation of the hatchery begins.

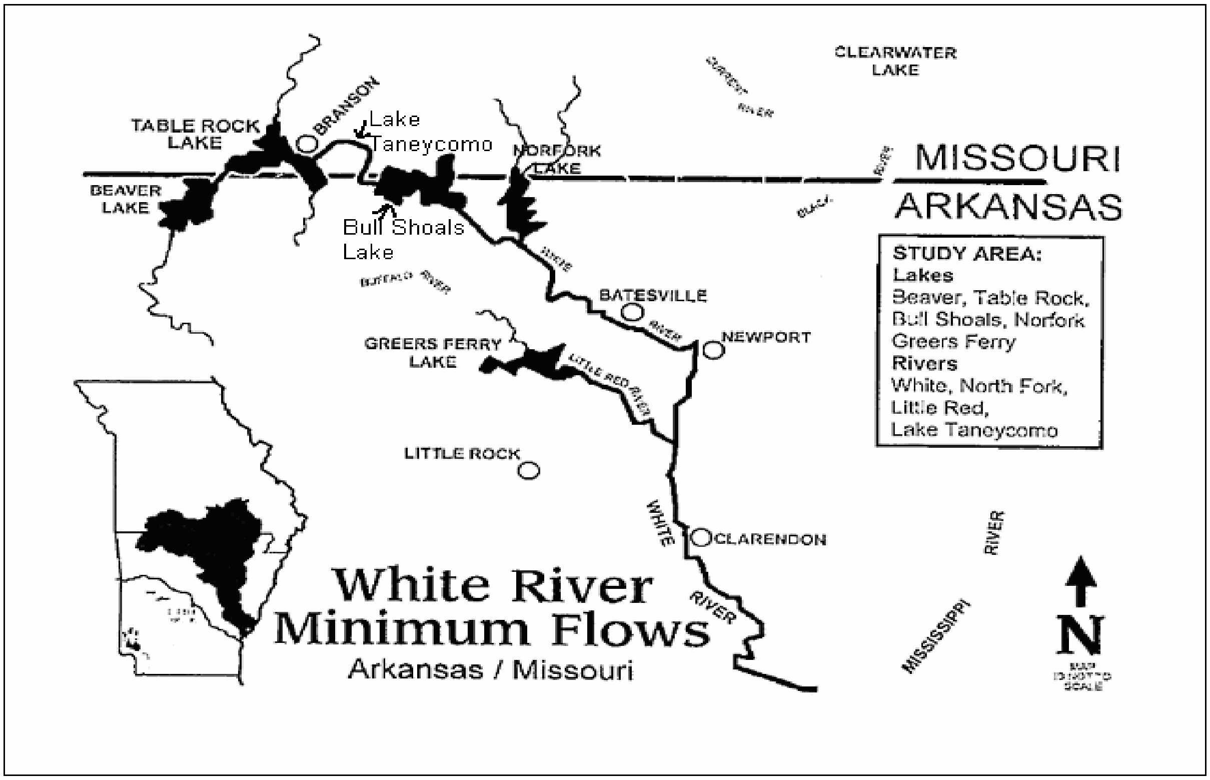
(c) REPEAL.—Section 374 of the Water Resources Development Act of 1999 (113 Stat. 321) and section 304 of the Water Resources Development Act of 2000 (Public Law 106–541) are repealed.

In Subsection (c), the law de-authorized minimum flows and the associated storage reallocations at Beaver, Table Rock, and Greers Ferry Dams. The fish hatchery at Beaver mentioned in Subsection (b) will be addressed at a later time in a separate report.

The law directed Southwestern to determine the losses to the Federal hydropower purpose at the Bull Shoals and Norfork projects. It further specified that Southwestern, in consultation with the project licensee and the relevant state public utility commissions, determine the impacts on Federal Energy Regulatory Commission (FERC) Project No. 2221, the non-Federal Ozark Beach hydroelectric project in Missouri. The project is owned and operated by Empire District Electric Company (Empire). Ozark Beach is on the White River and impounds Lake Taneycomo between Table Rock Dam and Bull Shoals Lake (see Figure 1).

According to the law, the form of compensation to the Federal hydropower purpose for the impacts caused by the reallocations will be as an offset through a reduction in its allocated costs. That reduction will equal the present value of those impacts to the Federal hydropower purpose as determined by Southwestern at the time of implementation of the minimum flows. Empire will be fully compensated based on the present value of the impacts to the non-Federal project as determined by Southwestern at the time of project implementation. The official time of project implementation will be specified by the Corps.

Figure 1 – Study Area



3.0 Determination of Hydropower Impacts Due to Minimum Flows

The following items were determined by Southwestern for both the Federal and non-Federal impacts (unless otherwise specified):

1. Energy losses due to the reallocations
2. Capacity losses due to the reallocations
3. Replacement cost of the lost energy
4. Replacement cost of the lost capacity
5. Increased Bull Shoals maintenance costs (Federal only)
6. Inflation
7. Present Value Determination of the losses

In addition, the law requires that Southwestern consult with the non-Federal project licensee (Empire) and the relevant state public utility commissions. Because Empire provides electricity to consumers in Arkansas, Kansas, Missouri, and Oklahoma, coordination is required with all four state public utility commissions.

4.0 SUPER Program Analysis

4.1 SUPER Reservoir Simulation Program

Southwestern used the Corps' SUPER computer simulation program in the development of the energy and capacity losses. SUPER is a computer program for simulating the operation of a multipurpose reservoir system. It was developed in the Southwestern Division of the Corps and has been used by the Fort Worth, Little Rock, and Tulsa Districts of the Corps for over 30 years. The SUPER program has been updated on a regular basis during that time.

The projects were built at various times, and operational plans have changed many times during the period of record. SUPER models the reservoir system for the entire period of record as it exists today and is operated under the desired operational scenario. The value in using SUPER is the ability to model various scenarios and to determine the relative differences in the results.

4.2 SUPER Minimum Flows Storage and Storage Accounting

The authorized plan at Bull Shoals, BS-3, includes the reallocation of five feet of flood storage. The conservation and seasonal pool levels at Bull Shoals will be raised five feet. The authorized plan at Norfork, NF-7, includes the reallocation of 1.75 feet of conservation storage and 1.75 feet of flood storage. The conservation and seasonal pool levels at Norfork will be raised 1.75 feet. The Corps determined the amount of minimum flows storage to be provided at both Bull Shoals and Norfork. For the reallocations of flood storage, both dependable yield mitigation storage (DYMS) and hydropower yield protection operation (HYPO) storage were included.

In a reallocation of conservation storage, the storage reallocated is taken from an existing conservation storage user. There is no change in the size of the conservation pool or in the yield per acre-foot of conservation storage. Since the conservation reallocation is taken from hydropower storage, there is a negative impact to the hydropower purpose.

When a reallocation of flood control storage occurs, the yield per acre-foot of the additional storage (from the flood pool) is not as great as the yield per acre-foot of the original conservation (water supply and hydropower) storage. When the reallocated flood storage and existing conservation storage are combined into a new conservation storage, the new total storage has a yield per acre-foot that is reduced when compared to the yield of the original conservation storage. In reallocations of flood storage for water supply, it is Corps policy to provide a portion of the additional storage to the existing water supply users, or DYMS, to maintain the yield of their original storage. While the Corps has not typically viewed hydropower in the same way, current Corps policy does allow operational changes to minimize the impacts to hydropower. HYPO storage was included for the flood storage reallocations at Bull Shoals and Norfork to maintain the yield of the hydropower storage as well. The use of DYMS and HYPO is discussed in the Corps report "White River Minimum Flows Reallocation Study Report" dated July 2004.

The SUPER program was modified in 2001-2002 to account for the storage allocated to minimum flows at the projects. The input to the program describes the amount of storage available for minimum flows and the desired minimum flow release at each project. The program performs a daily accounting of inflows to and outflows from the minimum flows storage. If the minimum flows storage is depleted, minimum flow releases are suspended until the storage receives additional inflow.

4.3 SUPER Runs for Minimum Flows Analysis

The original SUPER runs were performed by the Corps using the November 2002 version of the program. The program has had several updates since then, including a recent modification of the storage accounting procedure to correct some computational errors. Southwestern used the October 2007 version of the program. The SUPER Base Run and Minimum Flows Run were formulated and performed under the following constraints:

4.3.1 Base Run

- Existing Conditions Run = W08X01 (Southwestern run designation).
- Existing conditions as defined by the Little Rock District Corps (W01X01) with the following changes:
  - Minor key control point changes required in the SUPER program update. The changes were made by the SUPER developer and include adding Clearwater Lake to the list of reservoirs using the Newport key control point and changing the key control point for Greers Ferry Lake from Georgetown to Judsonia.
  - Balancing levels made consistent at Bull Shoals and Norfork. The regulation criteria for both projects were adjusted as necessary to maintain consistency.
  - The Greers Ferry conservation pool level was updated to the current regulation plan. Since the Corps run was performed, the pool level has been raised 0.14 feet due to flood control storage reallocations for water supply. Balancing levels were updated to be consistent.
  - Clearwater seasonal pool changes and Poplar Bluff regulation criteria changes as in the Corps minimum flow run (W06X03). In the original (2001) runs performed by the Corps, the Clearwater and Poplar Bluff data were consistent between the runs. The Clearwater and Poplar Bluff data have been updated by the Corps since then as reflected in the 2006 run. The changes should have little effect on minimum flows. The goal is to be consistent between the base and minimum flow runs.
  - Water supply withdrawals were updated to include current contracts and current studies being performed by the Corps. Withdrawals for the proposed trout production facility at Beaver were not included.
- Period of Record 1940-2003 (64 years of daily data).
- Current seasonal pool plans at all projects.
- New hydropower loads developed by Southwestern in 2007. The loads were updated previously in 2001 and in 2004.

4.3.2 Minimum Flows Run

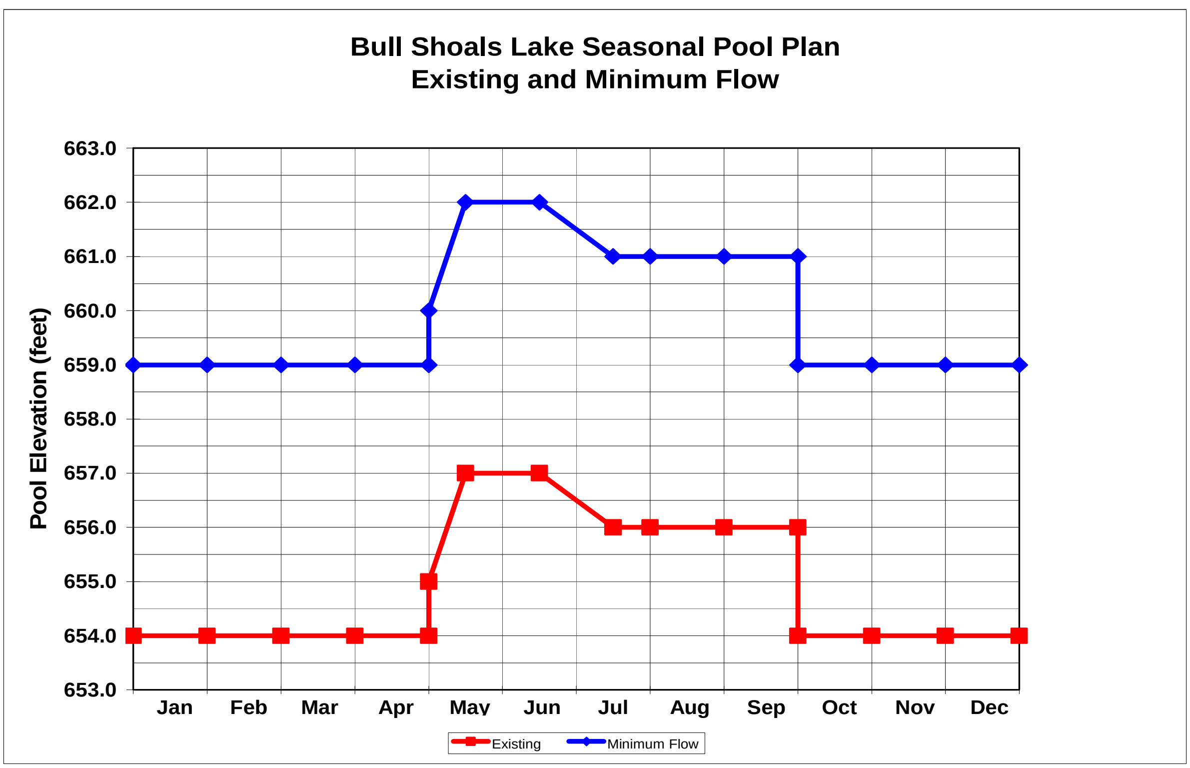
General

- Minimum Flows Run = W08X02 (Southwestern run designation).
- Minimum flows implemented as in the Corps run (W06X03) with modifications as made to the base run (balancing levels, regulation criteria, water supply, etc.) for consistency.
- Water storage accounting performed to ensure that minimum flows are not released when the minimum flow storage is empty.

Bull Shoals

- Plan BS-3, reallocation of five feet of flood storage at Bull Shoals.
- Both the normal (non-seasonal) and seasonal pool elevations increased by five feet (Figure 2).
- Minimum flow at Bull Shoals made with a main unit whenever the project is not otherwise generating. The required minimum flow release (including 210 cfs for leakage and station service) is 800 cfs.
- HYPO storage included to maintain the yield of the hydropower storage at Bull Shoals. The total amount of flood storage reallocated is 233,000 acre-feet which includes 111,271 acre-feet for DYMS and HYPO and 121,729 acre-feet for minimum flows storage as computed by the Corps.

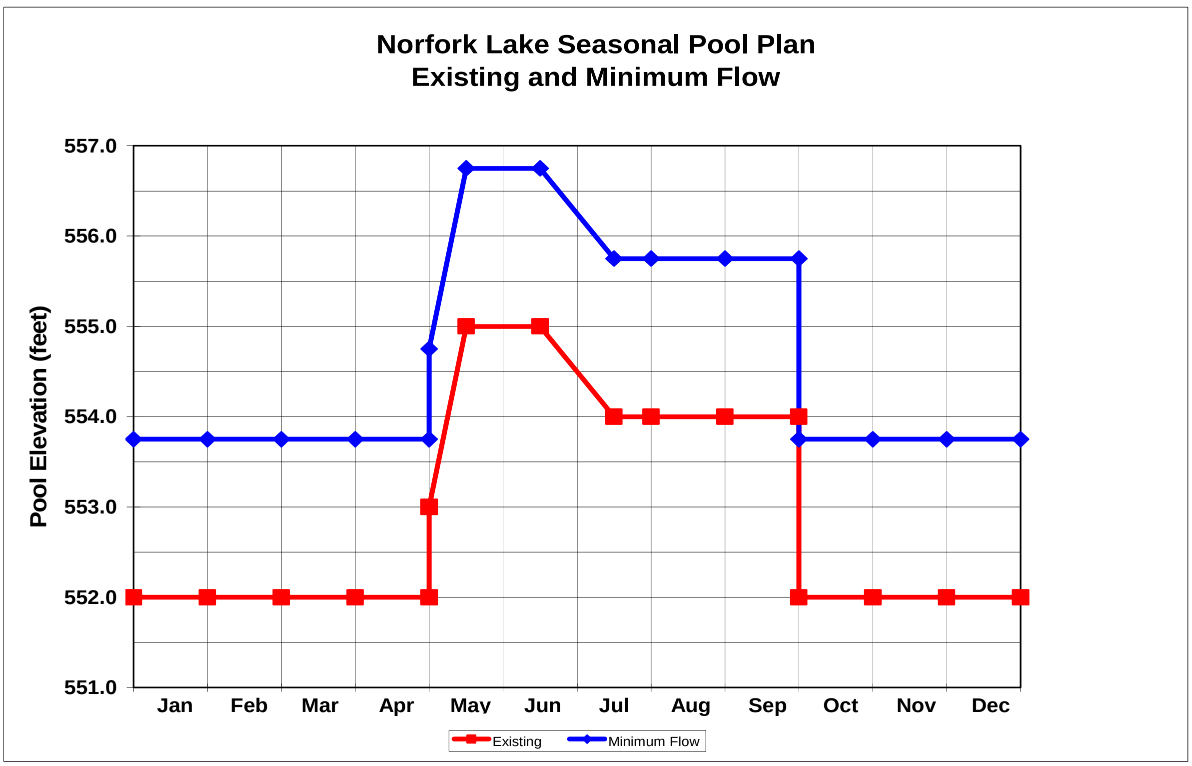
Figure 2 – Bull Shoals Pool Elevations



Norfork

- Plan NF-7, reallocation of 1.75 feet of conservation storage and 1.75 feet of flood storage at Norfork.
- Both the normal (non-seasonal) and seasonal pool elevations increased by 1.75 feet (Figure 3).
- Minimum flow releases at Norfork will be spilled through the use of a siphon whenever the project is not generating. The required minimum flow release (including 115 cfs for leakage, station service, and hatchery releases) is 300 cfs.
- HYPO storage included for the 1.75 feet of flood storage reallocated to maintain the yield of the hydropower storage at Norfork. The amount of flood storage reallocated is 38,900 acre-feet which includes 21,881 acre-feet for DYMS and HYPO and 17,019 acre-feet for minimum flows storage as computed by the Corps.
- The 1.75 feet reallocated from conservation storage contains 29,200 acre-feet as computed by the Corps. All of that reallocated storage comes from hydropower storage and will be available for minimum flows storage.
- The total amount of storage available for minimum flows is 46,219 acre-feet as computed by the Corps.

Figure 3 – Norfork Pool Elevations



5.0 Energy and Capacity Losses

5.1 The Power Equation

Southwestern used a spreadsheet analysis of output from the SUPER program to determine the energy and capacity losses for both the Federal and non-Federal projects. In both analyses, the power equation was used. The power equation is defined as follows:

$$Power = (Q * NetHead * Efficiency * \gamma * 0.7457) / (550 * 1000)$$

Where

- Power = instantaneous plant capacity in megawatts (MW).
- Q = discharge through the turbine in cubic feet per second (cfs)
- NetHead = Pool elevation – tailwater elevation – friction loss (feet)
- Efficiency = Plant (combined turbine efficiency and generator efficiency) efficiency (fraction)
- γ = the weight of water, commonly 62.4 pounds per cubic foot
- 0.7457 = conversion factor (0.7457 kilowatts (kW) = 1 horsepower)
- 550 = conversion factor (550 foot-pounds per second = 1 horsepower)
- 1000 = conversion factor (1000 kW = 1 MW)

The power computed with the power equation for each day was multiplied by 24 hours to get an energy value for the entire day in megawatt-hours (MWh).

5.2 Federal Hydropower

Southwestern performed a spreadsheet analysis of the SUPER daily output data to determine the energy and capacity losses to Federal hydropower. The methodology used in the analysis was similar to Southwestern’s analysis performed in 2002 and 2003 for the study. The earlier analysis was performed on a monthly basis. The current results are very close to the earlier findings. The following paragraphs provide the results of the analysis of the SUPER output.

5.3 Bull Shoals

5.3.1 Energy Losses. At Bull Shoals, the normal leakage and station service releases total 210 cfs. Those releases are made around the clock and are shown in SUPER as leakage. The total desired release for minimum flows is 800 cfs based on the Corps report and SUPER runs. When the project is not producing normal generation and minimum flow storage is available, releases will be made from one of the main units at a rate of 590 cfs to make a total release of 800 cfs. Any releases made for minimum flows during non-generation times are included by SUPER in the total leakage for the day.

In Southwestern’s spreadsheet analysis, generation losses were computed using the power equation with SUPER leakage values in excess of the 210 cfs each day, the SUPER daily pool elevation, and the SUPER block loading tailwater elevation. The estimated plant efficiency was 85 percent, and the estimated friction loss through the turbines was 0.5 feet. Those are the same efficiency and friction loss values that were used in the SUPER model by the Corps and Southwestern. The Corps' Hydroelectric Design Center (HDC) developed a report in April 2002 entitled "White River Minimum Flow Study – Power Producing Options." In Section 4.2 of that report, HDC described how field performance testing was used to determine the 85 percent efficiency to be used in SUPER. Based on Southwestern's calculations, releases made for minimum flows during non-generation times would produce 53,379 MWh of energy annually if used for normal generation.

The authorized plan at Bull Shoals, BS-3, includes the reallocation of five feet of flood storage. The conservation and seasonal pool levels at Bull Shoals will be raised five feet. Because plan BS-3 includes storage to maintain the yield of the hydropower storage, Southwestern's ability to produce current quantities of on-peak energy is not diminished. In addition, because the minimum flow releases will be made through one of the main units, there will be energy produced with those releases. However, the minimum flow releases through a main unit will be made at a much lower rate of generation and therefore at a much lower efficiency than normal generation. Since the energy that is produced from the minimum flow releases will be generated at a time when the energy is not needed to fulfill Federal peaking energy contracts, it is similar in value to the off-peak energy normally generated during flood control operations. The energy loss at Bull Shoals that results from utilizing low generation rates and efficiencies for minimum flows will be considered off-peak energy.

Southwestern used the power equation for each day to compute the energy that could be produced with the low generation releases for minimum flows. The tailwater elevation used in the calculation was 450.54 (the tailwater elevation corresponding to 800 cfs), and the efficiency was estimated to be 45 percent. The April 2002 HDC report mentioned earlier in this section described field testing of a main Bull Shoals unit at low discharge rates. The HDC testing determined the unit efficiency to be 43 percent at a discharge of 597 cfs. Based on these parameters, low generation releases for minimum flows will produce 29,524 MWh annually of off-peak energy.

The net loss of energy at Bull Shoals will be the difference between the amount of energy that could be produced by the minimum flow releases during normal generation and the amount of energy that will be produced by a main unit for minimum flow releases at a much reduced efficiency. Therefore, there will be a net loss of 23,855 MWh of off-peak energy annually at Bull Shoals. An example of the Bull Shoals energy loss calculations is included in Appendix A.

<u>5.3.2 Capacity Losses.</u> Southwestern bases its marketable capacity on the worst drought in the period of record. The critical drought occurred in Southwestern's system during the period from June 1953 through August 1954, with August 1954 being the critical month. Thus, the computed capacity loss was also determined based on that drought period. Any reduction in the yield of the hydropower storage will result in a reduction of the capacity that can be supported by the storage. A reduction in the supportable capacity results in a capacity loss. Because plan BS-3 reallocates flood storage and includes HYPO storage for

hydropower, there will be no reduction in yield of the storage allocated to the Federal hydropower purpose and no reduction in the Bull Shoals energy production during the critical drought. Therefore, there will be no loss of capacity at Bull Shoals.

5.4 Norfork

5.4.1 Energy Losses. At Norfork, the normal leakage and station service releases total 115 cfs. Those releases are made around the clock and are shown in SUPER as leakage. The total desired release for minimum flows is 300 cfs based on the Corps report and SUPER runs. When the project is not producing normal generation and minimum flow storage is available, releases will be made using a siphon at a rate of 185 cfs to make a total release of 300 cfs. Any releases made for minimum flows during non-generation times are included by SUPER in the total leakage for the day.

In Southwestern's spreadsheet analysis, energy losses were computed using the power equation with SUPER leakage values in excess of the 115 cfs each day, the SUPER daily pool elevation, and the block loading tailwater elevation from SUPER. The estimated plant efficiency was 85 percent, and the estimated friction loss through the turbines was 0.5 feet. Those are the same efficiency and friction loss values that were discussed in the April 2002 HDC report and used in the SUPER model by the Corps and Southwestern. Based on Southwestern's calculations, releases spilled through a siphon for minimum flows during non-generation times would produce 13,524 MWh of energy annually if used for normal generation releases. An example of the Norfork energy loss calculations is included in Appendix B.

Unlike Bull Shoals, where minimum flow releases will be made through a main turbine, minimum flow releases at Norfork will be made through a siphon. All of the energy that could be produced with the minimum flow releases, whether from flood or conservation storage, will be lost. The authorized plan at Norfork, NF-7, includes the reallocation of 3.5 feet of storage. One half of the storage reallocation for minimum flows is being reallocated from the flood pool with HYPO included, and the other half of the storage reallocation is being reallocated from conservation storage. As a result, both the conservation and seasonal pool levels at Norfork will be raised 1.75 feet. Because the reallocation is split equally between conservation and flood storage, Southwestern assumed an equal split between on-peak (conservation storage) and off-peak (flood pool storage) energy losses.

The energy lost from the flood pool reallocation half is considered off-peak energy, similar to the Bull Shoals reallocation. The half of the reallocation which is being reallocated from conservation storage will cause a reduction of the volume and yield of the hydropower storage. That loss in storage and yield of the hydropower storage will translate to a loss of on-peak energy and capacity. As explained in the previous paragraph, one half of the total energy loss is assumed to be on-peak energy and one half of the total energy loss is assumed to be off-peak energy. Therefore, there will be an energy loss of 6,762 MWh of on-peak energy and 6,762 MWh of off-peak energy annually at Norfork.

5.4.2 Capacity Losses. As discussed in the section on capacity losses at Bull Shoals, Southwestern bases its marketable capacity on the worst drought in the period of record. The critical drought occurred in Southwestern's system during the period from June 1953 through August 1954, with August 1954 being the critical month. The month of August is typically used in Southwestern studies as the critical month. July and August are the highest electrical demand months for Southwestern, and pool elevations are normally lower in August than in July. The critical drought extended beyond August 1954, but the system refilled before August 1955. Therefore, the 15-month period from June 1953 through August 1954 is used as the critical period for Southwestern's calculations of capacity loss, with August 1954 used as the critical month.

Any reduction in the yield of the hydropower storage will result in a reduction of the capacity that can be supported by the storage. The storage that is reallocated from flood storage and includes HYPO storage for hydropower results in no loss of storage or yield for hydropower. Therefore, there is no capacity loss associated with the flood storage half of the storage reallocation. However, the storage that is reallocated from conservation storage directly reduces the storage and yield of the hydropower storage. That reduction in storage and yield of the hydropower storage will result in a loss of supportable capacity during the critical drought and, therefore, a capacity loss associated with the conservation storage half of the storage reallocation.

Southwestern's method for determining capacity losses uses procedures (energy loss divided by peaking hours required) similar to those used by Corps' Hydropower Analysis Center (HAC) in determining the lost capacity. Southwestern uses a longer critical period (similar to the critical period used in a water yield analysis) than HAC (uses two to four months during the peak demand period). Most importantly, Southwestern is compelled to use the critical drought capacity instead of the average available capacity. Southwestern's rationale and methodology are discussed in Southwestern's draft white paper, "Southwestern Power Administration – Water Storage Reallocations Hydropower Impacts" dated July 18, 2005. The draft white paper is included as Appendix H.

During the critical 15-month period from June 1953 through August 1954, the total calculated energy loss at Norfork due to minimum flow releases is 11,794 MWh. During a portion of that period, minimum flow storage was depleted and minimum flow releases were suspended. The 11,794 MWh energy loss during the critical 15-month period is less than the 13,524 MWh average annual energy loss due to the suspended minimum flow releases. The one half of the energy loss that comes from the reallocation of hydropower storage, or 5,897 MWh, is on-peak energy and would be associated with a loss of capacity. Southwestern markets power from its interconnected system at a rate of 1,200 kilowatt-hours (kWh) per kilowatt (kW) of marketed capacity each year, or an average of 100 kWh per kW per month. The capacity loss is the capacity that the lost on-peak energy could support for 1,500 hours of generation (15 months times 100 hours of generation per month), or 5,897 MWh divided by 1,500 hours. The computed capacity loss at Norfork is 3.93 MW.

5.5 Summary of Federal Hydropower Energy and Capacity Losses

A summary of the Federal hydropower energy and capacity losses is shown in Table 1.

Table 1 – Federal Hydropower Annual Energy and Capacity Losses

Project	Total Energy Loss, MWh	On-Peak Energy Loss, MWh	Off-Peak Energy Loss, MWh	Capacity Loss, MW
Bull Shoals	23,855	0	23,855	0.00
Norfork	13,524	6,762	6,762	3.93
Total Losses	37,379	6,762	30,617	3.93

5.6 Non-Federal Project

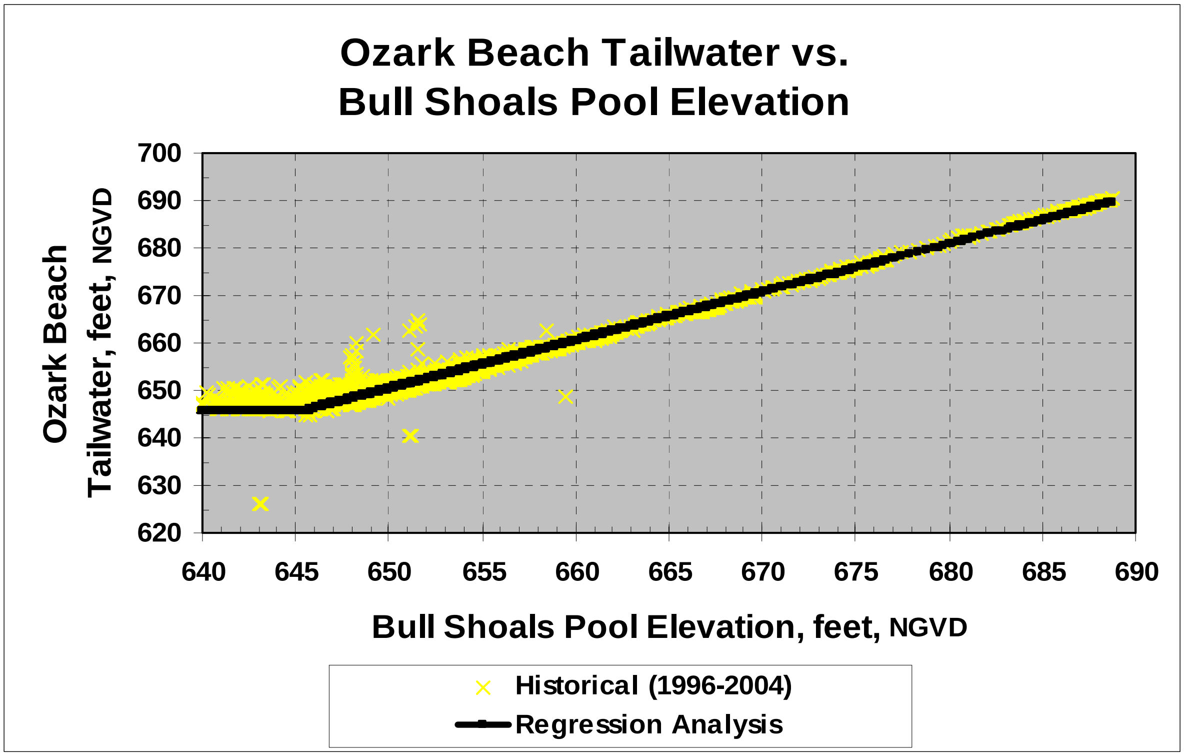
Southwestern performed a separate spreadsheet analysis of the SUPER daily output data to determine the energy and capacity losses at Ozark Beach. The SUPER output was from the same two simulation runs described in section 4.3. The implementation of the authorized plan will result in a reduction of the amount of gross head (headwater elevation minus the tailwater elevation) available to produce power at Ozark Beach. Public Law 109-103 deauthorized minimum flows at Table Rock, the project upstream from Ozark Beach, so there is no change in the operation at Table Rock. Any losses at Ozark Beach will be due to the loss of head at the project. In addition, Ozark Beach is operated as a run of river project with a fairly constant pool elevation and minimal storage. It is not a storage project. Therefore, a slightly different type of analysis was required to determine the capacity losses than that performed for Bull Shoals and Norfork, which are storage projects.

5.6.1 Spreadsheet Model Description. Ozark Beach is located on the White River between Table Rock Dam and Bull Shoals Dam. Because the project is operated as a run of river project with little storage, Southwestern's model assumed that the water that is released from Table Rock Dam in a day will flow through the turbines at Ozark Beach or be spilled during that same day. The Ozark Beach drainage area is about 8.5 percent larger than the Table Rock drainage area. Southwestern used a drainage area ratio analysis of the intervening area inflow between Table Rock Dam and Bull Shoals Dam (as developed for the SUPER model) to add to the Table Rock outflows in estimating the Ozark Beach inflows. Using that technique, the average daily inflows into Ozark Beach are about 9 percent larger than the average daily outflows from Table Rock. The increased Ozark Beach inflows were used in both the base and alternative cases.

Due to the close proximity, the tailwater elevation below Ozark Beach can be directly related to the pool elevation above Bull Shoals Dam. A separate analysis by Southwestern of historical Bull Shoals pool elevations and tailwater elevations immediately below Ozark Beach showed that the tailwater elevation can be reliably estimated based on the Bull Shoals pool elevation (see Figure 4). Because Ozark Beach is a run of river project with limited water storage, the pool elevation above Ozark Beach was estimated at 701.0 for all days.

Based on the plant data provided by Empire, Southwestern estimated that a plant efficiency of 75 percent with the old turbines and 85 percent with the new turbines and a friction loss of 0.5 feet would be reasonable values for use in the power equation calculations. Data for the old turbines was only used in verifying the spreadsheet model (see Section 5.6.2).

Figure 4 – Ozark Beach Tailwater versus Bull Shoals Pool Elevation



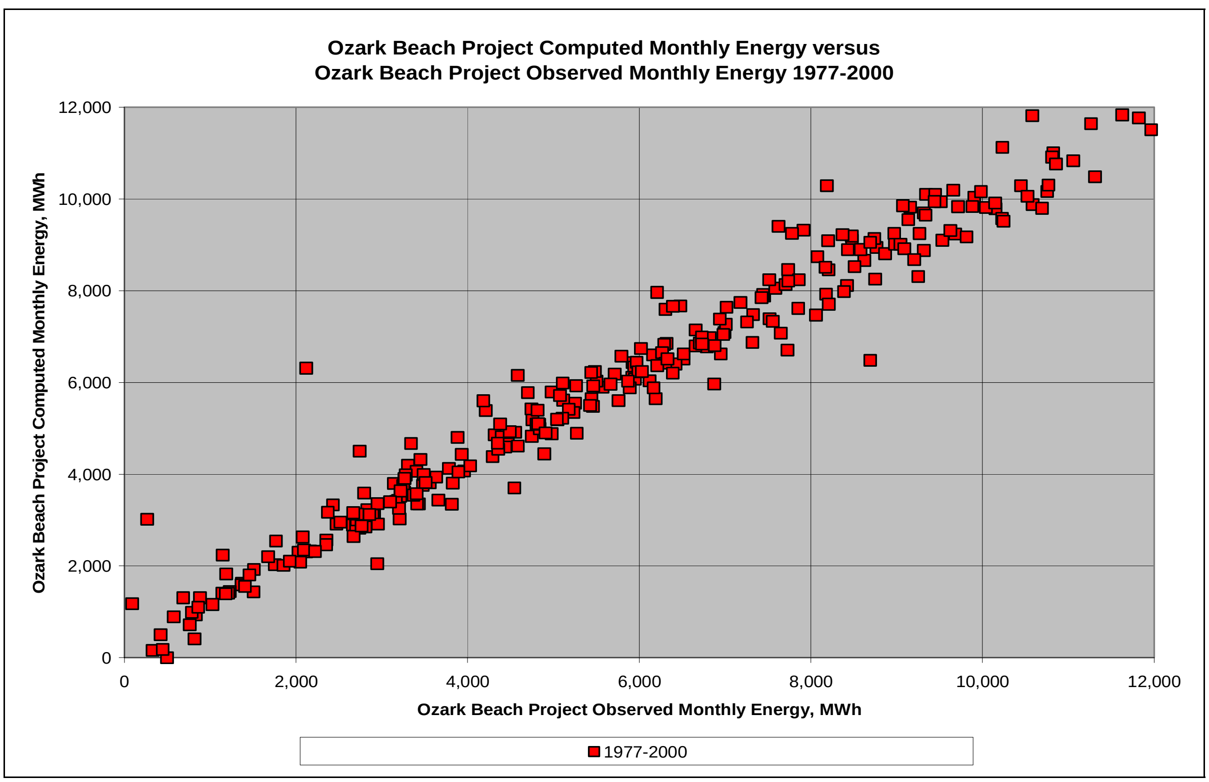
The daily spreadsheet calculation proceeded as follows:

1. Compute the tailwater elevation based on the Bull Shoals midnight pool elevation.
2. Compute the gross head (= 701.0 minus the computed tailwater elevation).
3. Determine the maximum plant capacity for the day by looking up the gross head in the Empire-provided head vs. generating capability table and interpolating. Data for the old turbines was used in verifying the model. Data for the new turbines was used in determining the losses (Appendix C).
4. Using the power equation, calculate the discharge associated with the maximum plant capacity determined in step 3.
5. Compute the Ozark Beach inflow by adding the Table Rock discharge and a drainage area ratio of the intervening area inflow between Table Rock Dam and Bull Shoals Dam.
6. If the Ozark Beach inflow for the day is greater than the discharge computed in step 4, the daily generation is the maximum plant capacity times 24 hours and the additional discharge is assumed to be spilled.

7. If the Ozark Beach inflow for the day is less than the discharge computed in step 4, the power equation is used to calculate the daily energy generated based on the available discharge. There is no spill.
8. Go to the next day.

5.6.2 Spreadsheet Model Verification. The verification of the spreadsheet model for Ozark Beach was performed using historical data. Empire provided monthly generation data from the project for the thirty year period 1977-2006. They also provided gross head versus generating capability tables for both the old turbines and new turbines. Generation during the period 1977-2000 was with the old turbines. Empire performed an upgrade of the turbines during the period 2001-2005. Southwestern used the 1977-2000 period for verifying the spreadsheet model. Daily discharges from Table Rock Dam, the daily intervening area inflow between Table Rock Dam and Bull Shoals Dam (as developed for the SUPER model), and midnight pool elevations at Bull Shoals Lake from historical data were used as input to the spreadsheet model. The performance data for the old turbines was used in verifying the model. As noted in the previous section, the plant efficiency was estimated at 75 percent and the friction loss was estimated at 0.5 feet. Using the 1977-2000 historical data, the results showed a strong correlation between the computed monthly generation and the actual monthly generation at Ozark Beach (see Figure 5). From those results, it was determined that the spreadsheet model would be an appropriate method for determining the energy losses due to White River Minimum Flows.

Figure 5 – Computed versus Observed Generation at Ozark Beach



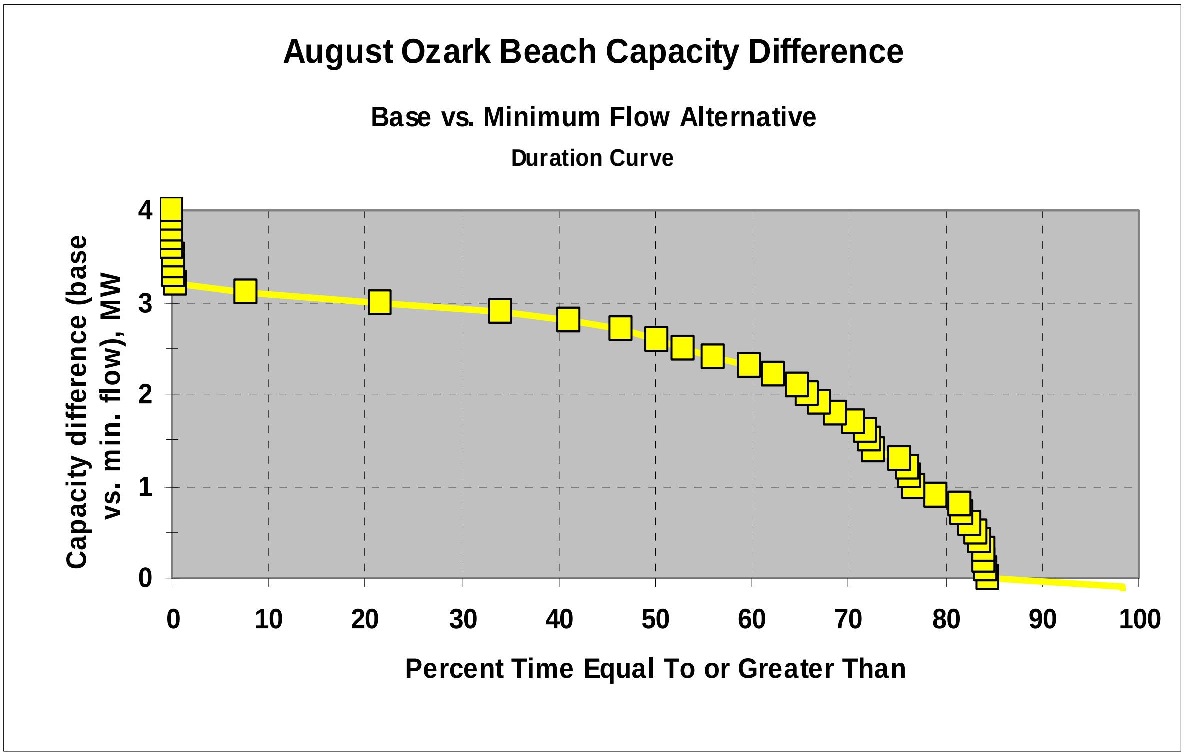
5.6.3 Spreadsheet Model Application - Energy Losses. As stated previously, any losses at Ozark Beach will be due to a loss of head at the project. Southwestern used a spreadsheet analysis of the SUPER daily output data from the base run and minimum flow run. The SUPER data used were the daily discharges from Table Rock, the daily intervening area inflow between Table Rock Dam and Bull Shoals Dam, and the midnight pool elevations at Bull Shoals. As described in Section 5.6.1, Southwestern assumed the pool elevation at Ozark Beach to be a constant 701.0, the plant efficiency with the new turbines was 85 percent, and the friction loss through the plant was 0.5 feet. The gross head versus generating capability table for the new turbines, provided by Empire, was used (Appendix C). From the spreadsheet analysis, the annual energy loss at Ozark Beach was computed to be 8,998 MWh. The Corps had previously estimated the annual energy loss to be 6,150 MWh, and Empire had estimated the annual energy loss to be 12,436 MWh. A portion of the non-Federal energy loss calculations is included in Appendix D.

In previous discussions, the Corps, Empire, and Southwestern agreed that reasonable percentages of on-peak and off-peak generation for the project are 67 percent on-peak and 33 percent off-peak. Using these percentages, the annual energy loss is 6,029 MWh of on-peak energy and 2,969 MWh of off-peak energy at Ozark Beach.

5.6.4 Spreadsheet Model Application - Capacity Losses. There will be a capacity loss at Ozark Beach due to the loss of head at the project as described previously. Because the project is a run of river project and not a storage project, the capacity loss calculation was developed with a slightly different type of analysis than that performed at Bull Shoals and Norfork. The capacity loss was computed by comparing the plant capacity values in the base SUPER run and the minimum flows SUPER run. The average difference in capacity over the 23,376 days in the period of record is 1.87 MW. The median difference is 2.34 MW. A duration analysis of the daily differences in capacity revealed that the difference was 3.00 MW or greater about 30 percent of the time. In addition, the difference was 3.00 MW or greater about 30 percent of the time during the typically high electrical load months of July and August (Figure 6).

For a storage project, a reduction of capacity during the critical period is considered to be a capacity loss to the project. For a run of river project, capacity that is unavailable 30 percent of the time, especially during the peak electrical demand months, is not reliable or marketable. Therefore, the capacity loss at Ozark Beach is 3.00 MW. The Corps did not estimate a capacity loss, and Empire had estimated a capacity loss of 3.00 MW.

Figure 6 – Duration Curve of August Capacity Loss at Ozark Beach



5.7 Summary of Non-Federal Hydropower Energy and Capacity Losses

A summary of the Non-Federal hydropower energy and capacity losses is shown in Table 2.

Table 2 – Non-Federal Hydropower Annual Energy and Capacity Losses

Project	Total Energy Loss, MWh	On-Peak Energy Loss, MWh	Off-Peak Energy Loss, MWh	Capacity Loss, MW
Ozark Beach	8,998	6,029	2,969	3.00

6.0 Replacement Costs

Southwestern used a similar methodology in determining the replacement costs of energy and capacity for both the Federal and non-Federal losses.

6.1 Federal Hydropower – Energy Values

In valuing the energy losses to Federal hydropower, Southwestern used energy cost forecast information developed by Platts Power Outlook Research Service, a subscription-based wholesale North American power market forecast service. Platts is a division of

McGraw-Hill Companies, Inc. which develops power price forecasts for all the North American Electric Reliability Corporation (NERC) regions. Platts provides a 20-year forecast of projected power values on both a monthly and annual basis, and values are calculated for both on-peak and off-peak (on-peak is generally from 6 AM to 10 PM Monday through Friday). Platts' data sets are proprietary and are used under subscription by Southwestern.

In its preliminary analysis of the impacts of White River Minimum Flows to the Ozark Beach project, the Corps proposed the use of data from Platts. The Corps and Empire agreed that the Platts "High Fuel Value" energy cost data would be appropriate for valuing the replacement energy.

In its evaluation of previous Corps reallocation studies, including its previous evaluation of White River Minimum Flows, Southwestern used energy values developed by the Corps using older FERC methodology. While Southwestern has maintained that the values produced by the Corps under those older criteria undervalue the energy benefits foregone in storage reallocations, we believed it was important to be consistent with methodologies used in our previous evaluations. Southwestern requested and received updated capacity and energy replacement cost values from the HAC entitled "Thermal Plant Power Values for the Southwest Region" dated November 2007. The data is included in Appendix E. The costs were developed using the same FERC methodology mentioned previously.

For replacing energy lost to the Federal hydropower purpose, Southwestern revised its analysis to use the Platts High Fuel Value energy cost forecast instead of the FERC energy values. The change was made for three primary reasons: 1) the Corps and Empire had previously agreed that the Platts High Fuel Value energy cost forecast numbers most accurately represented the replacement cost of energy; 2) comments from electric industry participants strongly supported the use of an industry source such as Platts; and 3) Southwestern's additional research revealed that the Platts values for on-peak energy compare favorably with the FERC and current market values; however, the Platts values for off-peak energy are much more reflective of the current market than the FERC values.

The Platts on-peak energy values for 2008 are lower than the HAC-produced FERC methodology values for a Combustion Turbine Plant (the alternative Southwestern had previously used as the most likely alternative to replace on-peak energy) in Arkansas, and the Platts off-peak energy values for 2008 are higher than the HAC-produced FERC methodology values for a Coal-Fired Steam Plant (the alternative Southwestern had previously used as the most likely alternative to replace lost off-peak energy) in Arkansas. On-peak and off-peak energy values are inflated at the selected rate of inflation for years beyond the Platts twenty-year forecast.

6.2 Federal Hydropower – Capacity Values

In valuing the capacity losses to Federal hydropower, Southwestern used the type of capacity that will most likely be used to replace those losses. The HAC produced a report entitled "Greers Ferry Powerhouse - Hydropower Value Update" dated February 2007 for a water supply reallocation study being performed by the Little Rock District. In the report, HAC used FERC methodology for computing the value of capacity for replacing hydropower. The FERC methodology includes allowances for transmission costs and incorporates capacity value adjustments to account for differences in reliability and operating flexibility between hydropower projects and their thermal alternative. The HAC analysis determined that the least cost replacement thermal power plant type for operation at plant factors less than 22.9 percent would be a gas-fired combustion turbine. For operations at plant factors greater than 39.5 percent, a coal-fired steam generating plant would be the least cost thermal plant type. The least cost thermal plant type operating between the two plant factors would be a gas-fired combined cycle generating plant.

Southwestern markets power from its interconnected system at a rate of 1,200 kWh per kW of marketed capacity each year. The 1,200 hours of firm generation results in an annual plant factor of 13.7 percent. Generation from a gas-fired combustion turbine plant would be the most likely replacement for lost capacity. For replacing capacity lost to the Federal hydropower purpose, Southwestern used the capacity value for a combustion turbine developed by the Corps using FERC methodology and shown in Appendix E. The HAC-calculated FERC methodology value for a Combustion Turbine Plant in Arkansas is currently $61.30 per kW-yr.

6.3 Non-Federal Project – Energy Values

Southwestern used the Platts "High Fuel Value" case energy values as described in Section 6.1 in valuing replacement energy for the non-Federal hydropower project. The Platts on-peak energy values for 2008 are higher than the HAC-calculated FERC methodology values for a Combined Cycle Plant (the alternative Southwestern had previously used as the most likely alternative to replace on-peak energy) in Missouri, and the Platts off-peak energy values for 2008 are higher than the HAC-calculated FERC methodology values for a Coal-Fired Steam Plant (the alternative Southwestern had previously used as the most likely alternative to replace lost off-peak energy) in Missouri. On-peak and off-peak energy values are inflated at the selected rate of inflation for years beyond the Platts twenty-year forecast.

6.4 Non-Federal Project – Capacity Values

In valuing the capacity losses to the non-Federal project, Southwestern used the type of capacity that will be purchased to replace those losses. Because the project is a run of river project and not a storage project like Bull Shoals and Norfork, the capacity was valued differently. Storage projects in the region have limited inflow and storage and produce energy only for short periods of time – similar to a combustion turbine. A run of river project will generally operate at a greater plant factor.

The HAC report for Greers Ferry stated that the least cost replacement thermal power plant type for operation at plant factors greater than 39.5 percent would be coal-fired steam generating plant, and for plant factors between 22.9 percent and 39.5 percent it would be a gas-fired combined cycle generating plant. Based on historical data from Empire and assuming 67 percent on-peak and 33 percent off-peak, on-peak generation has occurred at

Ozark Beach at about a 30 percent plant factor. Therefore, generation from a combined cycle plant would be the most likely replacement for lost capacity. For replacing capacity lost to the non-Federal hydropower project, Southwestern used the HAC-produced FERC methodology value for a Combined Cycle Plant for the state of Missouri, currently $128.47 per kW-yr.

6.5 Summary of Replacement Cost Development

Throughout the entire process, Southwestern attempted to use consistent methodologies. Southwestern used the Platts energy cost forecast and the HAC-calculated FERC methodology capacity values in calculating both the Federal and non-Federal hydropower losses. As noted earlier, Southwestern has used the FERC-based, HAC-calculated values for both energy and capacity for many years in computing the impacts to Federal hydropower of storage reallocations for water supply. The HAC-calculated FERC methodology capacity values compare reasonably well with current market conditions. However, HAC-calculated FERC methodology values for off-peak energy are not reflective of the current market.

7.0 Additional Losses

7.1 Increased Maintenance at Bull Shoals Powerhouse

Because minimum flow releases at Bull Shoals Dam will be through a main turbine, the main turbines will require additional maintenance due to additional run times. Also, running the units at the very low outputs required for the minimum flow releases will cause additional cavitation damage to the turbines. The Little Rock District of the Corps estimated in October 2007 that additional maintenance at Bull Shoals will cost $68,000 annually. That cost is used in the analysis.

7.2 Low Dissolved Oxygen Impacts

Currently, generation at both Bull Shoals and Norfork Dams is impacted annually due to low dissolved oxygen (DO) conditions in the releases from both dams, and the reaches below both projects are listed as impaired in accordance with Section 303(d) of the Clean Water Act of 1973, as amended. When the new plan is implemented, there could be additional impacts on operations. The hypolimnion will be higher relative to the penstock elevations at both projects, possibly causing more low DO water to flow through the turbines during generation. Southwestern has made no attempt to quantify the loss value of the potential impact.

7.3 Carbon Dioxide Tax

Empire proposed that a premium should be included in the energy costs for a carbon dioxide tax because they believe the Congress will pass legislation implementing such a tax in the near future. Because there is no way to reliably estimate if, when, or how a carbon dioxide tax would be implemented, Southwestern did not include losses based on a carbon dioxide tax. If carbon dioxide tax legislation is implemented before the final payment or offset is completed, the impacts to both Federal and non-Federal hydropower should be quantified and included in the compensation calculation.

7.4 Renewable Portfolio Standards

Empire also proposed that a renewable risk premium be included in the energy costs as compensation in case a renewable portfolio standard is made mandatory at either the state or national level. It is difficult to quantify the impacts if a renewable portfolio standard were made mandatory. The State of Missouri currently has voluntary goals for adopting renewable energy, but there are no mandatory targets. Southwestern's position on a renewable risk premium is the same as on a possible carbon dioxide tax: If a state or Federal mandatory renewable portfolio standard that qualifies any of the three projects studied is implemented before the final payment or offset is completed, the impacts to both Federal and non-Federal hydropower should be quantified and included in the compensation calculation.

7.5 Empire Roadway and Access Issues

Empire initially proposed that costs to mitigate roadway and access issues should be included in the non-Federal losses. The capital expenditure necessary to mitigate those issues was estimated to be $200,000. Empire and Southwestern determined that, according to PL109-103, Section 132(a)(2), the cost should be borne by the non-Federal sponsor of the project.

8.0 Operational Considerations

8.1 Firm Energy

The 1986 Draft Operating Arrangement (Exhibit B to the 1980 Memorandum of Understanding between the United States Department of Energy, Southwestern Power Administration and the United States Department of the Army, Corps of Engineers) specifies daily firm energy amounts at each Southwestern Division project to be made available to Southwestern when hydropower operations are curtailed due to downstream flooding. Those values are also listed and discussed in the current White River Basin Water Control Master Manual dated March 1993. In general, hydropower generation is not to be limited to less than those firm energy amounts unless significant flood damage reductions can be achieved. The daily firm energy for Bull Shoals and Norfork is 1,352 MWh and 410 MWh, respectively, and would typically be scheduled by Southwestern to meet the most critical "peak" electrical demands of the day.

The availability of firm energy from each of the projects is essential to preserving Southwestern's ability to meet its power delivery obligations. Releases made as a part of the White River Minimum Flow project which are not scheduled by Southwestern to meet its contractual peaking obligations must not reduce the daily firm energy amounts currently available. The analysis of the impacts of minimum flows to the hydropower purpose at the two Federal projects assumes that to be the case. If not, additional compensation would be required to offset the resulting increased energy purchases. Southwestern estimates that 2,000 MWh of on-peak energy would have to be purchased annually to replace the lost firm energy at Norfork, and 7,800 MWh of on-peak energy would have to be purchased annually to replace the lost firm energy at Bull Shoals. The annual value of those increased purchases in 2008 dollars would be $168,000 at Norfork and $664,000 at Bull Shoals. Based on the assumptions used in Sections 10 and 11 of this report, the present value of the lifetime replacement cost of firm energy, if decreased because of the minimum flow requirements, would be about $5 million at Norfork and $20 million at Bull Shoals.

8.2 Water Temperature Control

The Operating Arrangement and the Water Control Master Manual currently specify minimum releases to be made from Bull Shoals and Norfork to maintain water temperatures suitable for the downstream trout fishery. From May 1 through October 15 and for air temperatures above 85° F, the combined 3-day release from Bull Shoals and Norfork shall not be less than 6,000 cfs-days (approximately 2,000 MWh). The additional releases made as a part of the White River Minimum Flows project should be considered as meeting a portion of the 3-day requirement and Southwestern's generation requirements reduced accordingly. The SUPER modeling was performed under that assumption. If the projects are operated differently than that assumption, additional compensation would be required.

8.3 Reservoir Drawdown Limits

One-week and 4-week drawdown limits are currently in place at most of the Corps' hydropower storage projects to reduce the impacts to in-lake users and activities. Southwestern's marketing plan and operational practices take those limits into account. This analysis assumes Southwestern will continue to be able to utilize the entire energy amounts currently available within those limits. In order to avoid additional costs (and compensation) to the hydropower purposes, the drawdown limits must be expanded to accommodate the additional releases made for minimum flow purposes. Based on average historical plant factors, the 4-week drawdown limits at both Bull Shoals and Norfork should be increased by 0.5 feet, to 5.0 feet and 5.5 feet, respectively, to accommodate the minimum flow releases. The 1-week limits should be increased by 0.2 feet at both projects.

8.4 Storage Accounting

The Corps has identified reallocated storages at Bull Shoals and Norfork, 121,729 acre-feet and 46,219 acre-feet, respectively, that will be used to meet additional minimum flow requirements. The SUPER minimum flow run shows those storages are depleted and minimum flows suspended on several occasions during the 64-year period of record analyzed. To avoid additional impacts to hydropower beyond those determined by this study, the Corps must carefully monitor the use of the minimum flow storage. Monthly storage accounting computations will indicate minimum flow reductions which must be implemented to avoid suspending those flows or overdrafting the minimum flow storage.

9.0 Annual Losses

Based on the energy, capacity, and additional losses developed by Southwestern, the annual losses (in 2008 dollars) for Federal hydropower are shown in Table 3.

Table 3 – Federal Hydropower Annual Losses (2008 Dollars)

Project	Item	Annual Loss	Unit Cost	Annual Cost
Bull Shoals	On-Peak Energy	0 MWh	$85.19/MWh	$0
Bull Shoals	Off-Peak Energy	23,855 MWh	$50.78/MWh	$1,211,300
Bull Shoals	Capacity	0 MW	$61.30/kW-yr	$0
Bull Shoals	Increased Maintenance			$68,000
Norfork	On-Peak Energy	6,762 MWh	$85.05/MWh	$575,100
Norfork	Off-Peak Energy	6,762 MWh	$50.49/MWh	$341,400
Norfork	Capacity	3.93 MW	$61.30/kW-yr	$240,900
Total Losses				$2,436,700

Based on the energy and capacity losses developed by Southwestern, the annual losses (in 2008 dollars) for the non-Federal hydropower project are shown in Table 4.

Table 4 – Non-Federal Hydropower Annual Losses (2008 Dollars)

Project	Item	Annual Loss	Unit Cost	Annual Cost
Ozark Beach	On-Peak Energy	6,029 MWh	$86.06/MWh	$518,800
Ozark Beach	Off-Peak Energy	2,969 MWh	$50.75/MWh	$150,700
Ozark Beach	Capacity	3.00 MW	$128.47/kW-yr	$385,400
Total Losses				$1,054,900

10.0 Inflation

The EIA produces a document entitled *Annual Energy Outlook* (AEO) each year. In it, they project the inflation over the next 25 years. The projected inflation rate is called the "reference case." The AEO also projects the inflation rates in "low growth" and "high growth" scenarios. The AEO for 2007 projects a "reference case" inflation rate of 2.0 percent, a "high growth" inflation rate of 1.5 percent, and a "low growth" inflation rate of 2.5 percent.

For this report, Southwestern used the EIA "reference case" inflation rate of 2.0 percent. The inflation rate was used on the replacement costs of energy and capacity for both the Federal and non-Federal projects. It was also used in projecting the future costs of increased maintenance at Bull Shoals Dam.

At the time of implementation, the inflation rate used in the calculations will be the "reference case" inflation rate from the current AEO. The inflation rate assumed by Empire in its analysis was the "low growth" rate of 2.5 percent. The Corps used no inflation in its analysis.

11.0 Present Value Determination

11.1 Assumptions

The present value of the energy and capacity losses for both the Federal and non-Federal projects and the increased maintenance costs at Bull Shoals at the estimated time of minimum flows implementation were determined. The present value was calculated based on the following assumptions:

- Implementation Date – The assumed date of implementation is January 1, 2011.
- Project life – Southwestern used a 50-year project life in its analysis. The Corps and Empire had used 50 years as the project life in their preliminary analyses.
- Discount Rate – The discount rate used in the present value calculations will be the current rate on 30-year U.S. Treasury notes. The current rate is available at http://www.treasurydirect.gov/RT/RTGateway?page=institHome and is currently 4.375 percent. The Corps used a rate of 5.125 percent in its analysis in 2005. Empire used the 30-year U.S. Treasury note rate in their analysis. That rate was 4.8 percent at the time of their analysis.

11.2 Federal Hydropower

Based on the previously described analysis and above assumptions, the present value of the losses to Federal Hydropower is shown in Table 5. The calculation of the present value is detailed in Appendix F.

Table 5 – Present Value of Losses to Federal Hydropower

Item	**Present Value (2011)**
Energy	$76,863,100
Capacity	$7,680,900
Increased Maintenance at Bull Shoals	$2,168,100
Total	$86,712,100

11.3 Non-Federal Project

Based on the previously described analysis and above assumptions, the present value of the losses to the non-Federal project at Ozark Beach is shown in Table 6. The calculation of the present value is detailed in Appendix G.

Table 6 – Present Value of Losses to Non-Federal Hydropower

Item	Present Value (2011)
Energy	$21,647,100
Capacity	$12,288,000
Total	$33,935,100

11.4 Actual Calculation

The actual offset to the Federal hydropower purpose and compensation due to Empire will be calculated at the time of implementation of the White River Minimum Flows Project as specified by the Corps based the current values of the following parameters:

- Energy replacement cost values – Platts "High Fuel Value" case energy cost projections from Platts Power Outlook Research Service.
- Capacity Rates – Previous Thermal Plant Power Values for the Southwest Region (developed using FERC methodology) have been voluntarily calculated and provided by HAC. HAC's capability and willingness to provide future values is assumed.
- Inflation Rate – The projected "reference case" inflation rate in the current EIA AEO.
- Discount Rate – The current rate on 30-year U.S. Treasury notes.

As long as the authorized minimum flow plan does not change from the assumptions documented in this report, it will not be necessary to recalculate the energy and capacity losses. Any changes to the pool levels, storage amounts for minimum flows, or desired minimum flow releases will require a recalculation of the losses. As mentioned previously, Southwestern did not include any cost for a carbon dioxide tax in its calculations. It will be necessary to include a carbon dioxide tax on the value of replacement energy if legislation implementing such a tax is enacted prior to the date of implementation.

12.0 Consultation Concerning Impacts to Non-Federal Project

Public Law 109-103, Section 132, Subsection (a)(3) states that "The Administrator of Southwestern Power Administration, in consultation with the project licensee and the relevant state public utility commissions, shall determine any impacts on electric energy and capacity generated at Federal Energy Regulatory Commission Project No. 2221 caused by the storage reallocation at Bull Shoals Lake, based on data and recommendations provided by the relevant state public utility commissions."

Southwestern met with Empire representatives on several occasions to discuss the project and Empire produced a report detailing their calculation of energy and capacity losses at Ozark Beach due to the implementation of the White River Minimum Flows project. Empire's report is included as Appendix I. Empire provided data and information as requested by Southwestern necessary for Southwestern's analysis.

All of the state public utility commissions relevant to Empire (Arkansas, Kansas, Missouri, and Oklahoma) were made aware of the discussions between Southwestern and Empire early in the process. A representative from the Missouri Public Service Commission was included in one of the Empire meetings by teleconference, and Southwestern has been in contact with the chairman of the Commission several times, by letter, email, and telephone.

Appendix A – Bull Shoals Energy Loss Sample Calculations

Tailwater:	459.5						Tailwater:	450.54					
Efficiency:	0.85						Efficiency:	0.45					
Head Loss	0.5						Head Loss	0.5					
Norm. Leal	210												
Minimum Flow Requirement, cfs:			800										
Average Annual Energy Loss thru Minimum Flow Spill, MWh:							53,379			29,525			23,855

Date	Bull Shoals 12-M SPP Elev., Ft.	Bull Shoals 12-M Pool Elev., Ft.	Bull Shoals Total Leakage, cfs	Bull Shoals Min Flow Release, cfs	BS Daily Energy Loss, MWH	BS Monthly Energy Loss, MWH	BS Annual Energy Loss, MWH	BS Daily Min Flow Energy, MWh	BS Monthly Min Flow Energy, MWH	BS Annual Min Flow Energy, MWH	BS Daily Net Energy Loss, MWh	BS Monthly Net Energy Loss, MWH	BS Annual Net Energy Loss, MWH
01/01/40	659.00	658.90	727.6	517.6	177.7			98.3			79.4		
01/02/40	659.00	658.82	727.6	517.6	177.6			98.3			79.3		
01/03/40	659.00	658.74	727.6	517.6	177.5			98.2			79.3		
01/04/40	659.00	658.68	727.6	517.6	177.5			98.2			79.3		
01/05/40	659.00	658.62	727.6	517.6	177.4			98.2			79.3		
01/06/40	659.00	658.64	800.0	590.0	202.3			111.9			90.4		
01/07/40	659.00	658.63	800.0	590.0	202.3			111.9			90.4		
01/08/40	659.00	658.55	727.6	517.6	177.4			98.1			79.2		
01/09/40	659.00	658.49	727.6	517.6	177.3			98.1			79.2		
01/10/40	659.00	658.44	727.6	517.6	177.3			98.1			79.2		
01/11/40	659.00	658.40	727.6	517.6	177.2			98.1			79.2		
01/12/40	659.00	658.35	727.6	517.6	177.2			98.0			79.1		
01/13/40	659.00	658.39	800.0	590.0	202.0			111.8			90.2		
01/14/40	659.00	658.40	800.0	590.0	202.0			111.8			90.2		
01/15/40	659.00	658.35	727.6	517.6	177.2			98.0			79.1		
01/16/40	659.00	658.32	727.6	517.6	177.2			98.0			79.1		
01/17/40	659.00	658.29	727.6	517.6	177.1			98.0			79.1		
01/18/40	659.00	658.25	727.6	517.6	177.1			98.0			79.1		
01/19/40	659.00	658.21	727.6	517.6	177.1			98.0			79.1		
01/20/40	659.00	658.22	800.0	590.0	201.8			111.7			90.2		
01/21/40	659.00	658.21	800.0	590.0	201.8			111.7			90.2		
01/22/40	659.00	658.12	727.6	517.6	177.0			97.9			79.0		
01/23/40	659.00	658.06	727.6	517.6	176.9			97.9			79.0		
01/24/40	659.00	657.99	727.6	517.6	176.9			97.9			79.0		
01/25/40	659.00	657.93	727.6	517.6	176.8			97.8			79.0		
01/26/40	659.00	657.86	727.6	517.6	176.8			97.8			78.9		
01/27/40	659.00	657.88	800.0	590.0	201.5			111.5			90.0		
01/28/40	659.00	657.87	800.0	590.0	201.5			111.5			90.0		
01/29/40	659.00	657.79	727.6	517.6	176.7			97.8			78.9		
01/30/40	659.00	657.73	727.6	517.6	176.6			97.8			78.9		
01/31/40	659.00	657.67	727.6	517.6	176.6	5689.3		97.7	3148.1		78.9	2541.2	

Appendix B – Norfork Energy Loss Sample Calculations

Norfork							
SUPER Data (W08X02) - 50-50 w/ DYMS for FP, W08X01 leakage, new loads							
Tailwater:	377.7						
Efficiency:	0.85						
Head Loss	0.5						
Norm. Leal	115						
Minimum Flow Requirement, cfs:			300				
Average Annual Energy Loss thru Minimum Flow Spill, MWh:							13,524
Date	**Norfork 12-M SPP Elev., Ft.**	**Norfork 12-M Pool Elev., Ft.**	**Norfork Total Leakage, cfs**	**Norfork Min Flow Release, cfs**	**Norfork Daily Energy Loss, MWH**	**Norfork Monthly Energy Loss, MWH**	**Norfork Annual Energy Loss, MWH**
01/01/40	553.75	553.67	269.5	154.5	46.8		
01/02/40	553.75	553.59	269.5	154.5	46.8		
01/03/40	553.75	553.51	269.5	154.5	46.7		
01/04/40	553.75	553.43	269.5	154.5	46.7		
01/05/40	553.75	553.35	269.4	154.4	46.7		
01/06/40	553.75	553.37	300.0	185.0	55.9		
01/07/40	553.75	553.39	300.0	185.0	55.9		
01/08/40	553.75	553.31	269.4	154.4	46.7		
01/09/40	553.75	553.23	269.4	154.4	46.6		
01/10/40	553.75	553.15	269.4	154.4	46.6		
01/11/40	553.75	553.08	269.4	154.4	46.6		
01/12/40	553.75	553.01	269.4	154.4	46.6		
01/13/40	553.75	553.04	300.0	185.0	55.8		
01/14/40	553.75	553.08	300.0	185.0	55.8		
01/15/40	553.75	553.03	269.4	154.4	46.6		
01/16/40	553.75	552.98	269.4	154.4	46.6		
01/17/40	553.75	552.92	269.3	154.3	46.5		
01/18/40	553.75	552.86	269.3	154.3	46.5		
01/19/40	553.75	552.80	269.3	154.3	46.5		
01/20/40	553.75	552.83	300.0	185.0	55.8		
01/21/40	553.75	552.86	300.0	185.0	55.8		
01/22/40	553.75	552.80	269.3	154.3	46.5		
01/23/40	553.75	552.72	269.3	154.3	46.5		
01/24/40	553.75	552.65	269.3	154.3	46.5		
01/25/40	553.75	552.57	269.3	154.3	46.4		
01/26/40	553.75	552.50	269.3	154.3	46.4		
01/27/40	553.75	552.53	300.0	185.0	55.7		
01/28/40	553.75	552.55	300.0	185.0	55.7		
01/29/40	553.75	552.47	269.3	154.3	46.4		
01/30/40	553.75	552.39	269.2	154.2	46.4		
01/31/40	553.75	552.31	269.2	154.2	46.3	1517.3	

Appendix C – Ozark Beach – Head vs. Capability (Old and New Turbines)

	Old Wheels			New Wheels				
Head (ft)	kW / Gen	kW / 4 Gen	kWh / 24 hr	#6 & #7 (MW)	#5 & #8 (MW)	kW / Gen	kW / 4 Gen	kWh / 24 hr
19	0	0	0	0.0	0.0	0	0	0
20	475	1,900	45,600	0.5	0.6	550	2,200	52,800
21	588	2,350	56,400	0.6	0.7	650	2,600	62,400
22	700	2,800	67,200	0.7	0.9	800	3,200	76,800
23	800	3,200	76,800	0.8	1.0	900	3,600	86,400
24	900	3,600	86,400	0.9	1.1	985	3,940	94,560
25	1,000	4,000	96,000	1.0	1.1	1,050	4,200	100,800
26	1,100	4,400	105,600	1.1	1.2	1,150	4,600	110,400
27	1,200	4,800	115,200	1.3	1.4	1,325	5,300	127,200
28	1,375	5,500	132,000	1.5	1.5	1,475	5,900	141,600
29	1,550	6,200	148,800	1.6	1.7	1,625	6,500	156,000
30	1,725	6,900	165,600	1.7	1.8	1,785	7,140	171,360
31	1,900	7,600	182,400	2.0	2.2	2,075	8,300	199,200
32	2,058	8,233	197,592	2.3	2.5	2,350	9,400	225,600
33	2,217	8,867	212,808	2.4	2.7	2,525	10,100	242,400
34	2,375	9,500	228,000	2.5	2.8	2,650	10,600	254,400
35	2,492	9,967	239,208	3.0	3.1	3,050	12,200	292,800
36	2,608	10,433	250,392	3.1	3.2	3,150	12,600	302,400
37	2,725	10,900	261,600	3.2	3.3	3,250	13,000	312,000
38	2,842	11,367	272,808	3.4	3.5	3,450	13,800	331,200
39	2,958	11,833	283,992	3.6	3.7	3,650	14,600	350,400
40	3,075	12,300	295,200	3.7	3.9	3,800	15,200	364,800
41	3,195	12,780	306,720	3.9	4.1	4,000	16,000	384,000
42	3,315	13,260	318,240	4.1	4.3	4,195	16,780	402,720
43	3,435	13,740	329,760	4.2	4.4	4,275	17,100	410,400
44	3,555	14,220	341,280	4.3	4.5	4,390	17,560	421,440
45	3,675	14,700	352,800	4.4	4.6	4,475	17,900	429,600
46	3,815	15,260	366,240	4.5	4.7	4,600	18,400	441,600
47	3,955	15,820	379,680	4.7	4.8	4,725	18,900	453,600
48	4,095	16,380	393,120	4.8	5.1	4,950	19,800	475,200
49	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
50	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
51	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
52	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
53	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
54	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
55	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
56	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
57	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800
58	4,235	16,940	406,560	4.9	5.2	5,050	20,200	484,800

Appendix D – Ozark Beach Energy Loss Sample Calculations

Base Run Calculations

										FL =	0.5	Efficiency=	0.85
Table Rock - Ozark Beach (New Wheels)													
SUPER output - W08X01 (base run)										Average Annual Energy, MWh			72,356
Date	**Table Rock Total Discharge, cfs**	**Bull Shoals Calc QIA, cfs**	**Drainage Area Ratio of BS QIA, cfs**	**Ozark Beach Calc Inflow, cfs**	**Bull Shoals 12-M Pool Elev., Ft.**	**Gross Head, feet**	**Adjusted BS Pool Elev., Ft. (1)**	**Adjusted Gross Head, feet**	**Maximum Capacity (from Table), MW**	**OB Full Discharge Capacity, cfs**	**OB Daily Energy, MWh**	**OB Monthly Energy, MWH**	**OB Annual Energy, MWH**
01/01/40	2,221	41	7	2,227	653.91	47.09	654.28	46.72	18.993	5,715	177.7		
01/02/40	2,221	0	0	2,221	653.85	47.15	654.22	46.78	19.032	5,719	177.4		
01/03/40	2,222	36	6	2,228	653.78	47.22	654.15	46.85	19.076	5,723	178.2		
01/04/40	2,222	395	67	2,289	653.74	47.26	654.11	46.89	19.102	5,726	183.3		
01/05/40	2,223	518	88	2,310	653.69	47.31	654.06	46.94	19.133	5,729	185.2		
01/06/40	120	404	69	189	653.73	47.27	654.10	46.90	19.108	5,727	15.1		
01/07/40	120	594	101	221	653.76	47.24	654.13	46.87	19.089	5,725	17.7		
01/08/40	2,223	462	78	2,301	653.68	47.32	654.05	46.95	19.140	5,730	184.5		
01/09/40	2,223	544	92	2,316	653.64	47.36	654.01	46.99	19.165	5,732	185.8		
01/10/40	2,224	676	115	2,339	653.61	47.39	653.98	47.02	19.184	5,734	187.8		
01/11/40	2,224	773	131	2,356	653.58	47.42	653.95	47.05	19.204	5,736	189.3		
01/12/40	2,225	845	143	2,368	653.55	47.45	653.92	47.08	19.223	5,738	190.4		
01/13/40	120	905	153	273	653.61	47.39	653.98	47.02	19.184	5,734	22.0		
01/14/40	120	1,137	193	313	653.66	47.34	654.03	46.97	19.153	5,731	25.1		
01/15/40	2,225	1,088	185	2,409	653.62	47.38	653.99	47.01	19.178	5,734	193.4		
01/16/40	2,225	1,390	236	2,461	653.61	47.39	653.98	47.02	19.184	5,734	197.6		
01/17/40	2,225	1,036	176	2,401	653.59	47.41	653.96	47.04	19.197	5,736	192.9		
01/18/40	2,226	991	168	2,394	653.57	47.43	653.94	47.06	19.210	5,737	192.4		
01/19/40	2,226	912	155	2,381	653.55	47.45	653.92	47.08	19.223	5,738	191.4		
01/20/40	120	392	66	186	653.59	47.41	653.96	47.04	19.197	5,736	15.0		
01/21/40	120	344	58	178	653.60	47.40	653.97	47.03	19.191	5,735	14.3		
01/22/40	2,226	344	58	2,285	653.52	47.48	653.89	47.11	19.242	5,740	183.8		
01/23/40	2,227	358	61	2,287	653.48	47.52	653.85	47.15	19.267	5,743	184.2		
01/24/40	2,227	360	61	2,288	653.43	47.57	653.80	47.20	19.299	5,746	184.4		
01/25/40	2,228	358	61	2,288	653.38	47.62	653.75	47.25	19.331	5,749	184.7		
01/26/40	2,228	389	66	2,294	653.33	47.67	653.69	47.31	19.363	5,753	185.3		
01/27/40	120	448	76	196	653.37	47.63	653.74	47.26	19.337	5,750	15.8		
01/28/40	120	501	85	205	653.39	47.61	653.76	47.24	19.325	5,749	16.5		
01/29/40	2,228	530	90	2,318	653.32	47.68	653.68	47.32	19.369	5,753	187.3		
01/30/40	2,229	547	93	2,322	653.28	47.72	653.64	47.36	19.395	5,756	187.8		
01/31/40	2,230	545	92	2,322	653.24	47.76	653.60	47.40	19.420	5,759	187.9	4433.9	

(1) See discussion and Figure 4 in Section 5.5.1.

Minimum Flows Run Calculations

										FL =	0.5	Efficiency=	0.85
Table Rock - Ozark Beach (New Wheels)													
SUPER output - W08X02 (minimum flow run)										Average Annual Energy, MWh			63,359
Date	**Table Rock Total Discharge, cfs**	**Bull Shoals Calc QIA, cfs**	**Drainage Area Ratio of BS QIA, cfs**	**Ozark Beach Calc Inflow, cfs**	**Bull Shoals 12-M Pool Elev., Ft.**	**Gross Head, feet**	**Adjusted BS Pool Elev., Ft. (1)**	**Adjusted Gross Head, feet**	**Maximum Capacity (from Table), MW**	**OB Full Discharge Capacity, cfs**	**OB Daily Energy, MWh**	**OB Monthly Energy, MWH**	**OB Annual Energy, MWH**
01/01/40	2,221	41	7	2,227	658.90	42.10	659.34	41.66	15.813	5,343	158.2		
01/02/40	2,221	0	0	2,221	658.82	42.18	659.26	41.74	15.864	5,350	158.1		
01/03/40	2,222	36	6	2,228	658.74	42.26	659.18	41.82	15.915	5,356	158.9		
01/04/40	2,222	395	67	2,289	658.68	42.32	659.12	41.88	15.954	5,361	163.5		
01/05/40	2,223	518	88	2,310	658.62	42.38	659.06	41.94	15.992	5,366	165.2		
01/06/40	120	404	69	189	658.64	42.36	659.08	41.92	15.979	5,365	13.5		
01/07/40	120	594	101	221	658.63	42.37	659.07	41.93	15.986	5,365	15.8		
01/08/40	2,223	462	78	2,301	658.55	42.45	658.99	42.01	16.037	5,372	164.9		
01/09/40	2,223	544	92	2,316	658.49	42.51	658.93	42.07	16.075	5,377	166.1		
01/10/40	2,224	676	115	2,339	658.44	42.56	658.88	42.12	16.107	5,381	168.0		
01/11/40	2,224	773	131	2,356	658.40	42.60	658.84	42.16	16.132	5,384	169.4		
01/12/40	2,225	845	143	2,368	658.35	42.65	658.79	42.21	16.164	5,388	170.5		
01/13/40	120	905	153	273	658.39	42.61	658.83	42.17	16.138	5,385	19.7		
01/14/40	120	1,137	193	313	658.40	42.60	658.84	42.16	16.132	5,384	22.5		
01/15/40	2,225	1,088	185	2,409	658.35	42.65	658.79	42.21	16.164	5,388	173.4		
01/16/40	2,225	1,390	236	2,461	658.32	42.68	658.75	42.25	16.183	5,391	177.3		
01/17/40	2,225	1,036	176	2,401	658.29	42.71	658.72	42.28	16.202	5,393	173.1		
01/18/40	2,226	991	168	2,394	658.25	42.75	658.68	42.32	16.228	5,396	172.8		
01/19/40	2,226	912	155	2,381	658.21	42.79	658.64	42.36	16.253	5,400	172.0		
01/20/40	120	392	66	186	658.22	42.78	658.65	42.35	16.247	5,399	13.5		
01/21/40	120	344	58	178	658.21	42.79	658.64	42.36	16.253	5,400	12.9		
01/22/40	2,226	344	58	2,285	658.12	42.88	658.55	42.45	16.310	5,407	165.4		
01/23/40	2,227	358	61	2,287	658.06	42.94	658.49	42.51	16.349	5,412	165.8		
01/24/40	2,227	360	61	2,288	657.99	43.01	658.42	42.58	16.393	5,417	166.2		
01/25/40	2,228	358	61	2,288	657.93	43.07	658.36	42.64	16.431	5,422	166.4		
01/26/40	2,228	389	66	2,294	657.86	43.14	658.29	42.71	16.476	5,428	167.1		
01/27/40	120	448	76	196	657.88	43.12	658.31	42.69	16.463	5,426	14.3		
01/28/40	120	501	85	205	657.87	43.13	658.30	42.70	16.470	5,427	14.9		
01/29/40	2,228	530	90	2,318	657.79	43.21	658.22	42.78	16.521	5,433	169.2		
01/30/40	2,229	547	93	2,322	657.73	43.27	658.16	42.84	16.559	5,438	169.7		
01/31/40	2,230	545	92	2,322	657.67	43.33	658.10	42.90	16.597	5,443	169.9	3978.2	

(1) See discussion and Figure 4 in Section 5.5.1.

Appendix E – Thermal Plant Power Values for the Southwest Region

THERMAL PLANT POWER VALUES FOR THE SOUTHWEST REGION				
Produced by US Army Corps of Engineers, Hydropower Analysis Center - CENWD-PDW-A				
November 2007				
Combined Cycle Plant				
	Capacity Value	Energy Value		
	(per kW-yr)	(per MWh)		
Arkansas	$127.44	$57.95		
Kansas	$128.47	$51.75		
Louisiana	$127.44	$61.24		
Missouri	$128.47	$56.45		
Oklahoma	$127.44	$55.51		
Texas	$127.44	$53.15		
Average	$127.78	$56.01		
Coal-Fired Steam Plant				
	Capacity Value	Energy Value		
	(per kW-yr)	(per MWh)		
Arkansas	$238.21	$17.50		
Kansas	$248.94	$14.12		
Louisiana	$236.95	$20.67		
Missouri	$249.14	$13.75		
Oklahoma	$238.03	$14.39		
Texas	$232.70	$21.96		
Average	$240.66	$17.06		
Combustion Turbine Plant				
	Capacity Value	Energy Value		
	(per kW-yr)	(per MWh)		
Arkansas	$61.30	$91.44		
Kansas	$62.33	$81.51		
Louisiana	$61.30	$96.72		
Missouri	$62.33	$89.04		
Oklahoma	$61.30	$87.53		
Texas	$61.30	$83.76		
Average	$61.64	$88.33		

Appendix F – Present Value Calculation for Federal Hydropower

Federal Hydropower Energy Losses								
Inflation rate =		2.00%		On-Peak and Off-Peak Energy Values based on				
Discount rate =		4.375%		Platts Power Outlook Research Service				
BS energy loss =		23,855	MWh	High Fuel Value case energy price forecast				
NF energy loss =		13,524	MWh	2008 Q1				
On-peak energy loss =		6,762	MWh	For Southwest Power Pool				
Off-peak energy loss =		30,617	MWh	Nominal $/MWh				
Total energy loss =		37,378	MWh					
	Year	On-peak	Value	On-pk loss	Off-peak	Value	Off-pk loss	Total Loss
	2008	6,762	$85.05	$575,073	30,617	$50.71	$1,552,696	$2,127,770
	2009	6,762	$77.51	$524,079	30,617	$47.99	$1,469,328	$1,993,407
	2010	6,762	$66.51	$449,739	30,617	$40.42	$1,237,535	$1,687,273
	present value of 2011-2060 stream in 2011							**$76,863,111**
1	2011	6,762	$60.39	$408,333	30,617	$35.91	$1,099,328	$1,507,661
2	2012	6,762	$62.01	$419,320	30,617	$38.40	$1,175,738	$1,595,058
3	2013	6,762	$65.43	$442,415	30,617	$41.08	$1,257,623	$1,700,038
4	2014	6,762	$65.88	$445,493	30,617	$42.97	$1,315,642	$1,761,134
5	2015	6,762	$68.22	$461,260	30,617	$45.49	$1,392,830	$1,854,090
6	2016	6,762	$68.10	$460,507	30,617	$46.99	$1,438,525	$1,899,033
7	2017	6,762	$71.15	$481,085	30,617	$49.47	$1,514,710	$1,995,795
8	2018	6,762	$74.39	$503,045	30,617	$51.93	$1,589,793	$2,092,837
9	2019	6,762	$79.03	$534,361	30,617	$55.84	$1,709,603	$2,243,963
10	2020	6,762	$80.42	$543,755	30,617	$57.65	$1,764,975	$2,308,729
11	2021	6,762	$86.79	$586,848	30,617	$62.52	$1,914,221	$2,501,069
12	2022	6,762	$97.95	$662,308	30,617	$70.74	$2,165,951	$2,828,259
13	2023	6,762	$110.02	$743,935	30,617	$80.46	$2,463,411	$3,207,346
14	2024	6,762	$116.39	$786,983	30,617	$87.05	$2,665,160	$3,452,143
15	2025	6,762	$124.98	$845,095	30,617	$95.79	$2,932,722	$3,777,816
16	2026	6,762	$129.10	$872,968	30,617	$100.89	$3,088,868	$3,961,836
17	2027	6,762	$132.69	$897,252	30,617	$106.29	$3,254,228	$4,151,480
18	2028	6,762	$135.35	$915,197	30,617	$108.42	$3,319,313	$4,234,509
19	2029	6,762	$138.05	$933,501	30,617	$110.58	$3,385,699	$4,319,199
20	2030	6,762	$140.82	$952,171	30,617	$112.80	$3,453,413	$4,405,583
21	2031	6,762	$143.63	$971,214	30,617	$115.05	$3,522,481	$4,493,695
22	2032	6,762	$146.50	$990,638	30,617	$117.35	$3,592,931	$4,583,569
23	2033	6,762	$149.44	$1,010,451	30,617	$119.70	$3,664,789	$4,675,240
24	2034	6,762	$152.42	$1,030,660	30,617	$122.09	$3,738,085	$4,768,745
25	2035	6,762	$155.47	$1,051,273	30,617	$124.54	$3,812,847	$4,864,120
26	2036	6,762	$158.58	$1,072,299	30,617	$127.03	$3,889,104	$4,961,403
27	2037	6,762	$161.75	$1,093,745	30,617	$129.57	$3,966,886	$5,060,631
28	2038	6,762	$164.99	$1,115,620	30,617	$132.16	$4,046,224	$5,161,843
29	2039	6,762	$168.29	$1,137,932	30,617	$134.80	$4,127,148	$5,265,080
30	2040	6,762	$171.65	$1,160,691	30,617	$137.50	$4,209,691	$5,370,382
31	2041	6,762	$175.09	$1,183,905	30,617	$140.25	$4,293,885	$5,477,789
32	2042	6,762	$178.59	$1,207,583	30,617	$143.05	$4,379,762	$5,587,345
33	2043	6,762	$182.16	$1,231,734	30,617	$145.91	$4,467,358	$5,699,092
34	2044	6,762	$185.80	$1,256,369	30,617	$148.83	$4,556,705	$5,813,074
35	2045	6,762	$189.52	$1,281,496	30,617	$151.81	$4,647,839	$5,929,335
36	2046	6,762	$193.31	$1,307,126	30,617	$154.84	$4,740,796	$6,047,922
37	2047	6,762	$197.18	$1,333,269	30,617	$157.94	$4,835,612	$6,168,880
38	2048	6,762	$201.12	$1,359,934	30,617	$161.10	$4,932,324	$6,292,258
39	2049	6,762	$205.14	$1,387,133	30,617	$164.32	$5,030,970	$6,418,103
40	2050	6,762	$209.25	$1,414,875	30,617	$167.61	$5,131,590	$6,546,465
41	2051	6,762	$213.43	$1,443,173	30,617	$170.96	$5,234,222	$6,677,395
42	2052	6,762	$217.70	$1,472,036	30,617	$174.38	$5,338,906	$6,810,942
43	2053	6,762	$222.05	$1,501,477	30,617	$177.87	$5,445,684	$6,947,161
44	2054	6,762	$226.49	$1,531,507	30,617	$181.42	$5,554,598	$7,086,105
45	2055	6,762	$231.02	$1,562,137	30,617	$185.05	$5,665,690	$7,227,827
46	2056	6,762	$235.64	$1,593,380	30,617	$188.75	$5,779,004	$7,372,383
47	2057	6,762	$240.36	$1,625,247	30,617	$192.53	$5,894,584	$7,519,831
48	2058	6,762	$245.16	$1,657,752	30,617	$196.38	$6,012,475	$7,670,227
49	2059	6,762	$250.07	$1,690,907	30,617	$200.31	$6,132,725	$7,823,632
50	2060	6,762	$255.07	$1,724,725	30,617	$204.31	$6,255,379	$7,980,105

Federal Hydropower Capacity Losses					**Bull Shoals Increased Maintenance**		
Total Capacity Loss=		3.93	MW		Estimated annual costs =		$68,000
Capacity Value =		$61.30	$/kW-yr				
Combustion Turbine Plant for Arkansas (Nov 2007)							
Inflation rate =		2.00%					
Discount rate =		4.375%					
Year	Cap loss	Value	Total Loss		Year	Annual Maint	
2008	3.93	$61.30	$240,909		2008	$68,000	
2009	3.93	$62.53	$245,727		2009	$69,360	
2010	3.93	$63.78	$250,642		2010	$70,747	
			$7,680,910			**$2,168,046**	
2011	3.93	$65.05	$255,655		2011	$72,162	
2012	3.93	$66.35	$260,768		2012	$73,605	
2013	3.93	$67.68	$265,983		2013	$75,077	
2014	3.93	$69.03	$271,303		2014	$76,579	
2015	3.93	$70.41	$276,729		2015	$78,111	
2016	3.93	$71.82	$282,263		2016	$79,673	
2017	3.93	$73.26	$287,909		2017	$81,266	
2018	3.93	$74.72	$293,667		2018	$82,892	
2019	3.93	$76.22	$299,540		2019	$84,549	
2020	3.93	$77.74	$305,531		2020	$86,240	
2021	3.93	$79.30	$311,641		2021	$87,965	
2022	3.93	$80.88	$317,874		2022	$89,725	
2023	3.93	$82.50	$324,232		2023	$91,519	
2024	3.93	$84.15	$330,716		2024	$93,349	
2025	3.93	$85.83	$337,331		2025	$95,216	
2026	3.93	$87.55	$344,077		2026	$97,121	
2027	3.93	$89.30	$350,959		2027	$99,063	
2028	3.93	$91.09	$357,978		2028	$101,044	
2029	3.93	$92.91	$365,138		2029	$103,065	
2030	3.93	$94.77	$372,440		2030	$105,127	
2031	3.93	$96.66	$379,889		2031	$107,229	
2032	3.93	$98.60	$387,487		2032	$109,374	
2033	3.93	$100.57	$395,237		2033	$111,561	
2034	3.93	$102.58	$403,141		2034	$113,792	
2035	3.93	$104.63	$411,204		2035	$116,068	
2036	3.93	$106.72	$419,428		2036	$118,390	
2037	3.93	$108.86	$427,817		2037	$120,757	
2038	3.93	$111.04	$436,373		2038	$123,173	
2039	3.93	$113.26	$445,101		2039	$125,636	
2040	3.93	$115.52	$454,003		2040	$128,149	
2041	3.93	$117.83	$463,083		2041	$130,712	
2042	3.93	$120.19	$472,345		2042	$133,326	
2043	3.93	$122.59	$481,791		2043	$135,992	
2044	3.93	$125.05	$491,427		2044	$138,712	
2045	3.93	$127.55	$501,256		2045	$141,487	
2046	3.93	$130.10	$511,281		2046	$144,316	
2047	3.93	$132.70	$521,506		2047	$147,203	
2048	3.93	$135.35	$531,937		2048	$150,147	
2049	3.93	$138.06	$542,575		2049	$153,150	
2050	3.93	$140.82	$553,427		2050	$156,213	
2051	3.93	$143.64	$564,495		2051	$159,337	
2052	3.93	$146.51	$575,785		2052	$162,524	
2053	3.93	$149.44	$587,301		2053	$165,774	
2054	3.93	$152.43	$599,047		2054	$169,090	
2055	3.93	$155.48	$611,028		2055	$172,471	
2056	3.93	$158.59	$623,249		2056	$175,921	
2057	3.93	$161.76	$635,714		2057	$179,439	
2058	3.93	$164.99	$648,428		2058	$183,028	
2059	3.93	$168.29	$661,396		2059	$186,689	
2060	3.93	$171.66	$674,624		2060	$190,422	

Appendix G – Present Value Calculation for Non-Federal Hydropower

Empire Energy Losses										**Empire Capacity Losses**			
Inflation rate =		2.00%		On-Peak and Off-Peak Energy Values based on						Total Capacity Loss=		3	MW
Discount rate =		4.375%		Platts Power Outlook Research Service									
On-peak % =		67%		High Fuel Value case energy price forecast						Capacity Value =		$128.47	$/kW-yr
Off-peak % =		33%		2008 Q1						Combined Cycle Plant for Missouri (Nov 2007)			
Total energy loss =		8,998	MWh	For Southwest Power Pool									
On-peak loss =		6,029	MWh	Nominal $/MWh									
Off-peak loss =		2,969	MWh										
Carbon Tax =		$0	per ton	Annual carbon tax computed in 2011-EDEC-Platts									
CT Risk Premium=		0%											
	Year	On-peak	Average Value	On-pk loss	Off-peak	Average Value	Off-pk loss	Total Loss		Year	Cap loss	Value	Total Loss
	2008	6,029	$86.06	$518,837	2,969	$50.75	$150,702	$669,540		2008	3.00	$128.47	$385,410
	2009	6,029	$79.55	$479,561	2,969	$48.08	$142,766	$622,327		2009	3.00	$131.04	$393,118
	2010	6,029	$67.88	$409,209	2,969	$40.36	$119,829	$529,038		2010	3.00	$133.66	$400,981
				present value of 2011-2060 stream in 2011				**$21,647,123**					**$12,288,040**
1	2011	6,029	$61.20	$368,966	2,969	$35.66	$105,898	$474,864		2011	3.00	$136.33	$409,000
2	2012	6,029	$62.73	$378,175	2,969	$38.22	$113,483	$491,658		2012	3.00	$139.06	$417,180
3	2013	6,029	$66.16	$398,838	2,969	$40.78	$121,084	$519,922		2013	3.00	$141.84	$425,524
4	2014	6,029	$66.85	$402,988	2,969	$42.78	$127,042	$530,030		2014	3.00	$144.68	$434,034
5	2015	6,029	$69.42	$418,536	2,969	$45.47	$135,019	$553,555		2015	3.00	$147.57	$442,715
6	2016	6,029	$69.35	$418,106	2,969	$47.22	$140,207	$558,313		2016	3.00	$150.52	$451,569
7	2017	6,029	$72.62	$437,819	2,969	$49.86	$148,048	$585,867		2017	3.00	$153.53	$460,601
8	2018	6,029	$75.77	$456,802	2,969	$52.32	$155,359	$612,161		2018	3.00	$156.60	$469,813
9	2019	6,029	$80.54	$485,565	2,969	$56.59	$168,043	$653,608		2019	3.00	$159.74	$479,209
10	2020	6,029	$81.64	$492,189	2,969	$58.35	$173,247	$665,436		2020	3.00	$162.93	$488,793
11	2021	6,029	$88.33	$532,502	2,969	$63.19	$187,629	$720,131		2021	3.00	$166.19	$498,569
12	2022	6,029	$100.01	$602,935	2,969	$71.75	$213,050	$815,985		2022	3.00	$169.51	$508,540
13	2023	6,029	$112.67	$679,268	2,969	$82.60	$245,281	$924,549		2023	3.00	$172.90	$518,711
14	2024	6,029	$117.99	$711,339	2,969	$88.67	$263,277	$974,616		2024	3.00	$176.36	$529,085
15	2025	6,029	$127.25	$767,119	2,969	$97.93	$290,786	$1,057,904		2025	3.00	$179.89	$539,667
16	2026	6,029	$131.96	$795,530	2,969	$103.72	$307,970	$1,103,500		2026	3.00	$183.49	$550,460
17	2027	6,029	$135.93	$819,460	2,969	$109.61	$325,468	$1,144,929		2027	3.00	$187.16	$561,470
18	2028	6,029	$138.65	$835,849	2,969	$111.80	$331,978	$1,167,827		2028	3.00	$190.90	$572,699
19	2029	6,029	$141.42	$852,566	2,969	$114.04	$338,617	$1,191,184		2029	3.00	$194.72	$584,153
20	2030	6,029	$144.25	$869,618	2,969	$116.32	$345,390	$1,215,007		2030	3.00	$198.61	$595,836
21	2031	6,029	$147.13	$887,010	2,969	$118.65	$352,297	$1,239,308		2031	3.00	$202.58	$607,753
22	2032	6,029	$150.07	$904,750	2,969	$121.02	$359,343	$1,264,094		2032	3.00	$206.64	$619,908
23	2033	6,029	$153.08	$922,845	2,969	$123.44	$366,530	$1,289,376		2033	3.00	$210.77	$632,306
24	2034	6,029	$156.14	$941,302	2,969	$125.91	$373,861	$1,315,163		2034	3.00	$214.98	$644,952
25	2035	6,029	$159.26	$960,128	2,969	$128.43	$381,338	$1,341,466		2035	3.00	$219.28	$657,851
26	2036	6,029	$162.45	$979,331	2,969	$130.99	$388,965	$1,368,296		2036	3.00	$223.67	$671,008
27	2037	6,029	$165.69	$998,917	2,969	$133.61	$396,744	$1,395,662		2037	3.00	$228.14	$684,428
28	2038	6,029	$169.01	$1,018,896	2,969	$136.29	$404,679	$1,423,575		2038	3.00	$232.71	$698,117
29	2039	6,029	$172.39	$1,039,274	2,969	$139.01	$412,773	$1,452,046		2039	3.00	$237.36	$712,079
30	2040	6,029	$175.84	$1,060,059	2,969	$141.79	$421,028	$1,481,087		2040	3.00	$242.11	$726,321
31	2041	6,029	$179.35	$1,081,260	2,969	$144.63	$429,449	$1,510,709		2041	3.00	$246.95	$740,847
32	2042	6,029	$182.94	$1,102,886	2,969	$147.52	$438,038	$1,540,923		2042	3.00	$251.89	$755,664
33	2043	6,029	$186.60	$1,124,943	2,969	$150.47	$446,798	$1,571,742		2043	3.00	$256.93	$770,777
34	2044	6,029	$190.33	$1,147,442	2,969	$153.48	$455,734	$1,603,176		2044	3.00	$262.06	$786,193
35	2045	6,029	$194.14	$1,170,391	2,969	$156.55	$464,849	$1,635,240		2045	3.00	$267.31	$801,917
36	2046	6,029	$198.02	$1,193,799	2,969	$159.68	$474,146	$1,667,945		2046	3.00	$272.65	$817,955
37	2047	6,029	$201.98	$1,217,675	2,969	$162.87	$483,629	$1,701,304		2047	3.00	$278.10	$834,314
38	2048	6,029	$206.02	$1,242,028	2,969	$166.13	$493,301	$1,735,330		2048	3.00	$283.67	$851,001
39	2049	6,029	$210.14	$1,266,869	2,969	$169.45	$503,168	$1,770,036		2049	3.00	$289.34	$868,021
40	2050	6,029	$214.34	$1,292,206	2,969	$172.84	$513,231	$1,805,437		2050	3.00	$295.13	$885,381
41	2051	6,029	$218.63	$1,318,050	2,969	$176.30	$523,495	$1,841,546		2051	3.00	$301.03	$903,089
42	2052	6,029	$223.00	$1,344,411	2,969	$179.83	$533,965	$1,878,377		2052	3.00	$307.05	$921,150
43	2053	6,029	$227.46	$1,371,300	2,969	$183.42	$544,645	$1,915,944		2053	3.00	$313.19	$939,573
44	2054	6,029	$232.01	$1,398,726	2,969	$187.09	$555,538	$1,954,263		2054	3.00	$319.45	$958,365
45	2055	6,029	$236.65	$1,426,700	2,969	$190.83	$566,648	$1,993,348		2055	3.00	$325.84	$977,532
46	2056	6,029	$241.39	$1,455,234	2,969	$194.65	$577,981	$2,033,215		2056	3.00	$332.36	$997,083
47	2057	6,029	$246.21	$1,484,339	2,969	$198.54	$589,541	$2,073,880		2057	3.00	$339.01	$1,017,024
48	2058	6,029	$251.14	$1,514,026	2,969	$202.51	$601,332	$2,115,357		2058	3.00	$345.79	$1,037,365
49	2059	6,029	$256.16	$1,544,306	2,969	$206.56	$613,358	$2,157,664		2059	3.00	$352.70	$1,058,112
50	2060	6,029	$261.28	$1,575,192	2,969	$210.70	$625,626	$2,200,818		2060	3.00	$359.76	$1,079,274

Appendix H – Southwestern's Draft White Paper

Southwestern Power Administration
Water Storage Reallocations
Hydropower Impacts

Dated 07/18/2005

DRAFT

Southwestern Power Administration
Water Storage Reallocation
Hydropower Impacts

Executive Summary

The purpose of the paper is to document the Southwestern Power Administration's (Southwestern) concerns with the procedures used by the US Army Corps of Engineers (Corps) in determining and compensating the hydropower purpose for impacts resulting from water storage reallocations at Corps projects.

1. Capacity Loss Calculations. The Corps uses average year capacity losses instead of the critical year capacity losses used by Southwestern to market the capacity. While the Corps' method may be applicable in determining the feasibility of new hydropower, Southwestern does not believe it is applicable to existing hydropower that is already meeting market energy and capacity needs. As such, a loss of Southwestern's marketable capacity is a loss in the National electrical energy market.

2. Energy Loss Calculations. Both agencies generally use the same procedure to calculate energy losses. Southwestern is concerned that the "water storage yield" amount used in the simulations as withdrawal for the water represents the minimum amount that can be withdrawn. Southwestern encourages development of a method that represents a maximum, or at least an average, withdrawal rate.

3. Capacity Cost Calculations. Southwestern generally agrees with the Corps use of the Federal Energy Regulatory Commission's (FERC) procedure to develop the cost of alternative sources of generation. Southwestern believes the alternative generation source should be selected based on the replacement of capacity as used in the power sales contract and not based on the project's average annual generation.

4. Energy Cost Calculations. Because Southwestern occasionally purchases energy in the market, it is familiar with the energy costs. Southwestern cannot typically purchase replacement energy at the unit costs assumed in the Corps' study. The energy market has changed significantly in the past several years and the procedures used to estimate the price of energy must therefore also change. Southwestern suggests the use of properly selected FERC calculated energy values as appropriate in determining the energy replacement costs. Care should also be taken in the studies in handling on-peak and off-peak energy.

5. Compensation Issues. The Corps agrees to provide compensation for benefits foregone through the life of the current power sales contracts. Southwestern believes that its 1980 Final Power Allocations assures the Federal customers continuation of their contracted capacity and energy. It would therefore

follow that the hydropower purpose should be credited for the benefits foregone through the life of the project (much as the water supply users are guaranteed the water storage through the life of the project). Southwestern also believes that a procedure to provide the hydropower purpose the financial credit should be developed and included in the Corps' water storage reallocation reports.

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Southwestern Power Administration
Water Storage Reallocations
Hydropower Impacts

Purpose: To provide Southwestern Power Administration's (Southwestern) general observations and concerns with the US Army Corps of Engineers (Corps) methods of determining the hydropower purpose impacts resulting from water storage reallocations at Corps projects along with any associated compensation.

Background: The Corps occasionally reallocates water storage from one purpose to another at their multipurpose lake projects (most often, but not always, for municipal and industrial water supply usage). Whenever a reallocation occurs at a project that includes hydropower as a project purpose, there is typically a negative impact to the hydropower purpose. During the study phase, the Corps requests their Hydropower Analysis Center (HAC) to determine the impact of the proposed water storage reallocation to the hydropower purpose. Determination of the hydropower impacts by HAC is generally composed of four parts: 1) amount of capacity lost, 2) amount of energy lost, 3) value of capacity lost, and 4) value of energy lost. As a result of reviewing numerous such studies, Southwestern has several areas of concern with the methodologies being used to determine those amounts and values. Additionally, Southwestern also has concern with how the Corps compensates the hydropower purpose once those impacts are determined. The following is a discussion of the current methods and proposed changes.

Capacity Loss: The determination of the amount of dependable capacity lost as the result of a water storage reallocation at a Corps project is of critical importance to Southwestern. Reliable capacity with associated energy is the major resource Southwestern has to market in order to repay the nation's hydropower investment in the project. In benefit calculations, the "…dependable capacity of a project is used to represent the amount of thermal capacity that would be displaced by the hydro plant. More specifically, it is intended to identify how much thermal capacity would be required to carry the same amount of system peak load as would be carried by the hydro plant…" [Section 6-7b(1) of the Corps' EM 1110-2-1701, Hydropower, dated 31 December 1985]. HAC and Southwestern differ in the method used to compute the dependable capacity loss in the case of storage reallocations.

a) HAC's Method: In Southwestern's marketing area, HAC typically uses the average availability method as described in Section 6-7g of the Corps' EM 1110-2-1701. HAC's justification for such usage is that hydropower in Southwestern's area represents only a small portion of the region's generating resources and as such, random hydrologic variations can be considered equivalent to random thermal generating plant forced outages.

In general, the average availability method computes the dependable capacity for a critical load demand period for each year of a given period-of-record based on energy produced and peaking demand hours (never allowing it to be more than machine capability). The dependable capacity for each year is then averaged over the period-of-record to determine the project's dependable capacity. To determine the impacts of a reallocation, the average dependable capacity is determined for both a base case and an alternative case modified to represent the proposed reallocation. The difference in the two cases is the capacity loss due to the proposed reallocation.

More specifically, in the average availability method, a period-of-record simulation is made for the base and modified conditions. The annual peak demand period is determined in consultation with Southwestern (typically June through August in Southwestern's area) and the project's average weekly energy output is computed for that peak demand period for each year of the simulation. Southwestern provides HAC with the critical flow year as used in its studies. In order to calculate the number of peaking hours required from the project each week, the average weekly energy for the peak demand period of the critical year of the base case is divided by the amount of capacity that Southwestern markets from the project. The average weekly energy for the peak demand period for each year of the entire period-of-record is then divided by the number of hours required by week as computed above to determine the potential supportable capacity. That value for each year is compared with machine capability (reduced for loss of head based on headwater and tailwater conditions) and the lower value chosen for the actual supportable capacity. The actual supportable capacity computed for each year of the period-of-record is averaged and used as the dependable capacity of the project. Using the required number of hours per week from the base case, the actual supportable capacity is computed for the alternative's modified conditions. The alternative average capacity is subtracted from the base average capacity to determine the loss of dependable capacity that is used in the study to determine revenues and benefits lost due to the proposed reallocation.

b) <u>Southwestern's Method</u>: Southwestern's method used to determine the lost capacity reflects how the capacity is marketed and used in the region. The capacity available from the Corps' hydropower projects is the only capacity available to Southwestern to meet the obligations of Federal long-term power sales contracts in its area. The revenues collected from those power sales contracts are used to repay the Federal investment in the projects, with interest. Southwestern has entered into those power sales contracts after determining the amount of capacity available for marketing based on the ability of the hydropower projects to reliably provide capacity and firm energy throughout the worst drought of record. The Federal customers receiving the electricity request long-term power sales contracts in order to provide them sufficient time to make arrangements for replacement generation sources if the hydropower is no longer available. Based on Section 5 of the Flood Control Act of 1944, as amended, and on discussions with the Office of Management and Budget, Southwestern believes that it only has the authority to market the capacity dependably available at the projects. If the capacity is not available because of a drought period, Southwestern cannot purchase replacement capacity, even if it was available, and therefore, Southwestern cannot market that capacity through the Federal power sales contracts. (Special allowance is made for forced outages that are expected to return to service). If Southwestern cannot market the capacity on a long-term basis, then it is not available to the region as a generating resource and must be replaced in the long-term with the construction of thermal plant capacity. Therefore, benefits from the hydropower capacity that was marketed and now lost are no longer a benefit to the Nation.

Southwestern, from time to time, purchases energy on the shoulders of the peak during drought conditions to conserve water in storage to preserve the marketed project capacity. Southwestern must maintain the ability to meet the peak capacity demands solely with its hydropower resources. In system projects, an attempt is made to maintain a balance of the projects' storage to equitably address the needs of all the water users.

As mentioned, Southwestern determines the capacity loss of a water storage reallocation based on a critical drought period (instead of average conditions). A period-of-record simulation is made for both the base case (existing conditions) and an alternative case (modified to represent the proposed water storage reallocation yield). The peaking loads used in the alternative case are reduced by the amount of the reallocated water storage yield in order to maintain the minimum pool elevation achieved in the base case in the high load month of August during the critical drought period. From the two runs, the energy produced during the critical drought period (from the time the water surface receded into the power storage until the minimum August pool is reached) is computed. The critical drought period will often exceed one year. The number of peaking hours needed for the critical drought period is based on Southwestern's power sales contracts (1,200 hours per year) and a critical loading pattern based on the requirements of those contracts. The lost capacity is then computed by taking the amount of energy lost during the critical drought period between the base and alternative cases and dividing it by the number of peaking hours needed during the drought period.

c) Comparison: Southwestern's method uses procedures (energy loss divided by peaking hours required) similar to those used by HAC in determining the capacity lost. Southwestern uses a longer critical period (similar to the critical period used in a water yield analysis) than HAC (uses two to four months during the peak demand period). Most importantly, Southwestern is compelled, for reasons stated above, to use the critical drought capacity instead of the average available capacity. In addition, the critical drought conditions have a greater impact than random hydrologic variations and in Southwestern's area, critical drought conditions occur in several of the major river basins concurrently. Southwestern believes that the HAC method can be properly used in planning studies to determine whether new hydropower projects should be constructed. However, once a project is constructed and marketed into the electrical system, it has been established as a generating resource meeting specific electrical loads. Without the ability to provide capacity throughout the critical drought period, Southwestern cannot make the capacity available for long-term marketing. If that generating resource were no longer available for long-term marketing, it would have to be replaced by equivalent thermal plant capacity at the associated cost. Therefore, the capacity lost to the electrical system would be the amount of capacity lost during the critical drought period.

d) Flood control reallocation: When the proposed water storage reallocation is taken from the flood control storage, the impacts on the hydropower purpose will vary. If the reallocation provides for hydropower yield protection operation (HYPO) for the hydropower purpose, similar to the dependable yield mitigation storage for the water supply purpose, the hydropower storage capabilities remain whole, and there is no impact on the marketable capacity. If HYPO is not provided to protect the yield of the storage for hydropower, then the impact of the yield reduction of the hydropower storage must be determined and the associated capacity loss determined.

Energy Loss: Both HAC and Southwestern use the same method to compute the amount of energy lost from a proposed water storage reallocation. A period-of-record simulation is made for both the base case (existing conditions) and an alternative case (modified to represent the proposed water storage reallocation yield). The average annual energy produced is computed in both simulations. The average annual energy produced by the alternative case is subtracted from the base case value and the result is the average annual energy loss associated with the proposed water storage reallocation.

Southwestern's concern in the process is typically limited to efforts to assure that the proposed reallocation is properly modeled in the simulation runs. Southwestern believes that use of the water storage yield as the normal withdrawal in the simulation underestimates the amount of water that can normally be withdrawn from the storage. The yield represents the amount of water that can be withdrawn in the critical drought period. During the rest of the period-of-record, withdrawals exceeding the yield can be made from the water storage. Since there are normally no restrictions in the Corps' water storage contracts to limit the withdrawal amount and in order to properly model the impacts, the maximum withdrawal rate for each period must be assumed. When the potential withdrawal (average withdrawal instead of critical drought withdrawal) is properly modeled in the simulation, the energy losses associated with the reallocation would increase. With that exception, Southwestern generally agrees with the energy loss values computed by HAC. However, in a few studies, a distinction should be made to differentiate between the loss and gain of on-peak and off-peak energy in order for proper cost values to be assigned to each. Southwestern is willing to work with the Corps in developing a process to better model the potential average water withdrawal available from proposed storage reallocations.

Capacity Cost: Once the amount of capacity loss is established, the cost or value of the capacity lost must be determined. Both capacity revenues and benefits foregone are computed by HAC. The revenues are straightforward and are based on the capacity loss multiplied by the current rates Southwestern is charging for the capacity in the power sales contracts. The capacity cost used by HAC to calculate benefits foregone represents the unit cost of constructing an increment of the most likely thermal generating alternative to replace the lost hydropower capacity. HAC computes the capacity unit values for coal-fired steam, gas-fired combined cycle, and combustion turbine plants using procedures developed by the Federal Energy Regulatory Commission (FERC). The capacity values are computed for the applicable region based on the current interest rate with the construction costs adjusted to the current price level. Southwestern agrees with the use of the FERC model in determination of the capacity values. However, it appears that the construction costs, although brought to the current price level, are based on older data and should be updated based on new construction cost information.

HAC uses the FERC thermal alternative cost information to develop a thermal screening curve of annual costs versus the operating plant factors. A project hourly generation duration curve is also developed from a typical generation year. From those two curves, HAC selects a least-cost thermal mix that represents the least-cost thermal alternative for generation of the typical annual generation from the project. Weighting factors are calculated to represent that mix and applied to the previously calculated FERC unit capacity values for each thermal alternative. A composite unit capacity value is calculated and multiplied by the previously calculated capacity loss to determine the capacity benefit loss from the proposed reallocation.

Southwestern believes that, while the HAC approach provides a reasonable thermal mix for the modified project's average annual generation, it does not represent the most likely thermal alternative for the capacity and energy that is being lost because of the reallocation. Southwestern believes that the thermal generating alternative selected to replace the lost hydropower capacity should be based on replacement of capacity as used in the power sales contracts to meet the firm peaking energy requirements. The hydropower storage at a project provides the dependability that makes the capacity marketable. It is used to meet the 1,200 hours per year of energy guaranteed in the power sales contracts (not the average annual generation). The loss of the use of a portion of that storage reduces the amount of marketable capacity at the project available to meet the 1,200 hours. The thermal generating alternative used to replace the product Southwestern markets from those projects would be used to provide 1,200 hours per year, or a plant factor of 13.7 percent. Therefore, Southwestern believes that the most likely thermal generating alternative for most of the water storage reallocations proposed in its area should be a gas-fired combustion turbine.

Energy Cost: After the amount of energy loss is estimated, the cost or value of the lost energy must be determined. Both energy revenues and benefits foregone are computed by HAC. The energy portion of the revenue foregone is computed by multiplying the energy loss by Southwestern's current energy rate. Both on-peak and off-peak rates are available in Southwestern's current rate structure.

a) On-peak energy: Because the hydropower storage at a project is used to produce peaking energy, the impact in Southwestern's area of reducing the hydropower storage is the loss of peaking energy. HAC and Southwestern differ in the method used to compute the value of the energy loss in the case of storage reallocations.

1) HAC's Method: HAC uses the computer model PROSYM, which is developed and maintained by Henwood Energy Services, to develop the

area power system cost of producing an equivalent amount of thermal replacement energy to offset that hydropower energy lost due to the reallocation. It appears that the model tries to absorb the lost energy into the existing resources, assuming that there is sufficient energy in reserve to meet the loss, and to replace the loss with the existing thermal generating alternative that has the lowest production cost.

2) Southwestern's Method: While Southwestern believes that the model and procedure used by HAC had merit in previous planning studies in determining the feasibility of constructing new hydropower facilities, it believes the value used by HAC in the studies for the replacement cost of the peaking energy loss is not valid. In the existing open, de-regulated energy market, the replacement of the lost hydropower energy will be made through either the purchase of peaking energy at market-based rates or through the construction of a new thermal generating plant. The price of energy in the new market-driven industry is no longer based on production costs, but rather on supply and demand. Southwestern has responsibility for the purchase of peaking energy from time to time to preserve water storage in the reservoirs. Therefore, it has practical experience in the energy market. The unit cost of peaking energy purchased by Southwestern is considerably more than the energy unit cost used by HAC in the studies. The unit cost of energy used by HAC in the studies is not reasonable or representative of the actual energy market. Until a market cost forecast model is developed, Southwestern believes that the peaking energy replacement costs can adequately be represented by use of the FERC energy values computed for the gas-fired combustion turbine.

b) Off-peak energy: In studies where the proposed water storage reallocation is from the flood control pool and HYPO is provided to protect the hydropower yield, the capability of the hydropower storage is not impacted. Energy loss in that case should be considered off-peak energy and its cost or value should reflect the lower costs. Additionally, in a recent study, the reallocation energy loss was offset by energy generated through new, larger station service units that generated when the main units were not used. In the study, all the energy was treated as having the same value. Since the main units are typically run to produce energy when needed to meet the firm peaking energy requirements of the power sales contracts, the energy from the new station service units should be considered as off-peak energy (not used to meet the peaking energy requirements). In the energy market, such off-peak energy has a much lower value. Southwestern recommends that when similar conditions are evaluated, the off-peak energy should be valued at the FERC energy value for the coal-fired steam as the most likely thermal alternative to replace the off-peak energy in the benefits calculations.

Compensation: Southwestern has concerns with two issues involving compensation to the hydropower purpose for any proposed water storage reallocation. The first issue involves the amount of compensation and the second involves the procedure for compensation.

a) Amount: Appendix E of the Corps' ER 1105-2-100, Planning Guidance Notebook, dated 22 Apr 2000, allows for hydropower to receive a financial credit of revenues foregone when hydropower is adversely impacted by water storage reallocations. Additionally, where existing Federal power delivery contracts require market purchases of power as a result of storage reallocations and withdrawal, the additional credit for funds expended for purchases is provided. In essence, the latter provision gives the hydropower purpose a financial credit for the replacement costs or benefits foregone for the duration of the power sales contracts.

Under the same Appendix E, the permanent right to storage is discussed for water supply users that continue to make payments pursuant to their agreement with the government. Southwestern believes that the Federal power customers have a similar guarantee of continued benefits under Southwestern's Final Power Allocations published in the Federal Register on March 24, 1980. It states, "SWPA will not withdraw any capacity now under contract to a preference customer in order to sell the capacity to another preference customer. As contracts expire, SWPA will offer to enter into peaking contracts for the sale of a like amount of capacity with 1200 kWh/kW/yr of associated energy." It further states that "Capacity that becomes available with the expiration of a preference customer contract is to be used for continued service to that preference customer and is, therefore, not available for allocation to others." The 1980 Final Power Allocations provides the permanent right to the capacity and associated energy to the existing preference customers provided that the "power allottee will accept the amounts allocated with its attendant terms" and "transmission facilities will be available to move this power to load centers." As such, Southwestern believes that, while compensation for the loss of hydropower capacity and energy associated with the reallocation of water storage should continue to be based on the replacement costs or benefits foregone for the term of the contract, the contract should be considered permanent, or without end.

b) Procedure: In order to assure that the proposed hydropower compensation is accomplished, Southwestern believes that the water storage reallocation reports should have clearly delineated procedures that outline the process for providing a financial credit to the hydropower purpose. It is imperative that the hydropower purpose actually receives the credit on the financial books in order that Southwestern's electrical rates can reflect the proposed compensation. Southwestern is willing to work with the Corps in the development of a standard financial credit procedure for hydropower compensation.

Appendix I – Empire Report

Empire District Electric Company

Determination of Costs for Energy and
Capacity Lost from the "Reallocation" of
Flood Storage from Bull Shoals Lake

Dated August 2007

Determination of Costs for Energy and Capacity Lost from the "Reallocation" of Flood Storage from Bull Shoals Lake

August 2007

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Key Findings

The key findings of this analysis to determine the value to The Empire District Electric Company (Empire) of lost capacity and energy at its Ozark Beach hydroelectric facility (located near Branson, Missouri) can be summarized as follows:

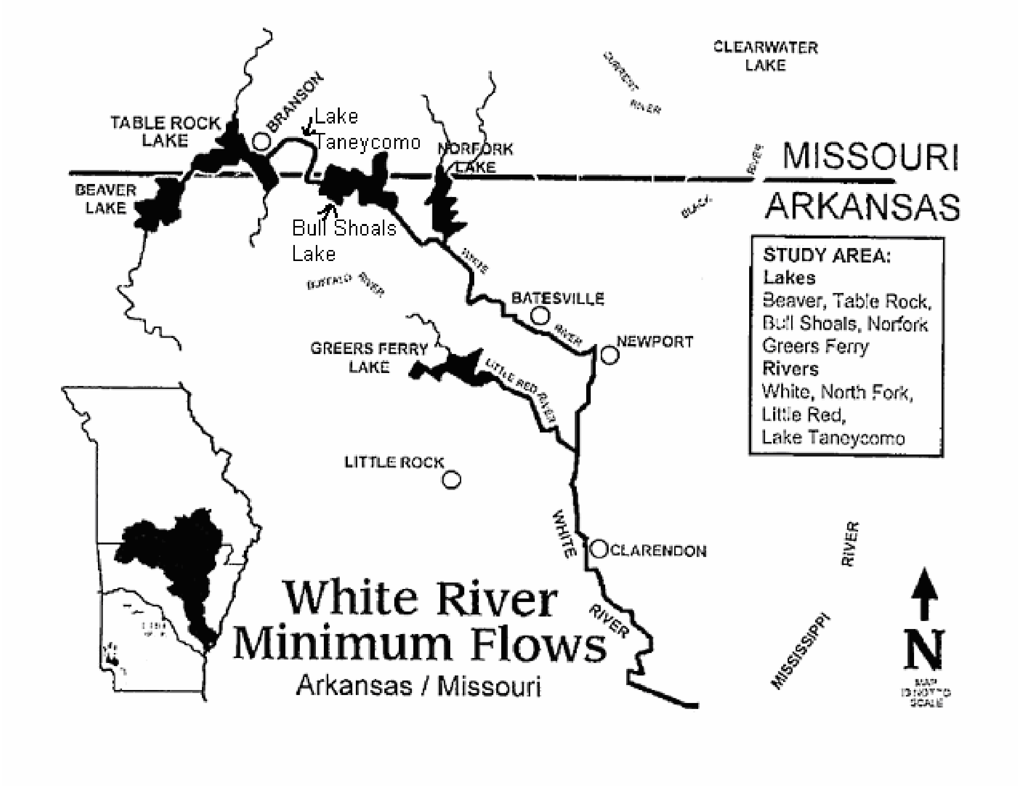
- Empire will lose five feet of net head with which to generate electricity at its Ozark Beach hydroelectric dam as a result of the Reallocation of storage in the White River by the U.S. Army Corps of Engineers (Corps).
- The Administrator of the Southwestern Power Administration (SWPA), in consultation with Empire and the relevant state public utility commissions, is required under the FY 2006 Energy & Water Development Appropriation Act (Public Law 109-103) to determine the impact on electric energy and capacity at Ozark Beach from the Reallocation based on the "present value of the estimated future lifetime replacement costs of the electrical energy and capacity" at the time of implementation of the Reallocation. Subsequent to that determination, the Corps of Engineers is required to fully compensate Empire.
- Empire will lose 3 MW of capacity each year as a result of the Reallocation. In addition, generation of 12,436 MWh will need to be replaced annually as a result of the lost hydroelectric generation.
- Empire estimates its total costs to be reimbursed if the Reallocation is implemented in 2011 to be $31.3 million as of January 1, 2011 $.

Background

The Water Resource Development Acts (WRDA) of 1999 (Section 374) and 2000 (Section 304) required the U.S. Army Corps of Engineers (Corps) to examine the possible modification of operations at the five lakes on the White River in Missouri and Arkansas. Historically, these five lakes (Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry – see Figure 1) were operated primarily for flood control and hydroelectric power generation, and to a lesser extent water supply. If water were to be reallocated to allow for minimum flow requirements such as would be needed to enhance trout fisheries, this would require a "Reallocation" of the existing storage as all storage in the lakes is already allocated.

Hence the Corps undertook a 2004 "White River Minimum Flows Reallocation Study" to determine the effects of the reallocation of storage. The primary effect on the only non-federal hydroelectric power plant impacted by the Reallocation, The Empire District Electric Company's (Empire) Ozark Beach plant, will be that it will raise its tail water below the dam by five feet. With this Reallocation, Ozark Beach will lose five feet of head with which to generate electricity. The water gained in the Bull Shoals Lake by the raising of the power pool elevation from 654 to 659 mean sea level (MSL) would now be used to provide minimum water flows deemed necessary to sustain a tail water trout fishery below the Bull Shoals Lake (the lake into which the water from Empire's Ozark Beach hydroelectric facility discharges).

Figure 1



The FY 2006 Energy and Water Development Appropriation Act (Public Law 109-103) implements two scenarios from the 2004 Reallocation Study: NF-7 (a scenario related to Norfork Lake and not affecting Empire) and BS-3 (the scenario increasing the power pool elevation in Bull Shoals Lake by five feet to allow water to support minimum flow). No reallocation scenarios are to be implemented for Beaver Lake, Table Rock Lake, or Greers Ferry Lake. In addition, the Act requires the Administrator of the Southwestern Power Administration (SWPA), in consultation with Empire and the relevant state public utility commissions, to determine the impact on electric energy and capacity at Ozark Beach from the Reallocation based on the "present value of the estimated future lifetime replacement costs of the electrical energy and capacity" at the time of implementation of the Reallocation. Subsequent to that determination, the Corps of Engineers is required to fully compensate Empire (See Appendix A).

In Bull Shoals Lake, two different elevations were established when the dam was built: flood-control pool and power pool (conservation pool). The flood-control pool is defined as that portion of the total storage space in the reservoir to be occupied only by water from flood events. The flood-control pool at Bull Shoals Lake is between 695 and 654 MSL with the ability to store about 2.36 million acre feet of water. The power-pool is defined as that portion of the total storage space in the reservoir lying below the flood control storage for the purpose of supplying water for power generation. At Bull Shoals Lake, the power pool is between 654 and 628.5 MSL with the ability to store about 1 million acre feet of water.

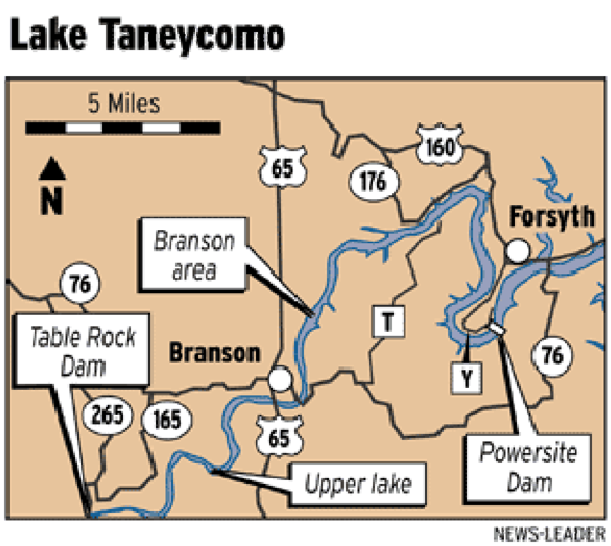
Bull Shoals Dam was completed in July of 1951 and is located approximately 7 miles north of Cotter, Arkansas at White River Mile 418.6. It has a maximum height above the river bed of 256 feet, is 2,256 feet in length, has 17 spillway crest gates, and is the fifth largest concrete dam in the United States. Bull Shoals Lake has a surface area of approximately 45,440 surface acres, 740 miles of shoreline, and a lake elevation of 654 MSL at the top of the conservation pool and 71,240 surface acres, 1,050 miles of shoreline, and a lake elevation of 695 MSL feet at the top of the flood-control pool. On the average, the lake will be at or below the figures used for the conservation pool because that is what is used as the guide level for the generation of hydroelectric power. Both the dam and lake are controlled by the Corps.[1]

The Corps has previously calculated and provided to Empire its estimates for the costs that Empire will incur due to the Reallocation. Empire is in agreement with some of the Corps' basic assumptions and disputes others. This report documents the methodology used and the results obtained by Empire in determining the appropriate value to reimburse Empire for the future lifetime replacement costs of the electrical energy and capacity associated with the impacts of the Reallocation at Ozark Beach.

Empire's Ozark Beach Facility

Empire, an investor-owned utility headquartered in Joplin, Missouri, operates what it calls the Ozark Beach hydroelectric facility (in Missouri) which forms Lake Taneycomo, located on the White River downstream of Table Rock Lake (in Missouri) and upstream of Bull Shoals Lake (in Arkansas) (see Figures 1 and 2).

Figure 2



[1] General information can be obtained through the Resident Engineer, Mountain Home Resident Office, U.S. Army Corps of Engineers, Mountain Home, Arkansas 72653. The telephone number is 501-425-2700.

Figure 3
Ozark Beach Dam

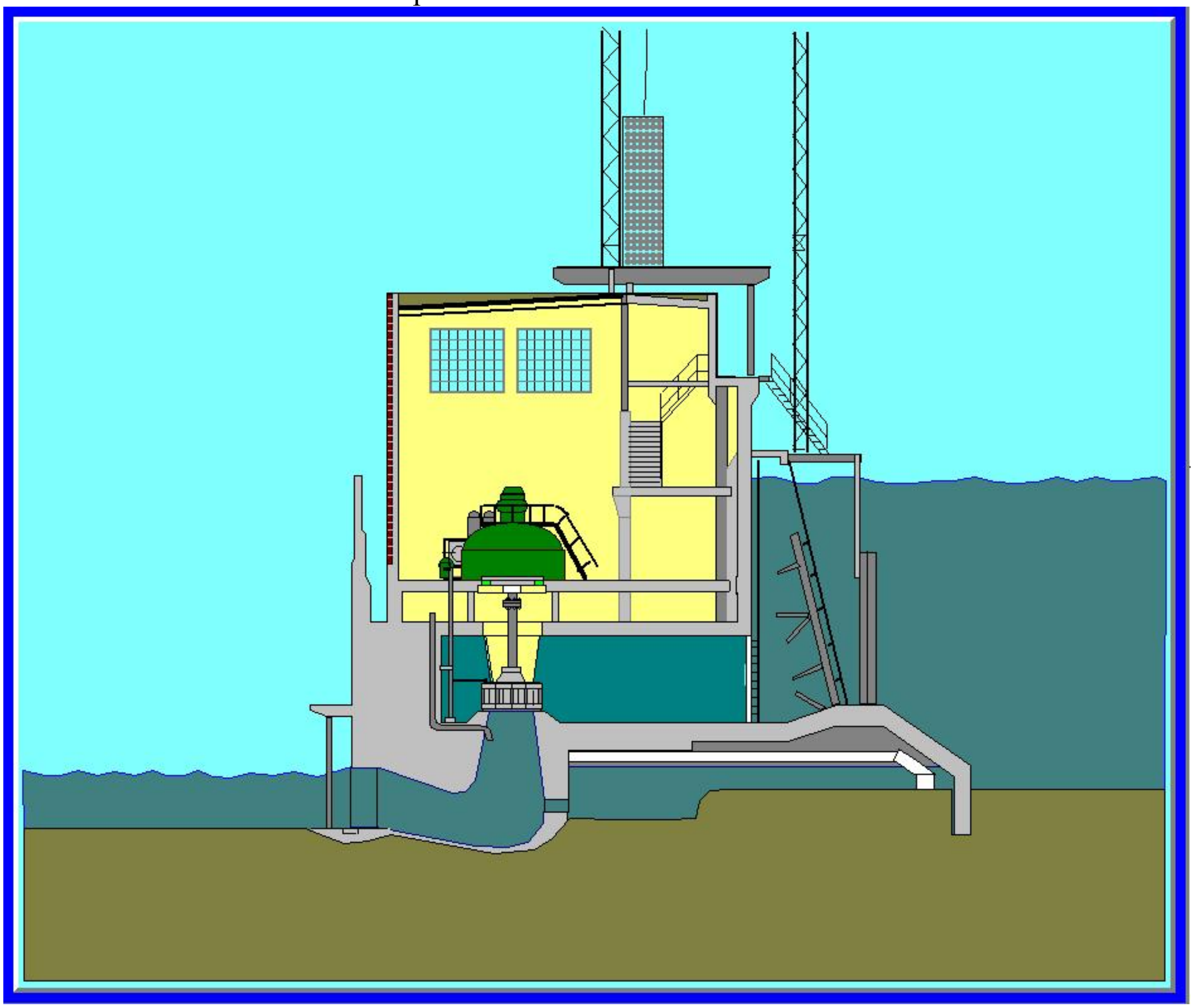
Table Rock Lake and Bull Shoals Lake are operated by the Corps' Little Rock District. With the installation of upgraded water wheels during 2002-2005, Ozark Beach has the capacity of 20 MW at full head. It is designated as license number 2221 by the Federal Energy Regulatory Commission.

Key Hydraulic Parameters

Understanding of net head, and thus the impact of a change in five feet of the power pool elevation for the Bull Shoals Lake, is important in understanding the rationale and methodology used by Empire for calculating the amount of funds it is to be reimbursed for lost energy and capacity from Ozark Beach.

The height of the water in Lake Taneycomo (to the right of the powerhouse as shown in Figures 3 and 4) is normally between 699 to 703 MSL. The water in Bull Shoals Lake (as shown to the left in Figures 3 and 4) ranges, while in power pool, from 648 to 654 MSL. The difference in water elevation from above the dam to below the dam is referred to as net head. Currently, net head varies with the elevations in both Lake Taneycomo and Bull Shoals, ranging from less than 20 to 53 feet.

Figure 4
Operation of Ozark Beach



Explanation of Capacity and Energy Losses

Lost Capacity: The Ozark Beach facility is currently capable of generating 20 MW at maximum head. After the Reallocation is implemented, Empire will lose capacity of 3 MW. This amount of capacity is calculated by considering both the changes in net head anticipated from the Reallocation and the demonstrated performance of the upgraded water wheels. Because this capacity will be lost year round, Empire will need to replace this capacity with either a firm purchase in the market or with a new generating resource.

Lost Energy: Currently, due to friction losses, Ozark Beach can only generate when the net head is at least 20 feet. The figure for net head is determined by comparing the water elevation in Lake Taneycomo and the water elevation at Bull Shoals. Per the equation in Appendix B, power generation increases with net head. After the Reallocation is implemented, the minimum net head requirement will not change. Ozark Beach will still be able to generate only when the net head is at least 20 feet, and now the floor will effectively be five feet higher than before. Assuming that the elevation of Lake Taneycomo remains at historic levels, the net head will now be 5 feet less than before the change, therefore the net head at the top of the new power pool elevation would be 41 - 44 feet.

Calculation for Lost Energy

To determine the amount of energy that would be lost to Empire at Ozark Beach, twenty-nine years of historical generation data at the plant (November 1977 to October 2006) were analyzed. From these 29 years of actual data, the following monthly averages were computed:

- Lake Taneycomo elevation
- Bull Shoals elevation
- Capacity Factor (the percent of the time Ozark Beach was generating)

The resulting values are shown in Appendix C and below in Table 1 and total 12,436 MWh lost energy for an average year.

Table 1
Energy Lost from Ozark Beach Due to White River Reallocation

Month	Energy Lost (MWh)
January	775
February	1,073
March	1,049
April	1,436
May	1,243
June	1,311
July	1,463
August	1,085
September	724
October	608
November	671
December	999
Total	12,436

This compares to the monthly values totaling 6,150 MWh as calculated by the Corps and shown in Appendix D. The differences between Empire's calculations and the Corps' calculations are due to a misinterpretation about the net head and the conditions under which Empire can generate at Ozark Beach and the change in operation resulting from the upgrading of the water wheels.

Financial Parameter Assumptions

The rate of inflation and the discount rate are both required to determine the expected lifetime costs of the lost capacity and energy. Empire is assuming a 2.5% rate of inflation for the 50-year lifetime used for the calculation.[2] A discount rate of 4.8% is used reflecting the current rate on Treasury 30-year notes, the closest equivalent to Empire's cost of cash for the period of time being analyzed. The Corps did not use any inflation figures in its calculations and used a 5.125% discount rate.

Calculation of Capacity Cost

Empire will need to replace 3 MW, the lost capacity from Ozark Beach. Between 2008 and the end of the fifty-year period being examined, Empire will need to add new generating capacity on a regular basis. Current projections show Empire's peak demand growing from the 1,173 MW in 2007 to 1,881 MW in 2026. Empire is required by the Southwest Power Pool to carry a capacity margin of 12%, which equates to a reserve margin of 13.7%. Empire's current resources total 1,270 MW. By 2026 (the current end of Empire's resource planning period), Empire will have added over 900 MW of generating capacity including conventional resources (coal and natural gas) and renewable resources (wind).

The capacity to replace the 3 MW lost from Ozark Beach will either need to be purchased on the market or built. Assuming the capacity and energy would be such as would come from a replacement unit in the form of a combined cycle unit, the capacity cost is $594/kW in 2005 $, which is inflated to 2011 $ at the rate of inflation.[3] The other parameters needed to calculate the replacement capacity cost are a levelized fixed charge rate of 11.75%, associated with the 35-year design life of the combined cycle unit, and a lifetime of 50 years (although capital costs are levelized and calculated only for the 35-year expected design life of the combined cycle unit).[4] The net present value of the replacement costs for the capacity is $4.2 million as of January 1, 2011 if the Reallocation is implemented in 2011.

The Corps did not calculate the value of lost capacity costs.

Calculation of Energy Cost

At the time of the initial analysis, the Corps and Empire agreed that the use of the Platts Power Outlook Service projections of market prices for the High Fuel Value case were an appropriate set of values to use to determine the lost energy costs. In addition, Empire will insist that those values be used with the rate of inflation included for the entire 50-

[2] From the EIA *Annual Energy Outlook* 2007. This is the highest rate of inflation among the three cases examined.
[3] EIA *Annual Energy Outlook* 2007. Cost estimate for Advanced Gas/Oil Combined Cycle, not the Advanced Combined Cycle with Carbon Sequestration.
[4] Empire's spreadsheet for calculation of levelized fixed charge rate provided to the Southwestern Power Administration.

year lifetime over which such costs are being valued. As a result of the decision of the U.S. Supreme Court on April 2, 2007, allowing the Environmental Protection Agency to classify carbon dioxide as a greenhouse gas, Empire now believes that a cap and trade system or a carbon dioxide tax will be enacted by the U.S. Congress. Additional costs must be included in the Ozark Beach lost energy calculation to reimburse Empire for the loss of this renewable energy.

In addition to the price of energy, another important parameter in the calculation process is the split between how much energy is generated on-peak (and therefore should be priced at the on-peak values) and how much energy is generated off-peak (with the corresponding lower off-peak values Empire is using the split used by The Corps of 67% on-peak/33% off-peak.

To account for the expected carbon dioxide regime, Empire assumed a five percent premium would be added to all market prices from 2011 through the end of the study. In addition, all replacement energy for the MWh lost from Ozark Beach (which is a renewable resource and does not generate any carbon dioxide) is assumed to be replaced by capacity that produces carbon dioxide. On-peak (67% of the time), this energy is produced by natural gas generation from a combined cycle unit. Off-peak, this energy is produced by coal-fired generation. The carbon dioxide emissions are assumed to be taxed at a rate of $20/ton throughout the study period.

Empire estimates that its lost energy costs as of January 1, 2011 for implementation of the Reallocation in 2011 are $27.2 million over the 50-year lifetime. The Corps had previously calculated this value as totaling $7.3 million.

Other Costs to Empire

In addition to the energy and capacity costs associated with the Reallocation, Empire will experience increased costs of plant operation. These costs are due to high tail water and the capital expenditures necessary to mitigate roadway and access issues. The cost to mitigate roadway and access issues is $200,000 initially with a net present value of $200,000. Empire and SWPA have discussed that these costs will be borne by the Arkansas Game and Fish Commission and should not be incorporated into these calculations.

Total Costs

The total cost to Empire includes the lost capacity costs, the lost energy costs, and the increased operational costs at the dam. The present value for each of these categories is provided in Table 2. The total costs as of January 1, 2011 for 2011 implementation to Empire associated with the Reallocation of White River Minimum Flows is $31.3 million.

Table 2
Total Costs to Empire of White River Reallocation – 2011 Implementation

Category	Net Present Value to January 1, 2011
Capacity	$4,100,000
Energy	$27,200,000
Operating	$0
TOTAL	$31,300,000

Sensitivity Analysis

Empire and SWPA agreed that analysis would be conducted to ascertain the change in the magnitude of the expected total costs as the assumptions changed. The projections for total costs that result from changes in input assumptions including the rate of inflation, the amount of energy lost at Ozark Beach, the level of the carbon tax, the risk premium associated with future market prices, and other parameters are shown in Table 3.

Table 3
Results of Sensitivity Analysis

Description of Case/Parameter Change	Total Cost of Reallocation to Empire
Base Case	$31,300,000
Inflation Reduced to 1.5%	$29,500,000
Inflation Reduced to 2%	$30,300,000
Inflation Increased to 3%	$32,300,000
Risk Premium Reduced to 0%	$30,100,000
Risk Premium Increased to 10%	$32,400,000
Lost Energy totals 10,000 MWh per year	$25,900,000
Lost Energy totals 11,000 MWh per year	$28,100,000
Lost Energy totals 13,000 MWh per year	$32,500,000
Carbon Tax $10/ton	$29,400,000
Carbon Tax $30/ton	$33,100,000
Combined Cycle Capacity Cost, $1000/kW – 2005 $	$33,100,000

Discussions with the Southwestern Power Administration

At meetings in June and August of 2007, SWPA and Empire personnel discussed drafts of this report and SWPA's needs in determining the magnitude of costs to be paid to Empire. SWPA indicated that it needed to have a mathematical model developed by November 2007 that would be able at the time of the Reallocation implementation (expected to be federal Fiscal Year 2009 or later) to determine the level of reimbursement costs. Empire personnel agreed to make its model available and to document each parameter assumption such that SWPA could adopt the Empire model. Descriptions of data assumptions and sources are found in Appendix E.

Conclusions

Empire expects to receive the full value for the costs it will experience for the Reallocation of Minimum Flows on the White River. The total costs for that reimbursement over the 50-year lifetime of the facility are $31.3 million as of January 1, 2011 if implementation is in 2011.

SEC. 132. WHITE RIVER BASIN, ARKANSAS.—(a) MINIMUM FLOWS.—
(1) IN GENERAL.—The Secretary is authorized and directed to implement alternatives BS–3 and NF–7, as described in the White River Minimum Flows Reallocation Study Report, Arkansas and Missouri, dated July 2004.
(2) COST SHARING AND ALLOCATION.—Reallocation of storage and planning, design and construction of White River Minimum Flows project facilities shall be considered fish and wildlife enhancement that provides national benefits and shall be a Federal expense in accordance with section 906(e) of the Water Resources Development Act of 1986 (33 U.S.C. 2283(e)). The non-Federal interests shall provide relocations or modifications to public and private lakeside facilities at Bull Shoals Lake and Norfork Lake to allow reasonable continued use of the facilities with the storage reallocation as determined by the Secretary in consultation with the non-Federal interests. Operations and maintenance costs of the White River Minimum Flows project facilities shall be 100 percent Federal. All Federal costs for the White River Minimum Flows project shall be considered non-reimbursable.
(3) IMPACTS ON NON-FEDERAL PROJECT.—The Administrator of Southwestern Power Administration, in consultation with the project licensee and the relevant state public utility commissions, shall determine any impacts on electric energy and capacity generated at Federal Energy Regulatory Commission Project No. 2221 caused by the storage reallocation at Bull Shoals Lake, based on data and recommendations provided by the relevant state public utility commissions. The licensee of Project No. 2221 shall be fully compensated by the Corps of Engineers for those impacts on the basis of the present value of the estimated future lifetime replacement costs of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project. Such costs shall be included in the costs of implementing

the White River Minimum Flows project and allocated in accordance with subsection (a)(2) above.

(4) OFFSET.—In carrying out this subsection, losses to the Federal hydropower purpose of the Bull Shoals and Norfork Projects shall be offset by a reduction in the costs allocated to the Federal hydropower purpose. Such reduction shall be determined by the Administrator of the Southwestern Power Administration on the basis of the present value of the estimated future lifetime replacement cost of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project.

(b) FISH HATCHERY.—In constructing, operating, and maintaining the fish hatchery at Beaver Lake, Arkansas, authorized by section 105 of the Water Resources Development Act of 1976 (90 Stat. 2921), losses to the Federal hydropower purpose of the Beaver Lake Project shall be offset by a reduction in the costs allocated to the Federal hydropower purpose. Such reduction shall be determined by the Administrator of the Southwestern Power Administration based on the present value of the estimated future lifetime replacement cost of the electrical energy and capacity at the time operation of the hatchery begins.

(c) REPEAL.—Section 374 of the Water Resources Development Act of 1999 (113 Stat. 321) and section 304 of the Water Resources Development Act of 2000 (Public Law 106–541) are repealed.

Appendix B

Formula for Calculation of Hydropower as a Function of Head

The amount of power that can be generated in a hydroelectric facility is proportional to the amount of head as can be seen from equation (1).

$$P = \eta * \rho * g * h * V \qquad (1)$$

where:
P = power (J/s or watts)
η = turbine efficiency
ρ = density of water (kg/m^3)
g = acceleration of gravity ($9.81\ m/s^2$)
h = head (m, this is the difference in height between the inlet and outlet water surfaces)
V = flow rate (m^3/s)

Appendix C

Ozark Beach Energy Lost Due to Reallocation
Table 1

			Current Allocation			Reallocation			
Month	**Lake Taneycomo Elevation**	**Capacity Factor (%)**	**Bull Shoals Elevation**	**Net Head (ft)**	**Expected Generation (MWh) New Wheels**	**Bull Shoals Elevation**	**Net Head (ft)**	**Expected Generation (MWh) New Wheels**	**Generation Loss (MWh)**
January	701.18	49.11	653.63	47.55	6,906	658.63	42.55	6,131	775
February	701.54	59.16	653.30	48.24	7,872	658.30	43.24	6,798	1,073
March	701.77	66.51	654.42	47.35	9,352	659.42	42.35	8,303	1,049
April	701.91	67.31	657.35	44.56	8,510	662.35	39.56	7,076	1,435
May	701.50	55.67	661.15	40.35	6,296	666.15	35.35	5,053	1,243
June	701.18	45.52	661.52	39.66	4,785	666.52	34.66	3,474	1,311
July	701.05	52.03	658.63	42.42	6.496	663.63	37.42	5,033	1,463
August	700.83	54.00	655.08	45.74	7,192	660.08	40.74	6,107	1,085
September	700.56	37.23	651.76	48.80	5,308	656.76	43.80	4,584	724
October	700.41	30.96	650.54	49.87	4,653	655.54	44.87	4,045	608
November	700.76	40.52	650.73	50.04	5,893	655.73	45.04	5,222	671
December	701.33	49.74	653.25	48.07	7,327	658.25	43.07	6,328	999
						Average Annual Generation Loss =			**12,436**

Appendix D

Ozark Beach Energy Lost Due to Reallocation (as calculated by the U.S. Army Corps of Engineers in 2005)

Month	Energy (MWh)
January	540
February	604
March	743
April	557
May	360
June	379
July	741
August	737
September	393
October	290
November	317
December	489
Total Year	**6,150**

Appendix E

Data Requirements and Sources

The loss calculation spreadsheet has been provided to SWPA by Empire. A new spreadsheet reflecting the new assumptions since the August 2007 meeting has been provided to SWPA.

1. Market prices for power used to calculate the cost of the lost energy are the on-peak and off-peak energy only (not including capacity) prices available from the latest *Outlook for North America* prepared by Platts. Empire and SWPA agreed to use the High Fuel Value cases. At the future point in time that SWPA needs to calculate the reimbursement costs, Empire will provide the values from Platts to SWPA. These values are available for 20 forecasted years only. The rate of inflation to be used for the remaining years of the analysis (the analysis is for 50 years from the date of implementation) will be the highest of the three rates of inflation currently being used by the EIA in its *Annual Energy Outlook* for CPI between the reference case, low growth, and high growth cases.

2. Discount rate: Current rate on 30-year U.S. Treasury notes is available on http://www.treasurydirect.gov/RT/RTGateway?page=institHome.

3. The capital cost for combined cycle unit in $/kW is to be obtained from the latest *Annual Energy Outlook* prepared by the EIA. The inflation rate to be used to get the capital cost as of the date of implementation will be the same rate of inflation as used above from the EIA *Annual Energy Outlook*. Empire will provide the appropriate adders to SWPA to account for the Allowance of Funds Used During Construction and other adders that are necessary to properly determine the construction cost as of the date of commercial operation.

4. Levelized fixed charge rate for 35-year design life: This value can be calculated using the spreadsheet provided to SWPA by Empire and updated periodically using inputs that Empire will provide to SWPA.

5. Carbon dioxide tax - $/ton. Dependent on future rulings.

6. Risk premium associated with market prices due to implementation of the carbon tax. Still to be resolved.

Appendix J – Public Comments

Public Comments Received On

Draft Determination
White River Minimum Flows Study
Determination of Offset to the Federal Hydropower
Purpose and Impacts on Non-Federal Project

Dated January 2008

February 29, 2008

Mr. George Robbins
Director, Division of Resources and Rates
Southwestern Power Administration
One West Third
Tulsa, OK 74103

Dear Mr. Robbins:

The Empire District Electric Company (Empire) appreciates the opportunity to provide its comments as the licensee at the Federal Energy Regulatory Commission Project No., 2221 (Ozark Beach) on the information filed by the Southwestern Power Administration (SWPA) in the Federal Register on February 5, 2008 (pages 6717-6719) with regard to the White River Reallocation and the documents supporting that information. Thank you for providing us with all of the backup documentation.

Our comments are divided into the following topic areas:

1. Energy lost at Ozark Beach
2. Split of on-peak and off-peak energy
3. Capacity lost at Ozark Beach
4. Price assigned to lost capacity
5. Price assigned to on-peak energy loss
6. Price assigned to off-peak energy loss
7. Loss of renewable energy from Ozark Beach
8. Accounting for carbon tax risk
9. Operating costs for replacement capacity
10. Total costs to Empire
11. Housekeeping details

1. Energy Lost at Ozark Beach

As the Southwestern Power Administration is aware from our series of meetings in 2007 and the analysis that Empire conducted, including the sensitivity analysis, the energy lost at Ozark Beach due to the White River Reallocation is the value that is the most disputed and has the most significant impact on the final dollar value calculated for the total reimbursement to Empire. The initial estimate of lost energy from the Corps of Engineers was 6,150 MWh. Empire's August 2007 report reflects a value for lost energy of 12,436 MWh. The January 2008 Draft Report by SWPA estimates the energy lost as 5,792 MWh on-peak and 2,853 MWh off-peak for a total of 8,645 MWh.

Empire has serious concerns about the results reflected in the SWPA analysis which are derived in large part by the SUPER program. We specifically question the applicability of the SUPER program to accurately model relatively small changes in actual conditions at Ozark Beach as opposed to overall macro level changes in an entire river basin. The largest concern relates to the average tailwater elevation differences in the before and after modeling for the White River Reallocation. The results from the SUPER program are only reflecting a 3.3 foot difference in tailwater elevation (Appendix A), when in fact the Reallocation requires a 5 foot difference as reflected in Figure 2 of your report. While a difference of 1.7 foot may be minor in analysis of an entire river basin, it represents a 34% understatement in the results for Ozark Beach. If this discrepancy alone were modified, increasing the lost energy by the ratio of 5 to 3.3 would result in a value for lost energy higher than Empire's figure of 12,436 MWh. Empire strongly believes that this issue needs to be revisited and that the lost energy value that is appropriate is a minimum of 12,436 MWh.

Additionally, Empire does not believe the Super program is accurately capturing the efficiency and energy gains due to the addition of new water wheels at Ozark Beach. If you compare the Super program base run (which includes the figures for the new turbines) against the same period of the historic computation or Empire's actual energy generation for that time, the Super program only predicts a 3.5% increase in power generation (Appendix B). In fact, it should show a 16% increase to properly reflect the difference between the old and new turbine wheels installed at Ozark Beach.

Another concern is the basis of using 1940-2003 water data in the model including the 18 years prior to the installation of the Table Rock dam. Empire does not understand how the modeling can be accurate for those early years and properly reflect the operation of Ozark Beach. This calls the entire methodology into question.

Finally, Empire is not able to determine if the Super program is properly modeling overall water flow through Ozark Beach. The water flow through Ozark Beach is not equal to Table Rock output, but rather about 8% higher due to flows coming into Lake Taneycomo.

We are very cognizant that the Empire ratepayers are the ones who shoulder the risk of analysis that does not properly account for the loss of energy and capacity at Ozark Beach. We are striving to protect their interests.

2. Split of on-peak and off-peak energy

As far back as the analysis conducted by the Corps of Engineers, a 67% on-peak and 33% off-peak split has been used. This split is acceptable to Empire.

3. Capacity lost at Ozark Beach

Empire agrees with SWPA that the capacity lost at Ozark Beach is 3 MW.

4. Price assigned to Lost Capacity

SWPA has proposed using the cost of a combined cycle facility to calculate the cost of the lost capacity. Empire agrees that a combined cycle facility is the appropriate choice for replacement capacity and that capacity costs should be reflected over the entire 50 years. Empire's 2007 analysis did not capture the capacity cost for the entire 50 years. Revised calculations show our estimate of capacity costs using a 2007 value for combined cycle capacity costs of $1093/kW (which would be equivalent to the 128.46/kW-year used by SWPA) is now $9.2 million.

The appropriate costs to use for a combined cycle unit at the time of implementation of the Reallocation should be from a source that contains current cost information, such as the Platts Power Outlook which Empire recommends for using for the on-peak and off-peak energy prices. Such a source captures the significant increases in capital costs currently being experienced in the market. Empire does not have access nor is it able to verify numbers put together by the Corps' Hydropower Analysis Center which appears to be based on old and out-dated numbers that don't reflect current market conditions for, among other components, steel, concrete, and labor.

5. Price assigned to on-peak energy loss

SWPA has proposed using the price of power generated from combined cycle facilities in Missouri for the on-peak energy price. Empire had previously proposed using a price that was more reflective of the entire market in which Empire operates and to obtain those values from an industry source. Empire still believes that using data from an industry source (Platts) would be appropriate in this calculation process and urges SWPA to reconsider its approach.

6. Price assigned to off-peak energy loss

SWPA has proposed using the price of power generated from coal-fired steam in Missouri for the off-peak energy price. Empire had previously proposed using a price that was more reflective of the entire market, as off-peak energy is often supplied by natural gas and not only coal-fired generation. Empire would ask that SWPA reconsider its methodology and use the Platts forecast for both on-peak and off-peak market energy – to properly reflect the split in the types of generation at the margin during both on-peak and off-peak hours year round.

7. Loss of renewable energy from Ozark Beach

The State of Missouri has implemented voluntary requirements for utilities within the state to meet a Renewable Portfolio Standard. There are currently petitions circulating that would make renewable energy requirements mandatory.

The loss of capacity and energy from Ozark Beach reduces Empire's ability to comply with this renewable energy requirement. Empire believes that it needs to be fairly compensated for the loss of the renewable energy that will no longer be generated by Ozark Beach. One method to do so would be to reinstate the risk premium methodology that was incorporated in Empire's spreadsheets as provided to SWPA in 2007 and agreeing on the level of the associated risk premium. This issue could only become more important if Missouri were to make the voluntary requirement mandatory or if a national Renewable Portfolio Standard were enacted. Our current analysis assumes a 5% renewable risk premium. This risk premium is to keep the Empire ratepayers from shouldering all of the long-term risk associated with the loss of energy and capacity from Ozark Beach.

8. Accounting for carbon risk

The costs associated with the implementation of a carbon tax will be completely borne by Empire's ratepayers if such a tax is enacted after the White River Reallocation moves forward. SWPA's appears to support inclusion of carbon costs in the damage calculation if a law is enacted prior to the White River Reallocation implementation. Unfortunately, a carbon tax could be enacted after the damage payment is made, and Empire's ratepayers would incur additional costs for the extra carbon tax that they will incur due to the loss of energy from the Ozark Beach facility.

We believe it appropriate to include damages for carbon costs, and we request that SWPA consider including a payment for carbon costs. Our analysis has incorporated a $20/ton carbon tax implemented in 2012. Again, this assumption is to keep the Empire ratepayers from shouldering all of the long-term risk associated with the loss of energy and capacity from Ozark Beach.

9. Operating costs for replacement capacity

As SWPA is aware, the level of reimbursement due to Empire is to be determined in agreement with the regulatory commissions that oversee its rates. The Missouri Public Service Commission notes that fixed operating and maintenance (O&M) costs for the replacement capacity were not incorporated in the 2007 analysis. Empire has added fixed O&M costs to the analysis and determined that this cost amounts to almost another $1 million over the 50 years being examined.

10. Total Costs to Empire

With the assumptions described above and summarized below, the total amount due to Empire as a result of the White River Reallocation is $42,347,977:

- Energy lost: 12,436 MWh
- Capacity lost: 3 MW
- On-peak/off-peak energy split: 67%/33%
- Capacity price, combined cycle unit, $1093/kW in 2007 $; replacement combined cycle unit installed in 2046 at inflated capital cost
- Energy price, first quarter 2008 Platts
- Carbon tax, $20/ton
- Renewable energy risk, 5% risk premium on both off-peak and on-peak energy prices
- Fixed O&M cost of $11.18/kW in 2007$

Total Costs to Empire of White River Reallocation – 2011 Implementation

Category	Net Present Value to January 1, 2011
Capacity	$9,200,894
Energy (updated with new Platts #)	$27,334,198
Carbon Tax Risk	$3,637,241
Renewable Energy Risk	1,366,710
Fixed O&M	808,934
TOTAL	$42,347,977

Empire expects that the total level of costs for which its ratepayers are to be reimbursed will be recalculated with current pricing values for all parameters at the time the determination is made to move forward with the White River Reallocation and ask for funding from the U.S. Congress. These values are only placeholders demonstrating how the methodology would work.

11. Housekeeping details

Please change the references in your report from "Powersite Dam" to "Ozark Beach" as that is the official name of the facility. These occur at least on pages 4, 13-16, 24, C-1, and D-1 of the January 2008 Draft Report.

Empire acknowledges that SWPA has spent much time and effort on this project, including several meetings with Empire personnel. We appreciate this effort.

In addition, thank you for your consideration of our comments.

Sincerely,

Tom Snyder

Tom Snyder

Appendix A

Table Rock - Ozark Beach (New Wheels)
SUPER output - W08X02 (minimum flow run)

						lookup	lookup	+1	lookup
Date	**Table Rock Total Discharge, cfs**	**Bull Shoals 12-M Pool Elev., Ft.**	**Gross Head, feet**	**Adjusted BS Pool Elev., Ft.**	**Adjusted Gross Head, feet**	**look-up capacity in table**	**nearest head**	**head+1'**	**head+1' capacity (table)**
12/08/03	1,518	651.89	49.11	652.23	48.77	19.800	48	49	20.200
12/09/03	1,518	652.00	49.00	652.35	48.65	19.800	48	49	20.200
12/10/03	1,518	652.10	48.90	652.45	48.55	19.800	48	49	20.200
12/11/03	1,517	652.17	48.83	652.52	48.48	19.800	48	49	20.200
12/12/03	1,516	652.16	48.84	652.51	48.49	19.800	48	49	20.200
12/13/03	120	652.27	48.73	652.62	48.38	19.800	48	49	20.200
12/14/03	120	652.30	48.70	652.65	48.35	19.800	48	49	20.200
12/15/03	1,514	652.27	48.73	652.62	48.38	19.800	48	49	20.200
12/16/03	1,514	652.28	48.72	652.63	48.37	19.800	48	49	20.200
12/17/03	1,514	652.29	48.71	652.64	48.36	19.800	48	49	20.200
12/18/03	1,513	652.22	48.78	652.57	48.43	19.800	48	49	20.200
12/19/03	1,513	652.20	48.80	652.55	48.45	19.800	48	49	20.200
12/20/03	120	652.24	48.76	652.59	48.41	19.800	48	49	20.200
12/21/03	120	652.24	48.76	652.59	48.41	19.800	48	49	20.200
12/22/03	1,512	652.29	48.71	652.64	48.36	19.800	48	49	20.200
12/23/03	1,512	652.41	48.59	652.76	48.24	19.800	48	49	20.200
12/24/03	1,511	652.44	48.56	652.79	48.21	19.800	48	49	20.200
12/25/03	1,511	652.38	48.62	652.73	48.27	19.800	48	49	20.200
12/26/03	1,511	652.36	48.64	652.71	48.29	19.800	48	49	20.200
12/27/03	120	652.38	48.62	652.73	48.27	19.800	48	49	20.200
12/28/03	120	652.50	48.50	652.85	48.15	19.800	48	49	20.200
12/29/03	1,510	652.48	48.52	652.83	48.17	19.800	48	49	20.200
12/30/03	1,510	652.42	48.58	652.77	48.23	19.800	48	49	20.200
12/31/03	1,510	652.39	48.61	652.74	48.26	19.800	48	49	20.200

660.74	AVG MinFlow Adjusted BS Pool Elev., Ft
657.46	AVG Base Adjusted BS Pool Elev., Ft
3.28	Difference between MinFlow run to Base run

Appendix B

	WRMF_Empire_Super.xls SUPER output - W08x01 (Base tab) / OB Daily Energy MWH, column M (new wheels)	OBHistorical.xls / OB Daily Energy MWH column M (old wheels)
10/03/02	66.9	138.2
10/04/02	67.8	80.0
10/05/02	15.7	11.3
10/06/02	15.9	10.7
10/07/02	70.6	46.0
10/08/02	71.3	18.5
10/09/02	72.1	85.8
10/10/02	73.0	83.4
10/11/02	73.8	25.1
10/12/02	17.0	18.3
10/13/02	17.2	34.9
10/14/02	76.1	93.4
10/15/02	76.6	128.2
10/16/02	76.7	248.4
10/17/02	76.7	137.3
10/18/02	76.7	114.4
10/19/02	17.5	54.4
10/20/02	17.5	30.3
10/21/02	76.8	154.4
10/22/02	76.8	284.2
10/23/02	76.8	236.7
10/24/02	76.9	184.2
10/25/02	76.9	142.5
10/26/02	17.6	11.6
10/27/02	17.6	12.1
10/28/02	76.9	204.9
	1,811,158	1,749,868

1,811,158 / 1,749,868
103.50%

Super with new wheels only show 3.5% more MWH when compared to Historical MWH with old wheels

Commissioners

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Secretary/Chief Regulatory Law Judge

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General Counsel

March 5, 2008

Mr. George Robbins
Director, Division of Resources and Rates
Southwestern Power Administration
One West Third
Tulsa, Oklahoma 74103

RE: **White River Minimum Flows – Determination of Federal and Non-Federal Hydropower Impacts**

Dear Mr. Robbins:

This letter conveys the comments of the Missouri Public Service Commission ("MoPSC") on the Draft Report of the Southwestern Power Administration ("SWPA") on White River Minimum Flows – Determination of Federal and Non-Federal Hydropower Impacts. SWPA is responsible for determining the appropriate amount of a one-time payment to The Empire District Electric Company ("Empire") as compensation for the value of the capacity loss and energy loss that will be caused by the modification in 2011 of the operating level of the Bull Shoals Lake on the White River by the U.S. Army Corps of Engineers ("Corps"). The lake level modification will result in a loss of five (5) feet of usable head at Empire's Ozark Beach Hydroelectric Plant, reducing the amount of energy the plant can produce. SWPA has estimated the appropriate compensatory payment at $21,363,721, the net present value of the lost capacity. SWPA's Draft Report was summarized in the Federal Register, Vol. 73, No. 24, February 5, 2008, at pages 6717 to 6719; comments are due by March 6, 2008.

The MoPSC Staff ("Staff") reviewed SWPA's Draft Report and a study produced by Empire entitled Determination of Costs for Energy and Capacity Lost from the "Reallocation" of Flood Storage from Bull Shoals Lake. Staff also participated in a conference call with SWPA and Empire discussing Empire's results and has reviewed both Empire's spreadsheet work papers and SWPA's spreadsheet work papers. Staff has also participated in conference calls with Empire and its consultant.

Southwestern Power Administration (SWPA) Study Summary:

SWPA calculated the net present value to Empire of the lost generation at the Ozark Beach facility to be $21,363,721. SWPA used a model furnished by the Corps to determine the annual loss of energy at the Ozark Beach facility from the lake level modification at 8,645 MWhrs. SWPA used an averaged cost of peak ($56.45/MWhr) and off-peak ($13.75/MWhr) power generation in Missouri provided by the Corps to calculate the value of the lost MWhrs. SWPA used a capacity purchase demand cost (128$/kW-yr) obtained from the Corps to calculate the value of the 3 MW of lost capacity. SWPA also used a 2% inflation rate and a 5% discount rate. (See the attached summary.)

The Empire District Electric Company (Empire) Study Summary:

Empire calculated the net present value of the lost generation at the Ozark Beach facility to be $42,347,977. Empire used 30 years of historical monthly data, adjusted to reflect the lake level modification, to determine the annual loss of energy at 12,436 MWhrs. Empire used the high fuel value forecasted peak and off-peak prices from Platt's Power Outlook Services for 20 years and a 2.5% annual increase (i.e., inflation rate) to calculate the value of the lost MWhrs. Empire also included a carbon tax risk of 5% to the cost of energy to account for any possible unknowns which might affect the use of carbon fuels, including renewable programs, over the next 50 years. Empire used a cost of $1093 /kW for a new combined cycle plant, which it states is comparable to SWPA's demand charge of $128/kW-yr, to determine the value of the 3 MW of lost capacity. Empire also included a carbon tax of $20/ ton on the energy replaced with non-hydro generation. Empire used a 4.8% discount rate from the EIA Annual Energy Outlook 2007 report. (See the attached summary.)

Missouri Public Service Commission Staff Review Summary:

The Staff is unable to determine the accuracy of the model used by SWPA. However, Staff believes that the issues raised by Empire regarding the accuracy of the model have merit. In particular, the SWPA model failed to account for the efficiency gain actually seen at the dam with the new turbine wheel replacements and the model was unable to capture the expected five (5) feet of head loss. Thus, Staff considers that there are significant reasons to doubt the accuracy of SWPA's calculations.

In contrast, Empire used 30 years of actual data in the SWPA spreadsheets instead of the model output and manually entered a head loss of 5 feet, which then resulted in an energy loss closer to Empire's estimate.

The SWPA report used energy prices obtained from the Corps. However, Staff does not believe these prices for peak and off-peak power are representative of actual prices. Staff contacted the Corps' Hydropower Analysis Center ("HAC") and discussed its methodology and calculation of energy prices. Based on this conversation, it appears that the energy prices provided by the Corps to SWPA were calculated as market clearing prices and thus do not reflect market conditions that influence actual energy market prices, such as unit forced outages in the system, transmission constraints, weather, and the like. Staff reviewed the historical actual purchased energy prices from previous rate cases and found that average actual prices are higher than the HAC calculated prices.

The SWPA study also does not account for any carbon tax. Staff expects the loss of capacity and energy from the hydro plant will most likely be replaced with carbon-based generation, and with a carbon tax of some type expected to be enacted in the near future, Staff believes that a factor must be added to account for it. While it is true, as the SWPA study pointed out, that the level of the tax is not now known, Staff does not consider "zero" to be an acceptable estimate.

Using the average spot purchase energy price ($61.76/MWhr) from three rate cases, the known value of other energy costs from Empire, and the capacity costs from Empire, Staff calculated the net present value of the generation lost at Empire's Ozark Beach facility due to the lake level modification at $40,246,100. Staff used a 2.5% rate of inflation and a 4.8% discount rate. (See the attached calculation.)

Conclusion:

Based on the foregoing, it is the position of the MoPSC that the compensatory one-time payment to Empire should be at least $40,246,100 rather than $21,363,721 as proposed by SWPA.

Respectfully submitted,

JEFF DAVIS
Chairman
Missouri Public Service Commission

Connie Murray
CONNIE MURRAY
Commissioner
Missouri Public Service Commission

ROBERT M. CLAYTON, III
Commissioner
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LINWARD "LIN" APPLING
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Terry Jarrett
TERRY JARRETT
Commissioner
Missouri Public Service Commission

Attachment

SUMMARY OF CALCULATIONS

EMPIRE COST ESTIMATE
REVISED

Amount of Annual Energy lost based from historical actual	12436 MWhrs
Amount of Capacity lost	3 MW
Cost of replacement capacity	$9,200,894 NPV
Based on 1093$/kW CC unit installed	
Fixed O&M costs	$808,934 NPV
Cost of carbon tax for generation lost	$3,637,241 NPV
$20/ ton	
Cost of purchase power for generation lost	$27,334,198 NPV
Based on Platts projected costs, then 2.5%	
Cost of carbon tax risk on purchase power	$1,366,710 NPV
TOTAL	$42,347,977 NPV

SWPA COST ESTIMATE

Amount of Annual Energy lost based from model of river	8645 MWhrs
Amount of Capacity lost	3 MW
Cost of purchasing replacement capacity	$10,955,038 NPV
Based on 128.47 $/kW-yr for CC unit	
inlflated at 2% per yr	
Cost of purchase power for generation lost	$10,408,683 NPV
Based on peak $56.45, off pk $13.75	
inflated at 2% per yr	
TOTAL	$21,363,721 NPV

STAFF ESTIMATE

Amount of Annual Energy lost from Empire results	12436 MWhrs
Amount of Capacity form Empire	3 MW
Cost of replacement capacity	$9,200,894 NPV
From Empire	
Fixed O&M costs from Empire	$808,934 NPV
Cost of carbon tax for generation lost	$3,637,241 NPV
$20/ ton from Empire	
Cost of purchase power for generation lost	$25,232,322 NPV
Based on Staff analysis of act historical	
purchased power prices $61.76 inflated	
at 2.5% per yr	
Cost of carbon tax risk on purchase power	$1,366,710 NPV
from Empire	
TOTAL	$40,246,100 NPV

March 6, 2008

Via Electronic Mail
Mr. George Robbins
Director, Division of Resources and Rates
Southwestern Power Administration
One West Third
Tulsa, OK 74103

Re: White River Minimum Flows – Determination of Federal and Non-Federal Hydropower Impacts

Dear Mr. Robbins:

This is in response to the Federal Register Notice on White River Minimum Flows – Determination of Federal and Non-Federal Hydropower Impacts published on Tuesday February 5, 2008. The following comments on the Southwestern Power Administration's Draft Report, dated January 2008, are submitted on behalf of the Northeast Texas Electric Cooperative, Inc. ("NTEC") and Tex-La Electric Cooperative of Texas, Inc. ("Tex-La") (hereinafter the "Cooperatives").

NTEC and Tex-La appreciate the opportunity to comment on the proceeding and support the efforts of Southwestern Power Administration to receive input from the impacted parties in order to determine the most accurate accounting of costs associated with the reallocation study. In our opinion, the engineering procedure used in the report more accurately calculates actual losses in energy and capacity at the water projects than other past computations by the Corps of Engineers. However, the dollar values for the lost capacity and energy under-represent the actual costs needed to replace the losses for the life of the project. We encourage Southwestern to utilize assumptions that more accurately reflect current market conditions.

Additional specific comments on the report are attached. If you have any questions or concerns with these comments, please contact the Cooperatives' economic/engineering consultants at GDS Associates, either Tom Gebhard at (512) 494-0369 x-123 or David Brian at (770) 425-8100. Thank you for the opportunity to provide feedback in this proceeding.

Respectfully submitted,

/s/ Christine C. Ryan

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UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

White River Minimum Flows
Determination of Federal and Non-Federal Hydropower Impacts

INITIAL COMMENTS OF NORTHEAST TEXAS ELECTRIC COOPERATIVE, INC. AND TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC.

Pursuant to the February 5, 2008 "Notice of Public Review and Comment," 73 Fed. Reg. 6717, Northeast Texas Electric Cooperative, Inc. ("NTEC") and Tex-La Electric Cooperative of Texas, Inc. ("Tex-La") (hereinafter "Cooperatives"), file Comments on the Draft Report: White River Minimum Flows – Determination of Federal and Non-Federal Hydropower Impacts. NTEC and Tex-La are generation and transmission cooperatives that own generation, and purchase power at wholesale, to serve their member cooperatives for distribution to ultimate consumers. The Cooperatives are customers of Southwestern Power Administration ("SWPA" or "Southwestern"). Under existing contracts with SWPA, NTEC receives 127.5 Megawatts (MW) of capacity and associated energy, of which 102 MW is system capacity and 25.5MW is from Narrows. Tex-La receives 28.175MW of capacity and associated energy, 27.5MW of which is from Denison Dam and approximately 700kW is from system capacity. Narrows, like Denison, is priced as a system resource and therefore any impacts to the system rates affect the costs to the Cooperatives.

The Cooperatives have a direct interest in the determination of the impact of the proposed water storage reallocation to the extent that it would impact the quantity, the cost, or the scheduling of federal hydropower generation. Tex-La has an additional interest in this proceeding, in that some of the methodologies employed here may serve as precedent for the determination of hydropower impacts and replacement costs in connection with the pending reallocation of storage at Denison Dam.

The Cooperatives applaud SWPA for the reasoned and transparent analysis in the Draft Report, and for its consideration of various alternatives. The Cooperatives are, however, concerned with overly conservative valuations of the cost of replacement energy, as well as an inflation forecast number that fails to incorporate the unique inflationary pressures that can be expected in the electric power generation sector.

An additional concern is that customers of SWPA are losing a carbon dioxide (CO_2) emissions-free source of power and the initial replacement valuations are based upon CO_2 emissions intensive power generation. While the Cooperatives recognize that there is not currently in place any statutory or regulatory scheme which places a price upon the emission of CO_2, such potential costs exist during the lifetime of the study. Those costs remain unaccounted and unplanned for in the life of the study.

1. **Section 5.0 – Energy and Capacity Losses**

In this section, Southwestern presents a reasonable approach to the calculation of lost energy and capacity from storage reallocation. The energy loss procedure determines the capacity that would need to be purchased to replace the dependable capacity lost from the storage reallocation. Capacity used to meet customer demands during peak periods must be available and useable one hundred percent (100%) of the time. The capacity loss calculation in the report accurately determines the amount of loss based on how much capacity is lost during the peak demand period and during the critical drought period of the water storage project. That criteria corresponds to the criteria used by the rural electric cooperatives in supplying electric power to their customers. Those procedures are fully supported.

2. **Section 6.0 – Replacement Costs**

This section represents an ostensibly reasonable, albeit highly conservative, methodology for calculating the dollar value needed to replace capacity and energy in today's electric market. NTEC and Tex-La believe that the values developed from the procedure using the Federal Energy Regulatory Commission ("FERC") program are minimum cost values for each item valued. In today's market place coal-fired energy is not available to wholesale customers who have to go out and replace lost hydropower energy. Low–cost coal energy is generally reserved for rate base paying customers. Energy on the margin available in off-peak periods is more typically natural gas based than coal based, since the energy produced by coal-based resources has been allotted to retail load and existing contractual commitments. Coal is not an appropriate replacement for the lost hydropower energy. A more likely alternative is some form of natural gas energy. It is our understanding that SWPA has an energy loss rate charge of over $50.00/Megawatt Hour ("MWH"). We also understand that a considerable amount of the energy used to support those losses is off-peak energy. The off-peak energy values using Platts as the source would be above the $50.00/MWH value. Therefore, Cooperatives believe that the off-peak energy should be valued in the $50.00/MWH range, which would be more reasonable in today's marketplace. We would encourage SWPA to use the Platts source for the value of off-peak energy or to investigate the procedure used to update the variables in the FERC program to make sure the variables were correctly valued.

The values for on-peak energy and capacity construction costs used by SWPA compare reasonably well with recent experience in the electricity market. However, current experience with avoided peaking energy costs reflects an avoided energy cost approximately twelve (12) times the cost of natural gas prices. Average projections for natural gas are about $8.00, with gas currently a little above the $9.00 mark. Therefore, we would expect the peaking value of energy to begin at $100.00/MWH. The cost of new power plants has increased significantly in recent years because of the escalating demand for materials, labor, and equipment. Depending upon the technology, we assume the cost of new combustion turbine peaking capacity to be above $70.00/kilowatt year ("kw-yr"). Therefore, we believe the values used in the Draft Report are conservative in today's marketplace.

3. Section 10.0 – Inflation

The Energy Information Administration ("EIA") Annual Energy Outlook 2007, states on page 68, that "from 1980 to 2005, inflation has averaged 3.5 percent per year…" yet last year's EIA outlook justifies the downward deviation from the historical average on the basis of projected gains in labor activity. However, at the time of the report, the EIA also projected the price of a barrel of oil would remain approximately $60 through 2030. The historically accurate rate of inflation of 3.5% is a reliable number that is not subject to disputes over methodology. NTEC and Tex-La question the applicability of the all-urban Consumer Price Index ("CPI") to accurately reflect the long-term costs of replacing CO_2 emissions-free federal hydropower. NTEC and Tex-La suggest that high capital startup costs and limited supply of available replacement generation and transmission are reflective of repressed inflationary pressures not accounted for by the

CPI number. Furthermore, the costs associated with electric generation are not particularly sensitive to gains in labor productivity. Rather, the cost of capital materials and fuels represent the largest factors in the cost of generation. We do not believe that materials and fuel costs will moderate at the same level as overall inflation over the next fifty (50) years.

Alternatively, NTEC and Tex-La suggest looking to an industry specific producer price index which more closely mirrors the increased costs associated with electric power generation. The rate of inflation used in the report differs from the Bureau of Labor Statistics ("BLS") Producer Price Index ("PPI") for the industry. The BLS database,[1] which is specific to the electric power generation utility business, reflects significantly higher rising costs than the 2% number representing the "all-urban CPI."

4. **Section 11.0 Present Value Determination**

The selection of the current rate on 30-year U.S. Treasury notes to be used as the discount rate in the present value calculation is a reasonable rate to use for capital projects.

---

[1] *See* U.S. Dept. of Labor, U.S. Bureau of Labor Statistics, PPI Detailed Report, Vol 12. No. 1 (Data for January 2008), available at: http://www.bls.gov/ppi/ppidr200801.pdf (Detailing the PPI for Electric Power Generation Utilities at Industry Code: 221110 Product Code: 2211104).

Respectfully submitted,

<u>/s/ Christine C. Ryan</u>

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Counsel to Northeast Texas Electric
Cooperative, Inc. and Tex-La Electric
Cooperative of Texas, Inc.

SOUTHWESTERN POWER RESOURCES ASSOCIATION

PARTNERS WITH THE RIVER - HYDROPOWER TO THE PEOPLE

March 6, 2008

Mr. George Robbins, Director
Division of Resources and Rates
Southwestern Power Administration
One West Third Street
Tulsa, OK 74103

Re: White River Minimum Flows – Determination of Federal and Nonfederal Impacts

Dear Mr. Robbins:

Southwestern Power Resources Association (SPRA) represents the rural electric cooperatives and municipally owned electric utilities that purchase hydropower generated at 24 Corps of Engineers multipurpose water resource projects in this region, including the Bull Shoals and Norfork projects. SPRA respectfully submits its comments on the above referenced draft report. Because of the nature of its membership and its mission, SPRA limits its comments to those sections of the report dealing with impacts to the Bull Shoals and Norfork projects of implementing the White River minimum flow releases authorized in Public Law 109-103.

Process for determining quantity of lost energy and capacity

SPRA strongly supports the process Southwestern uses for identifying and quantifying the energy and capacity lost due to reallocation of storage at Bull Shoals and Norfork, as well as the process for determining whether particular energy lost is peaking energy versus off-peak energy. We believe the process utilized by SWPA is superior in several ways to the process currently in use by the Corps to determine hydro energy and capacity losses due to storage reallocation. Specifically:

- Use of hydropower yield protection operation (HYPO) to maintain the yield of hydropower storage when storage is reallocated from the flood pool. The Corps uses a similar process, dependable yield mitigation storage (DYMS), to maintain the dependable yield of existing water supply storage users when storage is reallocated from the flood pool. Use of HYPO provides parity for hydropower customers.

- Dependable capacity is determined on the drought of record, rather than average available capacity used by the Corps. Southwestern's procedure corresponds to standard electric utility practices in this regard.

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- As directed by the legislation, repayment of the power purpose of the projects would be reduced by the replacement value of lost energy and capacity as determined by Southwestern. Current Corps practices, in practical application, limit hydro compensation to the revenues foregone by Southwestern.

Quantifying the value of hydropower losses due to storage reallocation

Although the process used by Southwestern in its draft report to quantify the value of hydropower losses due to implementation of minimum flow releases at Bull Shoals and Norfork is vastly superior to that currently used by the Corps in its reallocation studies, *all* such processes are limited by the subjective nature of certain variables necessary to determine appropriate compensation to the power purpose. These variables include:

- The value of off-peak energy;
- The value of peaking energy;
- The value of peaking capacity;
- Anticipated inflation of energy costs over the remaining life of the projects; and
- The discount rate used to determine net present value.

Because of the nature of our association's mission, SPRA's staff is not involved in the sale and purchase of electric energy and capacity. When such information is needed, we seek it from our members who *are* involved in daily sale and purchase of energy and capacity in power markets. SPRA is aware that at least two of our members intend to offer comments on the values used by Southwestern for off-peak energy, peaking energy and peaking capacity. Consequently, we defer to and support the values offered by our members in their comments for these commodities.

SPRA recognizes Southwestern's need to cite credible sources for estimates of these subjective variables. Certainly, the Energy Information Agency (EIA) is a credible source for estimates of average annual energy inflation for the next 50 years. However, use of the "reference case" 2.0 percent inflation rate seems unreasonably low, in light of rapid increases in energy prices over the past five years; rapid increases in the fuels used to generate electricity during this same period; the rapid increase in materials used to build generation facilities such as copper, steel, aluminum and concrete; the outlook for increases in these same commodities for the next 10 years due to increasing global demand for energy; and the pressure on energy prices that is likely to occur as the United States and perhaps other countries seek to reduce greenhouse gas emissions. At a minimum, the "low growth" EIA value of 2.5 percent should be used.

SPRA supports the use of the interest rate for 30-year U.S. Treasury notes in effect at the time minimum flow releases are implemented as the appropriate discount rate for determining net present value of hydropower impacts. This is the same interest rate charged on new capital investments in the federal power system, and this rate was reaffirmed by Congress in its Department of Energy appropriation for FY 2008.

Finally, all stakeholders in this reallocation process should realize that the process used by Southwestern to determine the compensation required for impacts to the hydropower purpose at the two federal projects, even while superior to the process used by the Corps for similar purposes, is simply a "snapshot" of what the impacts will be at the time of implementation of minimum flow releases, assuming that assumptions made for energy and capacity replacement costs, the inflation rate for energy costs over the next 50 years, and the discount rate are accurate. To the extent that these values change over the next 50 years, the impacts to the federal hydropower purpose will change. While it is possible that such changes might lead to a decrease in total hydropower impacts, in view of empirical evidence over the past 50 years and the likelihood of major impacts on energy values due to increased pressure to reduce greenhouse gasses, it is more likely that the actual impacts over the 50-year period will be greater than those forecast.

This being said, SPRA has no recommendation for a better process to determine compensation to the federal hydropower purpose, and thus endorses the process utilized by Southwestern. Certainly, SPRA wholeheartedly supports Southwestern's expressed intent to recalculate the compensation based upon the value of the variables cited above on the date that minimum flow releases are implemented.

Changes in reservoir operations upon implementation of minimum flow releases

Southwestern did an excellent job in identifying changes in federal reservoir operations that would affect the impact of minimum flow releases on hydropower. These include:

- Additional maintenance costs of $68,000 annually at Bull Shoals due to additional run-time and additional cavitation damage to turbines due to use of existing turbine-generator units at very low outputs for release of minimum flows at that project (section 7.1). SPRA supports Southwestern's decision to include these costs in hydropower impacts and compensation.
- The potential for more low dissolved oxygen releases at both federal projects during generation (section 7.2). To the extent that mitigation might be required for these impacts, the hydropower purpose should be compensated accordingly, or, alternatively, the nonfederal sponsor should pay for mitigation costs.
- Any reduction in firm energy amounts available when hydropower operations are curtailed due to downstream flooding attributable to minimum flow releases should be compensated (section 8.1).

- The draft report assumed that minimum flow releases will be included in the three-day requirement for releases when ambient air temperatures exceed 85 degrees F (section 8.2). SPRA supports Southwestern's conclusion that hydropower compensation should be recalculated to reflect costs incurred if this assumption is not correct.
- The draft report recommends that four-week and one-week drawdown limits at Bull Shoals and Norfork be adjusted to reflect minimum flow releases (section 8.3). SPRA supports this recommendation. If it is not carried out, the impact to hydropower operations should be recalculated to reflect this impact.
- SPRA supports Southwestern's conclusion that the Corps must carefully monitor use of minimum flow storage to avoid additional impacts to hydropower (section 8.4).

Conclusion

The draft report was very straightforward, easy to read and comprehend. SPRA thanks Southwestern for this opportunity to submit its comments, and it looks forward to working with Southwestern, the Corps and all stakeholders in implementing minimum flow releases at the Bull Shoals and Norfork projects.

Sincerely,

Ted Coombes

Ted Coombes
Executive Director

Appendix K – Response to Public Comments

Southwestern's Responses to
Public Comments Received On

Draft Determination
White River Minimum Flows Study
Determination of Offset to the Federal Hydropower
Purpose and Impacts on Non-Federal Project

Dated January 2008

White River Minimum Flows – Draft Determination Report
Public Comments and Southwestern's Responses

Southwestern Power Administration (Southwestern) published a "Notice of Public Review and Comment" in the Federal Register on February 5, 2008, concerning its Draft Determination Report on the White River Minimum Flows Study. There was a 30-day public comment period which ended on March 6, 2008. Southwestern received four sets of comments in response to the Federal Register notice:

1. Empire District Electric Company (**Empire**) – The licensee of the non-Federal, Federal Energy Regulatory Commission (FERC) licensed Ozark Beach hydropower project on the White River in Missouri.
2. Missouri Public Service Commission (**MOPSC**) – The public utility commission for the state of Missouri.
3. Northeast Texas Electric Cooperative, Inc. (**NTEC**) and Tex-La Electric Cooperative of Texas, Inc. (**Tex-La**) – Customers of Southwestern.
4. Southwestern Power Resources Association (**SPRA**) – Trade association which represents the rural electric cooperatives and municipally owned electric utilities that purchase Federal hydropower marketed by Southwestern.

All respondents are associated with the electrical industry and are in a position to understand current and future costs and trends.

The major comments, by categories, and Southwestern's responses are as follows:

1. **Energy Losses**
   a) **Empire** questioned "the applicability of the SUPER program to accurately model relatively small changes in actual conditions at Ozark Beach as opposed to overall macro level changes in an entire river basin."

   Response: *SUPER was designed and programmed to simulate the operation of a multipurpose reservoir system. SUPER models the reservoir system for the entire period of record as it exists today and is operated under a specific operational scenario. The value in using SUPER is the ability to model various scenarios and to determine the relative differences in the results. The Corps has successfully used SUPER for much smaller changes in many water storage reallocation studies. Southwestern believes the combination of SUPER and Southwestern's spreadsheet model accurately captures the "relatively small changes" in conditions at Ozark Beach.*

   b) **Empire** noted that Southwestern's spreadsheet analysis of the SUPER output shows an average 3.3 foot difference in the Ozark Beach tailwater elevation between the base and minimum flow runs. The Bull Shoals pool level is being raised 5 feet. The 1.7 foot difference represents a 34% understatement in the results for Ozark Beach.

Response: *It is not reasonable to assume that the Bull Shoals pool elevation will always be five feet higher after the minimum flows project is implemented. While five feet of flood control storage will be reallocated at Bull Shoals for minimum flows, any water stored in that reallocated storage will be released for minimum flow requirements. Those releases will be made whenever Southwestern is not generating at Bull Shoals Dam. As a result of those releases from the reallocated storage, the pool level will be drawn down on a regular basis and the reallocated storage will not typically be full. The desired downstream minimum flow releases are greater than the storage will yield. Therefore, the storage is frequently depleted. During the critical drought period, the pool level would be near pre-minimum flow levels.*

c) **Empire** stated that the non-Federal energy loss should be, as a minimum, Empire's computed value of 12,436 MWh.

Response: *Empire's calculated energy loss was based on the assumption that the loss of head at Ozark Beach will be a constant five feet after minimum flows are implemented. That will not be the case. See Southwestern's response to b) above.*

d) **Empire** "does not believe the Super program is accurately capturing the efficiency and energy gains due to the addition of new water wheels at Ozark Beach." Empire compared the calculated generation in the spreadsheet model for the SUPER Base Run (with the new wheels) versus the calculated generation for the corresponding time period in the spreadsheet verification model (with the old wheels) and also with Empire's actual energy generation. Empire also noted that there is only a 3.5% increase in generation while Empire believes it should show a 16% increase.

Response: *The historical Table Rock outflows and Bull Shoals pool elevations are slightly different from the SUPER output because SUPER is modeling the reservoir system as it exists today, with all current water supply contracts and the current plan of operation. If the performance data for the old and new wheels are used with the same inflow data, a reasonable difference in generation is determined.*

Southwestern performed the daily generation calculation for the SUPER Base Run with the performance data for the old wheels to verify the model with existing historical data. With the assumed generating efficiency for the old wheels of 75% and the assumed friction loss of one half foot, there was a very strong correlation with historical generation at the project. The calculated average annual generation with the new wheels is about 17% higher than the calculated average annual generation with the old wheels. The historical data was used only to verify that Southwestern's spreadsheet model could reasonably predict the generation at Ozark Beach with the Table Rock outflows and Bull Shoals pool elevations as inputs.

The new wheels were used in both the base and alternative computations in order to determine the difference caused by the operation of Bull Shoals to meet the minimum flow requirements, not the increase from the installation of the new wheels. The main use of SUPER is in comparing the relative differences between the two operational scenarios, not in trying to reproduce history.

e) **Empire** questioned the 1940-2003 period of record in SUPER which includes 18 years before Table Rock Dam was built. Empire "does not understand how the modeling can be accurate for those early years and properly reflect the operation of Ozark Beach."

Response: *It is standard practice in hydrologic engineering to use existing stream gage information to develop historical flow data at dam sites. The flow data are used in hydrologic models to model the reservoir system over as long a period of record as gage data is available. Reservoirs were designed based on hydrologic models that predicted the system operation with the reservoir in place. That is not unique to SUPER or Southwestern, but it is standard practice in hydrologic engineering and simulation modeling.*

f) **Empire** noted that Southwestern used only the releases from Table Rock Dam as the inflows for Ozark Beach. They stated that the Ozark Beach inflows are about 8% higher than Table Rock outflows due to intervening area inflow.

Response: *Southwestern agrees that the inflows into Ozark Beach will typically be larger than the outflows from Table Rock Dam. Southwestern did not consider the intervening area inflow between Table Rock Dam and Ozark Beach in its initial analysis. The Ozark Beach drainage area is about 8.5 percent larger than the Table Rock drainage area.*

The analysis has been updated using a drainage area ratio analysis of the intervening area inflow originating between Table Rock Dam and Bull Shoals Dam (as developed for the SUPER model) to add to the Table Rock outflows in estimating the Ozark Beach inflows. Using that technique, the average daily inflows into Ozark Beach are about 9 percent larger than the average daily outflows from Table Rock. The updated daily inflows were used in the computations for both the base and alternative cases. After the change, the calculated average annual energy loss at Ozark Beach increased from 8,645 MWh to 8,998 MWh.

g) **Empire** stated "We are very cognizant that the Empire ratepayers are the ones who shoulder the risk of analysis that does not properly account for the loss of energy and capacity at Ozark Beach. We are striving to protect their interests."

Response: *Likewise, the Federal hydropower customers bear the risk that Southwestern's analysis does not properly quantify the impacts at the Bull Shoals and Norfork projects. Southwestern's intent is, to the extent possible, to* *accurately identify and quantify the impacts of the White River Minimum Flows project for both the Federal and non-Federal hydropower projects.*

h) **MOPSC** stated "the SWPA model failed to account for the efficiency gain actually seen at the dam with the new turbine wheel replacements and the model was unable to capture the expected five (5) feet of head loss. Thus, Staff considers that there are significant reasons to doubt the accuracy of SWPA's calculations."

Response: *Do not concur. See responses to b), c), and d).*

i) **NTEC and Tex-La** state that "Southwestern presents a reasonable approach to the calculation of lost energy and capacity from storage reallocation."

Response: *Concur.*

j) **SPRA** "strongly supports the process Southwestern uses for identifying and quantifying the energy and capacity lost due to reallocation of storage at Bull Shoals and Norfork, as well as the process for determining whether particular energy lost is peaking energy versus off-peak energy."

Response: *Concur.*

2. **Capacity Losses**

a) **Empire** "agrees with SWPA that the capacity lost at Ozark Beach is 3 MW."

Response: *Though our techniques for determining the capacity loss at Ozark Beach were different, we agree on the amount of lost capacity.*

b) **NTEC and Tex-La** state that "The capacity loss calculation in the report accurately determines the amount of loss based on how much capacity is lost during the peak demand period and during the critical drought period of the water storage project."

Response: *Concur.*

c) **SPRA** "strongly supports the process Southwestern uses for identifying and quantifying the energy and capacity lost due to reallocation of storage at Bull Shoals and Norfork, as well as the process for determining whether particular energy lost is peaking energy versus off-peak energy."

Response: *Concur.*

3. **Replacement Costs of Energy**

a) **Empire** proposed that Southwestern use cost data that is more reflective of the entire market in which Empire operates. They noted that off-peak energy is often supplied by natural gas and not only coal-fired generation. Empire had previously proposed and still believes that an industry source such as Platts would provide more appropriate values for replacement costs of on-peak and off-peak energy.

Response: *The preliminary analysis of the impacts at Ozark Beach by the Corps proposed the use of the "High Fuel Value" energy cost data developed by Platts Power Outlook Research Service, a wholesale North American power market forecast service. Platts is a division of McGraw-Hill Companies, Inc. Empire agreed with the Corps on the use of the Platts energy cost data for the Corps analysis.*

Southwestern initially used energy values developed by the Corps using Federal Energy Regulatory Commission (FERC) methodology for both the Federal and non-Federal impacts in order to be consistent with its evaluation of previous Corps reallocation studies, including its previous evaluation of White River Minimum Flows. While Southwestern was aware that the values produced by the Corps under older FERC criteria undervalue the energy benefits foregone in storage reallocations, we believed it was important to be consistent with our previous evaluations. The FERC values that Southwestern used for on-peak energy compare favorably with the Platts on-peak values. However, the FERC values that Southwestern used for off-peak energy are significantly lower than the Platts off-peak values.

After receiving public comments on our Draft Determination Report, Southwestern requested and received a copy of the spreadsheet "program" developed at FERC and used by the Corps in the development of replacement energy costs. The Corps' Hydropower Analysis Center (HAC) modified the program several years ago (pre-2000), but FERC has terminated support of the program. HAC continues to update the indices in the spreadsheet, but there is no active support for the program.

Southwestern revised its analysis for its Proposed Determination to use the Platts High Fuel Value energy cost forecast instead of the FERC energy values. The change was made for three primary reasons: 1) the Corps and Empire had previously agreed that the Platts High Fuel Value energy cost forecast numbers most accurately represented the replacement cost of energy; 2) comments from electric industry participants strongly supported the use of an industry source such as Platts; and 3) Southwestern's additional research revealed that the Platts values for on-peak energy compare favorably with the FERC and current market values; however, the Platts values for off peak energy are much more reflective of the current market than the FERC values.

As a result of the revision, the annual energy losses (in 2008 dollars) changed from Southwestern's initial analysis. The Federal on-peak energy value decreased from $91.44/MWh to $85.05/MWh, and the off-peak energy value increased from $17.50/MWh to $50.49/MWh. The non-Federal on-peak energy *value increased from $56.45/MWh to $86.06/MWh, and the off-peak energy value increased from $13.75/MWh to $50.75/MWh.*

b) **MOPSC** says the energy values developed by the Corps using the FERC methodology are too low. They used the average spot purchase energy price from three rate cases for their analysis.

Response: *Concur. See response to a).*

c) **NTEC and Tex-La** state that "In today's market place coal-fired energy is not available to wholesale customers who have to go out and replace lost hydropower energy. Low-cost coal energy is generally reserved for rate base paying customers." They also state that "Coal is not an appropriate replacement for the lost hydropower energy. A more likely alternative is some form of natural gas energy."

Response: *Concur. See response to a).*

d) **NTEC and Tex-La** noted that Southwestern's current rate for losses is over $50.00/MWh. They believe that off-peak energy should be valued in the $50.00/MWh range, which would be more reasonable in today's market.

Response: *Southwestern's rate for replacing non-Federal transmission losses is not determined from either the FERC or Platts values. It is based on actual purchases to replace losses incurred in transmitting non-Federal power and has no correlation to this determination.*

e) **NTEC and Tex-La** stated that the Corps on-peak energy value is reasonable, but conservative. Based on current and projected prices for natural gas, they believe that on-peak energy values should begin at $100.00/MWh.

Response: *See response to a).*

f) **NTEC and Tex-La** encourage Southwestern to use Platts values or to update the FERC program to properly reflect market values of on-peak and off-peak energy.

Response: *Concur. See response to a).*

4. **Replacement Costs of Capacity**

a) **Empire** agrees that a combined cycle facility would be appropriate for replacing lost capacity at Ozark Beach. They prefer that Southwestern use capacity costs from Platts but did not state what the Platts cost would currently be. Their calculation uses $1,093/kW (which they say is equivalent to the $128.47/kW-yr used by Southwestern) and produces a present value of $9.2 million compared to $11.0 million calculated by Southwestern.

Response: *While public comments expressed much disagreement with the replacement costs of energy used by Southwestern in its initial evaluation, there was limited discussion of the replacement costs of capacity used by Southwestern. Empire recommended Platts capacity cost data but used the FERC value in their updated calculation. NTEC and Tex-La state that the capacity value used is reasonable but conservative. Southwestern will continue to utilize the capacity cost data produced by the Corps using FERC methodology in its analysis.*

b) **NTEC and Tex-La** say FERC capacity values as computed and used by HAC for Federal hydropower are "reasonable", but "conservative". They "assume the cost of new combustion turbine peaking capacity to be above $70.00/kW-yr."

Response: *See response to a).*

5. **Maintenance Costs**

a) **Empire** added fixed O&M costs of $11.18/kW in 2007 dollars for the replacement capacity. That added about $800,000 to the present value non-Federal impacts. They did not detail how the O&M cost figure was derived or cite a source for referral at the time of the final calculation.

Response: *According to the Corps, the FERC method capacity value calculation performed by HAC includes fixed O&M costs. The inclusion of additional O&M costs would double count those costs. Therefore, no additional costs are required and none will be included.*

6. **Inflation**

a) **Empire** did not discuss Southwestern's use of the "reference case" inflation rate of 2.0 percent from the Energy Information Administration (EIA) *Annual Energy Outlook*. They used the EIA "low growth" inflation rate of 2.5 percent in their initial and updated analysis.

Response: *Southwestern recognizes that historical inflation rates have been higher than the EIA "reference case" rate proposed by Southwestern in its draft determination. Economic conditions over the next 50 years are difficult if not impossible to reliably predict. Since the EIA is the independent statistical and analytical agency within the U.S. Department of Energy, Southwestern will defer to the projection of the EIA and will continue to use the "reference case" inflation rate in the latest Annual Energy Outlook in the determination of the Federal and non-Federal hydropower impacts.*

b) **MOPSC** used 2.5 percent inflation in their energy cost analysis and Empire's numbers for all other costs.

Response: *See response to a).*

c) **NTEC and Tex-La** cite the EIA *Annual Energy Outlook 2007* – "from 1980 to 2005, inflation has averaged 3.5 percent per year…", and they "question the applicability of the all-urban Consumer Price Index ('CPI') to accurately reflect the long-term costs of replacing CO_2 emissions-free federal hydropower." They suggest looking to "an industry specific producer price index which more closely mirrors the increased costs associated with electric power generation."

Response: *See response to a). Southwestern researched to find a source for a long-term, energy-specific inflation forecast but was unsuccessful.*

d) **SPRA** says "at a minimum, the 'low growth' EIA value of 2.5 percent should be used."

Response: *See response to a).*

7. **Present Value Determination**

a) **Empire**, in its August 2007 report detailing its analysis of the impacts at Ozark Beach (Appendix I in Southwestern's draft report), proposed the use of the current rate on 30-year U.S. Treasury notes for the discount rate. They used 4.8 percent in their initial analysis, which was the 30-year Treasury rate in effect at that time. The rate had gone up to 5.0 percent by the time of Southwestern's analysis. In February 2008, the rate dropped to 4.375 percent. Empire continued to use 4.8 percent in its review of Southwestern's draft determination report.

Response: *There is no disagreement on the parameters for the present value determination. The 50-year project life was used by the Corps in its preliminary analysis, and Empire and Southwestern agreed on that term. Empire used 4.8 percent for the discount rate in both its initial and follow-up analysis, but that number was based on the 30-year U.S. Treasury rate in effect at the time of their initial analysis. The use of the 30-year Treasury rate in the analysis was first proposed by Empire. Southwestern will use the 30-year Treasury rate in effect at the time of the final calculation as the discount rate.*

b) **NTEC and Tex-La** stated "The selection of the current rate on 30-year U.S. Treasury notes to be used as the discount rate in the present value calculation is a reasonable rate to use for capital projects."

Response: *Concur. See response to a).*

c) **SPRA** "supports the use of the interest rate for 30-year U.S. Treasury notes in effect at the time minimum flow releases are implemented as the appropriate discount rate for determining net present value of hydropower impacts. This is the same interest rate charged on new capital investments in the federal power system, and this rate was reaffirmed by Congress in its Department of Energy appropriation for FY 2008."

Response: *Concur. See response to a).*

8. **Carbon Tax and Renewable Portfolio Standard**
   a) **Empire** included a $20/ton carbon tax and a 5% renewable risk premium in their calculation of the non-Federal impacts.

   Response: *Since there is no way to reliably estimate if, when, or how a carbon dioxide tax would be implemented, Southwestern did not include losses based on a carbon dioxide tax. The impacts to both Federal and non-Federal hydropower should be quantified and included in the compensation calculation if any carbon dioxide tax legislation is implemented before the final payment or offset is completed.*

   Also, since there is no way to reliably estimate if, when, or how a renewable portfolio standard would be implemented, the impacts would be difficult to quantify. The State of Missouri currently has voluntary goals for adopting renewable energy, but there are no mandatory targets. Southwestern's position on a renewable risk premium is the same as on a possible carbon dioxide tax: If a state or Federal mandatory renewable portfolio standard that qualifies any of the three projects studied is implemented before the final payment or offset is completed, the impacts to both Federal and non-Federal hydropower should be quantified and included in the compensation calculation.

   The authorizing legislation for the White River Minimum Flows project states that Empire will be compensated with a one-time payment "on the basis of the present value of the estimated future lifetime replacement costs of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project." If the compensation to Empire were changed from a one-time payment to payments over a number of years, compensation for the impacts of a carbon dioxide tax or a renewable portfolio standard for the remainder of the payments should be computed and applied if either were implemented during that series of payments.

   b) **MOPSC** specifically addressed the carbon tax, stating that they do not consider "zero" to be an acceptable estimate. They did not discuss a "risk premium", but they included Empire's risk numbers in their calculations.

   Response: *See response to a).*

   c) **NTEC and Tex-La** note that while "there is not currently in place any statutory or regulatory scheme which places a price upon the emission of CO_2, such potential costs exist during the lifetime of the study."

   Response: *See response to a).*

9. **Other**

a) **Empire** requested that all references to "Powersite Dam" to be changed to "Ozark Beach" which is the official name of the non-Federal hydropower project.

   Response: *Concur. All references to Powersite Dam in Southwestern's report have been changed to Ozark Beach.*

PEER REVIEW:
WHITE RIVER MINIMUM FLOWS
Southwestern Power Administration
Determination of Offset to the Federal Hydropower Purpose and Impacts on Non-Federal Project
6 October 2008

1. Purpose. The purpose of this Peer Review is to develop a White Paper concerning the Southwestern Power Administration (SWPA) calculations and findings included in the White River Minimum Flows (WRMF) Study Determination of Offset to the Federal Hydropower Purpose and Impacts on Non-Federal Project, dated June 2008. This paper provides a fair assessment of methods and conclusions used by SWPA by logically laying out the US Army Corps of Engineers, USACE, observations of the SWPA Hydropower Determination.

2. Background. The White River Minimum Flows project was originally authorized by section 374 of WRDA 99 and section 304 of WRDA 00. The original authorization modified the operation of the White River Lakes to include storage for the tailwater trout fisheries if the ASA (CW) determined the work was technically sound, environmentally acceptable, and economically justified. A reallocation study was completed in FY04, but did not recommend a project for construction. Section 132 of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork lakes, as described in the FY04 Reallocation Report, at full Federal expense in accordance with section 906(e) of WRDA 86. Authorized Plan BS-3 reallocates 5 feet of flood control storage at Bull Shoals Lake for the minimum flows release of 590-cfs through the main turbine. The top of the conservation pool elevation will be raised by 5-feet to from 654.0 to 659.0. Authorized Plan NF-7 reallocates 3.5 feet of storage at Norfork Lake to be evenly divided (50:50) between the conservation and flood control pools to provide a minimum flows' release of 185-cfs. NF-7 requires a siphon and valve system with a layered intake to be constructed and operated in concert with the existing Station Service Unit to make the minimum flows releases. The top of the conservation pool elevation will be raised by 1.75 feet to from 552.0 to 553.75.

Implementation requires: 1. Completion of the Project Decision Document, Supplemental Environmental Impact Statement (SEIS) and Record of Decision (ROD), Preconstruction Engineering & Design (PED) and Construction Phases; 2. Congress must allocate funds to compensate Empire District Electric Company (FERC license 2221) and Empire District Electric Company (FERC license 2221) must be compensated; 3. The non-Federal sponsor, Arkansas Game and Fish Commission, must sign a Project Participation Agreement (PPA) and modify adversely impacted lake recreation facilities; 4. Corps facility modifications must be designed and constructed; 5. Storage at Bull Shoals and Norfork Lakes must be captured.

Hydrology & Hydraulics Appendix
White River Minimum Flows Study

1. GENERAL

The purpose of this addendum to the Hydrology & Hydraulics (H&H) Report of the White River Minimum Flow Feasibility Study is to present additional H&H analysis. The results of the detailed hydrologic analysis performed from the Reservoir System Model (SUPER) on the Current Operational Plan (SUPER Run W01X01R) and the Proposed Plan, BS-3 & NF-7, (SUPER Run W06X03) are shown in Appendix to this addendum. This section presents the methods used in developing the frequency and duration relationships.

2. FREQUENCY RELATIONSHIPS

Pool elevation and discharge frequency relationships at downstream "key" locations, or control points, were developed using techniques defined in EM 1110-2-1415 entitled "Hydrologic Frequency Analysis", dated March 5, 1993. The pool elevations and control point flows were determined based upon available data from the White River System model developed for SUPER. SUPER is a system of linked computer programs that have been designed to perform and analyze a "period of record" simulation for a specific system of multipurpose reservoirs using various plans of regulation.

The White River System model is made up of five multipurpose storage reservoirs (Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry) and also a small flood control reservoir (Clearwater) on the Black River. There are also six control points on the White River, four control points on the Black River and one control point on the Little Red River. The hydrologic period of simulation for this study is October 1940 through September 2003 or 63 years of daily records (23,010 days).

The White River Basin is a basin that has changed dramatically over the last 50 years. The first reservoir was completed in 1948 and the latest was completed in 1964. The guidelines presented in EM 1110-2-1415 states that frequency and duration studies must be performed using uniform data. Since the White River Basin has changed so much since 1950 as well as changes to the regulating plan (current plan has been in effect since 1998), the data recorded at gage locations during this period would not be uniform. In order to perform frequency and duration studies, the gage data must be modified to represent a uniform condition in the basin. This is the purpose of the White River System model developed with SUPER. The model

3. Federal Hydropower Impacts at Bull Shoals and Norfork Lakes. Currently, SWPA has calculated the loss to the Federal purposes at Bull Shoals and Norfork Lakes to be $86,712,100. The loss values were calculated on the basis of the present value of the estimated future lifetime (50-years assumed by SWPA) replacement cost of the electrical energy and capacity assuming an implementation date for the White River Minimum Flows operation of January 1, 2011. The final cost will depend upon the official date of implementation to be specified. The procedures used in the SWPA Hydropower Determination used to calculate the current impacts to the Federal Hydropower purpose will be used to determine the final cost once the official date for implementation of the White River Minimum Flows is set and storage at Bull Shoals and Norfork Lake begins to be captured.

4. Non Federal Hydropower Impacts. The Energy and Water Development Appropriations Act, 2006, (PL 109-103), Section 132, White River Basin, Arkansas subset (3), requires the Administrator of the Southwestern Power Administration (SWPA), in consultation with the project licensee and the relevant state public utility commissions, to determine any impacts on electric energy and capacity generated at Federal Energy Regulatory Commission Project No. 2221 (Empire District Electric Company) caused by the storage reallocation associated with plan BS-3 at Bull Shoals Lake. Empire District Electric Company shall be fully compensated by the Corps of Engineers for those impacts on the basis of the present value of the estimated future lifetime replacement costs of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project. Currently, SWPA has calculated the loss to Empire District Electric Company to be $33,935,100. The loss values were calculated on the basis of the present value of the estimated future lifetime (50-years assumed by SWPA) replacement cost of the electrical energy and capacity assuming an implementation date for the White River Minimum Flows operation of January 1, 2011. The final cost will depend upon the official date of implementation to be specified. The procedures used in the SWPA Hydropower Determination used to calculate the current impacts to the Federal Hydropower purpose will be used to determine the final cost once the official date for implementation of the White River Minimum Flows is set and storage at Bull Shoals and Norfork Lake begins to be captured.

5. Procedure of Hydropower Generation Loss Assessment. The general procedures employed in the use of the SUPER model for the assessment of hydropower generation losses are not unlike those employed by USACE. Generation losses appear to be reasonable and appropriate.

6. Energy Value. There is agreement among Empire Electric Company, SWPA, and USACE to use Platts Power Outlook Research Service, (Platts) market-clearing price forecast for electrical energy. The SWPA analysis uses values from the FERC spreadsheet model provided by the USACE, but the use of Platts as a source for energy market-clearing prices is a straight forward, transparent, and well-documented approach to developing a value for lost hydropower that reflects current market transactions.

SWPA uses Platts to verify their assumptions, but actual use of the most recent Platts base case forecast would be appropriate.

At the time of the writing of the SWPA report, Platts energy market-clearing prices in the Platts base case forecast were lower than the purchase prices SWPA and its customers have experienced, particularly in recent drought years. The Platts prices listed in the High-Fuel Cost Case seemed to better reflect the higher prices experienced by SWPA and its customers, through correlation is not well-established.

The High-Fuel Cost and Low-Fuel Cost Cases of monthly energy prices are consistently 29% greater and 39% less than the Base Case respectively. According to Platts, *"…these cases were designed to give roughly an 80% confidence that prices for energy generation fuels which drive the electrical energy market-clearing price will be within the range defined by the high-fuel and low-fuel cases."*

The period of analysis in the WRMF study is stated to be 50 years. Use of the 2008 Platts High-Fuel Cost Case creates a nearly 30% bias in a long-term forecast for energy prices over the 50-year period. A more appropriate use of the High-Fuel Cost Case would be a short-term forecast when short-term conditions indicate an upward displacement in fuel prices.

Recently, Platts revised their forecasts to reflect higher fuel costs, and the current base case forecast is similar to the earlier high-fuel cost case. Final calculations upon implementation should reflect base case forecasts except to the extent that short-term conditions indicate that a short-term deviation from the base is appropriate.

7. Capacity Determination.

The definition of marketable capacity for SWPA is tied to the marketing strategy developed. Capacity has been tied to a guarantee of 1200 MWh for each MW of capacity purchased based on experience of limited hydropower resources in the region. This strategy provides a marketable product with acceptable reliability to meet customer needs. Typically this product is marketed for a shorter period than the period of analysis.

Another method of determining the loss of capacity involves looking at the simulation for the period of record (1940-1992) to determine if there is sufficient water/energy available to support 70 MW of marketable capacity for the months of low water and high power demand or load each year. The period of summer peak demand was defined as weeks 20-37 which is mid-May through mid-September each year. The change in the inability to support the marketable capacity for the critical season under the various alternative storage reallocations (flow diversions) is summed over the period of record. The average capacity shortage is used as the measure of the long-term annual loss to marketable capacity. This method is typically used by the Corps of Engineers when calculating National Economic Development benefits for hydropower projects, but is not necessarily a method that accurately predicts actual market transactions.

These differences are reflected in the differing magnitudes of capacity loss and the application of capacity unit values. The calculation of dependable capacity is an assessment of the risk that the generation will not be available upon request. This calculation varies across regions.

8. Value of Capacity.

SWPA uses a value of capacity that was extracted from a USACE spreadsheet model that uses various cost indexes to ascertain the cost of constructing, maintaining, and operating thermal generation plant types. That spreadsheet model was developed to support a screening curve analysis method that was not adopted by SWPA.

The Screening Curve analysis method uses information extracted from existing plant generation to deduce the role assigned to the hydropower plant in the system of generating resources. Based on plant generation and schedules the proportion and type of replacement thermal generation resource is assigned based on generation type cost. This composite of generation resource types represents the least cost adjustment in the generation resource system to accommodate the loss of project hydropower in the system. This composite unit cost is the marginal system capacity cost of the incremental loss of hydropower at this project.

SWPA does not use the screening curve method and elected to use one specific value from the spreadsheet. Use of the Platts energy+capacity On-Peak energy value would likely provide a more accurate model for actual on-peak market transactions.

> Platts "…*forecasts two separate wholesale power price components—capacity and energy. The energy component is forecast in terms of $/MWh. The capacity component is determined on an annual basis and forecast in terms of $/kW-yr. To derive an average on-peak price (including the capacity component) the annual capacity price is converted to $/MWh assuming that the annual price is allocated to 48% of the hours in a year. The 48% load factor represents the fraction of on-peak hours in a week—16 hours per day for five days per week."*

Application of Platts Energy+Capacity On-Peak energy value would avoid differences in the definition and determination of capacity loss. This value does not require the separate computation of capacity loss but implies a level of capacity to support firm on-peak energy. Firm energy would be the equivalent of a SWPA charge that includes both the capacity charge (guaranteed 1,200 MWh/MW) and the associated energy charge.

It would also be possible to obtain additional Platts model runs for market price forecasts for the period of the day that more nearly represents the hydropower plant peaking dispatch.

10. Replacement Cost Calculations

SWPA presents its calculations of estimated replacement costs in appendices F and G for Federal and non-Federal Hydropower, respectively. The replacement cost of energy and capacity losses was estimated by first determining the annual energy (on-peak and off-peak) and capacity losses, and then applying an appropriate unit value to those losses as they are expected to occur in each year of the period of analysis. Annual energy and capacity values were drawn from Platts Outlook for Energy in North America. The annual costs were summed over the fifty-year period of analysis and discounted to determine the present value of the replacement costs.

In general, the valuation process used by SWPA is appropriate and will produce a reasonable estimate of expected costs to purchase replacement energy and capacity. There is one change that SWPA must make in its calculations; however, and a second suggestion that would help put the estimates in context, given the broad uncertainties and significant volatility in the energy markets.

The required change is in the handling of inflation in the calculations, or more specifically in the inflation component of the discount rate. Platts publishes its 20-year forecasts in nominal terms, which include inflation, and in constant dollars, which exclude inflation. SWPA has used the inflation-adjusted values in its calculations, which is fine, although it introduces an unnecessary element of uncertainty into the calculations. It is unnecessary, because the inflation included in the forecast should be offset by an inflation component in the discount rate. It is the practice of economists to discount nominal values with a nominal discount rate and to discount constant values with a real discount rate. In this report, SWPA has used nominal (inflated) energy and capacity values, but has performed the discounting calculations with a real discount rate that does not include inflation. To correct this inconsistency, SWPA could add the inflation estimate (2%) to the discount rate (4.375%) to determine the appropriate nominal discount rate, which would be 6.375%. The preferred approach however is to exclude inflation from both sides of the equation and to work with constant dollars. Apparently, inflation has been included in the SWPA calculations because of the concern that market prices will increase over time, thereby eroding the value of the payment made in today's dollars. That concern can more appropriately be addressed through a choice of investment vehicles that mimics price fluctuations in the energy markets. For its calculations, SWPA is encouraged to use Platts' constant-dollar forecast. Discounting should continue to be done at the real rate, 4.375%.

The inflation rate is one example of a broad uncertainty in the electricity markets. Similarly, there are other sources of uncertainty that could cause the calculations in SWPA's report to vary considerably from actual future conditions. Platts discusses these uncertainties in its reports and concludes that fuel costs are the most significant source of uncertainty and volatility. Platts develops forecasts for three scenarios in the SPP, the base condition, a high-fuel scenario and a low-fuel scenario. Its stated goal is to have 80% confidence that the actual fuel prices will fall within the range of the scenarios. SWPA, in concurrence with some Corps staff, used values from the high-fuel cost scenario to complete its calculations, because the first-year estimates in the high-fuel forecast were most representative of actual prices paid by SWPA in recent market transactions. That is a reasonable basis for choosing a starting condition for the calculations, however, it ignores the uncertainty in future conditions. The single estimate of future conditions should be put into context with other scenarios for market conditions. In this case, that means the other Platts forecasts should be presented as well. Platts considers the high and low forecast to be a sensitivity test. Using those alternate forecasts will give the decision makers in the WRMF project an opportunity to assess the effects of current market conditions on the payment calculations. As it happens, Platts has included a structural adjustment in its July 2008 forecast that resulted in a base forecast that is similar to their previous high-fuel scenario. The high-fuel scenario in the newest forecast is 25-50% higher than in the November 2007 and February 2008 reports. SWPA could not have anticipated this structural adjustment, but the change does highlight the uncertainty and volatility in the forecasts. This point is all the more relevant in light of recent shocks to the global economy and uncertainty over near- and long-term demand for resources. It is possible, even likely, that Platts will reverse its July 2008 adjustment. SWPA should continue to use whichever estimate it considers “most-likely”, but it should place this estimate in context by showing how the other Platts scenarios would affect the SWPA calculations.

Conclusions

The Hydropower Peer Review assesses the methods and conclusions used by SWPA in determining the impacts to the Federal and non-Federal hydropower purposes affected by the proposed White River Minimum Flows project. It is important to understand that the final cost will depend upon the official date of implementation to be specified during Construction phase. Generally the procedures used by SWPA in calculating the impacts are sound.

The SWD SUPER model adequately assessed generation loss, generation losses appear to be reasonable and appropriate. Also, Ozark Beach Hydroelectric Project, (Empire Electric FERC licensee No. 2221), SWPA, and the Corps agree on the use of Platts Power Outlook Research Service, (Platts) market-clearing price forecast for electrical energy.

However, some of SWPA’s use of Platts data causes bias in long-term forecasts, and SWPA’s worst case philosophy for determining marketable capacity and the value of capacity also contribute worst case impacts to the Federal and non-Federal hydropower purposes. During Design phase, additional Platt’s model runs could be obtained to fine tune SWPA’s forecasts. Also, SWPA is encouraged to use Platts’ constant-dollar forecast. Discounting should continue to be done at the real rate, 4.375%. With regards to inflation rate and uncertainty, SWPA is encouraged to use whichever estimate it considers “most-likely” (base condition, a high-fuel scenario and a low-fuel scenario), but it should place this estimate in context by showing how the other Platts scenarios would affect the SWPA calculations.

White River Basin, Arkansas, Minimum Flows
Project Report

July 2004 White River Minimum Flows Reallocation Report

a. Chief of Engineers Report

b. Reallocation Report

APPENDIX D

DEPARTMENT OF THE ARMY
OFFICE OF THE CHIEF OF ENGINEERS
WASHINGTON, D.C. 20310-2600

REPLY TO
ATTENTION OF

JUL 30 2004

CEMP-SWD (1105-2-10a)

SUBJECT: White River Minimum Flow, Reallocation Study, Arkansas and Missouri

THE SECRETARY OF THE ARMY

1. I submit for transmission to Congress my report on White River Minimum Flow, Reallocation Study, Arkansas and Missouri. It is accompanied by the report of the District Engineer. This report was prepared in final response to Section 374 of the Water Resources Development Act (WRDA) of 1999 and Section 304 of WRDA 2000. These authorities provide for potential reallocation of storage for five existing Corps reservoirs; Beaver Lake, Table Rock Lake, Bull Shoals Lake, Norfork Lake and Greers Ferry Lake, all located in the White River Basin of Arkansas and Missouri. The reallocations would provide specific reservoir storage to make available minimum flows which would improve and sustain existing tail water trout fisheries. Section 374 of WRDA 1999 and Section 304 of WRDA 2000 authorize the reallocation of a specific number of feet of storage at each of the five reservoirs, however, the legislation does not specify the volume of storage to be reallocated or the elevation of such storage. Accordingly, these reports identified and evaluated various options to implement this reallocation.

2. The five lakes are multi-purpose reservoirs that were constructed between 1940 and 1970 and are operated under the White River Basin water management plan. This plan provides a comprehensive system of water control regulation which encompasses the entire White River Basin, incorporates all the basin projects and their many purposes, and provides seasonal flood control and hydropower releases based on the agricultural practices of the lower basin and other land uses downstream of the projects. The plan also addresses the needs of the downstream fishery by providing a mechanism to maintain cool water temperatures based on monitored and forecasted ambient air temperatures. It also provides a deviation procedure to respond to unforeseen and emergency conditions which either are not in the plan or for which the plan is singulary inadequate.

3. The reporting officer has not made a recommendation regarding Corps implementation of a reallocation alternative at this time; as such, National Environmental Policy Act (NEPA) analyses have not been completed. Prior to any Corps implementation, an implementation report and NEPA document would have to be completed and some refinements to the costs and benefits of various alternative plans may be made.

4. The authorizing legislation states that reallocation alternatives must be economically justified, technically sound, and environmentally acceptable. During this study phase, the Little Rock District identified and evaluated over 1,000 alternatives that reallocated storage from either the flood control pool, or the conservation pool, or both pools. The district report identifies a National Economic Development (NED) plan (the plan that would provide the greatest net economic benefits) for each reservoir, as well as other economically justified plans. The plans are also technically sound, and are considered environmentally acceptable. The environmental acceptability of the alternatives is based on quantitative and qualitative analyses conducted to date and professional judgment. A final determination of environmental acceptability would be made upon completion of the NEPA process and other environmental compliance.

5. The authorizing legislation provides that the report must determine whether modifications adversely affect other project purposes. Authorized project purposes include flood control, water supply, fish and wildlife, hydropower, and recreation. The district report finds that all plans, to varying degrees, would impact one or more of the existing and authorized project purposes. The most significantly affected project purpose would be hydropower. Most of the reallocation alternatives would adversely affect hydropower outputs, unless substantial additional capital investments were made in new power generating facilities at the reservoirs. The Federal power marketing agency for these reservoirs, Southwestern Power Administration (SWPA), makes yearly payments to the Federal treasury for the hydropower debt. A reduction in power output caused by the reallocation would not reduce the hydropower debt that SWPA would be required to cover in the sale of power to their customers. In addition, the Corps would not be responsible for the loss of benefits to the hydropower industry that would result from the reallocation, and absent a non-Federal payment for the value of reservoir storage, the Corps has no means to reduce or otherwise compensate for the loss to hydropower. If hydropower losses are not compensated, and if the Corps were to reallocate regardless of this, SWPA would have to reduce power sales to some customers and would likely raise their rates for sale of remaining power to account for the lost power production.

6. For all reallocation alternatives, recreation benefits for the tail water trout fisheries would increase. However, depending on the alternative, the existing warm water lake fisheries may exhibit minor benefits or minor adverse affects for the first few years. Regardless of the minimum flow reallocation, and after a few years, the lake fishery would be expected to adjust to the changed conditions and again exhibit the conditions of the current lake fisheries. These fisheries are now, and will continue to be largely influenced by water level management of the multipurpose reservoirs.

7. All identified reallocation alternatives would incur costs to the Federal government. These costs would be a result of the structural modifications of the reservoir facilities required to produce the specified minimum flows. In addition, there could be adverse impacts on the recovery of revenues to the U.S. Treasury from hydropower production and sales.

8. The specific cost to the Federal Government would depend on which alternative reallocation plan is implemented and the applicable cost-sharing. Specifically, the designation of the reallocation purpose as recreation, ecosystem restoration, or mitigation will determine the impact and magnitude of costs to the Federal government. In addition, such designation will impact the preferred implementation options and the categorization of the outputs. Some interested parties have proposed that the cost for the allocation be viewed as mitigation because the existing

reservoirs contributed to the degradation of warm water fisheries, and that the Corps should pay all costs associated with sustaining tail water trout fisheries. Classifying the reallocation as mitigation would result in allocation of the reallocation costs to all the project purposes and cost shared accordingly. Others have proposed that the reallocation should be treated as ecosystem restoration, and thus, cost shared 65 percent Federal and 35 percent non-Federal. However, the Corps position is that the five authorized reservoir projects were fully mitigated when constructed and the reallocations for the purpose of sustaining tail water trout fisheries represents project modification for the purpose of recreation. Recreation is cost shared 50 percent Federal and 50 percent non-Federal.

9. The Corps does have the authority to reallocate water at all five of the reservoirs. It is the Corps position that the primary purpose of the project would be to improve and sustain existing tail water trout fisheries, and the primary benefits that would be attained by the plan would be recreation. Based on existing law and Corps policy, the Corps could implement the reallocation with a willing non-Federal cost sharing sponsor in accordance with the cost-sharing for recreation as established by Section 103(c)(4) of WRDA 1986, 50 percent Federal and 50 percent non-Federal. In addition, under current Corps policies for reallocations of storage for recreation, the Corps would charge the recreation non-Federal sponsor for 50 percent of the updated costs of storage. With the income from the sale of storage, the Corps would credit SWPA for revenue losses. Absent assessment of charges for use of storage, the Corps would not have any means to compensate SWPA for the loss of hydropower and it is therefore anticipated that SWPA would have to reduce sales and raise its power rates to the power customers. As there would be implementation costs to the Federal government, appropriations in addition to the project's operation and maintenance budgets would be necessary to implement the reallocation project. To date, there have been no non-Federal sponsors that have agreed to cost share and participate in the implementation of the project in a manner consistent with Corps policy.

10. Other implementation scenarios that have been suggested by interested parties would require additional authorization and direction from Congress. Additional legislation would be needed to reduce the hydropower debt and the annual payment that SWPA makes to the Federal treasury by an amount equal to the annual loss of hydropower. This would eliminate or at least reduce the need for SWPA to increase their power rates as a result of the reallocation, but would not affect the potential for reductions in power sales. Additionally, further congressional direction and authorization would be needed to specify reallocation to a purpose other than recreation. The allocation of project costs could be based on a specific project purpose, or Congress could direct a specific cost-sharing percentage.

11. The district report makes no recommendation for any alternative plan or implementation option, nor further Federal actions regarding reallocation for minimum flows at the five Corps reservoirs. As such, NEPA coordination and public review have not been completed. However, throughout the reallocation study process, the Arkansas Game and Fish Commission (AGFC) and the Missouri Department of Conservation (MDC) have participated as project sponsors. SWPA, the U.S. Fish and Wildlife Service (USFWS), other Federal and state agencies, and the public have also participated in the reallocation study process. AGFC and SWPA have provided correspondence expressing their views regarding the district report. These letters are included in the district report. In summary, the AGFC fully supports the NED reallocation plans for all reservoirs in Arkansas, but they believe that the reallocation should be viewed as mitigation and

that the implementation costs should be 100 percent Federal. AGFC also supports the notion of crediting SWPA so that power rates are not increased. SWPA provides that of the 17 reservoirs that they market as a system, 57 percent of the total hydropower storage is located in those five White River projects. A loss of that water storage will negatively impact the reliability and marketability of the electricity. Any loss of electrical energy and capacity from the projects would have to be taken from current customers and could result in higher electrical rates. Power users have expressed that they do not want their power rates to increase as a result of the potential reallocations. SWPA has also provided alternative valuations of lost power benefits that have been included in the district's report. In some instances, use of the values provided by SWPA would result in different plans being economically justified. The U.S. Fish and Wildlife Service has expressed no objection to the implementation of the identified minimum flows reallocation alternatives and release scenarios. Full NEPA compliance and public review will be required if the Corps proceeds with implementation of a reallocation alternative for the White River Basin reservoirs.

12. I generally concur with the findings of the reporting officers. I find that the district report addresses the provisions of sections 374 of WRDA 1999 and 304 of WRDA 2000. I find that the reallocation alternatives identified in the district report generally conform with essential elements of the U.S. Water Resources Council's Economic and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies, and that the alternatives are technically sound, economically justified, and environmentally acceptable, based on information known at this time. I find that the reallocation alternatives do impact other project purposes to varying degrees, and the alternatives would incur costs to the Federal government. In addition, no non-Federal sponsor has agreed to cost share and participate in the implementation of the project in a manner consistent with Corps policy. Accordingly, I do not recommend Corps implementation of a reallocation alternative at this time.

13. This letter report constitutes the final report of the Chief of Engineers as required by the authorizing legislation. The district will make their report available to interested parties. The recommendation contained herein reflects the information available at this time and current departmental policies governing formulation of individual projects. It does not reflect program and budgeting priorities inherent in the formulation of a national civil works construction program or the perspective of higher review levels within the executive branch.

CARL A. STROCK
Major General, U.S. Army
Chief of Engineers

US Army Corps of Engineers
Little Rock District

WHITE RIVER MINIMUM FLOWS REALLOCATION STUDY REPORT

JULY 2004

DEPARTMENT OF THE ARMY
SOUTHWESTERN DIVISION, CORPS OF ENGINEERS
1100 COMMERCE STREET
DALLAS TX 75242-0216

Reply to
Attention of:

CESWD-PDS-P

MEMORANDUM FOR Commander, US Army Corps of Engineers (CECW-ZA), 441 G St. NW, Washington, DC 20314-1000

SUBJECT: White River Minimum Flows, Arkansas/Missouri, Reallocation Report

I concur in the conclusions of the District Engineer.

JEFFREY J. BORKO
Colonel, EN
Commanding

Executive Summary

White River Minimum Flows Study
29 July 2004

Authorization. The Water Resource Development Acts (WRDA) of 1999 (Section 374) and 2000 (Section 304) modified the basic authorization and operation for the five multipurpose White River Basin lakes: Beaver, Table Rock, and Bull Shoals Lakes on the White River; Norfork Lake on the North Fork River; and Greers Ferry Lake on the Little Red River (See Figure 1. Under the original authorization, water levels have been managed primarily for flood control and hydroelectric power generation, and to a lesser extent water supply. The directive in WRDA 1999 and 2000 creates a new procedure for storing and managing water in the five lakes and requires the Corps to assess project benefits in view of these changes. Because all of the storage space in the lakes is already allocated to existing purposes and no unused storage or surplus storage available, there would need to be a reallocation of storage to implement the added measure. The reallocated storage is intended to provide small releases from participating reservoirs whenever flood or hydropower releases are not being made to ensure continuous minimum stream flow downstream. The specific amounts authorized to provide minimum flows necessary to sustain tail water trout fisheries within each of the White River Lakes is:

Beaver Lake	1.5	feet
Table Rock Lake	2	feet
Bull Shoals Lake	5	feet
Norfork Lake	3.5	feet
Greers Ferry Lake	3	feet

Further, the Secretary of the Army was directed to transmit to Congress a report by the Chief of Engineers to determine if reallocations would adversely affect other authorized purposes and identify Federal costs that will be incurred as a result of the project modifications. The report would also include the findings whether the work is technically sound, environmentally acceptable, and economically justified.

The report is intended to provide and overview of an array of alternatives evaluated to respond to the fore mentioned legislative directive. Each alternative storage reallocation scenario are presented with technically sound solutions to providing the minimum flows. Also, they have been found likely to be environmentally acceptable. The technical solutions come at some cost, but the real challenge is finding a balance in the economic equation between existing project purposes and the newly added requirements. Further, the designation of the added new procedure to reallocate storage to sustain minimum flows as recreation, ecosystem restoration or mitigation has significant impacts on cost, who bears that cost, the implementation and outputs of each alternative scenario. An array of alternative scenarios and their costs and benefits are summarized on the following pages. Based on existing law, legislative authorities, and Corps policy, and absent any further direction from Congress, the Corps would implement reallocation as recreation (cost shared 50/50). Implementation of these modifications is conditioned on further direction by Congress by selecting one or more of the alternative scenarios. A Non-Federal sponsor and completing National Environmental Protection Act (NEPA) compliance will be required before implementation.

Facility Capabilities. In June 2001, the Little Rock District Corps of Engineers (SWL) in coordination with the Arkansas Game and Fish Commission (AG&FC), Missouri Department of Conservation (MDC), Southwestern Power Administration (SWPA), and the U.S. Geological Survey (USGS) conducted minimum flows test releases. Investigations were conducted to determine existing release capabilities at each dam to meet the minimum flows criteria. With the exception of Bull Shoals, the participating dams could not generate hydropower with their main turbines while making the minimum flow releases. Bull Shoals could generate a small amount of power while discharging the target flows but the other four facilities had to pull power from the grid and run the turbines like motors in order to produce the target flows. The target releases through the Bull Shoals turbine did not produce noticeable cavitations. The tests also concluded that the target discharge could not be made with existing station service (SS) units. Therefore before minimum flows can be implemented, facility modification must be made to each participating facility, with the exception of Bull Shoals.

The release alternatives studied included use of existing SS units and a new siphon system, new SS units capable of making entire minimum flow release, and siphon only system. At Bull Shoals only, the existing main turbine was included as a possible release alternative.

Storage Reallocation Scenarios. WRDA authorized the Little Rock District Corps of Engineers to reallocate specific "feet" of storage from each of the five White River reservoirs. Three reallocation plans were formulated. The Corps modeled and studied minimum flows storage reallocations from flood pool only, conservation pool only, and a 50 percent flood pool and 50 percent conservation pool (50/50) reallocation scenarios (note: for reallocation of flood storage the result is an increase to average lake levels. This increase could necessitate relocation of some lake recreation and access facilities. An estimate for the relocations is included in the report. The requirement for relocations is an issue for additional study prior to implementation of minimum flows.) At each dam, for each proposed storage reallocation, three release alternatives have been modeled and analyzed (except at Bull Shoals, where four release alternatives have been modeled and analyzed). WRDA directed the Corps to determine whether the minimum flow reallocations and modifications would adversely affect other authorized purposes. Therefore the intent of Congress through WRDA was to identify reallocation and release scenarios that meets the minimum flows criteria in a manner that is not only economically advantageous but also minimizes impacts/effects to the flood control, recreation, and hydropower purposes. The following alternatives are alternatives that produce results that minimize adverse impacts to existing, authorized users, are economically justified, technically sound, and been found to likely be environmentally acceptable. Flood benefits, hydropower benefits, and recreation benefits as well as ecological impacts were used to identify these alternatives. The Arkansas Game and Fish Commission, as a potential local sponsor, has expressed that the locally preferred implementation plan for the Arkansas reservoirs is the identified NED plan. For a more detailed discussion of locally preferred plans, see Section VII, Locally Preferred Plans, in the White River Minimum Flows Reallocation Study Report.

Table 1 lists some of the pertinent costs associated with the NED and alternate plans for each project site. Specifically, and in order from left to right, Table 1 details the Federal and Non-Federal sponsors' financial obligation for the capital cost of the updated cost of storage. The Federal and Non-Federal sponsor would be required to pay 50 percent of the updated cost of storage if the project is designated recreation or they would pay 65 percent (Federal) and 35 percent (Non-Federal) if the project were designated ecosystem restoration. Each project alternative has impacts to hydropower. Although hydropower is not the only authorized project purpose that is affected, it is the project purpose that is affected the most. The Hydropower Analysis Center (HAC) computed the hydropower benefit losses to the power-marketing agency, Southwestern Power Administration (SWPA). Although HAC followed Corps guidance and policy when it computed the hydropower benefit losses, SWPA computed their own benefit losses and these values have been listed for comparison purposes. Lastly, each alternative has a construction cost associated with it. Table 1 details the Federal and Non-Federal sponsors' financial obligation for the capital cost of the construction cost. The Federal and Non-Federal sponsor would be required to pay 50 percent of the construction cost if the project is designated recreation or they would pay 65 percent (Federal) and 35 percent (Non-Federal) if the project were designated ecosystem restoration.

a. Beaver Lake. BV4, Siphon and existing SS unit with a conservation pool reallocation, reduces hydropower benefits by 0.4 percent and improves flood control benefits. The benefit to cost ratio for BV4 is 6.3 to 1.0 and would be considered the National Economic Development (NED) plan. First costs for implementation are $827,000. The minimum flows operation at Beaver Lake would improve eight miles of trout fishery with an annual improvement to the trout fishing industry of $364,000.

The alternate plan to the NED plan is a scenario that minimizes negative impacts to authorized project purposes or produces the most improvement to existing users. The alternate to the NED plan is plan BV5, new SS unit with a conservation pool reallocation, improves hydropower benefits by 0.7 percent and improves flood control benefits. The benefit to cost ratio for BV5 is 1.4 to 1.0. First costs for implementation are $5,615,000. The minimum flows operation at Beaver Lake would improve eight miles of trout fishery with an annual improvement to the trout fishing industry of $364,000.

b. Table Rock Lake. The NED Plan is TR5, new SS units with a conservation pool reallocation, reduces hydropower benefits by 0.5 percent, improves flood control benefits, and improves in-pool recreation benefits. The benefit to cost ratio for TR5 is 1.3 to 1.0. First costs for implementation are $10,678,000. The minimum flows operation at Table Rock Lake would improve 22 miles of trout fishery with an annual improvement to the trout fishing industry of $1,000,000.

The alternate plan to the NED plan is a scenario that minimizes negative impacts to authorized purposes or produces the most improvement to existing users. An alternate plan that meets these criteria is TR8, new SS units with a 50/50 reallocation, reduces hydropower benefits by 0.3 percent , decreases flood control benefits, and decreases in-pool recreation benefits. The benefit to cost ratio for TR8 is 1.2 to 1.0. First costs for implementation are $11,643,000. There are no environmental concerns with this plan. The minimum flows operation at Table Rock Lake would improve 22 miles of trout fishery with an annual improvement to the trout fishing industry of $1,000,000.

c. Bull Shoals Lake. Plan BS3, using the main turbine to achieve the minimum flows with a flood pool reallocation, reduces hydropower benefits by 1.6 percent and results in a 1 percent reduction in flood control benefits, however, the plan produces significant increases in tailwater benefits. Because of this improvement to the tailwater fishery and the resulting net increase in project benefits, the benefit to cost ratio for this plan is 71 to 1, and is considered the NED plan. First costs for implementation are $462,000. The minimum flows operation at Bull Shoals Lake would improve 66 miles of trout fishery with an estimated annual improvement to the trout fishing industry of $2,999,000.

No alternate plan was chosen for Bull Shoals. The NED plan represents the plan most likely to be accepted by the non-federal sponsor and stakeholders due to its low hydropower losses, relative to other plans, and its low first costs. All other plans have greater hydropower losses and/or greater annual costs that reduce the benefit to cost ratio to a fraction of the NED plans benefit to cost ratio.

d. Norfork Lake. NF4, existing SS unit and siphon with a conservation pool reallocation, reduces hydropower benefits by 3.2 percent, improves flood control benefits, and improves in pool recreation benefits. The benefit to cost ratio for NF4 is 16 to 1.0 and is considered the NED plan. First costs for implementation are $975,000. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000.

An alternate plan is NF2, new SS unit with a flood pool reallocation, improves hydropower benefits by 0.6 percent, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for NF2 is 2.2 to 1.0. First costs for implementation are $9,788,000. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000.

A second alternate plan is plan.NF8, new SS unit with a 50/50 reallocation, has no impact to hydropower, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for NF2 is 2.2 to 1.0. First costs for implementation are $9,788,000. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000.

e. Greers Ferry Lake. GF4, existing SS unit and siphon with a conservation pool reallocation, reduces hydropower benefits by 1.8 percent, improves flood control benefits, and improves in pool recreation benefits. The benefit to cost ratio for GF4 is 20.2 to 1.0 and is considered the NED plan. First costs for implementation are $959,000. The minimum flows operation at Greers Ferry Lake would improve 30 miles of trout fishery with an annual improvement to the trout fishing industry of $1,363,000.

An alternate plan is GF5, new SS unit with a conservation pool reallocation, improves hydropower benefits by 0.3 percent, improves flood control benefits, and improves in pool recreation benefits. The benefit to cost ratio for GF5 is 3.52 to 1.0. First costs for implementation are $6,711,000. The minimum flows operation at Greers Ferry Lake would improve 30 miles of trout fishery with an annual improvement to the trout fishing industry of $1,363,000.

Environmental Summary. Little Rock District is coordinating with natural resource agencies in the preparation of an Environmental Impact Statement. An environmental summary identifying impacts to the ecological features associated with each reallocation alternative is included in Chapter III, Environmental Summary. This report package does not include a draft EIS but will quantitatively and/or qualitatively identify potential impacts (beneficial or negative). If approved, this report is not sufficient for reallocation and release implementation. The NEPA process must be completed including a complete EIS with full public involvement. The Nature Conservancy will perform the Independent Technical Review of the Draft EIS.

Figure 1
Study Area Map

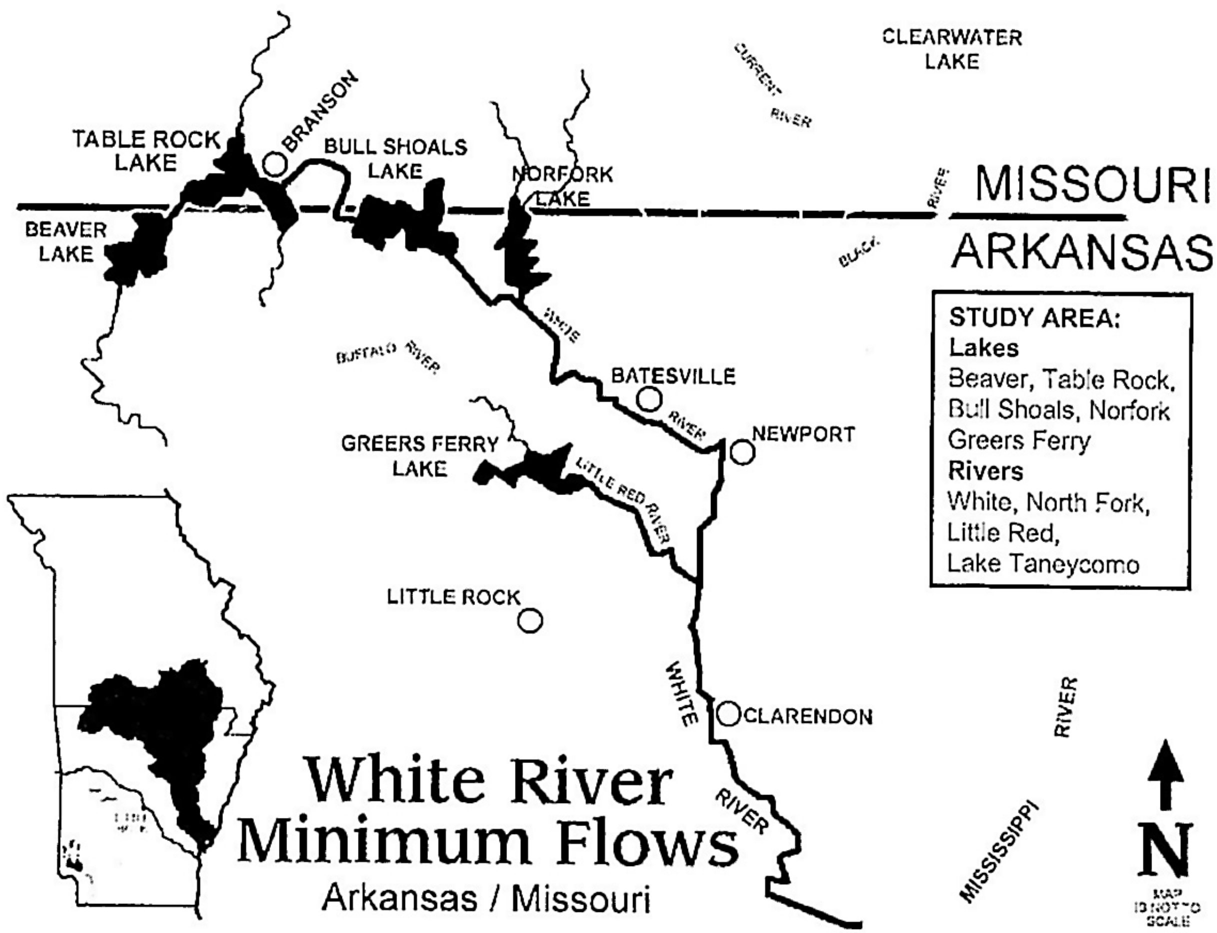


Table 1
Executive Cost Summary Table

Alternative	**Update Storage Cost - Cost Sharing Alternatives (First Cost)**			**Hydropower Benefits Forgone (Annual $'s) (1,3)**		**Facility Costs-Cost Sharing Alternatives (First Costs)**		
	Recreation	**Ecosystem Restoration**				**Recreation**	**Ecosystem Restoration**	
	50% Federal 50% Non-Federal (each)	65% Federal	35% Non-Federal	HAC Benefit Calculations	SWPA Benefit Calculations	50% Federal 50% Non-Federal (each)	65% Federal	35% Non-Federal
BV4 (2)	$ 2,157,000	$ 2,804,100	$ 1,509,900	$ 49,000	$ 483,000	$ 413,500	$ 537,500	$ 289,450
BV5	2,157,000	2,804,100	1,509,900	(92,000)	424,000	2,807,500	3,649,750	1,965,250
TR5 (2)	4,090,500	5,317,650	2,863,350	147,000	1,387,000	5,339,000	6,940,700	3,737,300
TR8	4,594,000	5,972,200	3,215,800	95,000	579,000	5,821,500	7,567,950	4,075,050
BS3 (2)	11,877,000	15,440,100	8,313,900	797,000	361,000	231,000	300,300	161,700
NF2	4,844,000	6,297,200	3,390,800	(72,000)	(6,000)	4,894,000	6,362,200	3,425,800
NF4 (2)	3,599,000	4,678,700	2,519,300	410,000	1,101,000	487,500	633,750	341,250
NF8	4,197,000	5,456,100	2,937,900	2,000	402,000	4,894,000	6,362,200	3,425,800
GF4 (2)	5,028,500	6,537,050	3,519,950	228,000	1,098,000	478,500	623,350	335,650
GF5	5,028,500	6,537,050	3,519,950	(45,000)	939,000	3,355,500	4,362,150	2,348,650

(1) Benefit calculations take into account the generation of energy from the minimum flow releases.
(2) NED Plan — alternative costs do not include interest during construction or operation and maintenance cost.
(3) See Main report, Section VI,b. Hydropower Revenues Forgone .

White River Minimum Flows
Reallocation Study
Report

APPENDICES

WHITE RIVER MINIMUM FLOWS STUDY

I. Study Background.

a. Authorization

The Water Resource Development Acts (WRDA) of 1999 (Section 374) and 2000 (section 304) modified the basic authorization and operation for the five multipurpose White River Basin lakes: Beaver, Table Rock, and Bull Shoals Lakes on the White River; Norfork Lake on the North Fork River; and Greers Ferry Lake on the Little Red River (See Figure 1. Under the original authorization, water levels have been managed primarily for flood control and hydroelectric power generation, and to a lesser extent water supply. The directive in WRDA 1999 and 2000 creates a new procedure for storing and managing water in the five lakes and requires the Corps to assess project benefits in view of these changes. Because all of the storage space in the lakes is already allocated to existing purposes and no unused storage or surplus storage available, there would need to be a reallocation of storage to implement the added measure. The reallocated storage is intended to provide small releases from participating reservoirs whenever flood or hydropower releases are not being made to ensure continuous minimum stream flow downstream. The specific amounts authorized to provide minimum flows necessary to sustain tail water trout fisheries within each of the White River Lakes is:

Beaver Lake	1.5 feet
Table Rock Lake	2 feet
Bull Shoals Lake	5 feet
Norfork Lake	3.5 feet
Greers Ferry Lake	3 feet

In addition, the Secretary was directed to transmit to Congress a report by the Chief of Engineers to determine if reallocations would adversely affect other authorized purposes, and if any Federal costs will be incurred in connection with the modification. Section 374 of WRDA 1999 and Section 304 of WRDA 2000 are quoted below.

Water Resource Development Act (WRDA) of 1999, Section 374 states:

SEC. 374. WHITE RIVER BASIN, ARKANSAS AND MISSOURI 1999.

(a) IN GENERAL. - Subject to subsection (b), the project for flood control, power generation, and other purposes at the White River Basin, Arkansas and Missouri, authorized by section 4 of the Act of June 28,1938 (52 Stat. 1218, chapter 795), and modified by House Document 917, 76th Congress, 3rd Session, and House Document 290, 77th Congress, 1st Session, approved August 18, 1941, and House Document 499, 83rd Congress, 2^{d} Session, approved September 3, 1954, and by section 304 of the

Water Resource Development Act of 1996 (110 Stat. 3711) is further modified to authorize the Secretary to provide minimum flows necessary to sustain tail water trout fisheries by reallocating the following amounts of project storage: Beaver Lake, 1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.

(b) REPORT. -

(1) IN GENERAL. - No funds may be obligated to carry out work on the modification under subsection (a) until completion of a final report by the Chief of Engineers finding that the work is technically sound, environmentally acceptable, and economically justified.

(2) TIMING. - The Secretary shall submit the report to Congress not later than July 30, 2000.

(3) CONTENTS. - The report shall include determinations concerning whether-

(A) the modifications under subsection (a) adversely affects other authorized project purposes; and

(B) Federal costs will be incurred in connection with the modification.

Water Resource Development Act (WRDA) of 2000, Section 304 states:

SEC. 304. WHITE RIVER BASIN, ARKANSAS AND MISSOURI 2000.

(a) IN GENERAL. - Subject to subsection (b), the project for flood control, power generation, and other purposes at the White River Basin, Arkansas and Missouri, authorized by section 4 of the Rivers and Harbors Act of June 28,1938 (52 Stat. 1218), and modified by House Document 917, 76th Congress, 3rd Session, and House Document 290, 77th Congress, 1st Session, approved August 18, 1941, and House Document 499, 83rd Congress, 2d Session, approved September 3, 1954, and by section 304 of the Water Resource Development Act of 1996 (110 Stat. 3711) is further modified to authorize the Secretary to provide minimum flows necessary to sustain tail water trout fisheries by reallocating the following recommended amounts of project storage: Beaver Lake, 1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.

(b) REPORT. -

(1) IN GENERAL. - No funds may be obligated to carry out work on the modification under subsection (a) until the Chief of Engineers, through completion of a final report, determines that the work is technically sound, environmentally acceptable, and economically justified.

(2) TIMING. - Not later than January 1, 2002, the Secretary shall transmit to Congress the final report.

(3) CONTENTS. - The report shall include determinations concerning whether-

(A) the modifications under subsection (a) adversely affects other authorized project purposes; and

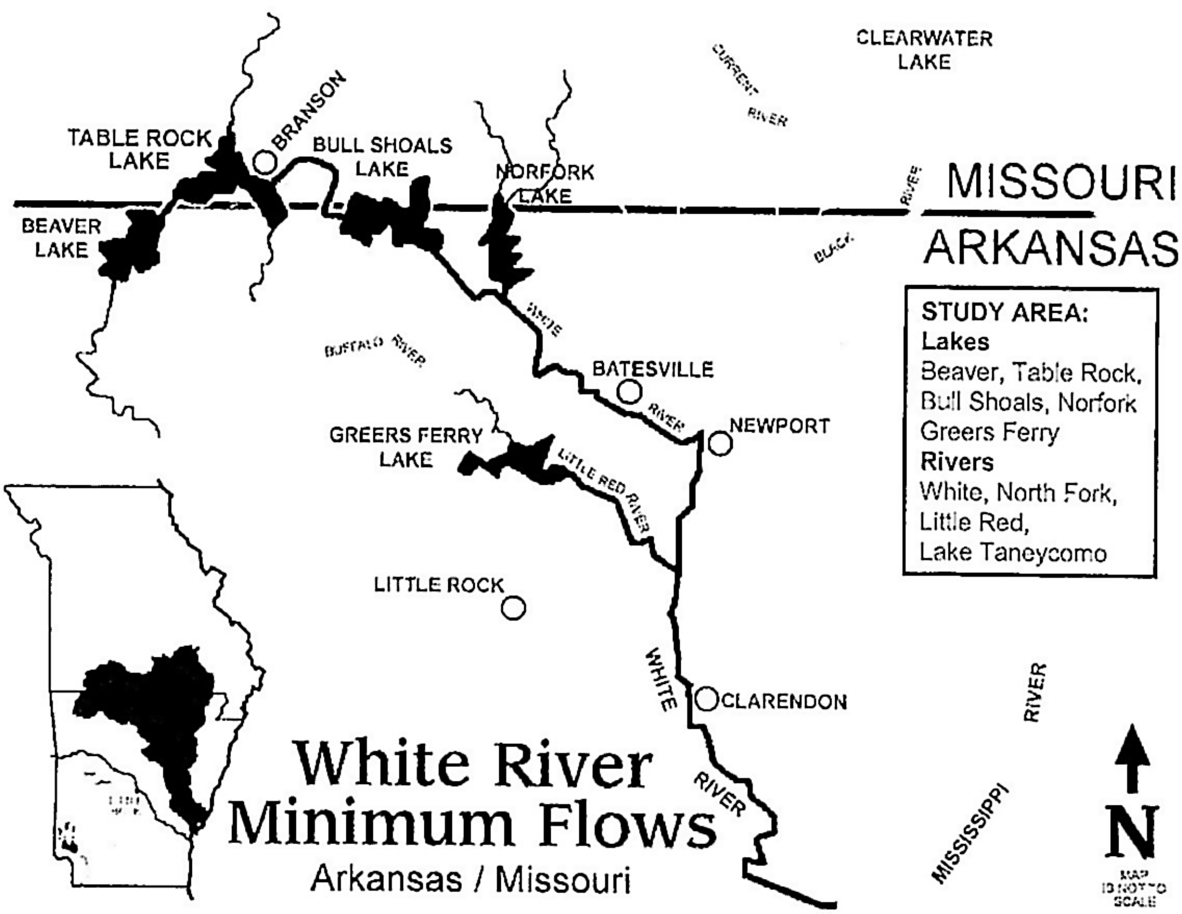
(B) Federal costs will be incurred in connection with the modification.

The report is intended to provide and overview of an array of alternatives evaluated to respond to the fore mentioned legislative directive. Each alternative storage reallocation scenario are presented with technically sound solutions to providing the minimum flows. Also, they have been found likely to be environmentally acceptable. The technical solutions come at some cost, but the real challenge is finding a balance in the economic equation between existing project purposes and the newly added requirements. Further, the designation of the added new procedure to reallocate storage to sustain minimum flows as recreation, ecosystem restoration or mitigation has significant impacts on cost, who bears that cost, the implementation and outputs of each alternative scenario. An array of alternative scenarios and their costs and benefits are summarized on the following pages. Based on existing law, legislative authorities, and Corps policy, and absent any further direction from Congress, the Corps would implement reallocation as recreation (cost shared 50/50). Implementation of these modifications is conditioned on further direction by Congress by selecting one or more of the alternative scenarios. A Non-Federal sponsor and completing National Environmental Protection Act (NEPA) compliance will be required before implementation.

b. Location

The study area includes Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry Lakes and their respective tailwaters along the White, North Fork, and Little Red Rivers. Figure 1 displays a map of the White river projects.

Figure 1: Study Area Map



Pertinent data for each project can be seen in the Pertinent Data Table below.

	BEAVER LAKE PERTINENT DATA		TABLE ROCK LAKE PERTINENT DATA		BULL SHOALS LAKE PERTINENT DATA	
Authorized Purposes	Current Storage Allocation		Current Storage Allocation		Current Storage Allocation	
Flood Control Pool	287,343 acre-ft	elev. 1120.43 - 1130	760,000 acre-ft	elev. 915 - 931	2,360,000 acre-ft	elev. 654 - 695
Conservation Pool	elev. 1077 - 1120.43		elev. 846 - 915		elev. 588 - 654	
- Hydropower	808,100 acre-ft		1,134,905 acre-ft		2,083,120 acre-ft	
- Water Supply	129,207 acre-ft		95 acre-ft		880 acre-ft	
- Fish and Wildlife	0 acre-ft		27,000 acre-ft		0 acre-ft	
- Recreation	0 acre-ft		0 acre-ft		0 acre-ft	

	NORFORK LAKE PERTINENT DATA		GREERS FERRY LAKE PERTINENT DATA	
Authorized Purposes	Current Storage Allocation		Current Storage Allocation	
Flood Control Pool	732,000 acre-ft	elev. 552 - 580	921,682 acre-ft	elev. 461.38 - 487
Conservation Pool	elev. 510 - 552		elev. 435 - 461.38	
- Hydropower	704,600 acre-ft		714,357 acre-ft	
- Water Supply	2,400 acre-ft		13,961 acre-ft	
- Fish and Wildlife	0 acre-ft		0 acre-ft	
- Recreation	0 acre-ft		0 acre-ft	

The lakes involved in the study have recreation facilities surrounding the lakes and downstream of the dams. The Corps has developed and continues to maintain over 80 parks around the participating lakes. These parks offer public use areas that include picnicking and camping facilities, launching ramps, and swim beaches. Also located on the lakes are commercial boat dock concessions where boat rental, boat storage, and other recreational supplies are available. The lakes support millions of recreational visits each year. In the 1960s, Table Rock Lake was termed “the fastest developing lake in the U.S.,” while Beaver reservoir developed into a residential lake with a few resorts. By 1982, Greers Ferry Lake was the seventeenth most visited Corps project in the nation. Additionally, according to the Arkansas Game and Fish Commission (AG&FC), the tailwaters of the five lakes support approximately 408,000 angler days per year, and 149,000 boat launches.

Currently, the lakes are authorized for flood control, hydropower, and water supply, but lake levels are not managed for the benefit of recreation. The directive in WRDA 1999 and 2000 creates a new operational consideration for the five lakes, and requires that the Corps reevaluate the use of these lakes considering the benefits of minimum flows to tailwater fisheries.

c. <u>Project Operation</u>

The objective of the existing White River Basin water management plan is to provide a comprehensive system of water use for the entire White River Basin. The plan incorporates all the basin projects and their many purposes. The plan provides seasonal flood control and hydropower releases based on the agricultural needs of the lower basin, and other land uses downstream of the projects. The plan also addresses the needs of the downstream fishery by providing a mechanism to maintain cool water temperatures based on monitored and forecasted ambient air temperatures. It also provides a deviation procedure to respond to unforeseen and emergency conditions which either are not in the plan or for which the plan is singulary inadequate.

1. **Flood Control**

The release of flood storage from Beaver, Table Rock, Bull Shoals, and Norfork Lakes is regulated by the Newport Guide Curve. Newport is located on the White River about 161 miles downstream of Bull Shoals Dam and just below the confluence with the Black River. Essentially, the amount of water released from the lakes is based on the stage (river height) at Newport. When the river stage at Newport is high, the lakes are storing water to prevent downstream flooding. Storing water causes lake levels to rise, filling up flood storage. Water is released from the lakes when the river stage at Newport begins to drop, until the lake levels are lowered back to the top of conservation pool. The lakes are lowered as quickly as possible to provide room for future floods, but at a rate which will not cause excess flooding downstream.

Once the release flow for a project is determined, the water is routed through the power turbines, or infrequently through the spillway or conduits as needed to meet the flood release requirement. Turbine releases are used as the first priority release mechanism unless they are incapable of supporting the required release.

The regulation plan calls for holding flood waters in Beaver’s flood pool whenever there is flood control storage in use at Table Rock or Bull Shoals. Beaver releases will be restricted thus conserving flood control storage in Table Rock, for the protection of the local reach immediately downstream, and in Bull Shoals, for flood regulation on the lower White River. For Bull Shoals and Table Rock, there is a prorated release plan based on respective reservoir storage in use, that provides for balanced reservoir filling. The regulation plan also provides for the prorating of flood control releases between Bull Shoals and Norfork so as to maintain equal percentages of available flood control storage in Norfork and the Beaver, Table Rock, Bull Shoals system. This provision amounts to a ratio of about 1.5 to 1.0 inches of runoff on the respective drainage areas and will better insure the full use of the total combined flood control storage when needed. Greers Ferry does not balance storage relative to the other four projects because the distance from the control points of the other projects precludes effective balancing. The releases from Greers Ferry are controlled by downstream regulating capacity primarily at Georgetown on the White River and secondarily to Judsonia on the Little Red River. Similarly to the four upper White River Basin projects, the primary release mechanism at Greers Ferry is the main hydropower turbines. If the turbines are incapable of making the required flood control release, addition releases are made through the spillway and or the conduit. Once the projects have emptied their flood control storages, hydropower and seasonal fishery requirements determine the project releases.

2. Hydroelectric Power

Hydropower produced at Corps dams in this region is marketed by the Southwestern Power Administration (SWPA). As described in the previous Flood Control section, the degree to which hydropower requirements control the quantity and timing of water releases depends on the elevation of the water stored and the stages at the downstream regulating control points.

When the lake elevations are in the flood pool, the Corps of Engineers controls the quantity and timing of all releases, until the conservation pool is reached. The one exception is the daily release volume needed for the generation of "firm power." Normally, hydropower production is constrained during downstream flood conditions. Even so, during flood control operations minimum hydropower releases are made to meet the requirements of firm power as set forth in the MOU between the Corps and SWPA dated 23 July 1980. Table 7-09, page 7-21 of the White River Master Manual lists minimum daily hydropower release volumes. During flood control operations, hydropower will be reduced to not less than these values. When restricted to firm power, the firm energy remaining for that day is computed by prorating the number of hours left in the day. If flooding conditions warrant greater restrictions, the Corps will declare a flood emergency and notify SWPA in accordance with the guidelines set forth in the draft Operating Arrangement between the Corps and SWPA. When in the flood pool, the primary objective of generation is to provide releases for recovery of flood storage space and operation requirements are forwarded to SWPA each weekday. Once in the conservation pool, SWPA determines the amount and timing of releases based on power needs, unless there is an overriding flood control or project need (e.g., additional releases in anticipation of a forecasted storm). Routine turbine releases are established at rates which will not exceed downstream regulating criteria.

3. Fisheries

The White River Lakes support in-lake and downstream fisheries that provide an important economic base for tourism. Construction of the dams and operation of the hydropower features contributed to the destruction of the warm water tailwater fisheries due to cold water releases. To replace the lost warm water fisheries, federally constructed fish hatcheries were constructed at Norfork and Greers Ferry. (Note: construction of the hatcheries was not part of the Corps White River projects. Rather, the hatcheries were funded under Department of Interior appropriations prior to the current concept of "mitigation".) This resulted in the development of a put-and-take cold water fishery downstream of each of the five multipurpose hydropower projects. The dependence of these trout fisheries upon hydropower releases has required consideration of downstream water temperatures when scheduling releases.

The largest of the fisheries is below Bull Shoals, extending downstream about 78 miles to Sylamore Creek. The North Fork River below Norfork is also a cold water fishery. Similar fisheries are below Beaver and Table Rock, both extending into the upper reaches of downstream lakes. The Lake Taneycomo fishery just downstream of Table Rock Lake is about 22 miles long and is the most densely used of the downstream fisheries. Below Greers Ferry the cold water fishery extends about 25 miles.

At Bull Shoals and Norfork a combined 2,000 day-second-feet (DSF) 3-day running average release is made when air temperatures at Calico Rock are forecasted at or above 85 degrees F and pool elevations are above 649 at Bull Shoals and 545 at Norfork. These requirements are part of a Memorandum of Understanding (MOU) between the Corps and SWPA. The Corps regulator must monitor the temperature sensors; these sensors are located below each of the hydropower projects and near the towns of at Fairview, Calico Rock, Sylamore, and Pangburn. These sensors request supplementary releases or changes in timing of releases as needed to keep water temperatures from exceeding 75 degrees F. The worst case scenario is a hot, dry 3-day weekend when generation requirements are at a minimum. At such times, without extra (non-power-related) releases pools in the river may be isolated by shoals and the fish may be unable to seek refuge in cooler waters.

d. <u>Problems</u>

The White River lakes were authorized and constructed primarily for flood control, hydroelectric power generation, and water supply. At Beaver, water supply storage was included in the original Congressional project authorization. Following construction, additional water supply storage has been added through reallocation at Beaver and at the other lakes. Also, subsequent to the construction of the lakes, municipal and industrial water supply, recreation, and environmental enhancement needs have developed.

Before the dams on the White, North Fork, and Little Red Rivers were built, these rivers provided warm-water fisheries. After construction of the dams, the tailwaters below the dams could not sustain warm-water fisheries because of the cold water hydropower releases. Federally constructed trout hatcheries were constructed and put-and-take trout were introduced and sustained in the tailwaters to offset the loss of the warm-water fisheries. However, no specific storage was ever authorized (prior to WRDA 99) in the lakes to maintain a minimum flow in the tailwaters. During periods of non-hydroelectric power generation, cold water releases are reduced drastically and the wetted perimeter of the tailwater is reduced.

The AG&FC has spent years studying the wetted perimeter in the tailwaters below the White River Dams that would most closely simulate healthy, natural trout fisheries. The result of the AG&FC's studies were the identification of optimum wetted perimeters obtained by the following target releases in cubic feet per second (cfs): Beaver Lake, 136 cfs; Table Rock Lake, 400 cfs; Bull Shoals Lake, 800 cfs; Norfork Lake, 300 cfs;

and Greers Ferry Lake, 200 cfs. The AG&FC obtained Congressional sponsorship for Section 374 of the Water Resources Development Act (WRDA) of 1999 and Section 304 of WRDA 2000, modifying the authorization of the White River lakes to reallocate specific amounts of project storage for the tailwater trout fisheries. Through this specific allocation of storage in the lakes for the trout fisheries, minimum flows may be sustained in the tailwaters during times of non-hydropower generation, increasing wetted perimetter and improving water quality.

The storage specified by WRDA is not enough to sustain the Minimum Flows releases during extreme drought years if the AG&FC target releases are maintained. "Yield" is defined as the rate of flow that a specific storage can provide while being discharged 24-hours per day, seven days per week, 365 days per year. Typically yield is defined as the constant release that can be sustained through a basin's drought of record. Study findings estimate the specified storage to be 80% to 90% "reliable" while meeting the proposed Minimum Flows criterea. While the storage identified in WRDA does not yield the target flow identified by the AG&FC, WRDA did not direct the Corps to optimize Minimum Flows releases to reflect the actual yield of the reallocated storage. No funds were to be obligated to carry out facilities modifications necessary to comply with the Minimum Flows criteria, "until the completion of a final report by the Chief of Engineers finding that the work is technically sound, environmentally acceptable, and economically justified".

e. Base Conditions

In the absence of action, the White River system will continue to be operated in accordance to current operational procedures; i.e., the lakes will be operated to provide flood control, hydroelectric power, municipal and industrial water supply, with due consideration to recreation and fish and wildlife demands. If the minimum flows provisions included in WRDA 1999 and 2000 are implemented, Little Rock District will include "minimum release" of water to sustain the downstream trout fishery. The Acts authorize the Corps to reallocate storage at each lake. The stored water will be used to make the target releases during low flow, hot weather periods when hydropower is not being generated. Since the WRDA specified storages cannot sustain the target minimum flows through a drought of record, there will be years when the Minimum Flows releases will be terminated because the Minimum Flows storage is depleted. These releases could not be implemented again until inflows recharge the storage.

II. Study Methodology and Models

The five projects identified in WRDA 1999 and 2000 are multipurpose projects. Each project has flood control, hydropower, water supply, recreation, and fish and wildlife functions. Little Rock District used the existing SUPER reservoir routing model to simulate 50 years of historical rainfall runoff in order to determine the impacts of the proposed minimum flows operations on other authorized purposes. Paragraph II.d., below, contains a detailed description of the use of the SUPER model. Output from the SUPER model was used to identify impacts to flood control and in-lake recreation. SUPER output was sent to Northwestern Division's Hydropower Analysis Center to quantify impacts to hydropower purposes. Little Rock District contracted with the University of Arkansas at Fayetteville to apply empirical economic methods to estimate willingness to pay for recreation impacts to the tailwater fisheries. North Pacific Division Hydropower Design Center devised non-power and power producing release alternatives, and the U.S. Geological Survey (USGS) performed minimum flows test release flow measurements.

a. Facility Modifications

In June 2001, Little Rock District, in coordination with the AG&FC, MDC, SWPA, and USGS, conducted minimum flows test releases. Investigations were conducted to determine existing release capabilities at each dam to meet the minimum flows criteria.   USGS took flow measurements to calibrate the main turbines, as well as to measure leakage, existing station service unit discharge, and hatchery outflow. The test releases produced a low flow-rating curve for the existing main turbines. Biologists measured the conditions produced by the target releases confirming that the releases did produce the favorable biological conditions predicted by the AG&FC. Local fishermen, landowners, and outfitters participated in the test release by observing and commenting on conditions produced by the target minimum flows release. The river conditions produced by the target flows were favorable to most wade fishermen, boat fishermen, outfitters, and landowners.

With the exception of Bull Shoals, the minimum flow releases through the participating dams were not adequate to generate hydropower with their main turbines. Bull Shoals could generate a small amount of power while discharging the target flows, but the other four facilities had to pull power from the grid and run the turbines like motors in order to produce the target flows. The target releases through the Bull Shoals turbine did not produce noticeable cavitations.   The tests also concluded that the existing station service (SS) units could not pass enough flow to meet the target discharge rates. Therefore, before minimum flows can be implemented, facility modifications must be made to each participating facility, with the exception of Bull Shoals. Little Rock District and North Pacific Division Hydropower Design Center (HDC) devised non-power and power producing release alternatives.

1. Existing Station Service Units and Siphons

The existing dam facilities include station service units (SS) that generate power for use by the Corps dam facilities. The SS units could be connected to the power grid so SWPA could market the excess power produced by the minimum flows target release not needed by the Corps facilities. However, the existing SS units are too small to make the full minimum flows release and will need an auxiliary release from a proposed siphon system. The auxiliary siphon system would include valves, a pipe through and along the dam, and a multi-layered intake system on the lakeside. This option provides the ability to remotely operate the valves to discharge a portion of the minimum flow releases in concert with the existing station service units. It would not affect other operations of the dam or powerhouse. The siphon is a non-power producing option.

2. New Station Service Units

One alternative considered was the installation of new SS units that would be large enough to discharge the entire minimum flows release. Similarly to the existing SS units, the proposed new SS units would be connected to the power grid so SWPA could market the excess power not needed by the Corps facilities.

3. Main Turbine

At Bull Shoals the minimum flows release was large enough to generate a small amount of hydropower with the existing main turbine. Use of the main turbine to facilitate minimum flows releases is considered an intermediate option or possibly the final solution at Bull Shoals. The remote operating computer language, SCADA, can be modified to use the main turbine for minimum flow releases. Test releases in June 2001 revealed that the use of main turbines to make minimum flows releases is only feasible at Bull Shoals.

4. Siphon Only

A siphon system includes valves, a pipe through and along the dam, and a multi-layered intake system on the lakeside. This option provides the ability to remotely operate the valves to discharge the minimum flows releases. It would not affect other operations of the dam or powerhouse. This is the only non-power producing option. A siphon only system has the most adverse impacts for the hydropower industry since no power can be generate and marketed during the minimum flow releases.

b. Alternatives for Reallocation

WRDA authorized the Little Rock District Corps of Engineers to reallocate specific vertical feet of storage from each of the five White River reservoirs. WRDA did not specify from which storage zone to reallocate the vertical feet of storage. Currently the lakes are divided into two zones, the flood pool and the conservation pool. Since each lake naturally has a roughly trapezoidal cross-section, its area increases with increasing elevation, so that the volume of storage provided by reallocating storage from the conservation pool is less than the volume of storage provided by the same vertical feet of storage from the flood pool. This is illustrated in Figures 2, 3, and 4 below.

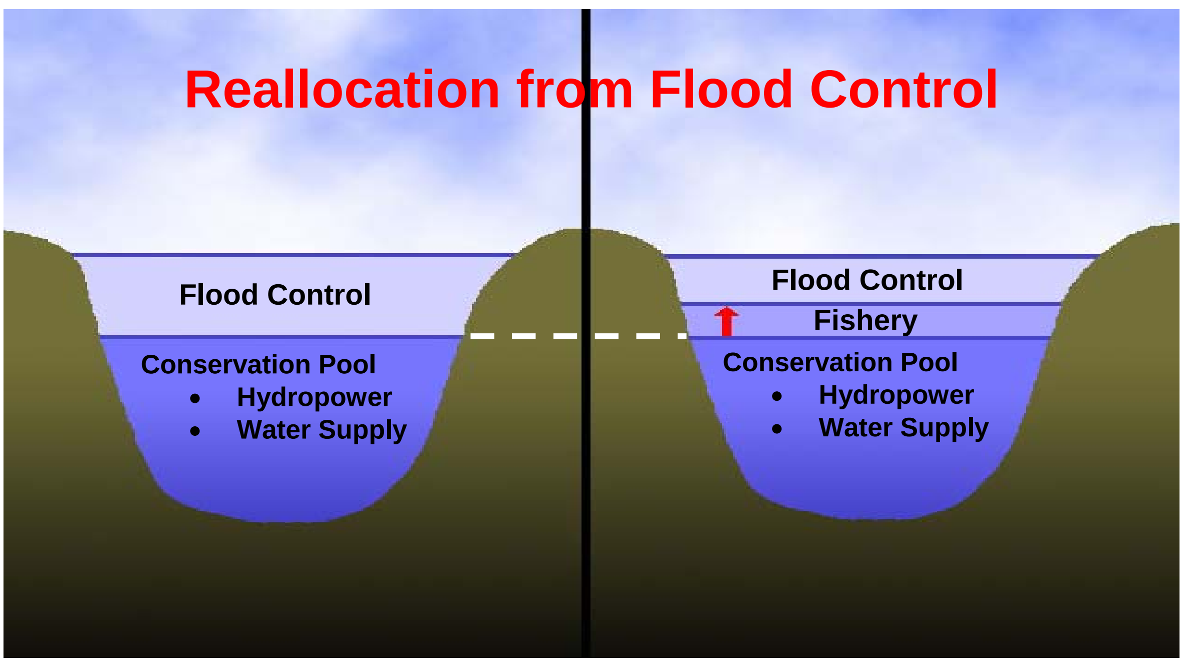
Three reallocation plans were formulated.

1. <u>Reallocate from Flood Pool</u>

The volume of the proposed minimum flows storage, in acre-feet, corresponding to the vertical feet of storage authorized in WRDA 1999 and 2000 was calculated by adding the proposed feet of storage to the elevation defining the current top of conservation pool (see Figure 2). A flood pool reallocation would therefore increase the volume of the conservation pool while reducing the volume of the flood pool by raising the top of conservation pool by the WRDA specified feet of storage. The volume of the incremental increase in conservation storage is calculated using the existing elevation-storage tables for each participating lake.

A flood pool reallocation would result in some changes to the Corps' flood operations. The Corps would continue to evacuate floodwaters as quickly as possible to provide maximum protection from future rainfall runoff. However, with a Flood Pool reallocation the Corps would cease flood operations sooner. Once flood releases are concluded, at the top of the new Conservation Pool, SWPA would either begin hydropower operations or minimum flows releases will resume.

Figure 2: Flood Pool Reallocation

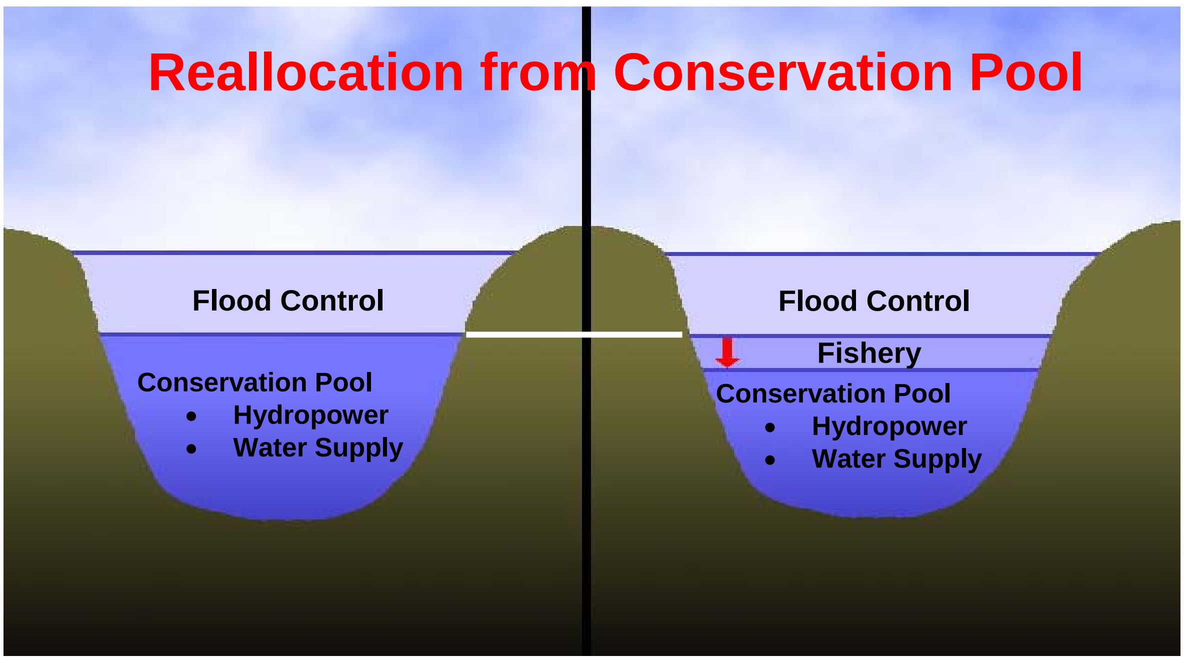


2. <u>Reallocate from Conservation Pool</u>

A conservation pool reallocation for minimum flows releases is a proportional reduction of volume used for hydropower generation. The volume of storage per foot at the top of the conservation pool is greater than volume of storage taken from the bottom of conservation pool. Therefore, the mid-point of storage was chosen as a reference point for the storage reallocation calculation so that a conservative volume of storage from the conservation pool would be taken from hydropower and designated for minimum flows. The mid-point method provides an average value of volume for the minimum flow releases in a manner equitable to both the hydropower purpose and the WRDA recommendation.

The volume of the proposed minimum flows storage, in acre-feet, corresponding to the vertical feet of storage authorized in WRDA 1999 and 2000 was calculated by first identifying the elevation representing the total storage mid-point of the Conservation Pool (see Figure 3). Second, the WRDA feet of storage was divided in half and added and subtracted to the mid-point elevation in order to establish the elevations bounding the volume of storage representing the WRDA feet. Finally, the acre-feet of storage to be reallocated for the minimum flows releases from the conservation pool was calculated by using the existing Conservation Pool elevation-storage tables, applying the upper and lower elevations bounding the WRDA storage to get respective acre-feet of storage, and taking the difference between to these two values, thus determining the incremental value of minimum flows storage in acre-feet corresponding to the WRDA specified vertical feet.

Figure 3: Conservation Pool Reallocation

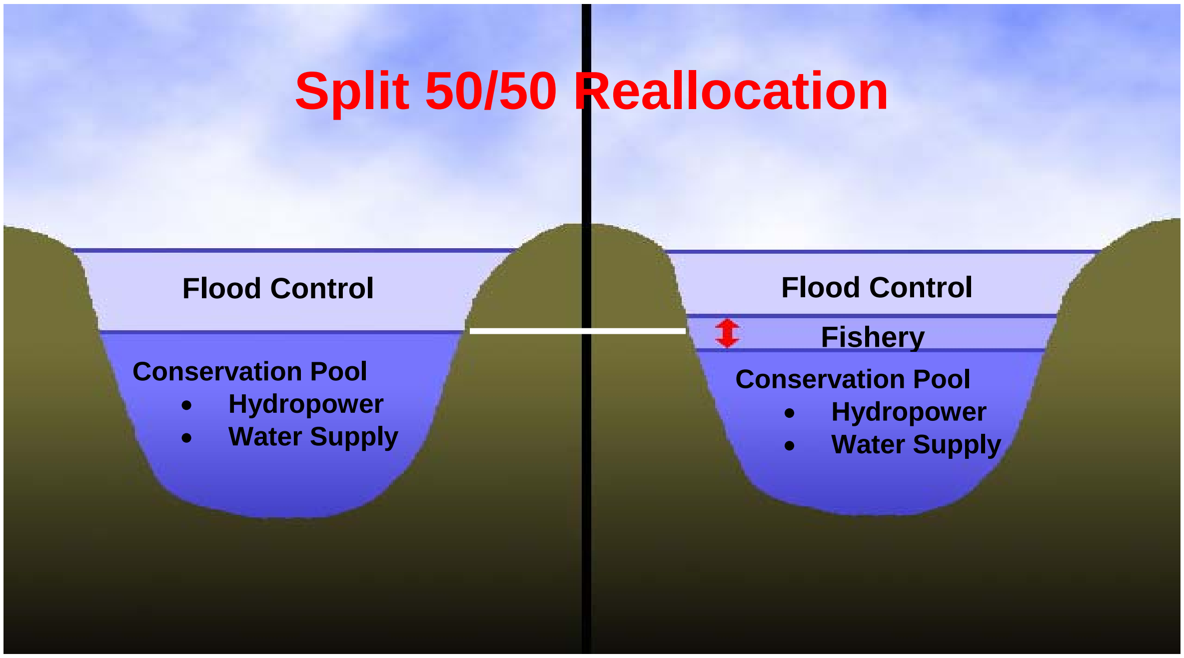


The reallocated Conservation Pool storage does not affect current flood operations. However, the minimum flows storage reallocated from the conservation pool reduces the storage available for hydropower generation. When the flood pool is empty, power is generated using water specifically allocated for that purpose. Once Corps flood releases are concluded, SWPA will still have the opportunity to use authorized storage to generate hydropower electricity. If SWPA chooses to not make hydropower releases, the minimum flow operations begin. During droughts the conservation pool may be depleted and refilled only when rainfall occurs. When hydropower storage is depleted due to drought, power-generating operations are stopped until inflows recharge conservation pool storage. Similarly to hydropower, in drought years the minimum flow releases will be halted whenever the specific volume of minimum flow storage has been used and will not be restarted until inflows have recharged the storage.

3. <u>Reallocate 50/50</u>

The volume of the proposed minimum flows storage, in acre-feet, corresponding to the feet of storage authorized in WRDA 1999 and 2000 was calculated in two steps. First, half of the proposed feet of storage was added to the elevation corresponding to the current top of conservation pool (see Figure 4). This resulted in an incremental increase in the top of conservation pool. The second step was similar to the conservation pool volume calculations mentioned in the **Conservation Pool Reallocation** paragraph above. With the 50/50 reallocation plan, the elevation of conservation pool storage mid-point was again located, and one quarter of the feet of WRDA defined storage was added and subtracted to the mid-point elevation. This defined a volume of storage corresponding to half of the required feet of storage. Applying the upper and lower elevations bounding the WRDA storage to get respective acre-feet of storage, then taking the difference between to these two values, half of the incremental value of minimum flows storage in acre-feet was calculated. The volume of the incremental rise into the flood pool was added to the incremental portion of the conservation pool to get the total volume of minimum flows storage corresponding to the WRDA feet of storage.

Figure 4: Split 50/50 Pool Reallocation



This reallocation scenario will result in reduced flood releases and reduced hydropower generation capability. The Corps will continue to evacuate floodwaters as quickly as possible to provide maximum protection from future rainfall runoff. However, with a flood pool reallocation the Corps will cease flood operations sooner than current operations. Once flood releases are concluded at the top of the new conservation pool, SWPA will either begin hydropower operations or minimum flows releases will resume. The reallocated conservation pool storage does not affect current flood operations. However, the portion of storage reallocated from the conservation pool reduces the storage available for hydropower generation. When the flood pools are empty, power is generated using water specifically allocated for that purpose. During droughts the power pool may be depleted and the lakes are refilled only when rainfall occurs. Once inflows replenish hydropower storage, SWPA will again have the opportunity to use their authorized storage to generate hydropower electricity. Similarly to hydropower, in drought years the minimum flow releases will be halted whenever the specific volume of minimum flow storage has been used and will not be restarted until inflows have recharged the storage.

c. <u>Hydropower</u>

The impact upon hydropower generation that will be caused by the proposed reallocation of storage for minimum flows releases from the five Corps of Engineers projects was calculated by Northwestern Division's Hydropower Analysis Center (HAC) using SUPER model output provided by Little Rock District. The hydropower valuation analysis included power benefits foregone, revenues forgone, and credit to the Federal Power Marketing Agency (Southwestern Power Administration). A copy of the Power Benefits Forgone Due to Storage Reallocation Report, prepared by HAC, is included in this report package as Appendix C. If a conservation pool reallocation plan is selected, and proposed minimum flows release methods does not generate power, SWPA's ability to produce hydropower benefits will be negatively impacted. SWPA's benefits, in certain cases, can be made whole by a combination of power producing release alternatives designated and Hydropower Yield Protection Operation (HYPO) reallocation plans (see paragraph **e. <u>Hydropower Yield Protection Operation</u>** below). For instance, Little Rock District's plan formulation includes proposed release alternatives capable of generating marketable power that minimizes impacts to SWPA, holds SWPA's yield whole, and in some instances produces net hydropower gains. Flood pool reallocation plans with HYPO keep SWPA's yield whole. The combination of flood pool reallocations with HYPO and marketable power from minimum flows releases significantly reduce negative impacts to SWPA.

It is noted that HAC and SWPA's hydropower impact analysis do not agree. HAC calculates capacity loss using the average year method, while SWPA contends that for this system, dependable capacity can only be calculated using the critical drought years. For NED analysis, the average year method is accepted and in agreement with current Corps policy. Therefore, that procedure is utilized in this report. Appendix A contains decision matrices that compare Corps and SWPA economic justification calculations. The SWPA calculations are included for comparison only; Corps hydropower calculations are used for economic justification.

d. <u>SUPER model</u>

The storage reallocation scenarios were modeled using the SUPER program, developed at the Southwestern Division of the Corps of Engineers. The SUPER program simulates, on a daily basis, the regulation of a system of multipurpose reservoirs based on a specified plan of regulation. The hydrologic output is presented in average daily values such as average daily lake level elevations. Project releases and river flows are given as daily average flows. Pool elevations are given as midnight elevations. For the White River Minimum Flows Study, Little Rock District modified the SUPER model algorithm to include a function that allowed SUPER to stop minimum flows releases when storage was depleted and restart releases once storage was recharged. Consistent with other Little Rock District uses of SUPER, the impacts of White River Minimum Flows operations were simulated over a 50-year period of record of historic rainfall and inflow.

The White River "Current Conditions" model was updated to reflect changes since 1998. The "Current Conditions" model is SUPER run W01X01 (first White River run of 2001). The changes are listed as follows:

(a) <u>Hydropower</u>. SWPA revised the SUPER hydropower loadings in April 2001. These changes were incorporated into the model. The power plant efficiency was changed to 0.85 for all the hydropower projects.

(b) <u>Reservoir Leakage and Water Supply Withdraw</u>.

Project	House (cfs)	Leakage (cfs)	Hatchery (cfs)	Total (cfs)	Water Supply (cfs)
Beaver	20	35	18	73	261.2
Table Rock	20	80	20	120	0.12
Bull Shoals	50	160	0	210	1.55
Norfork	20	55	40	115	7.74
Greers Ferry	20	30	20	70	20.86

(c) <u>Flood and Recreation Benefits.</u> The updated economics data is now current to FY-2001. The variables XLP (Late Plant Cost in dollars per acre), XNP (Net Profit in dollars per acre), and XPC (Production Cost in dollars per acre) were updated for improved pasture, Unimproved pasture, Soybeans, rice, corn, cotton, grain sorghum, alfalfa, wheat, double crop soybeans, and double crop wheat. The stage damage curves for Normal Cleanup were updated for Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry lakes. The Recreation Benefit functions were updated for Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry lakes.

The White River "Current Conditions" model was modified to simulate water supply reallocation from the power pool. The changes are listed as follows:

Required Minimum Flows Release. The existing house release, leakage rate, and hatchery discharge were subtracted from the target flow in order to identify the additional release needed to meet the minimum flows criteria. The incremental portions of the minimum flows release are shown below.

Project	House (cfs)	Leakage (cfs)	Hatchery (cfs)	Increase (cfs)	F/W Release Req'd (cfs)
Beaver	20	35	18	63	136
Table Rock	20	80	20	280	400
Bull Shoals	50	160	0	590	800
Norfork	20	55	40	185	300
Greers Ferry	20	30	20	130	200

The White River "Current Conditions" model was modified to simulate water supply reallocation from the flood pool. Below are descriptions of the storage reallocation scenarios. The run number is W02X08. The changes are listed as follows:

Raise top of Power Pool. The top of Power Pool was raised for each hydropower project to model the effect of reallocation from the flood pool. The Power Pools were raised as follows:

Project	Current Cond. EL. (ft.)	Increase (ft-msl)	Reallocated EL. (ft-msl)
Beaver	1120.43	1.5	1121.93
Table Rock	915	2	917
Bull Shoals	654	5	659
Norfork	552	3.5	555.5
Greers Ferry	461.3	3	464.3

Required Fishwater Release. The existing house release, leakage rate, and hatchery discharge were subtracted from the target flow in order to identify the additional releases needed to meet the minimum flows criteria. The incremental portions of the minimum flows release are identical to the releases for a conservation pool reallocation.

The White River "Current Conditions" model was modified to simulate splitting the water supply reallocation between the conservation pool and flood pool. The run number is W02X09. The changes are listed as follows:

Raise top of Power Pool. The top of Power Pool was raised for each hydropower project to model the effect of dividing the reallocation between the flood pool and the power pool. The Power Pools were raised as follows:

Project	Current Cond. EL. (ft.)	Increase (ft-msl)	Reallocated EL. (ft-msl)
Beaver	1120.43	0.75	1121.18
Table Rock	915	1	916
Bull Shoals	654	2.5	656.5
Norfork	552	1.75	553.75
Greers Ferry	461.3	1.5	462.8

Required Fishwater Release. The existing house release, leakage rate, and hatchery discharge were subtracted from the target flow in order to identify the additional releases needed to meet the minimum flows criteria. The incremental portions of the minimum flows release are identical to the releases for a conservation pool reallocation.

e. Hydropower Yield Protection Operation (HYPO)

Expanding conservation storage into the flood control pools will reduce the critical period dependable yield (which is produced from storage and inflow) per unit of storage. This occurs because, even though there is more conservation storage available from which to draft water, the inflow into the reservoir remains the same. Since existing water supply users will be sharing the same inflow, the yield per unit of storage decreases even though the total yield of the project increases. To avoid such negative impacts, sufficient storage will be reallocated to maintain the dependable yield of the existing water supply users while supplying water for fishery needs. This additional storage required to keep existing users whole is termed Dependable Yield Mitigation Storage (DYMS). This was applied to all water supply users. However, for hydropower the amount of time and or reliability of the storage assigned to the WRDA specified storage, was reduced in order to lessen the adverse Hydropower impacts. This operation is called Hydropower Yield Protection Operation (HYPO).

WRDA 1999 and 2000 authorized the Corps to reallocate a specified number of vertical feet of storage from each project to supply a minimum fishery flow. Three scenarios are evaluated; supplying fishery flow from the existing conservation storage, from a split of the needed storage with ½ from the existing conservation storage and ½ from the flood control storage, and all of the needed storage coming from the flood control pool. Figure 5 below is a table of the reallocated storage including the DYMS and HYPO storage to maintain the yield of the water supply users and the storage needed to minimize impacts to hydropower yield.

Figure 5: HYPO Data

100% FLOOD POOL REALLOCATION			
Project	WRDA Storage (Acre-Feet)	DYMS - HYPO (Acre-Feet)	Trout Storage (Acre-Feet)
Table Rock	87,000	48,308	38,692
Bull Shoals	233,000	111,271	121,729
Norfork	78,600	46,499	32,101
Greers Ferry	95,700	66,410	29,290

50% FLOOD POOL 50% CONSERVATION POOL REALLOCATION			
Project	WRDA Storage (Acre-Feet)*	DYMS - HYPO (Acre-Feet)	Trout Storage (Acre-Feet)
Table Rock	43,000	24,251	18,749
Bull Shoals	114,500	57,549	56,951
Norfork	38,900	21,881	17,019
Greers Ferry	47,600	39,241	8,359

* This is the flood control portion of the WRDA storage only. The total trout storage available to AG&FC also includes storage from Conservation Pool.

Project	WRDA Con. Storage (AF)	Trout Storage (AF)	Total Storage (AF)
Table Rock	34,500	18,749	53,249
Bull Shoals	98,800	56,951	155,751
Norfork	29,200	17,019	46,219
Greers Ferry	41,600	8,359	49,959

The input data for the reservoir routing model "SWD-SUPER", with the fishery storage accounting, was revised to include the DYMS and HYPO storage amounts, reducing the storage for the fishwater account. The resulting output was subjected to hydropower analysis. Benefits foregone were reduced as was energy gained through the fishwater release options. Revenue foregone was also reduced. Credit to the power-marketing agency, SWPA, was reduced as well, except for Beaver. The differences in the benefits come from the fact that under the DYMS and HYPO adjustment there is less water released for fish and in most years more water is retained in reservoir storage producing more energy.

f. Recreation

The incremental impact to recreation was considered for both lake recreation and tailwater recreation for each reallocation scenario. The tailwater recreation calculation was not part of the SUPER model analysis.

1. Tailwater Recreation

The University of Arkansas at Fayetteville (UAF) was contracted to estimate the economic benefits of increased minimum flows in the White, Norfork, and Little Red Rivers. UAF used the contingent valuation method (CVM) and statistical inference to determine respondent's willingness-to-pay, and then extrapolated those values to a broader population. The UAF report identifies two sets of values corresponding to tailwater recreation benefits associated with the proposed Minimum Flows releases. Copies of the UAF reports, CVM calculations, and CVM explanations are included in Appendix D.

Little Rock District hosted an Alternative Formulation Briefing (AFB) on 20 November 2003. Among the attendees, it was agreed that the Little Rock District would revise the CV benefits to eliminate existence values from the study. An existence value is a benefit received without direct use of a resource. For example, it would be the benefit someone derives from simply knowing the minimum flow releases had improved the trout habitat, without their actually fishing there. In order to remove these existence values, Little Rock District used data from the original surveys that indicated which respondents currently fish or would start fishing the tailwaters as a result of minimum flows implementation. This data was then used to recalculate the two sets of CV benefits. The most conservative revised estimate for tailwater recreation benefits is more than $3.4 million. The most optimistic revised value for tailwater benefits is over $21 million. The District has chosen to use the mid-point value from the conservative set of CV benefits. The average annual value of this benefit is about $7,044,000. It is noted that, because of the removal of existence values from the analysis, these estimates are based on a small sample size, and reflect less than fully rigorous statistical inference. See Appendix D for a complete explanation of the CVM calculations.

The CVM benefits were distributed by prorating increased recreation benefits by trout stream miles below each participating reservoir. The trout stream miles below Bull Shoals and Norfork Lakes are shared and were computed by splitting the river miles below the confluence of the Norfork and White Rivers. The miles of trout stream credited to each reservoir and the associated benefits are listed below in Table 1. A data request to AG&FC revealed that the statistical data defining the recreational capacity of trout fisheries in Arkansas could not be provided within the current Corps study schedule. AG&FC did qualitatively confirm that the capacity of the fisheries included in the study could adequately sustain the increased recreational demand that would result from the proposed minimum flows operations. See Appendix D for preliminary trout stream recreation demand and capacity calculations.

TABLE 1: Miles of Trout Stream by Project

SITE	Downstream Trout Fishery (miles)	Annual Benefits per Site
Beaver Lake	8	$364,000
Table Rock Lake	22	$1,000,000
Bull Shoals Lake	66	$2,999,000
Norfork Lake	29	$1,318,000
Greers Ferry Lake	30	$1,363,000
TOTALS	155	$7,044,000

In addition to the multi-reservoir analysis, a single reservoir analysis was completed to estimate the benefits of Minimum Flows. The underlying reason for the examination of benefits for a single reservoir is due to the uncertainty of implementing Minimum Flows at all five reservoirs. Therefore, Bull Shoals was chosen for this examination because it is one of the two projects cited in the surveys, it has the lowest implementation costs, and Bull Shoals has the most downstream trout fishery miles.

For this analysis, nearly identical procedures were used to calculate benefits. The most conservative and optimistic benefit estimates are $2.5 and $3.25 million, respectively. An explanation of the benefit calculations is in Appendix D.

2. <u>Lake Recreation</u>

The impact to lake recreation was calculated using SWD's SUPER model. SUPER uses seasonal visitor day curves to calculate recreation benefits with respect to pool elevation. The SUPER model analyzes historical information to estimate damages based on changes to stage and duration levels. There is a negative correlation between high-water conditions and visitor accessibility. SUPER model used the historical data and unit day values to determine the change in recreation benefits.

The unit day values were obtained by using Economic Guidance Memorandum 01-01, Unit Day Values for Recreation, fiscal year 2001. EGM 01-01 describes the unit day value method as the following:

> "The unit day value method for estimating recreation benefits relies on expert or informed opinion and judgment to approximate the average willingness to pay of users of Federal or Federally assisted recreation resources. … By applying a carefully thought-out and adjusted unit day value to estimated use, an approximation is obtained that may be used as an estimate of project recreation benefits."

The unit day value estimate was based on a point scale in the guidance memorandum. Points were assigned, by informed opinion, to five different categories: Recreation Experience, Availability of Opportunity, Carrying Capacity, Accessibility, and Environmental Quality. This value was used in conjunction with the SUPER model's stage duration and visitor data to determine the change in recreation benefits due to a change in stage and duration from the implementation of minimum flows.

Table 2 details the affected areas, change in recreation benefits, and costs to maintain and relocate facilities. The campsites and day use areas that would be inundated by water due to increased stage and duration are campgrounds and parks. The costs associated with a flood pool and split reallocation are due to relocating roads, parking lots, restrooms, picnic areas, boat ramps, and electrical facilities.

TABLE 2: Recreation Facility Costs and Benefits Foregone

	# of campsites & day use areas affected			Change in Recreation Benefits			Cost to Relocate Facilities		
Reallocation Scenario	Conservation Pool	Flood Pool	Split 50/50	Conservation Pool	Flood Pool	Split 50/50	Conservation Pool	Flood Pool	Split 50/50
Lake									
Beaver	N/A	49	25	3,000	(21,000)	(8,000)	N/A	$ 5,777,000	$ 2,889,000
Table Rock[1]	N/A	11	6	13,000	(97,000)	(43,000)	N/A	33,424,000	16,712,000
Bull Shoals	N/A	106	53	(33,000)	(139,000)	(51,000)	N/A	22,886,000	11,443,000
Norfork	N/A	84	42	13,000	(70,000)	(25,000)	N/A	12,212,000	6,106,000
Greers Ferry	N/A	31	16	14,000	(207,000)	(100,000)	N/A	7,681,000	3,841,000

[1] Table Rocks relocation costs are disproportional to the number of campsites affected due to 1.8 million square feet of roads and parking lots that would need to be relocated.

g. Flood Control

Flood control impacts were calculated by SUPER model. All stage damage curves were updated with the latest crop and property values. The benefits gained or forgone at the downstream index station for each reallocation alternative was distributed to the participating projects by prorating downstream impacts based upon historic flood damage prevention ratios. HEC-PBA, Project Benefit Accomplishment, package is a program that generates distribution ratios used to account for flood damages prevented with respect to contributing projects. The actual distribution ratios calculated for the years 1996 through 2001for the White River Basin were averaged and used to distribute flood control impacts associated with the White River Minimum Flows SUPER runs. The HEC-PBA values used in this study process went into the annual Reservoir Control Center (RCC) Reports for 1996 through 2001 and sent to SWD and HQUSACE.

h. Cost of Storage

The authorizing legislation directed the Corps to identify Federal costs incurred in connection with the project modifications. Costs for modifications to turbines, operating systems, relocations, and other costs, have been identified and are displayed in Appendix A, Economics. However, the legislation was silent on the issue of "storage costs". When the Corps reallocates storage for new water supply customers, the customer, in accordance with Corps regulations must repay the cost of that storage. Both WRDA 1999 and 2000 authorized the reallocation of storage for the purpose of minimum flow releases to be used to improve the trout habitat without mention of cost of storage. A letter dated 15 July 2003 from Congressman Boozman, 3rd District, Arkansas, stated that, "the intent of Congress was to require the local sponsor to cost share construction costs construction expenses, it was never their intent to require either Southwestern Power Administration or the project sponsors to pay for water storage reallocated for this project." Also, SWPA has made it clear that their financial burden should be reduced proportionally for any storage taken away from hydropower for use by another purpose.

1. Actual Cost of Storage

Under this alternative the sponsor would be required to repay the original cost of the storage that is being reallocated. The five White River Projects were completed during the period 1945 to 1965. Little Rock District's final cost allocation reports provided the finalized construction costs and interest rate for each project. These costs and interest rates were used to estimate the cost of storage that would have been charged if minimum flows had been implemented at the completion of each project. These costs are detailed in Appendix A. Although Little Rock District does not recommend cost of storage as a local cost, it is shown for informative purposes.

2. Updated Cost of Storage

Under this alternative the sponsor would be required to repay the updated cost of storage. Updated cost means the original costs of the project have been inflated to FY03 dollars. The storage cost is then based on this updated cost, the planning interest rate, and the amount of the reallocation. Again, Little Rock District's final cost allocation reports provided the finalized construction costs for each project. As directed in the IWR Report 96-PS-4, Chapter 4, Sections 4-5, the Engineering News Record (ENR) and Civil Works Construction Cost Index System (CWCCIS) were used to inflate project dollars. These costs and the current planning interest rate were used to estimate the updated cost of storage.

3. Calculating Storage Costs

Both the actual and updated storage costs are calculated similarly. The joint-use project costs, joint-use Operation and Maintenance (O&M) costs, and usable project storage data were taken from the final cost allocation reports and used to determine the storage cost. The ratio of the proposed reallocation to usable project storage is multiplied by the joint-use project cost to determine the cost of storage. Also, the ratio of the proposed reallocation to usable project storage is multiplied by the joint-use O&M cost to determine the proportional share of O&M that would need to be paid. The cost of storage and proportional share of O&M costs make up the total storage cost. This cost is then amortized over a 50-year period at the applicable interest rate. The actual cost of storage calculations use the actual joint-use costs, actual joint-use O&M, and a 2.5 percent interest rate while the updated cost of storage uses the updated joint-use project costs, FY03 joint-use O&M costs, and the FY04 planning interest rate, 5.625 percent. Appendix A shows the cost of storage by plan. For plan identification see tables in Section IV, Plan Formulation.

i. NEPA

Little Rock District, in preparing an Environmental Impact Statement (EIS), conducted multiple public meetings in 2001. An environmental summary identifying impacts to the ecological features associated with each reallocation alternative is included in Section III, Environmental Summary. This report package does not include a draft EIS but will quantitatively or qualitatively identify potential impacts (beneficial or negative). The NEPA process must be completed including a complete EIS with full public involvement prior to implementation of Minimum Flows measures.

III. Environmental Summary

This is a quantitative and qualitative summary of impacts identified in the development of the draft EIS. The draft EIS is under development and has not been distributed for public review. The NEPA document will require public review prior to implementation of the project.

The alternatives being analyzed in the ongoing study consist of reallocating storage for minimum flow releases out of the flood control pool, conservation (hydropower) pool, or a combination of 50 percent flood control and 50 percent conservation pool. The lake effects are direct effects to the USACE lands within the multipurpose projects' area or the tailwaters of each.

The H&H analyses and Super output were the primary tools used in this evaluation. The following is a brief description of the considerations used in this environmental consideration document. Table 3 below indicates the changes in the surface area of the conservation pool and flood pool under the different alternatives considered.

TABLE 3: Surface Area Change of the Conservation Pool Relative To Each Alternative

LAKE	REALLOCATION (feet)	STORAGE POOL	CONSERVATION POOL ELEVATION	SURFACE AREA (acre)	ACRE INCREASE	CHANGE (%)	STORAGE (acre ft)
Beaver	1.5	Conservation Pool	1,120.43	28,370			1,664,198
		Flood Pool	1,121.93	28,895	525	1.9	1,707,098
		50/50	1,121.18	28,633	263	0.9	1,685,648
Table Rock	2	Conservation Pool	915	43,070			2,702,000
		Flood Pool	917	44,140	1,070	2.5	2,789,000
		50/50	916	43,600	530	1.2	2,745,000
Bull Shoals	5	Conservation Pool	654	45,440			3,048,000
		Flood Pool	659	48,005	2,565	5.6	3,281,000
		50/50	656.5	46,715	1,275	2.8	3,162,500
Norfork	3.5	Conservation Pool	552	21,990			1,251,200
		Flood Pool	555.5	22,933	943	4.3	1,329,900
		50/50	553.75	22,454	464	2.1	1,290,138
Greers Ferry	3	Conservation Pool	461.44	31,598			1,924,360
		Flood Pool	464.44	32,654	1,056	3.3	2,020,300
		50/50	462.94	32,118	520	1.6	1,972,080

a. Lake or Shoreline Impacts

1. Lake Fisheries

Fisheries management options of large multipurpose reservoirs are limited due to the water level management objectives. Many times, lakes of this nature exemplify the "boom or bust" condition in standing crops. The shoreline is characterized by bluffs, shelf-rock, boulder, and cobble. Clay, silt, and sandy substrates are limited but occasionally occur in tributaries. There is very little aquatic vegetation and vegetative cover occurs only when encroaching terrestrial vegetation is inundated.

When comparing the effects of the proposed alternatives on the in-lake fisheries of the White River reservoirs, effects can generally be categorized as “minor adverse” if during the spawning and growing season of March through August lake levels are less than current operating conditions. Conversely, effects are said to be beneficial if the lake levels are higher during this same period. This is due to the fact that a healthy fishery requires that during the spawning season of March through June water levels should ideally be rising to flood potential spawning habitat and then remain stable or decline slowly during the growing period through summer.

Hydrologic modeling indicates that in general reallocation from the flood control pool essentially raises the top of the conservation pool and therefore would provide higher water levels in the lakes than under the current operating procedures. In theory and as stated previously these higher water levels would provide better spawning habitat for the lake fishery. The actual change in water levels depends on the amount of reallocation and other hydrologic conditions such as rainfall and inflows from upstream releases, would not be the same for every reservoir, and would differ from year to year.

Therefore, in general, reallocation from the flood control pool could provide beneficial effects to the lake fishery, however due to the topography of the White River Lakes with their steep shorelines the beneficial effects would be less than lakes with a definite flood plain around its shoreline.

In contrast to reallocation from the flood control pool, reallocation from the conservation (hydropower) pool would generally lower the conservation pool and therefore result in lower water levels than are currently obtained under the current operating procedures.

This lower lake level would be different in every reservoir and would be dependent on hydrologic conditions such as rainfall and upstream inflows.

Lower lake levels would not provide additional spawning habitat and could potentially exclude existing habitat that now exists. Therefore, this would generally be adverse to the fishery of the lakes.

Hydrologic modeling of reallocating from the conservation pool has shown that during the spawning and growing period lake levels would generally be lower, however in some of the reservoirs during some years the difference would be immeasurable.

A “split” reallocation of 50 percent from the flood pool and 50 percent from the conservation pool would result in lake levels that are generally higher than current conditions but lower than if taken out of the flood control pool. From an in-lake fishery viewpoint, this alternative would provide some beneficial effects through higher lake levels but not as high as from the flood control pool.

As previously stated the topography of the reservoirs (steep sided) limits the benefits of high water levels for spawning since there are limited flood plains to inundate. Higher water levels would provide some benefit for a few years by inundating vegetated areas that are currently never flooded. This would be temporary however, since the fishery habitat would eventually return to their current conditions since this vegetation would be drowned out. The health of the in-lake fisheries has and continues to be limited not by higher or lower lake levels alone but by the timing of lake levels during critical periods of the year.

In conclusion, the following general statements can be made about the alternatives being studied when compared to current conditions:

Reallocation from the flood control pool will provide limited minor benefits to the in-lake fishery by temporarily providing limited additional spawning habitat. The "split" alternative would potentially provide less benefit than the flood control reallocation. The reallocation of the conservation (hydropower) pool would result in minor adverse effects by potentially eliminating existing spawning habitat. It should be noted that much of the time during the spawning and growing season the water levels are almost immeasurable compared to current conditions therefore this adverse effect may not even exist some of the time. The operation of a multipurpose projects cause water level fluctuations that can be detrimental to the natural reproduction and recruitment of some species of fish. Generally, reallocation from the conservation pool will result in long-term negative effects and reallocation from the flood pool would result in short-term positive effects, due to the inundation of terrestrial vegetation, but after a period of years, the area will exhibit the characteristics of current littoral area (sparse shoreline vegetation and fish habitat).

Regardless of the minimum flow reallocation, the productivity of the lake fisheries is currently, and will continue to be, largely influenced by water level management of the multipurpose reservoirs.

2. <u>Terrestrial Vegetation</u>

It is assumed that any reduction in inundation duration will result in minor beneficial effects to the shoreline terrestrial vegetation by decreasing the time the area is inundated thus allowing productivity increases in vegetation components. A reallocation from the conservation pool is expected to produce minor benefits, whereas reallocation from the flood pool will produce minor adverse affect to vegetation. In either case, the density of the vegetation component is expected to be similar to current conditions after a few years of water level management.

3. <u>Wildlife</u>

The terrestrial wildlife effects are expected to track with the Terrestrial Vegetation and Wetland features. In general, a positive effect on the vegetation feature will result in habitat benefits to the terrestrial wildlife of the littoral area. Likewise, if the wetland feature exhibits a positive effect, the wildlife (small mammals and bird species) using this habitat will benefit. A minor positive effect is expected from additional terrestrial vegetation if the reallocation is made from the conservation pool due to duration reductions. Any reallocation from the Flood Pool will result in a short term negative effects due to the decrease of habitat available for some littoral wildlife species. A negative short term effect is expected as the existing terrestrial vegetation is lost but a long term positive effect is possible as the shoreline vegetation reestablishes.

4. <u>Water Quality</u>

There is no effect expected on the water quality of the reservoirs, this conclusion is based largely on Temperature and Dissolved Oxygen Hydrodynamics models completed by the USGS. Outside of the USGS study, there is potential for short-term minor increase in turbidity as vegetation dies and reservoir operations affect unprotected bank areas. In an effort to assess the impact of increased minimum flows on temperature and dissolved oxygen concentrations of reservoir water quality, the USGS developed hydrodynamic temperature, and dissolved oxygen models for each of the reservoirs with the exception of Greers Ferry. The Table Rock model is in draft. Simulations included (1) the impact of additional minimum flows on tailwater temperature and dissolved oxygen qualities (current conditions) and (2) increasing the water surface elevation to account for the proposed reallocated storage. In scenario (1) water temperatures appeared to increase ($<1^{o}C$) and dissolved oxygen appeared to decrease (<2.2 mg/l). Conversely, scenario (2) apparently lowered the outflow water temperature ($<1^{o}C$) and increased the dissolved oxygen concentrations ($<1^{o}C$). However, these results were within the boundaries or similar to the error between measured and simulated water column values. These results have been consistent in all of the models. While this modeling effort is worthy of note, the results are considered inconclusive for the minimum flow study.

5. <u>Groundwater</u>

The effects on aquifer recharge are intended to be captured in the groundwater feature. The effects are solely based on the premise that reduction or increase in duration of the conservation pool area will directly affect the recharge of the aquifer. Reallocation from the conservation pool will result in a long-term minor negative effect due to a reduction in duration. Conversely, a flood pool reallocation would be of long-term minor benefit due to the increased duration.

6. <u>Tailwater Impacts</u>

Increases in wetted area (amount of bottom substrate that is always covered) and duration will increase at each tailwater. The wetted area is important but the duration increase of this area is a critical component of increased ecological function. Increased wetted area (primarily riffle areas) is the sources of aquatic invertebrate production. Wetted area would substantially increase the area available for aquatic invertebrate (particularly aquatic insects) production. Increased aquatic insect production would not only provide a direct increase in forage available for trout but also for organisms such as sculpins, dace, stonerollers, and crayfish that are essential to the production of fish species. The increase in abundance of primary forage levels should translate to increased growth rates for trout.

Implementation of the target flow will result in wetted area increases ranging from 0.8 percent to 52 percent. Table 4 below shows the length and wetted area increase for each tailwater. The Beaver tailwater is directly influenced by Table Rock Lake and this accounts for the small percent increase of the wetted area.

Likewise, the Table Rock tailwater is influenced by Lake Taneycomo. The increase duration of this area is still beneficial to the ecosystem.

The tailwater water quality should improve from any release strategy that might result in dissolved oxygen (DO) increases. It is assumed that any alternative that includes installation of a new service unit would have technology that will increase the DO of the outflow. Selective withdrawal using a siphon release should allow for selection of DO concentrations and temperature of the outflow. An aeration mechanism would be needed with a siphon release. In addition to the DO concentration upon release, the shear volume of the proposed minimum releases will result in reaeration to increase as the flow passes through riffle/shoal areas. Reaeration rates will be more efficient in the upper areas of each tailwater. Maintenance of optimum temperatures will be better in the tailwater by avoiding periods of non-release.

TABLE 4: Tailwater: Wetted Areas

	River Mile		CFS					
Tailwater	Up Stream	Down Stream	Current Minimum	Target Minimum	Increase (acre)	Percent Increase	Acre per Mile	Acre per Mile Increase
Beaver	608.8	604.8	55	136	0.7	0.8	22.1	0.2
Table Rock	528.73	522.98	120	400	8.46	4.51	34.07	1.47
Bull Shoals	418.6	329.4	210	800	1490	32.1	68.8	16.7
Norfork	4.468	0.185	115	300	28.53	52.37	19.38	6.67
Greers Ferry	78.9	49	70	200	57.3	11.3	18.9	1.9

b. <u>Threatened and Endangered Species</u>

The duration data generated from the SUPER model simulations were used to evaluate potential effects on Threatened and Endangered species considering the Elevations of Concern identified by US Fish and Wildlife Service (USFWS). The differences observed annually and seasonally were evaluated for each elevation of concern. Additional analyses will be completed prior to the Draft EIS. The USACE completed a Biological Assessment (BA) on the endangered species at Bull Shoals and submitted it to USFWS. A brief discussion follows.

1. <u>Beaver Lake</u>

The USFWS identified several elevations of concern on the Beaver project relative to the potential affects on Threatened and Endangered (T&E) species. The elevations are 1110, 1120, 1130 and 1140. (See Table 5.) The species of concern at 1110, 1120 and 1130 was the endangered gray bat and its habitat (Pigeon Roost Cave). The reallocation will result in less duration of the elevation of concern. This difference will result in an increase in the availability of use of the natural entrance of the cave and is considered a positive effect. Concerns for the Ozark cave fish led to the inquiry about changes at 1120 – 1140. There have been no adverse effects identified to T&E species at Beaver.

TABLE 5: Beaver Annual Pool Elevation Data

Beaver Lake				
Annual Pool Elevation-Duration for Pool Elevations of Interest				
Elevation	Current	Conservation	Flood	Split 50/50
1110	91.2	86.65	86.92	86.74
1120.4	45.86	42.69	42.83	42.79
1121	38.19	35.98	36.59	35.26
1121.2	36.87	34.5	35.28	33.93
1121.9	30.77	28.52	28.98	27.94
1130	0.34	0.31	0.33	0.29
1140	0	0	0	0

Beaver Lake			
Differences in Annual Pool Elevation: Duration for Pool Elevations of Interest (Alternative minus Current)			
Elevation	Conservation	Flood	Split 50/50
1110	-4.54	-4.28	-4.45
1120.4	-3.17	-3.03	-3.07
1121	-2.21	-1.61	-2.93
1121.2	-2.37	-1.6	-2.94
1121.9	-2.25	-1.79	-2.84
1130	-0.04	-0.02	-0.05
1140	0	0	0

2. <u>Bull Shoals</u>

The USFWS identified 670, 675, and 690 as elevations of concern on the Bull Shoals project relative to the potential impacts on the endangered Tumbling Creek Cave Snail and its habitat. A recovery plan for this species has been completed by USFWS. The concern is that the velocities of drainage system of cave (and resulting sedimentation) are affected at the higher lake levels. There is <3 percent increase in duration at the 670 elevation if any storage in reallocated from the flood pool. A slight reduction (<1 percent) in duration is expected if the storage is reallocated from the conservation pool. There have been no adverse effects identified to T&E species at Bull Shoals. The USACE completed a Biological Assessment (BA) and submitted to USFWS in May 2004. The BA concluded the reallocation may affect but not likely to adversely affect the species. The conclusion was based on the following: 1) statistical analysis that Bull Shoals lake levels do not have statistically significant effect on the flows within Tumbling Creek cave, 2) the cave snail is not known to occur in the lower reaches of the drainage system and spring discharge areas, and 3) the elevation of concern (670 msl) is currently met or exceeded 38.4 days annually and a 10.4 days increase is not considered significant. An official response to the BA has not been received at this time.

TABLE 6: Bull Shoals Annual Pool Elevation Data

Bull Shoals Lake Annual Pool Elevation-Duration for Pool Elevations of Interest				
Elevation	Current	Conservation	Flood	Split 50/50
654	59.92	51.39	81.96	69.60
656.5	30.26	27.96	71.54	51.82
657	28.00	26.06	68.88	38.84
659	23.01	21.43	53.01	27.96
670	10.65	9.96	13.48	11.32
675	7.60	7.03	9.42	8.17
690	2.02	1.90	2.23	2.05
695	0.57	0.46	0.61	0.54

Bull Shoals Lake Differences in Annual Pool Elevation: Duration for Pool Elevations of Interest (Alternative minus Current)			
Elevation	Conservation	Flood	Split 50/50
654	-8.53	22.03	9.68
656.50	-2.31	41.27	21.56
657	-1.94	40.88	10.84
659	-1.58	30.00	4.95
670	-0.69	2.83	0.67
675	-0.57	1.82	0.57
690	-0.12	0.21	0.03
695	-0.11	0.04	-0.03

3. Greers Ferry

The USFWS identified 480, 490, and 500 as elevations of concern relative to the potential impacts on the candidate species yellow cheek darter in the Archey Fork arm. The percent difference between the current condition and each alternative plan is less than 1 percent on an annual or seasonal basis; therefore, there have been no adverse effects identified to T&E species at Greers Ferry.

TABLE 7: Greers Ferry Annual Pool Elevation Data

Greers Ferry Lake				
Annual Pool Elevation-Duration for Pool Elevations of Interest				
Elevation	Current	Conservation	Flood	Split 50/50
461	44.46	39.14	66.08	53.83
462.0	21.66	20.00	60.80	47.89
463	15.13	13.94	55.73	32.48
464	11.98	11.19	40.78	14.01
480	0.98	0.81	1.22	0.94
487	0.16	0.13	0.18	0.16
490	0.00	0.00	0.00	0.00
500	0.00	0.00	0.00	0.00

Greers Ferry Lake			
Differences in Annual Pool Elevation: Duration for Pool Elevations of Interest (Alternative minus Current)			
Elevation	Conservation	Flood	Split 50/50
461	-5.32	21.61	9.37
462.00	-1.65	39.14	26.23
463	-1.19	40.60	17.35
464	-0.79	28.80	2.03
480	-0.17	0.24	-0.04
487	-0.03	0.02	0.00
490	0.00	0.00	0.00
500	0.00	0.00	0.00

4. Table Rock

The USFWS identified 940, 960, and 1100 as critical elevations for T&E species around the lake. These elevations are above the top of the flood pool and will not be affected by this reallocation.

5. Norfork Lake

The elevations identified by USFWS as critical elevations (> 580) are above the top of the flood pool and will not be affected by this reallocation.

IV. Plan Formulation

In keeping with the National Economic Development (NED) objective to enhance the Nation’s output of goods and services and to improve national economic efficiency there exists an opportunity to evaluate the reallocation of storage in Beaver, Table Rock, Bull Shoals, Norfork, and Greers Ferry. This report identifies implementable plans including the NED plan, but the Corps of Engineers is not recommending any plan for implementation.

The NED plan is the alternative that reasonably maximizes economic net benefits. In this report, however, alternative costs have not been fully developed, and do not include interest during construction or annual operation and maintenance costs. Alternative net benefits are therefore subject to change after more comprehensive analyses are performed. The term "NED plan" is used in this report only with that caveat.

As stated previously, three storage reallocation scenarios at each lake have been analyzed: Flood Pool reallocation, Conservation Pool reallocation, and a 50/50 Flood/Conservation Pool reallocation. Also at each dam, for each proposed storage reallocation, three release alternatives have been modeled and analyzed (except at Bull Shoals, were four release alternatives have been modeled and analyzed). Appendix A, Economics, includes the decision matrices that were used to compare the economic impacts and outputs of each plan. No reallocation scenario adversely affects existing water supply users. All plans that are identified as potentially implementable and have a flood pool storage reallocation will include DYMS for water supply users and HYPO for hydropower. In keeping with the intent of Congress to identify plans that minimize impacts to existing users, implementable plans were identified that either improved flood control, recreation, and hydropower benefits, or had the smallest negative impacts.

a. <u>Beaver Lake</u>

Nine plans for implementing minimum flows at Beaver Lake were analyzed. Table 8, below, identifies each plan. Each plan was evaluated based on economic impacts to recreation, hydropower, and flood control; Table 9 is a summary of economic impacts by plan. The plans discussed in detail, see Section V, Final Array of Plans, are plans that meet the WRDA requirements to be economically justified, technically sound, environmentally acceptable, with minimal impact to existing uses. As part of the NEPA process, Little Rock District shared minimum flows reallocation and release plans with the U.S. Fish and Wildlife Service (USF&W). USF&W indicated that any flood pool reallocation at Beaver Lake could cause significant negative ecological impacts due to the cumulative impacts of previous water supply reallocations, and identified the most environmentally friendly reallocation plan as a conservation pool reallocation. The previous water supply storage reallocations have resulted in raising the top of Beaver Lake's conservation pool 0.43 feet from 1120.0 to 1120.43. This has reduced Beaver's flood control capacity and impacted karst topography. The U.S. Fish and Wildlife Service considers any new encroachment into the flood pool unacceptable. Based on USF&W coordination, conservation pool reallocations are the only environmentally acceptable storage reallocation at Beaver Lake.

TABLE 8: Beaver Plan Identification

LAKE	REALLOCATION SCENARIO	RELEASE METHOD	PLAN ID
BEAVER	FLOOD POOL	SIPHON & SS UNITS	BV1
	FLOOD POOL	NEW SS UNIT	BV2
	FLOOD POOL	SIPHON ONLY	BV3
	CON. POOL	SIPHON & SS UNITS	BV4
	CON. POOL	NEW SS UNIT	BV5
	CON. POOL	SIPHON ONLY	BV6
	50/50	SIPHON & SS UNITS	BV7
	50/50	NEW SS UNIT	BV8
	50/50	SIPHON ONLY	BV9

TABLE 9: Beaver Plan Summary

Beaver Lake Summary*

Flood Pool Reallocation	First Costs	Annual Costs[4]	Hydropower Benefits	% Change of Hydro Benefits	Flood Benefits[3]	Tailwater & In-Pool Rec. Benefits	Total Annual Benefits	Net Benefits	B/C Ratio
BV1	$ 827,000	$ 50,000	$ (75,000)	-0.6%	$ (10,000)	$ 340,000	$ 255,000	**$ 205,000**	**5.10**
BV2	$ 5,615,000	$ 338,000	$ 66,000	0.5%	$ (10,000)	$ 340,000	$ 396,000	**$ 58,000**	**1.17**
BV3	$ 713,000	$ 43,000	$ (216,000)	-1.6%	$ (10,000)	$ 340,000	$ 114,000	**$ 71,000**	**2.65**
Conservation Pool Reallocation									
BV4[1]	$ 827,000	$ 50,000	$ (49,000)	-0.4%	$ 2,000	$ 363,000	$ 316,000	**$ 266,000**	**6.32**
BV5[2]	$ 5,615,000	$ 338,000	$ 92,000	0.7%	$ 2,000	$ 363,000	$ 457,000	**$ 119,000**	**1.35**
BV6	$ 713,000	$ 43,000	$ (191,000)	-1.4%	$ 2,000	$ 363,000	$ 174,000	**$ 131,000**	**4.05**
Split Pool Reallocation									
BV7	$ 827,000	$ 50,000	$ (44,000)	-0.3%	$ (1,000)	$ 356,000	$ 311,000	**$ 261,000**	**6.22**
BV8	$ 5,615,000	$ 338,000	$ 97,000	0.7%	$ (1,000)	$ 356,000	$ 452,000	**$ 114,000**	**1.34**
BV9	$ 713,000	$ 43,000	$ (184,000)	-1.4%	$ (1,000)	$ 356,000	$ 171,000	**$ 128,000**	**3.98**

[1] NED Plan — *see discussion on p. 31, and note 4 below*

[2] Alternate Plan

[3] Includes Downstream and In-Pool Flood Benefits

[4] Annual Costs are the annualized first costs and used in calculating the b/c ratio. First costs are comprised of construction costs. O&M and interest during construction will need to be computed and incorporated into the annual costs prior to implementation.

* This table summarizes the benefit and cost tables shown in Appendix A. All cost and benefit data is derived from the tables in Appendix A. All other data in this table is for information only.

b. Table Rock Lake

Nine plans for implementing minimum flows at Table Rock Lake were analyzed. Table 10, below, identifies each plan. Each plan was evaluated based on economic impacts to recreation, hydropower, and flood control; Table 11 is a summary of economic impacts by plan. The plans discussed in detail, see Section V, Final Array of Plans, are plans that meet the WRDA requirements to be economically justified, technically sound, environmentally acceptable, with minimal impact to existing uses.

TABLE 10: Table Rock Plan Identification

LAKE	REALLOCATION SCENARIO	RELEASE METHOD	PLAN ID
TABLE ROCK	FLOOD POOL	SIPHON & SS UNITS	TR1
	FLOOD POOL	NEW SS UNIT	TR2
	FLOOD POOL	SIPHON ONLY	TR3
	CON. POOL	SIPHON & SS UNITS	TR4
	CON. POOL	NEW SS UNIT	TR5
	CON. POOL	SIPHON ONLY	TR6
	50/50	SIPHON & SS UNITS	TR7
	50/50	NEW SS UNIT	TR8
	50/50	SIPHON ONLY	TR9

TABLE 11: Table Rock Summary

Table Rock Lake Summary*

Flood Pool Reallocation	First Costs	Annual Costs[4]	Hydropower Benefits	% Change of Hydro Benefits	Flood Benefits[3]	Tailwater & In-Pool Rec. Benefits	Total Annual Benefits	Net Benefits	B/C Ratio
TR1	$ 2,727,000	$ 164,000	$ (533,000)	-1.7%	$ (40,000)	$ 896,000	$ 323,000	**$ 159,000**	**1.97**
TR2	$ 11,643,000	$ 700,000	$ (101,000)	-0.3%	$ (40,000)	$ 896,000	$ 755,000	**$ 55,000**	**1.08**
TR3	$ 2,316,000	$ 140,000	$ (727,000)	-2.3%	$ (40,000)	$ 896,000	$ 129,000	**$ (11,000)**	**0.92**
Conservation Pool Reallocation									
TR4	$ 1,762,000	$ 106,000	$ (705,000)	-2.2%	$ 5,000	$ 1,005,000	$ 305,000	**$ 199,000**	**2.88**
TR5[1]	$ 10,678,000	$ 642,000	$ (147,000)	-0.5%	$ 5,000	$ 1,005,000	$ 863,000	**$ 221,000**	**1.34**
TR6	$ 1,351,000	$ 82,000	$ (922,000)	-2.9%	$ 5,000	$ 1,005,000	$ 88,000	**$ 6,000**	**1.07**
Split Pool Reallocation									
TR7	$ 2,727,000	$ 164,000	$ (601,000)	-1.9%	$ (18,000)	$ 954,000	$ 335,000	**$ 171,000**	**2.04**
TR8[2]	$ 11,643,000	$ 700,000	$ (95,000)	-0.3%	$ (18,000)	$ 954,000	$ 841,000	**$ 141,000**	**1.20**
TR9	$ 2,316,000	$ 140,000	$ (810,000)	-2.5%	$ (18,000)	$ 954,000	$ 126,000	**$ (14,000)**	**0.90**

[1] NED Plan — *see discussion on p. 31, and note 4 below*

[2] Alternate Plan

[3] Includes Downstream and In-Pool Flood Benefits

[4] Annual Costs are the annualized first costs and used in calculating the b/c ratio. First costs are comprised of construction costs. O&M and interest during construction will need to be computed and incorporated into the annual costs prior to implementation.

* This table summarizes the benefit and cost tables shown in Appendix A. All cost and benefit data is derived from the tables in Appendix A. All other data in this table is for information only.

c. Bull Shoals Lake

Twelve plans for implementing minimum flows at Bull Shoals Lake were analyzed. Table 12, below, identifies each plan. Bull Shoals is the only project where the existing main turbines can be used to make the proposed minimum flows releases and generate power. Each plan was evaluated based on economic impacts to recreation, hydropower, and flood control; Table 13 is a summary of economic impacts by plan.

The plans discussed in detail, see Section V, Final Array of Plans, are plans that meet the WRDA requirements to be economically justified, technically sound, environmentally acceptable, with minimal impact to existing uses.

TABLE 12: Bull Shoals Plan Identification

LAKE	REALLOCATION SCENARIO	RELEASE METHOD	PLAN ID
BULL SHOALS	FLOOD POOL	SIPHON & SS UNITS	BS1
	FLOOD POOL	NEW SS UNIT	BS 2
	FLOOD POOL	MAIN TURBINE	BS 3
	FLOOD POOL	SIPHON ONLY	BS 4
	CON. POOL	SIPHON & SS UNITS	BS 5
	CON. POOL	NEW SS UNIT	BS 6
	CON. POOL	MAIN TURBINE	BS 7
	CON. POOL	SIPHON ONLY	BS 8
	50/50	SIPHON & SS UNITS	BS 9
	50/50	NEW SS UNIT	BS 10
	50/50	MAIN TURBINE	BS 11
	50/50	SIPHON ONLY	BS12

TABLE 13: Bull Shoals Summary

Bull Shoals Summary*

Flood Pool Reallocation	First Costs	Annual Costs[3]	Hydropower Benefits	% Change of Hydro Benefits	Flood Benefits[2]	Tailwater & In-Pool Rec. Benefits	Total Annual Benefits	Net Benefits	B/C Ratio
BS1	$ 1,714,000	$ 104,000	$ (2,350,000)	-4.6%	$ (79,000)	$ 2,860,000	$ 431,000	**$ 327,000**	**4.14**
BS2	$ 12,991,000	$ 782,000	$ (793,000)	-1.6%	$ (79,000)	$ 2,860,000	$ 1,988,000	**$ 1,206,000**	**2.54**
BS3[1]	$ 462,000	$ 28,000	$ (797,000)	-1.6%	$ (79,000)	$ 2,860,000	$ 1,984,000	**$ 1,956,000**	**70.86**
BS4	$ 1,331,000	$ 81,000	$ (2,582,000)	-5.1%	$ (79,000)	$ 2,860,000	$ 199,000	**$ 118,000**	**2.46**
Conservation Pool Reallocation									
BS5	$ 1,526,000	$ 92,000	$ (3,206,000)	-6.3%	$ 12,000	$ 3,007,000	$ (187,000)	**$ (279,000)**	**(2.03)**
BS6	$ 12,803,000	$ 770,000	$ (1,484,000)	-2.9%	$ 12,000	$ 3,007,000	$ 1,535,000	**$ 765,000**	**1.99**
BS7	$ 274,000	$ 16,000	$ (1,487,000)	-2.9%	$ 12,000	$ 3,007,000	$ 1,532,000	**$ 1,516,000**	**95.75**
BS8	$ 1,143,000	$ 69,000	$ (3,435,000)	-6.8%	$ 12,000	$ 3,007,000	$ (416,000)	**$ (485,000)**	**(6.03)**
Split Pool Reallocation									
BS9	$ 1,714,000	$ 104,000	$ (2,749,000)	-5.4%	$ (28,000)	$ 2,962,000	$ 185,000	**$ 81,000**	**1.78**
BS10	$ 12,991,000	$ 782,000	$ (1,090,000)	-2.2%	$ (28,000)	$ 2,962,000	$ 1,844,000	**$ 1,062,000**	**2.36**
BS11	$ 462,000	$ 28,000	$ (1,093,000)	-2.2%	$ (28,000)	$ 2,962,000	$ 1,841,000	**$ 1,813,000**	**65.75**
BS12	$ 1,331,000	$ 81,000	$ (2,980,000)	-5.9%	$ (28,000)	$ 2,962,000	$ (46,000)	**$ (127,000)**	**(0.57)**

[1] NED Plan — *see discussion on p. 31, and note 4 below*

[2] Includes Downstream and In-Pool Flood Benefits

[3] Annual Costs are the annualized first costs and used in calculating the b/c ratio. First costs are comprised of construction costs. O&M and interest during construction will need to be computed and incorporated into the annual costs prior to implementation.

* This table summarizes the benefit and cost tables shown in Appendix A. All cost and benefit data is derived from the tables in Appendix A. All other data in this table is for information only.

d. Norfork Lake

Nine plans for implementing minimum flows at Norfork Lake were analyzed. Table 14, below, identifies each plan. Each plan was evaluated based on economic impacts to recreation, hydropower, and flood control; Table 15 is a summary of economic impacts by plan. The plans discussed in detail, see Section V, Final Array of Plans, are plans that meet the WRDA requirements to be economically justified, technically sound, environmentally acceptable, with minimal impact to existing uses.

TABLE 14: Norfork Plan Identification

LAKE	REALLOCATION SCENARIO	RELEASE METHOD	PLAN ID
NORFORK	FLOOD POOL	SIPHON & SS UNITS	NF1
	FLOOD POOL	NEW SS UNIT	NF2
	FLOOD POOL	SIPHON ONLY	NF3
	CON. POOL	SIPHON & SS UNITS	NF4
	CON. POOL	NEW SS UNIT	NF5
	CON. POOL	SIPHON ONLY	NF6
	50/50	SIPHON & SS UNITS	NF7
	50/50	NEW SS UNIT	NF8
	50/50	SIPHON ONLY	NF9

TABLE 15: Norfork Summary

Norfork Lake Summary*

Flood Pool Reallocation	First Costs	Annual Costs[4]	Hydropower Benefits	% Change of Hydro Benefits	Flood Benefits[3]	Tailwater & In-Pool Rec. Benefits	Total Annual Benefits	Net Benefits	B/C Ratio
NF1	$ 3,834,000	$ 230,000	$ (153,000)	-1.2%	$ (33,000)	$ 1,242,000	$ 1,056,000	**$ 826,000**	**4.59**
NF2[2]	$ 9,788,000	$ 589,000	$ 72,000	0.6%	$ (33,000)	$ 1,242,000	$ 1,281,000	**$ 692,000**	**2.17**
NF3	$ 3,644,000	$ 219,000	$ (324,000)	-2.5%	$ (33,000)	$ 1,242,000	$ 885,000	**$ 666,000**	**4.04**
Conservation Pool Reallocation									
NF4[1]	$ 975,000	$ 58,000	$ (410,000)	-3.2%	$ 2,000	$ 1,321,000	$ 913,000	**$ 855,000**	**15.74**
NF5	$ 6,929,000	$ 417,000	$ (128,000)	-1.0%	$ 2,000	$ 1,321,000	$ 1,195,000	**$ 778,000**	**2.87**
NF6	$ 785,000	$ 47,000	$ (598,000)	-4.7%	$ 2,000	$ 1,321,000	$ 725,000	**$ 678,000**	**15.43**
Split Pool Reallocation									
NF7	$ 3,834,000	$ 230,000	$ (259,000)	-2.0%	$ (14,000)	$ 1,292,000	$ 1,019,000	**$ 789,000**	**4.43**
NF8[2]	$ 9,788,000	$ 589,000	$ (2,000)	0.0%	$ (14,000)	$ 1,292,000	$ 1,276,000	**$ 687,000**	**2.17**
NF9	$ 3,644,000	$ 219,000	$ (443,000)	-3.5%	$ (14,000)	$ 1,292,000	$ 835,000	**$ 616,000**	**3.81**

[1] NED Plan — *see discussion on p. 31, and note 4 below*

[2] Alternate Plan

[3] Includes Downstream and In-Pool Flood Benefits

[4] Annual Costs are the annualized first costs and used in calculating the b/c ratio. First costs are comprised of construction costs. O&M and interest during construction will need to be computed and incorporated into the annual costs prior to implementation.

* This table summarizes the benefit and cost tables shown in Appendix A. All cost and benefit data is derived from the tables in Appendix A. All other data in this table is for information only.

e. Greers Ferry Lake

Nine plans for implementing minimum flows at Greers Ferry Lake were analyzed. Table 16, below, identifies each plan. Each plan was evaluated based on economic impacts to recreation, hydropower, and flood control; Table 17 is a summary of economic impacts by plan. The plans discussed in detail, see Section V, Final Array of Plans, are plans that meet the WRDA requirements to be economically justified, technically sound, environmentally acceptable, with minimal impact to existing uses. There are 74 acres of property around Greers Ferry Lake that the Corps does not own or have flood easements. Any reallocation plan that requires raising the conservation pool would result in an effort to acquire easements or purchase the property. The Real Estate Plan cannot be completed until reallocation plans are finalized. Also, due to the cumulative impacts of previous and future water supply reallocations, and with regards to the possibility of negative environmental impacts resulting from raising the top of conservation pool, the most environmentally friendly reallocation plan is a conservation pool reallocation.

TABLE 16: Greers Ferry Plan Identification

LAKE	REALLOCATION SCENARIO	RELEASE METHOD	PLAN ID
GREERS FERRY	FLOOD POOL	SIPHON & SS UNITS	GF1
	FLOOD POOL	NEW SS UNIT	GF2
	FLOOD POOL	SIPHON ONLY	GF3
	CON. POOL	SIPHON & SS UNITS	GF4
	CON. POOL	NEW SS UNIT	GF5
	CON. POOL	SIPHON ONLY	GF6
	50/50	SIPHON & SS UNITS	GF7
	50/50	NEW SS UNIT	GF8
	50/50	SIPHON ONLY	GF9

TABLE 17: Greers Ferry Summary

Flood Pool Reallocation	First Costs	Annual Costs[4]	Hydropower Benefits	% Change of Hydro Benefits	Flood Benefits[3]	Tailwater & In-Pool Rec. Benefits	Total Annual Benefits	Net Benefits	B/C Ratio
GF1	$ 1,523,000	$ 91,000	$ (82,000)	-0.6%	$ (36,000)	$ 1,149,000	$ 1,031,000	**$ 940,000**	**11.33**
GF2	$ 7,275,000	$ 438,000	$ 140,000	1.1%	$ (36,000)	$ 1,149,000	$ 1,253,000	**$ 815,000**	**2.86**
GF3	$ 1,366,000	$ 82,000	$ (188,000)	-1.4%	$ (36,000)	$ 1,149,000	$ 925,000	**$ 843,000**	**11.28**
Conservation Pool Reallocation									
GF4[1]	$ 959,000	$ 57,000	$ (228,000)	-1.8%	$ 4,000	$ 1,373,000	$ 1,149,000	**$ 1,092,000**	**20.16**
GF5[2]	$ 6,711,000	$ 404,000	$ 45,000	0.3%	$ 4,000	$ 1,373,000	$ 1,422,000	**$ 1,018,000**	**3.52**
GF6	$ 802,000	$ 48,000	$ (351,000)	-2.7%	$ 4,000	$ 1,373,000	$ 1,026,000	**$ 978,000**	**21.38**
Split Pool Reallocation									
GF7	$ 1,523,000	$ 91,000	$ (156,000)	-1.2%	$ (13,000)	$ 1,261,000	$ 1,092,000	**$ 1,001,000**	**12.00**
GF8	$ 7,275,000	$ 438,000	$ 105,000	0.8%	$ (13,000)	$ 1,261,000	$ 1,353,000	**$ 915,000**	**3.09**
GF9	$ 1,366,000	$ 82,000	$ (276,000)	-2.1%	$ (13,000)	$ 1,261,000	$ 972,000	**$ 890,000**	**11.85**

[1] NED Plan — *see discussion on p. 31, and note 4 below*

[2] Alternate Plan

[3] Includes Downstream and In-Pool Flood Benefits

[4] Annual Costs are the annualized first costs and used in calculating the b/c ratio. First costs are comprised of construction costs. O&M and interest during construction will need to be computed and incorporated into the annual costs prior to implementation.

* This table summarizes the benefit and cost tables shown in Appendix A. All cost and benefit data is derived from the tables in Appendix A. All other data in this table is for information only.

V. Final Array of Plans

WRDA directed the Corps to determine whether the minimum flow reallocations and modifications would adversely affect other authorized purposes. To carry out this purpose, we identified reallocation and release scenarios that meet the minimum flows criteria in a manner that is economically advantageous and minimizes impacts to the flood control, recreation, and hydropower purposes. We have determined that the NED plan for the five lakes would produce about $7 million in annual tailwater benefits. The plan would also produce some adverse economic impacts to flood control, in-pool recreation, and hydropower. If an investment is made (except at Bull Shoals) to replace the existing house generating units (Station Service, SS) with larger units capable of handling the specified minimum flows, then the adverse impacts to hydropower are ameliorated (and if automatic venting turbines are used, environmental benefits are achieved). Also, in cases where flood control storage is reallocated, maintaining SWPA's yield (HYPO), this would marginally decrease the minimum flows reliability (recall that the specified storage reallocations are not matched with the specified minimum flows releases and are not 100 percent reliable) while minimizing adverse hydropower impacts. In addition, we have found that reallocating these relatively small amounts of flood control storage does not significantly affect the projects' flood control benefits.

The following alternatives produce results that minimize adverse impacts to existing authorized users, are economically justified, technically sound, and likely to be found environmentally acceptable. Flood benefits, hydropower benefits, and recreation benefits as well as ecological impacts were used to identify these alternatives. The EIS is currently in progress; therefore the ecological impacts have not been finalized and are preliminary. No significant ecological issues are expected with any of the described plans. For comparison purposes only, Little Rock District replaced HAC's hydropower valuation numbers with SWPA's numbers in the economic justification matrix. The decision matrix with SWPA's numbers can be seen in Appendix A. The use of SWPA's numbers changes the impact to hydropower revenues, benefits, and the benefit to cost ratio. In some cases the use of SWPA's hydropower numbers change which plans are considered the NED plan and in some cases which plan is most attractive as an alternate plan.

a. Beaver Lake

The NED and alternate plans for Beaver Lake are BV4 and BV5, respectively. When SWPA's numbers are used instead of HAC's numbers, there is no change in the NED plan or the alternate plan.

BV4, Siphon and existing SS unit with a conservation pool reallocation, reduces hydropower benefits by 0.4 percent (**using Corps hydropower numbers**) and improves flood control benefits. The benefit to cost ratio for BV4 is 6.3 to 1.0, and it would be considered the National Economic Development (NED) plan. First costs for implementation are $827,000. There are no environmental concerns with this plan. The minimum flows operation at Beaver Lake would improve eight miles of trout fishery with an annual improvement to the trout fishing industry of $364,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For BV4 hydropower benefits are reduced 4.0 percent and the benefit to cost ratio is –3.52 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

BV5, new SS unit with a conservation pool reallocation, improves hydropower benefits by 0.7 percent (**using Corps hydropower numbers**) and improves flood control benefits. The benefit to cost ratio for BV5 is 1.35 to 1.0. First costs for implementation are $5,615,000. There are no environmental concerns with this plan. The minimum flows operation at Beaver Lake would improve eight miles of trout fishery with an annual improvement to the trout fishing industry of $364,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For BV5 hydropower benefits are reduced 3.1 percent and the benefit to cost ratio is -0.17 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

b. <u>Table Rock Lake</u>

The NED and alternate plans for Table Rock Lake are TR5, and TR8. When SWPA's numbers are used instead of HAC's numbers the NED plan is TR1, and the most likely alternative plan is TR2.

TR5, new SS units with a conservation pool reallocation, reduces hydropower benefits by 0.5 percent (**using Corps hydropower numbers**), improves flood control benefits, and improves in-pool recreation benefits. The benefit to cost ratio for TR5 is 1.34 to 1.0, and it is considered the NED plan. First costs for implementation are $10,678,000. There are no environmental concerns with this plan. The minimum flows operation at Table Rock Lake would improve 22 miles of trout fishery with an annual improvement to the trout fishing industry of $1,000,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For TR5 hydropower benefits are reduced 4.3 percent and the benefit to cost ratio is –0.59 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

TR8, new SS units with a 50/50 reallocation, reduces hydropower benefits by 0.3 percent (**using Corps hydropower numbers**), decreases flood control benefits, and decreases in-pool recreation benefits. The benefit to cost ratio for TR8 is 1.2 to 1.0. For a 50/50 reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $15,841,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $11,643,000. There are no environmental concerns with this plan. The minimum flows operation at Table Rock Lake would improve 22 miles of trout fishery with an annual improvement to the trout fishing industry of $1,000,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For TR8 hydropower benefits are reduced 1.8 percent and the benefit to cost ratio is 0.51 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

TR1, Siphon & existing Station Service Unit and flood pool reallocation, reduces hydropower benefits 1.7 percent (**using Corps hydropower numbers**), decreases flood control benefits, and decreases in-pool recreation benefits. The benefit to cost ratio for TR1 is 2.0 to 1.0. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $31,681,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $2,727,000. There are no environmental concerns with this plan. The minimum flows operation at Table Rock Lake would improve 22 miles of trout fishery with an annual improvement to the trout fishing industry of $1,000,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For TR1 hydropower benefits are reduced 0.9 percent and the benefit to cost ratio is 3.4 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

TR2, new Station Service Unit with a flood pool reallocation, reduces hydropower benefits 0.3 percent (**using Corps hydropower numbers**), decreases flood control benefits, and decreases in-pool recreation benefits. The benefit to cost ratio for TR2 is 1.08 to 1.0. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $31,681,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $11,643,000. There are no environmental concerns with this plan. The minimum flows operation at Table Rock Lake would improve 22 miles of trout fishery with an annual improvement to the trout fishing industry of $1,000,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For TR2 hydropower benefits are not affected (0.0 percent change) and the benefit to cost ratio is 1.24 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

c. <u>Bull Shoals Lake</u>

The NED plan for Bull Shoals Lake is BS3. BS3 is still the best plan using SWPA's hydropower values. No alternate plan was chosen for Bull Shoals. The NED plan represents the plan most likely to be accepted by the non-federal sponsor and stakeholders due to its low hydropower losses, relative to other plans, and its low first costs. All other plans have greater hydropower losses and/or greater annual costs that reduce the benefit to cost ratio to a fraction of the NED plans benefit to cost ratio.

BS3, main turbine with a flood pool reallocation, reduces hydropower benefits by 1.6 percent **(using Corps hydropower numbers)**, an approximate reduction in flood control benefits of 1 percent, and reduces in-pool recreation benefits. The benefit to cost ratio for BS3 is 70.9 to 1.0, and it is considered the NED plan. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $21,693,000. This cost is not included in the economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $462,000. There are no environmental concerns with this plan. The minimum flows operation at Bull Shoals Lake would improve 66 miles of trout fishery with an annual improvement to the trout fishing industry of $2,999,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For BS3 hydropower benefits are reduced 0.7 percent and the benefit to cost ratio is 86.4 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

d. <u>Norfork Lake</u>

The NED and alternate plans for Norfork Lake are NF2, NF4, and NF8. When SWPA's hydropower numbers are used instead of HAC's hydropower numbers the NED plan is NF1, and the most likely alternative plan is NF2.

NF4, existing SS unit and siphon with a conservation pool reallocation, reduces hydropower benefits by 3.2 percent **(using Corps hydropower numbers)**, improves flood control benefits, and improves in pool recreation benefits. The benefit to cost ratio for NF4 is 15.7 to 1.0, and it is considered the NED plan. First costs for implementation are $975,000. There are no environmental concerns with this plan. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For NF4 hydropower benefits are reduced 9.2 percent and the benefit to cost ratio is 2.7 to 1.0. SWPA's hydropower evaluation for all plans studied is shown in Appendix A.

NF2, new SS unit with a flood pool reallocation, improves hydropower benefits by 0.6 percent **(using Corps hydropower numbers)**, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for NF2 is 2.2 to 1.0. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $11,576,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $9,788,000. There are no environmental concerns with this plan. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For NF2 there is no impact to hydropower benefits and the benefit to cost ratio is 2.1 to 1.0.

NF8, new SS unit with a 50/50 reallocation, has no impact to hydropower benefits **(using Corps hydropower numbers)**, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for NF2 is 2.2 to 1.0. For a 50/50 reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $5,788,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $9,788,000. There are no environmental concerns with this plan. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For NF8 hydropower benefits are reduced 3.2 percent and the benefit to cost ratio is 1.49 to 1.0.

NF1, Siphon and existing Station Service Unit with a flood pool reallocation, reduces hydropower benefits 1.2 percent **(using Corps hydropower numbers)**, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for NF1 is 4.6 to 1.0. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $11,576,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $3,834,000. There are no environmental concerns with this plan. The minimum flows operation at Norfork Lake would improve 29 miles of trout fishery with an annual improvement to the trout fishing industry of $1,318,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For NF1 hydropower benefits are reduced 1.4 percent and the benefit to cost ratio is 4.5 to 1.0.

e. <u>Greers Ferry Lake</u>

The NED and alternate plans for Greers Ferry Lake are GF4, and GF5. When SWPA's hydropower numbers are used instead of HAC's hydropower numbers the NED plan is GF1, and the most likely alternative plan is GF2.

GF4, existing SS unit and siphon with a conservation pool reallocation, reduces hydropower benefits by 1.8 percent **(using Corps hydropower numbers)**, improves flood control benefits, and improves in pool recreation benefits. The benefit to cost ratio for GF4 is 20.2 to 1.0, and it is considered the NED plan. First costs for implementation are $959,000. There are no environmental concerns with this plan. The minimum flows operation at Greers Ferry Lake would improve 30 miles of trout fishery with an annual improvement to the trout fishing industry of $1,363,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For GF4 hydropower benefits are reduced 8.7 percent and the benefit to cost ratio is 4.3 to 1.0.

GF5, new SS unit with a conservation pool reallocation, improves hydropower benefits by 0.3 percent **(using Corps hydropower numbers)**, improves flood control benefits, and improves in pool recreation benefits. The benefit to cost ratio for GF5 is 3.5 to 1.0. First costs for implementation are $6,711,000. There are no environmental concerns with this plan. The minimum flows operation at Greers Ferry Lake would improve 30 miles of trout fishery with an annual improvement to the trout fishing industry of $1,363,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For GF5 hydropower benefits are reduced 7.2 percent and the benefit to cost ratio is 1.08 to 1.0.

GF1, Siphon and existing SS Unit with a flood pool reallocation, reduces hydropower benefits 0.6 percent **(using Corps hydropower numbers)**, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for GF1 is 11.3 to 1.0. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $7,280,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $1,523,000. There are no environmental concerns with this plan. The minimum flows operation at Greers Ferry Lake would improve 30 miles of trout fishery with an annual improvement to the trout fishing industry of $1,363,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For GF1 hydropower benefits are reduced 1.1 percent and the benefit to cost ratio is 10.7 to 1.0.

GF2, new Station Service Unit with a flood pool reallocation, increases hydropower benefits 1.1 percent **(using Corps hydropower numbers)**, reduces flood control benefits, and reduces in pool recreation benefits. The benefit to cost ratio for GF2 is 2.9 to 1.0. For a flood pool reallocation the construction costs needed to relocate roads, bridges, and park facilities is estimated to be approximately $7,280,000. This cost is not included in the Economic analysis but is included in order to identify impacts to existing lake uses. First costs for implementation are $7,275,000. There are no environmental concerns with this plan. The minimum flows operation at Greers Ferry Lake would improve 30 miles of trout fishery with an annual improvement to the trout fishing industry of $1,363,000. For comparison only, Little Rock District is showing hydropower impacts and benefit to cost ratio using SWPA's hydropower evaluation. For GF2 hydropower benefits are increased 0.1 percent and the benefit to cost ratio is 2.6 to 1.0.

VI. Implementation and Cost Apportionment

WRDA 1999 and 2000 authorized the Secretary to provide minimum flows necessary to sustain tailwater trout fisheries by reallocating project storage. The reallocation and release scenarios studied result in significant ecological improvement to the cold-water fishery not only to trout but to all the aquatic species inhabiting the affected rivers, as well as provide benefits to the trout fishing recreation industry. WRDA instructed the

Corps to identify any Federal costs incurred, but did not provide guidance on cost sharing, project purposes, and cost of storage.

a. <u>Storage Costs</u>

Paragraph h of section II defines actual and updated storage costs. The difference between actual and updated cost of storage is the dollar amount of joint-use project costs that is used to calculate the cost of storage. Actual cost of storage uses the projects joint-use project cost from the final cost allocation reports, which were finalized in the early 1970's. Updated cost of storage uses joint-use project costs that have been inflated to present day values. When cost of storage is calculated, it is primarily based on the joint-use project costs and the percentage of water that is going to be reallocated out of the usable storage in the reservoir. Southwestern Power Administration is paying the actual cost of storage. Tables 18 and 19 detail the actual and updated annual cost of storage as well as the cost sharing responsibilities for recreation and ecosystem restoration, respectively.

TABLE 18: Federal and Non-Federal Cost Sharing Amounts, Actual Storage Costs

Reservoir	Annual Cost of Storage Actual Costs[1]	Cost Apportionment Actual Costs 50% Fed/Non Fed	65% Federal	35% Non-Federal
Beaver Lake				
-Conservation Pool Reallocation	$ 31,000	$ 15,500	$ 20,150	$ 10,850
-Flood Pool Reallocation	41,000	20,500	26,650	14,350
-50/50 Pool Reallocation	36,000	18,000	23,400	12,600
Table Rock Lake				
-Conservation Pool Reallocation	$ 41,000	$ 20,500	$ 26,650	$ 14,350
-Flood Pool Reallocation	52,000	26,000	33,800	18,200
-50/50 Pool Reallocation	46,000	23,000	29,900	16,100
Bull Shoals Lake				
-Conservation Pool Reallocation	$ 90,000	$ 45,000	$ 58,500	$ 31,500
-Flood Pool Reallocation	107,000	53,500	69,550	37,450
-50/50 Pool Reallocation	98,000	49,000	63,700	34,300
Norfork Lake				
-Conservation Pool Reallocation	$ 35,000	$ 17,500	$ 22,750	$ 12,250
-Flood Pool Reallocation	47,000	23,500	30,550	16,450
-50/50 Pool Reallocation	40,000	20,000	26,000	14,000
Greers Ferry Lake				
-Conservation Pool Reallocation	$ 63,000	$ 31,500	$ 40,950	$ 22,050
-Flood Pool Reallocation	72,000	36,000	46,800	25,200
-50/50 Pool Reallocation	67,000	33,500	43,550	23,450

[1] Actual costs are sunk costs.

TABLE 19: Federal and Non-Federal Cost Sharing Amounts, Updated Storage Costs

Reservoir	Annual Cost of Storage Updated Costs	Cost Apportionment Updated Costs 50% Fed/Non Fed	65% Federal	35% Non-Federal
Beaver Lake				
-Conservation Pool Reallocation	$ 276,000	$ 138,000	$ 179,400	$ 96,600
-Flood Pool Reallocation	366,000	183,000	237,900	128,100
-50/50 Pool Reallocation	321,000	160,500	208,650	112,350
Table Rock Lake				
-Conservation Pool Reallocation	$ 554,000	$ 277,000	$ 360,100	$ 193,900
-Flood Pool Reallocation	699,000	349,500	454,350	244,650
-50/50 Pool Reallocation	623,000	311,500	404,950	218,050
Bull Shoals Lake				
-Conservation Pool Reallocation	$ 1,200,000	$ 600,000	$ 780,000	$ 420,000
-Flood Pool Reallocation	1,430,000	715,000	929,500	500,500
-50/50 Pool Reallocation	1,309,000	654,500	850,850	458,150
Norfork Lake				
-Conservation Pool Reallocation	$ 472,000	$ 236,000	$ 306,800	$ 165,200
-Flood Pool Reallocation	635,000	317,500	412,750	222,250
-50/50 Pool Reallocation	550,000	275,000	357,500	192,500
Greers Ferry Lake				
-Conservation Pool Reallocation	$ 683,000	$ 341,500	$ 443,950	$ 239,050
-Flood Pool Reallocation	785,000	392,500	510,250	274,750
-50/50 Pool Reallocation	732,000	366,000	475,800	256,200

b. <u>Hydropower Revenues Foregone</u>

When the Corps reallocates storage for municipal and industrial water supply the water supply user pays the higher of hydropower benefits foregone, hydropower revenues foregone, hydropower replacement cost, flood control benefits foregone, or the updated cost of storage, Little Rock District projects are usually governed by the updated cost of storage. Hydropower revenues foregone are based on the current rates of the marketing agency, which in the case of White River Minimum Flows is the Southwestern Power Administration (SWPA). At the time that the Hydropower Analysis Center wrote its report, *White River Basin Projects White River, Arkansas and Missouri, White River Minimum Flow Study, Power Benefits Foregone Due To Storage Reallocation, August 2003,* the rates that were in effect were from 01 January 2002 and were:

Energy Charge: 7.00 mill/kWh
Capacity Charge: $30.72/kW-year

The energy charge would be applied to the average annual energy losses and the capacity charge would be applied to the loss in marketable capacity. The first value, energy charge, is the charge applied to the annual energy losses from the reallocation of storage. The second value, capacity charge, is applied to the capacity losses the

power marketing agency experiences from the reallocation. Table 20 details the revenue losses at each project.
Cost of storage is charged to recover possible losses to hydropower. In addition, the power marketing agency (PMA) can also receive a credit from the Treasury when Federal power delivery contracts require market purchases of power as a result of storage reallocations and withdrawals (ER 1105-2-100, Appendix E, E-57, pg. E-220). Should be noted that there is no way to reduce hydropower's costs absent revenue to the US Treasury from a cost-sharing sponsor or from specific legislation.

Table 20: Hydropower Revenues Foregone and PMA Credit

	Revenues Foregone Due To Storage Reallocation (Annual $'s)		
Reservoir	**Energy Revenue Foregone**	**Capacity Revenue Foregone**	**Total Revenue Foregone**
Beaver Lake			
-Conservation Pool Reallocation	$ 41,588	$ 1,031	$ 42,619
-Flood Pool Reallocation	48,771	1,031	49,802
-50/50 Pool Reallocation	40,605	1,031	41,636
Table Rock Lake			
-Conservation Pool Reallocation	$ 156,832	$ 668,364	$ 825,196
-Flood Pool Reallocation	131,865	170,941	302,806
-50/50 Pool Reallocation	137,959	460,141	598,100
Bull Shoals Lake			
-Conservation Pool Reallocation	$ 401,111	$ 1,119,283	$ 1,520,394
-Flood Pool Reallocation	278,542	882,706	1,161,248
-50/50 Pool Reallocation	337,576	986,640	1,324,216
Norfork Lake			
-Conservation Pool Reallocation	$ 93,536	$ 20,309	$ 113,845
-Flood Pool Reallocation	58,092	(26,674)	31,418
-50/50 Pool Reallocation	73,015	2,252	75,267
Greers Ferry Lake			
-Conservation Pool Reallocation	$ 81,883	$ 8,728	$ 90,611
-Flood Pool Reallocation	66,277	(813)	65,464
-50/50 Pool Reallocation	45,475	(3,624)	41,851

If this report results in an implementation plan for White River Minimum Flows reallocation and operation, the construction costs necessary to meet the Minimum Flows criteria must be cost shared. A case can be made, based on on-going NEPA analysis, that this project is environmental in nature and be identified as an Ecosystem Restoration project as defined by ER 1105-2-100, pg F-17, sec F-19 a. An Ecosystem Restoration project is cost shared 65 percent federally and 35 percent non-federally. It could also be considered a recreation project resulting in a 50 percent Federal, 50 percent Non-Federal cost share due to the artificial cold-water fishery is not a natural riverine environment within the project area, and the trout stocked in the rivers are non-native species (brown trout are native to Europe and Asia; rainbow and cutthroat trout are native to the western U.S.) The purpose of ecosystem restoration projects, as defined in ER 1165-2-501, is to restore significant ecosystem functions, structures and dynamic processes that have been degraded. Since trout are a non-native species, improvements for trout fishery could be classified and cost-shared as Recreation. However, the Arkansas Game and Fish Commission, Missouri Department of Conservation, and the Nature Conservancy maintain significant environmental impacts indicate ecosystem restoration. See Section IV. Environmental Summary, for ecological impacts resulting from proposed minimum flows.

c. OMRR&R

OMRR&R is operation, maintenance, repair, rehabilitation, and replacement costs. OMRR&R costs were not calculated and will need to be computed and included in the annual costs prior to implementation.

d. Project Purpose

1. Recreation

Implementation of Minimum Flows could be viewed as recreation because the majority of the project benefits stem from recreational fishing. There is no way to restore the original environment and therefore the existing fishery represents a recreational project rather than an environmental restoration project.

2. Restoration

Implementation of the project could be viewed as restoration because this project is environmental in nature as defined by ER 1105-2-100, pg F-17, sec F-19.a. The cold-water fishery in the tailwaters is not a natural riverine environment within the project area, and the trout stocked in the rivers are non-native species (brown trout are native to Europe and Asia; rainbow and cutthroat trout are native to the western U.S.) The purpose of ecosystem restoration projects, as defined in ER 1165-2-501, is to restore significant ecosystem functions, structures and dynamic processes that have been degraded. The original attempts to establish a cold-water fishery failed to include minimum flows. If the Corps were to construct a dam today minimum flows would be part of the mitigation plan.

3. Mitigation

The State considers White River Minimum Flows to be mitigation instead of restoration and should be fully federally funded. However, Corps policy and legal opinion is that this is not mitigation and not an option for consideration in the absence of legislation declaring the purpose of this project to be mitigation for damage to the lost warm water fishery

e. Cost Sharing

If White River Minimum Flows is implemented, all facility modifications must be cost shared between the Federal Government and a Non-Federal Sponsor. Table 21 details the implementation costs and identifies the Federal and Non-Federal shares.

Table 21: Federal and Non-Federal Implementation Cost Share

Plan Identification	Implementation First Costs	50% Federal & NonFederal Cost Share	65% Federal Cost Share	35% NonFederal Cost Share
BV4	$ 827,000	$ 413,500	$ 537,550	$ 289,450
BV5	5,615,000	2,807,500	3,649,750	1,965,250
TR5	10,678,000	5,339,000	6,940,700	3,737,300
TR8	11,643,000	5,821,500	7,567,950	4,075,050
BS3	462,000	231,000	300,300	161,700
NF2	9,788,000	4,894,000	6,362,200	3,425,800
NF4	975,000	487,500	633,750	341,250
NF8	9,788,000	4,894,000	6,362,200	3,425,800
GF4	959,000	479,500	623,350	335,650
GF5	6,711,000	3,355,500	4,362,150	2,348,850

VII. Locally Preferred Plan

a. Potential Sponsor View

The preferred plans for the Arkansas lakes are consistent with the States' belief that fish and wildlife impacts have never been appropriately mitigated. The AG&FC believes the public will benefit through a minimum flow operation more so than what is being experienced under the project's current operation. The excerpts below constitute AG&FC's preferred options:

1. AG&FC prefers, "the listed National Economic Development (NED) plan for each of the Arkansas projects: Beaver, Bull Shoals, Norfork and Greers Ferry. We agree with the Little Rock District Corps of Engineers' findings that the NED plans provide the best solutions for implementing the minimum flow plan. These outcomes will result in only slight or modest impacts to hydropower, flood control and in-lake recreation while implementing minimum flow under the lowest costs".

2. It is AG&FC's position, "that the cost of storage should be a federal responsibility and that the local sponsor, the Arkansas Game and Fish Commission, should not pay any cost of storage. As Congressman John Boozman highlighted in his letter to the Corps on July 15, 2003, the purpose of Section 374 of WRDA 1999 was to partially mitigate losses associated with construction of the dams by providing a more stable aquatic environment. Furthermore, we would argue that incremental changes in flow as a result of evolving power demands over the past few decades *have further deteriorated the in-stream ecosystems. Thus, any restoration costs should be a federal responsibility borne as a benefit to the nation".*

3. As mentioned above, AG&FC, "view this project as appropriate mitigation for the loss of habitat to support a native fishery. We believe any implementation costs should be at 100 percent federal expense".

4. AG&FC recognizes, "that the preferred option for Bull Shoals Lake may impact some lake facilities. However, we believe that any decision to relocate facilities should be based on a more in-depth evaluation of actual, real-time loss of use. We will work with the SWL to identify these facilities as part of a monitoring process once minimum flows are implemented".

5. The interim report mentions a credit to the marketing agency in order to reduce their liability to the federal government for loss of storage. AG&FC, "fully support this position".

A copy of the AG&FC's comments concerning the Locally Preferred Plans is in Appendix E. At this time Missouri has not expressed a Locally Preferred Plan for Table Rock Lake.

b. Southwestern Power Administration View

The excerpts below constitute Southwestern Power Administration's Views preferred options:

The Southwestern Power Administration (Southwestern), an agency of the Department of Energy, is authorized by Section 5 of the Flood Control Act of 1944 to market the electricity produced at the U.S. Army Corps of Engineers (Corps) hydropower projects in a six-state area to public bodies, mostly rural electric cooperatives and municipalities, at cost-based rates designed to repay to the U.S. Treasury all the costs associated with the hydropower production, including a joint-use portion of the original investment, with interest, the operation and maintenance expenses, and all specific hydropower costs. Southwestern markets power from 24 projects located in four states. The five Corps hydropower projects in the White River basin account for more than 30 percent of the energy and nearly 40 percent of the capacity Southwestern markets. Output from those projects account for more than one-third of the average annual revenues Southwestern deposits in the U.S. Treasury from all generating resources. The electricity's value comes from its reliability. The reliability comes from the availability of the very water storage that is being considered for reallocation. Of the 17 reservoirs that Southwestern markets as a system, 57 percent of the total hydropower storage is located in those five White River projects. A loss of that water storage will negatively impact the reliability and marketability of the electricity. Any loss of electrical energy and capacity from the projects will have to be taken from our current customers, mostly rural farmers and communities suffering from the current difficult economic situation, and force them to *pay higher electrical rates. Since all of the water storage in the five projects is already allocated to an authorized purpose and since those purposes are already fully utilizing that water storage to maximize the benefits to their purpose, any reallocation of the water storage for another purpose will have to come at an expense to an existing authorized purpose. Therefore, Southwestern believes that the beneficiary of any reallocated storage should provide compensation for the expenses involved and the benefits foregone by the other project purposes. As such, Southwestern believes it should not be required to continue recovering expenses in its rates for benefits its customers would no longer receive if a portion of its water storage were reallocated. Any reallocation from the projects' conservation storage would result in an electrical capacity loss, likely a significant loss, and could lead to a de-allocation of power to our customers, ultimately impacting six million end-users in six states. A storage reallocation from the flood control pool at the projects with an effort to maintain the hydropower water storage yield would result in only energy losses to the hydropower purpose and thus have less impact than any other form of storage reallocation.*

Southwestern has several specific concerns with the draft report based on the portions of earlier versions that it was allowed to review. Southwestern does not agree with the Corps' method of computing the electrical capacity lost from the proposed reallocations. The Corps uses an average year method. Southwestern, which is by law responsible for marketing the electricity, determines the marketable capacity based on the critical drought period - in order to assure reliability. Most of the alternatives considered will cause severe capacity loss. The Corps also values the energy portion at a rate lower than Southwestern can purchase it for in the market. The Corps does not appear to distinguish between the more valuable on-peak energy and the less valuable off-peak energy in their study. Additionally, the Corps' downstream recreational benefits to be derived from the proposed reallocation appear to be considerably over-estimated based on Southwestern's review. It appears that most of the proposed alternatives would not be in accordance with PL 104-303, Section 304, that states, "recreation and fish and wildlife…purposes do not adversely affect flood control, power generation, or other authorized purposes of the project."

White River Basin, Arkansas, Minimum Flows
Project Report

Cost

APPENDIX E

APPENDIX B7.0

COST ESTIMATING SECTION,
ENGINEERING INVESTIGATIONS AND ANALYSIS APPENDIX
WHITE RIVER MINIMUM FLOWS FEASIBILITY STUDY

TABLE OF CONTENTS

APPENDIX B7.0 – Cost Engineering White River Minimum Flows, Feasibility Study

B7.0-1 - <u>GENERAL</u> - The Water Resource Development Acts (WRDA) of 1999 and 2000 modified the basic authorization and operation for the five multipurpose White River Basin lakes, Beaver, Table Rock, and Bull Shoals Lakes on the White River; Norfork Lake on the North Fork River; and Greer Ferry Lake on the Little Red River. WRDA 99 & 00 directed the Corps to complete a study and report to determine if minimum flow reallocations adversely affect other authorized purposes. Also, this study is to identify Federal costs that will be incurred. A Reallocation Report, signed August 2004, analyzed reallocation and release scenarios at the 5 multipurpose White River lakes. The Reallocation Report identified economically justified, technically sound, and environmentally acceptable reallocation and release scenarios at each lake.

Subsequent to the completion of the Draft Environmental Impact Statement (DEIS), Section 132 of the FY 2006 Energy and Water Resources Development Act (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork lakes, as described in the Reallocation Report, at full Federal expense in accordance with section 906(e) of WRDA 86. Section 132 did not authorize implementation of Minimum Flows at Beaver, Norfork, and Greers Ferry Lakes. Also, Section 132 repealed the previous project authorities in WRDA 99 and WRDA 00, resulting in a new project.

The DEIS analyzed the impacts to the five White River Reservoirs, however; emphasis is placed on Bull Shoals and Norfork Lakes due to the changes made with the FY 2006 Energy and Water Resources Development Act (P.L. 109-103). Previous study efforts evaluating the other lakes is included in the DEIS in the interest of full disclosure.

The Final Environmental Impact Statement (FEIS) concludes that the trout tailwater fishery below Bull Shoals and Norfork dams will benefit from the increased wetted perimeter and dissolved oxygen levels resulting from increased minimum flows while negative impacts to hydropower and in-lake recreation will be fully mitigated.

The tentatively selected plan includes the reallocation of 5 vertical feet of flood control storage in Bull Shoals Lake and 1.7 vertical feet of flood control storage in Norfork Lake. Geographical Information System analyses of the reallocation of this storage showed impacts to recreation resources that are quantified in this feasibility cost estimate. Resources impacted include county roads, boat launch ramps, park access roads, parking lots for day use areas, and swim areas.

The construction cost of these replacement recreation features is to paid by the non-Federal Sponsor, the State of Arkansas.

The Cost Engineering and Support Team of the Little Rock District Corps of Engineers prepared preliminary cost estimates and the baseline cost estimate for impacts to project features due to implementation of the change of project operations to implement the White River Minimum Flows project.

The cost estimate, at Tab B, for the tentatively selected plan presented in this feasibility report were prepared in accordance with UFC 3-700-02A, Construction Cost Estimates, dated 1 March 2005. The cost account numbers in the estimate are in accordance with those prescribed in the "Work Breakdown Structure (WBS) for Civil Works Construction Cost Estimates". The cost estimate for the White River Minimum Flows Project has been developed through the Corps MII, Cost Estimating software, prepared in the October 2008 (FY 2009) price level, with a base year of 2010. The baseline estimate provides for all pertinent elements for a complete project ready for operation.

B7.0-2 STRUCTURAL SCOPE AND CONSIDERATIONS:

Major work items for the tentatively selected plan are clearing, grubbing, excavation, compacted earth fill, and paving, both concrete and asphalt.

The Little Rock District GIS personnel in consultation with Reservoir Control Branch and Operations personnel furnished a list and aerial photography of county roads and recreation features impacted by the raising of the conservation pools in Bull Shoals Lake and Norfork Lake. The costs for the baseline estimate are based upon quantities developed by the cost estimator because no other data were obtained. These quantities included timber clearing, excavation, backfill, culvert size and length, and paving.

The estimate is presented in MCACES MII, Version 3.4, using labor rates developed from 2006 Davis-Bacon and Arkansas Department of Labor Wage Determinations, 2007 equipment database for Region III containing Arkansas with adjustments for current electricity from cost estimator’s experience and fuel prices taken from the Energy Information Administration Website, and the 2006 Cost Library, version 3.0, databases with material prices updated to current price levels. Quotes were obtained for concrete and asphalt products from sources near the project area. Equipment costs were from EP 1110-1-8, Construction Equipment Ownership and Operating Expense Schedule, July 2007.

It is important to note that limited modeling and no engineering surveys were completed as part of this study. The lack of this information suggests the necessity of the application of a high level of contingency for the all items of work.

B7.0-3 DISCUSSION OF COSTS FOR BASELINE ESTIMATES BY ACCOUNT NUMBERS –

The tentatively selected plan’s cost will be briefly discussed below by account or feature. The features discussed will include: 02, Relocations; 04, Dams; 06, Fish and Wildlife

Facilities; 14 Recreation; 30, Planning, Engineering and Design, and 31, Construction Management.
Feature 01 - Lands And Damages-

Structural Lands and Damages cost represents all Real Estate costs associated with the construction of the project. All construction occurs on Federal property, therefore no need to quantify these costs.

Feature 02 - Relocations-

Costs in this feature represent those costs associated with relocating or raising isolated sections of county roads impacted by raising Bull Shoals Lake.

Feature 04 – Dams -

Costs in this feature represent the costs to provide a maintenance bulkhead for Norfork Dam. Also, these costs include the increased cost of the more frequent maintenance painting of the tainter gates of Bull Shoals Dam.

Feature 6 – Fish and Wildlife Facilities –

Work for the feature are a low percent of the total cost of this project, but construction difficulties would be encountered during the contract time. This is mitigation for impacts of the other project features. The work includes the installation of a siphon through the concrete dam forming Norfork Lake. The tunneling or boring through the concrete dam is envisioned to be with the use of truckable sectional work barges comprising the work platforms. A majority of the work will be above normal pool. Only a section of the intake pipe will be below normal pool extending to the bottom of the conservation pool.

Feature 14 – Recreation Facilities-

Costs in this feature represent those costs associated with raising or constructing new swim beaches, boat launch ramps, parking lots, and access roads. EM 1110-1-400, Engineering and Design, Recreation Facility and Customer Services Standards, dated 1 November 2004, was used as a guide for quantity development for recreation features. Other quantities were developed based upon the cost estimator's judgment.

Feature 30 – Planning, Engineering and Design –

Costs that made up this feature were supplied by the project manager with input from the various disciplines that will perform the work. Costs are for design calculations, drawings, engineering surveys, soil borings, cost estimates, contracting work, real estate planning and acquisition, and project management.

Feature 31-Construction Management –

These construction management (CM) costs represent total costs for the Construction Branch (District and Field Offices) and project management. These costs include the Technical Indirect and District Overhead markups for these respective organizations. The CM amount was determined by taking 10.0 percent of the construction cost.

B7.0-4 DISCUSSION OF CONTINGENCIES

The contingencies assigned to the cost estimate were based upon the judgment of the cost engineer with input from each design element. The relative degree of uncertainty of the line items is reflected in the contingencies. Generally the 'level of uncertainties' is high due to the lack of design effort used for creating the estimate. No subsurface borings or engineering surveys were performed during this feasibility study.

Feature 02 - Relocations - Relocation of the three segments of county roads are routine and were estimated with best available data. Therefore with the available information, a 25 percent contingency was thought to be appropriate for the relocation.

Feature 04 – Dams – The work components of this feature are not usual, but required a major amount of judgment, therefore the appropriate contingency percent is 25 percent.

Feature 06 – Fish and Wildlife Facilities –

Contingencies are judged to be 25 percent since no survey data was available. There is general geology information available and it is known there is considerable rock near the ground surface. If rock is encountered, the design will be field modified to avoid excavation of this rock.

Feature 14 – Recreation Facilities -

Construction quantities for these items were predominantly generated by the cost engineer based up common practice for this work in other jobs previously estimated. Recreation facility type and general quantity were provided from Environmental personnel preparing the environmental assessment. The cost estimator felt there were considerable unknowns and that the contingency rate should be 25 percent in accordance with UFC 3-700-05, Design Guide: Construction Cost Estimating, dated 5 January 2005.

Feature 30 – Planning, Engineering and Design –

The work for this account is directly related to the unknowns for the design work, so therefore, the contingency should be the same as for the construction features.

Feature 31 - Supervision and Administration (S&A). The contingency for S&A costs is 25%. This would include Construction LCPM. The cost estimator chose to use this level of contingency due to the unknowns about the designs.

B7.0-5 - ESCALATION

Escalation is based on the construction duration and economic indices in Appendix A of EM 110-2-1304, Civil Works Construction Cost Index System, revised 31 March 2008. The future economic indices were developed by the Walla Walla District in consultation with the Office of Management and Budget. See Tab C for the construction schedule. The design period is 4 years with 2.5 years overlapping construction work. The construction period was estimated to be 4.3 years. The construction start of the project was assumed to be June 2011 with completion in August 2015. Using the time periods developed in the construction schedule and construction costs developed in MII, a Total Project Cost Summary, at Tab A, was prepared for the various features yielding the fully funded cost for the White River Minimum Flows project.

**WHITE RIVER MINIMUM FLOWS,
UPPER WHITE RIVER BASIN,
ARKANSAS AND MISSOURI,
FEASIBILITY STUDY**

TAB A

- TOTAL PROJECT COST SHEET -

**** TOTAL PROJECT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared:	1-Oct-09				Program Year (Budget EC):			2010					
	Effective Price Level:	1-Oct-09				Effective Price Level Date:			1 OCT 10	FULLY FUNDED PROJECT ESTIMATE				
										Spent Thru:				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	1 OCT 10 ($K)	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
02	RELOCATIONS	1,571	393	25%	1,964	2.6%	1,612	403	2,015	-	4.6%	1,686	422	2,108
04	DAMS	3,007	752	25%	3,759	2.6%	3,085	772	3,857	-	4.1%	3,211	803	4,014
06	FISH & WILDLIFE FACILITIES	595	149	25%	744	2.6%	610	153	763	-	7.2%	654	164	818
14	RECREATION FACILITIES	8,459	2,115	25%	10,574	2.6%	8,679	2,170	10,849	-	6.7%	9,260	2,315	11,575
	CONSTRUCTION ESTIMATE TOTALS:	13,631	3,409		**17,040**		13,986	3,498	17,484		5.9%	14,811	3,704	18,515
01	LANDS AND DAMAGES			-	-		-	-	-	-		-	-	-
30	PLANNING, ENGINEERING & DESIGN	2,957	738	25%	3,696		3,033	752	3,785	-	4.3%	3,160	787	3,947
31	CONSTRUCTION MANAGEMENT	1,363	341	25%	1,704		1,399	349	1,748	-	5.7%	1,478	369	1,847
	PROJECT COST TOTALS:	17,951	4,488	25%	**22,440**		18,418	4,599	23,017		5.6%	19,449	4,860	**24,309**

CHIEF, COST ENGINEERING

Project Manager, Mike Biggs

CHIEF, REAL ESTATE

CHIEF, PLANNING AND ENVIRONMENTAL OFFICE

CHIEF, ENGINEERING AND CONSTRUCTION

CHIEF, OPERATIONS

CHIEF, CONSTRUCTION

CHIEF, CONTRACTING

CHIEF, PM-PB

CHIEF, DPM

ESTIMATED FEDERAL COST:	**5,159**
ESTIMATED NON-FEDERAL COST:	**19,150**
ESTIMATED TOTAL PROJECT COST:	**24,309**

Non Federal costs include Relocations and Recreational Facilities and their associated design and contract supervision and administration costs.

**** TOTAL PROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)					Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10				FULLY FUNDED PROJECT ESTIMATE				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
02	RELOCATIONS	1,571	393	25%	1,964	2.6%	1,612	403	2,015	2012Q2	4.6%	1,686	422	2,108
	CONSTRUCTION ESTIMATE TOTALS:	1,571	393	25%	**1,964**		1,612	403	2,015			1,686	422	2,108
01	LANDS AND DAMAGES		-		-					-				
30	PLANNING, ENGINEERING & DESIGN													
	Plans & Specs	157	39.3	25%	196	2.6%	161	40	201	2011Q4	3.6%	167	41	208
0.5%	Environmental Studies Documents	8	2.0	25%	10	2.6%	8	2	10	2011Q4	3.6%	8	2	10
1.0%	Cost Estimates	16	3.9	25%	20	2.6%	16	4	20	2011Q4	3.6%	17	4	21
1.0%	Contract Award Documents	16	3.9	25%	20	2.6%	16	4	20	2011Q4	3.6%	17	4	21
3.0%	Engineering & Design During Cons	47	11.8	25%	59	2.6%	48	12	60	2011Q4	3.6%	50	12	62
2.5%	Management Documents	39	9.8	25%	49	2.6%	40	10	50	2012Q2	4.6%	42	10	52
1.0%	Construction Review of P&S	16	3.9	25%	20	2.6%	16	4	20	2012Q2	4.6%	17	4	21
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	157	39.3	25%	196	2.6%	161	40	201	2012Q2	4.6%	168	42	210
	CONTRACT COST TOTALS:	2,026	507		**2,533**		2,078	519	2,597			2,172	541	**2,713**

**** TOTAL PROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)						Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10					FULLY FUNDED PROJECT ESTIMATE				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
04	DAMS	3,007	752	25%	3,759	2.6%	3,085	772	3,857	2012Q1	4.1%	3,211	803	4,014
	CONSTRUCTION ESTIMATE TOTALS:	3,007	752	25%	**3,759**		3,085	772	3,857			3,211	803	4,014
01	LANDS AND DAMAGES		-		-					-				
30	PLANNING, ENGINEERING & DESIGN													
	Plans & Specs	301	75.2	25%	376	2.6%	309	77	386	2011Q2	1.7%	314	78	392
1.0%	Environmental Studies Documents	15	3.8	25%	19	2.6%	15	4	19	2011Q2	1.7%	15	4	19
1.9%	Cost Estimates	30	7.5	25%	38	2.6%	31	8	39	2011Q2	1.7%	32	8	40
1.9%	Contract Award Documents	30	7.5	25%	38	2.6%	31	8	39	2011Q2	1.7%	32	8	40
5.7%	Engineering & Design During Cons	90	22.6	25%	113	2.6%	93	23	116	2011Q2	1.7%	95	23	118
4.8%	Management Documents	75	18.8	25%	94	2.6%	77	19	96	2012Q1	3.2%	79	20	99
1.9%	Construction Review of P&S	30	7.5	25%	38	2.6%	31	8	39	2012Q1	3.2%	32	8	40
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	301	75.2	25%	376	2.6%	309	77	386	2012Q1	3.2%	319	79	398
	CONTRACT COST TOTALS:	3,879	970		**4,849**		3,981	996	4,977			4,129	1,031	**5,160**

**** TOTAL PROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

Estimate Prepared: 2008(Jul - Sep)
Effective Price Level: 2009(Oct - Dec)

Program Year (Budget EC): 2010
Effective Price Level Date: 1 OCT 10

FULLY FUNDED PROJECT ESTIMATE

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
06	FISH & WILDLIFE FACILITIES	595	149	25%	744	2.6%	610	153	763	2013Q3	7.2%	654	164	818
	CONSTRUCTION ESTIMATE TOTALS:	595	149	25%	**744**		610	153	763			654	164	818
01	LANDS AND DAMAGES	-	-		-		-	-	-	-				
30	PLANNING, ENGINEERING & DESIGN									-				
	Plans & Specs	59	14.9	25%	74	2.6%	61	15	76	2011Q1	2.0%	62	15	77
0.5%	Environmental Studies Documents	3	0.7	25%	4	2.6%	3	1	4	2011Q1	2.0%	3	1	4
1.0%	Cost Estimates	6	1.5	25%	7	2.6%	6	2	8	2011Q1	2.0%	6	2	8
1.0%	Contract Award Documents	6	1.5	25%	7	2.6%	6	2	8	2011Q1	2.0%	6	2	8
3.0%	Engineering & Design During Cons	18	4.5	25%	22	2.6%	18	5	23	2011Q1	2.0%	18	5	23
2.5%	Management Documents	15	3.7	25%	19	2.6%	15	4	19	2013Q3	7.2%	16	4	20
1.0%	Construction Review of P&S	6	1.5	25%	7	2.6%	6	2	8	2013Q3	7.2%	6	2	8
										-				
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	59	14.9	25%	74	2.6%	61	15	76	2013Q3	7.2%	65	16	81
	CONTRACT COST TOTALS:	767	192		**959**		786	199	985			836	211	**1,047**

**** TOTAL PROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)					Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10				FULLY FUNDED PROJECT ESTIMATE				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
14	RECREATION FACILITIES	8,459	2,115	25%	10,574	2.6%	8,679	2,170	10,849	2013Q2	6.7%	9,260	2,315	11,575
	CONSTRUCTION ESTIMATE TOTALS:	8,459	2,115	25%	**10,574**		8,679	2,170	10,849			9,260	2,315	11,575
01	LANDS AND DAMAGES		-	25%	-				-	-				-
30	PLANNING, ENGINEERING & DESIGN													
	Plans & Specs	1,213	302.3	25%	1,516	2.6%	1,245	310	1,555	2012Q2	4.6%	1,302	324	1,626
0.5%	Environmental Studies Documents	42	10.6	25%	53	2.6%	43	11	54	2012Q2	4.6%	45	12	57
1.0%	Cost Estimates	85	21.1	25%	106	2.6%	87	22	109	2012Q2	4.6%	91	23	114
1.0%	Contract Award Documents	85	21.1	25%	106	2.6%	87	22	109	2012Q2	4.6%	91	23	114
2.5%	Management Documents	211	52.9	25%	264	2.6%	217	54	271	2012Q2	4.6%	227	56	283
3.0%	Engineering & Design During Cons	254	63.4	25%	317	2.6%	260	65	325	2013Q2	6.7%	277	69	346
1.0%	Construction Review of P&S	85	21.1	25%	106	2.6%	87	22	109	2013Q2	6.7%	93	23	116
										-				
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	846	211.5	25%	1,057	2.6%	868	217	1,085	2013Q2	6.7%	926	232	1,158
	CONTRACT COST TOTALS:	11,279	2,819		**14,099**		11,573	2,893	14,466			12,312	3,077	**15,389**

**** Norfork Lake ONLY SUBPROJECT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 1-Oct-09					Program Year (Budget EC): 2010				FULLY FUNDED PROJECT ESTIMATE				
	Effective Price Level: 1-Oct-09					Effective Price Level Date: 1 OCT 10				Spent Thru:				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	1 OCT 10 ($K)	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
02	RELOCATIONS			-						-				-
04	DAMS	2,828	707	25%	3,535	2.6%	2,902	725	3,627	-	4.1%	3,020	755	3,775
06	FISH & WILDLIFE FACILITIES	595	149	25%	744	2.6%	610	153	763	-	7.2%	654	164	818
14	RECREATION FACILITIES	3,109	777	25%	3,886	2.6%	3,190	797	3,987	-	6.7%	3,404	850	4,254
	CONSTRUCTION ESTIMATE TOTALS:	6,532	1,633		**8,165**		6,702	1,675	8,377		5.6%	7,078	1,769	8,847
01	LANDS AND DAMAGES			-	-		-	-	-	-		-	-	-
30	PLANNING, ENGINEERING & DESIGN	1,341	335	25%	1,676		1,377	339	1,716	-	3.8%	1,425	357	1,782
31	CONSTRUCTION MANAGEMENT	653	163	25%	817		670	168	838	-	5.0%	704	176	880
	PROJECT COST TOTALS:	8,526	2,132	25%	**10,658**		8,749	2,182	10,931		5.3%	9,207	2,302	**11,509**

ESTIMATED FEDERAL COST:	**4,853**
ESTIMATED NON-FEDERAL COST:	**6,656**
ESTIMATED TOTAL PROJECT COST:	**11,509**

Non Federal costs include Relocations and Recreational Facilities and their associated design and contract supervision and administration costs.

**** Norfork Lake ONLY SUBPROJECT COST SUMMARY ****

****** CONTRACT COST SUMMARY *****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)					Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10				FULLY FUNDED PROJECT ESTIMATE				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
02	RELOCATIONS			25%										
	CONSTRUCTION ESTIMATE TOTALS:													
01	LANDS AND DAMAGES		-		-					-				
30	PLANNING, ENGINEERING & DESIGN													
	Plans & Specs			25%										
	Environmental Studies Documents			25%										
	Cost Estimates			25%										
	Contract Award Documents			25%										
	Engineering & Design During Cons			25%										
	Management Documents			25%										
	Construction Review of P&S			25%										
31	CONSTRUCTION MANAGEMENT													
	Corps S&A			25%										
	CONTRACT COST TOTALS:													

**** Norfork Lake ONLY SUBPROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

Estimate Prepared: 2008(Jul - Sep)
Effective Price Level: 2009(Oct - Dec)

Program Year (Budget EC): 2010
Effective Price Level Date: 1 OCT 10

FULLY FUNDED PROJECT ESTIMATE

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
04	DAMS	2,828	707	25%	3,535	2.6%	2,902	725	3,627	2012Q1	4.1%	3,020	755	3,775
	CONSTRUCTION ESTIMATE TOTALS:	2,828	707	25%	**3,535**		2,902	725	3,627			3,020	755	3,775
01	LANDS AND DAMAGES		-		-					-				
30	PLANNING, ENGINEERING & DESIGN													
10.0%	Plans & Specs	283	70.7	25%	354	2.6%	290	73	363	2011Q2	1.7%	295	74	369
0.5%	Environmental Studies Documents	14	3.5	25%	18	2.6%	15	4	19	2011Q2	1.7%	15	4	19
1.0%	Cost Estimates	28	7.1	25%	35	2.6%	29	7	36	2011Q2	1.7%	30	7	37
1.0%	Contract Award Documents	28	7.1	25%	35	2.6%	29	7	36	2011Q2	1.7%	30	7	37
3.0%	Engineering & Design During Cons	85	21.2	25%	106	2.6%	87	22	109	2011Q2	1.7%	89	22	111
2.5%	Management Documents	71	17.7	25%	88	2.6%	73	18	91	2012Q1	3.2%	75	19	94
1.0%	Construction Review of P&S	28	7.1	25%	35	2.6%	29	7	36	2012Q1	3.2%	30	7	37
31	CONSTRUCTION MANAGEMENT													
10.0%	Corps S&A	283	70.7	25%	354	2.6%	290	73	363	2012Q1	3.2%	299	75	374
	CONTRACT COST TOTALS:	3,648	912		**4,560**		3,744	936	4,680			3,883	970	**4,853**

**** Norfork Lake ONLY SUBPROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

Estimate Prepared: 2008(Jul - Sep)
Effective Price Level: 2009(Oct - Dec)

Program Year (Budget EC): 2010
Effective Price Level Date: 1 OCT 10

FULLY FUNDED PROJECT ESTIMATE

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
06	FISH & WILDLIFE FACILITIES	595	149	25%	744	2.6%	610	153	763	2013Q3	7.2%	654	164	818
	CONSTRUCTION ESTIMATE TOTALS:	595	149	25%	**744**		610	153	763			654	164	818
01	LANDS AND DAMAGES	-	-		-		-	-	-	-				
30	PLANNING, ENGINEERING & DESIGN									-				
	Plans & Specs	59	14.9	25%	74	2.6%	61	15	76	2011Q1	2.0%	62	15	77
0.5%	Environmental Studies Documents	3	0.7	25%	4	2.6%	3	1	4	2011Q1	2.0%	3	1	4
1.0%	Cost Estimates	6	1.5	25%	7	2.6%	6	2	8	2011Q1	2.0%	6	2	8
1.0%	Contract Award Documents	6	1.5	25%	7	2.6%	6	2	8	2011Q1	2.0%	6	2	8
3.0%	Engineering & Design During Cons	18	4.5	25%	22	2.6%	18	5	23	2011Q1	2.0%	18	5	23
2.5%	Management Documents	15	3.7	25%	19	2.6%	15	4	19	2013Q3	7.2%	16	4	20
1.0%	Construction Review of P&S	6	1.5	25%	7	2.6%	6	2	8	2013Q3	7.2%	6	2	8
				25%						-				
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	59	14.9	25%	74	2.6%	61	15	76	2013Q3	7.2%	65	16	81
	CONTRACT COST TOTALS:	767	192		**959**		786	199	985			836	211	**1,047**

**** Norfork Lake ONLY SUBPROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)					Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10				FULLY FUNDED PROJECT ESTIMATE				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
14	RECREATION FACILITIES	3,109	777	25%	3,886	2.6%	3,190	797	3,987	2013Q2	6.7%	3,404	850	4,254
	CONSTRUCTION ESTIMATE TOTALS:	3,109	777	25%	**3,886**		3,190	797	3,987			3,404	850	4,254
01	LANDS AND DAMAGES		-	25%	-				-	-				-
30	PLANNING, ENGINEERING & DESIGN													
	Plans & Specs	411	102.7	25%	514	2.6%	422	105	527	2012Q2	4.6%	441	110	551
0.5%	Environmental Studies Documents	16	3.9	25%	19	2.6%	16	4	20	2012Q2	4.6%	17	4	21
1.0%	Cost Estimates	31	7.8	25%	39	2.6%	32	8	40	2012Q2	4.6%	33	8	41
1.0%	Contract Award Documents	31	7.8	25%	39	2.6%	32	8	40	2012Q2	4.6%	33	8	41
2.5%	Management Documents	78	19.4	25%	97	2.6%	80	20	100	2012Q2	4.6%	84	21	105
3.0%	Engineering & Design During Cons	93	23.3	25%	117	2.6%	96	24	120	2013Q2	6.7%	102	26	128
1.0%	Construction Review of P&S	31	7.8	25%	39	2.6%	32	8	40	2013Q2	6.7%	34	9	43
										-				
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	311	77.7	25%	389	2.6%	319	80	399	2013Q2	6.7%	340	85	425
	CONTRACT COST TOTALS:	4,111	1,027		**5,138**		4,219	1,054	5,273			4,488	1,121	**5,609**

**** Bull Shoals Lake ONLY SUBPROJECT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering

PREPARED: 18-Jul-08

Estimate Prepared: 1-Oct-09
Effective Price Level: 1-Oct-09

Program Year (Budget EC): 2010
Effective Price Level Date: 1 OCT 10

FULLY FUNDED PROJECT ESTIMATE

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Spent Thru: 1 OCT 10 ($K)	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
02	RELOCATIONS	1,571	393	25%	1,964	2.6%	1,612	403	2,015	-	4.6%	1,686	422	2,108
04	DAMS	179	45	25%	224	2.6%	183	46	229	-	3.9%	190	48	238
06	FISH & WILDLIFE FACILITIES			-						-				-
14	RECREATION FACILITIES	5,350	1,337	25%	6,687	2.6%	5,488	1,372	6,860	-	6.7%	5,855	1,464	7,319
	CONSTRUCTION ESTIMATE TOTALS:	7,099	1,775		**8,874**		7,283	1,821	9,104		6.2%	7,731	1,934	9,665
01	LANDS AND DAMAGES			-	-		-	-	-	-		-	- -	
30	PLANNING, ENGINEERING & DESIGN	1,616	404	25%	2,020		1,657	413	2,070	-	4.7%	1,736	431	2,167
31	CONSTRUCTION MANAGEMENT	710	177	25%	887		728	181	909	-	6.2%	773	192	965
	PROJECT COST TOTALS:	9,425	2,356	25%	**11,781**		9,668	2,415	12,083		5.9%	10,240	2,557	**12,797**

ESTIMATED FEDERAL COST: **303**
ESTIMATED NON-FEDERAL COST: **12,494**

ESTIMATED TOTAL PROJECT COST: 12,797

Non Federal costs include Relocations and Recreational Facilities and their associated design and contract supervision and administration costs.

**** Bull Shoals Lake ONLY SUBPROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering

PREPARED: 18-Jul-08

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)					Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10				FULLY FUNDED PROJECT ESTIMATE				
02	RELOCATIONS	1,571	393	25%	1,964	2.6%	1,612	403	2,015	2012Q2	4.6%	1,686	422	2,108
	CONSTRUCTION ESTIMATE TOTALS:	1,571	393	25%	**1,964**		1,612	403	2,015			1,686	422	2,108
01	LANDS AND DAMAGES		-		-					-				
30	PLANNING, ENGINEERING & DESIGN													
10.0%	Plans & Specs	157	39.3	25%	196	2.6%	161	40	201	2011Q4	3.6%	167	41	208
0.5%	Environmental Studies Documents	8	2.0	25%	10	2.6%	8	2	10	2011Q4	3.6%	8	2	10
1.0%	Cost Estimates	16	3.9	25%	20	2.6%	16	4	20	2011Q4	3.6%	17	4	21
1.0%	Contract Award Documents	16	3.9	25%	20	2.6%	16	4	20	2011Q4	3.6%	17	4	21
3.0%	Engineering & Design During Cons	47	11.8	25%	59	2.6%	48	12	60	2011Q4	3.6%	50	12	62
2.5%	Management Documents	39	9.8	25%	49	2.6%	40	10	50	2012Q2	4.6%	42	10	52
1.0%	Construction Review of P&S	16	3.9	25%	20	2.6%	16	4	20	2012Q2	4.6%	17	4	21
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	157	39	25%	196	2.6%	161	40	201	2012Q2	4.6%	168	42	210
	CONTRACT COST TOTALS:	2,026	507		**2,533**		2,078	519	2,597			2,172	541	**2,713**

**** Bull Shoals Lake ONLY SUBPROJECT COST SUMMARY ****

****** CONTRACT COST SUMMARY ******

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

	Estimate Prepared: 2008(Jul - Sep) Effective Price Level: 2009(Oct - Dec)					Program Year (Budget EC): 2010 Effective Price Level Date: 1 OCT 10				FULLY FUNDED PROJECT ESTIMATE				
WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
04	DAMS	179	45	25%	224	2.6%	183	46	229	2012Q1	4.1%	190	48	238
	CONSTRUCTION ESTIMATE TOTALS:	179	45	25%	**224**		183	46	229			190	48	238
01	LANDS AND DAMAGES		-		-					-				
30	PLANNING, ENGINEERING & DESIGN													
10.0%	Plans & Specs	18	4.5	25%	22	2.6%	18	5	23	2011Q2	1.7%	18	5	23
0.1%	Environmental Studies Documents	1	0.2	25%	1	2.6%	1		1	2011Q2	1.7%	1		1
0.1%	Cost Estimates	2	0.4	25%	2	2.6%	2		2	2011Q2	1.7%	2		2
0.1%	Contract Award Documents	2	0.4	25%	2	2.6%	2		2	2011Q2	1.7%	2		2
0.3%	Engineering & Design During Cons	5	1.3	25%	7	2.6%	5	1	6	2011Q2	1.7%	5	1	6
0.3%	Management Documents	4	1.1	25%	6	2.6%	5	1	6	2012Q1	3.2%	5	1	6
0.1%	Construction Review of P&S	2		25%	2	2.6%	2		2	2012Q1	3.2%	2		2
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	18	4	25%	22	2.6%	18	4	22	2012Q1	3.2%	19	4	23
	CONTRACT COST TOTALS:	230	57		**287**		236	57	293			244	59	**303**

Filename: 20081031 Corrected TPCS White River Minimum Flows.xls
Bull Shoals Lake

**** Bull Shoals Lake ONLY SUBPROJECT COST SUMMARY ****

**** CONTRACT COST SUMMARY ****

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

Estimate Prepared: 2008(Jul - Sep)
Effective Price Level: 2009(Oct - Dec)

Program Year (Budget EC): 2010
Effective Price Level Date: 1 OCT 10

FULLY FUNDED PROJECT ESTIMATE

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
06	FISH & WILDLIFE FACILITIES			25%						-				
	CONSTRUCTION ESTIMATE TOTALS:													
01	LANDS AND DAMAGES	-	-		-		-	-	-	-				
30	PLANNING, ENGINEERING & DESIGN			25%						-				
	Plans & Specs			25%						-				
#DIV/0!	Environmental Studies Documents			25%						-				
#DIV/0!	Cost Estimates			25%						-				
#DIV/0!	Contract Award Documents			25%						-				
#DIV/0!	Engineering & Design During Cons			25%						-				
#DIV/0!	Management Documents			25%						-				
#DIV/0!	Construction Review of P&S			25%						-				
#DIV/0!										-				
31	CONSTRUCTION MANAGEMENT													
	Corps S&A			25%						-				
#DIV/0!														
#DIV/0!														
	CONTRACT COST TOTALS:													

**** Bull Shoals Lake ONLY SUBPROJECT COST SUMMARY ****

****** CONTRACT COST SUMMARY ******

PROJECT: White River Minimum Flows
LOCATION: Upper White River Basin, Arkansas and Missouri

DISTRICT: SWL, LITTLE ROCK
POC: George Losak, Cost Engineering
PREPARED: 18-Jul-08

Estimate Prepared: 2008(Jul - Sep)
Effective Price Level: 2009(Oct - Dec)

Program Year (Budget EC): 2010
Effective Price Level Date: 1 OCT 10

FULLY FUNDED PROJECT ESTIMATE

WBS NUMBER	Civil Works Feature & Sub-Feature Description	COST ($K)	CNTG ($K)	CNTG (%)	TOTAL ($K)	ESC (%)	COST ($K)	CNTG ($K)	TOTAL ($K)	Mid-Point Date	ESC (%)	COST ($K)	CNTG ($K)	FULL ($K)
14	RECREATION FACILITIES	5,350	1,337	25%	6,687	2.6%	5,488	1,372	6,860	2013Q2	6.7%	5,855	1,464	7,319
	CONSTRUCTION ESTIMATE TOTALS:	5,350	1,337	25%	**6,687**		5,488	1,372	6,860			5,855	1,464	7,319
01	LANDS AND DAMAGES		-	25%	-				-	-				-
30	PLANNING, ENGINEERING & DESIGN													
15.0%	Plans & Specs	802	200.6	25%	1,003	2.6%	823	206	1,029	2012Q2	4.6%	861	215	1,076
0.5%	Environmental Studies Documents	27	6.7	25%	33	2.6%	27	7	34	2012Q2	4.6%	28	7	35
1.0%	Cost Estimates	53	13.4	25%	67	2.6%	55	14	69	2012Q2	4.6%	58	15	73
1.0%	Contract Award Documents	53	13.4	25%	67	2.6%	55	14	69	2012Q2	4.6%	58	15	73
2.5%	Management Documents	134	33.4	25%	167	2.6%	137	34	171	2012Q2	4.6%	143	36	179
3.0%	Engineering & Design During Cons	160	40.1	25%	201	2.6%	165	41	206	2013Q2	6.7%	176	44	220
1.0%	Construction Review of P&S	53	13.4	25%	67	2.6%	55	14	69	2013Q2	6.7%	59	15	74
										-				
31	CONSTRUCTION MANAGEMENT													
	Corps S&A	535	134	25%	669	2.6%	549	137	686	2013Q2	6.7%	586	146	732
	CONTRACT COST TOTALS:	7,168	1,792		**8,960**		7,354	1,839	9,193			7,824	1,957	**9,781**

**WHITE RIVER MINIMUM FLOWS,
UPPER WHITE RIVER BASIN,
ARKANSAS AND MISSOURI,
FEASIBILITY STUDY**

TAB B

- MCACES Cost Estimate -

Estimate for Construction of Mitigation Items

White River Minimum Flow Study Project Purpose Impact Cost - Public Facilities, Dam, Fish and Wildlife and Recreation Purposes

Estimated by	Cost Engineering & Support Team
Designed by	Litttle Rock District
Prepared by	George Losak
Preparation Date	7/1/2008
Effective Date of Pricing	10/1/2009
Estimated Construction Time	1,639 Days

Description	Page

Date	Author	Note
5/15/2008	Losak	The PED cost estimate was updated upon 15 May 2008 directions from the Project Manager who furnished revised data on the park and road facilities impacted by the White River Minimum Flows project. The data was only a spreadsheet and aerial photography with impacted areas marked. Electricity and fuel prices were updated based upon data from the U.S. Energy Information Administration. Engineering and Design costs were furnished by the respective technical disciplines. Corps of Engineers contract supervision and administration were obtained from SWL's Construction Branch. ASSUMPTIONS: 1. Project features can be constructed with the resources listed in the following cost estimate. 2. Material cost escalation will be equal to or less than that included in this cost estimate. INCLUSIONS: 1. Contingency of 10 percent. 2. Profit of 10 percent. 3. Job Office Overhead of 15 percent. 4. Home Office Overhead of 7.5 percent.
6/27/2008	Losak	The Water Resource Development Acts (WRDA) of 1999 and 2000 modified the basic authorization and operation for the five multipurpose White River Basin lakes, Beaver, Table Rock, and Bull Shoals Lakes on the White River; Norfork Lake on the North Fork River; and Greer Ferry Lake on the Little Red River. WRDA 99 & 00 directed the Corps to complete a study and report to determine if minimum flow reallocations adversely affect other authorized purposes. Also, this study is to identify Federal costs that will be incurred. A Reallocation Report, signed August 2004, analyzed reallocation and release scenarios at the 5 multipurpose White River lakes. The Reallocation Report identified economically justified, technically sound, and environmentally acceptable reallocation and release scenarios at each lake. Subsequent to the completion of the Draft Environmental Impact Statement (DEIS), Section 132 of the FY 2006 Energy and Water Resources Development Act (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork lakes, as described in the Reallocation Report, at full Federal expense in accordance with section 906(e) of WRDA 86. Section 132 did not authorize implementation of Minimum Flows at Beaver, Norfork, and Greers Ferry Lakes. Also, Section 132 repealed the previous project authorities in WRDA 99 and WRDA 00, resulting in a new project. The DEIS analyzed the impacts to the five White River Reservoirs, however; emphasis is placed on Bull Shoals and Norfork Lakes due to the changes made with the FY 2006 Energy and Water Resources Development Act (P.L. 109-103). Previous study efforts evaluating the other lakes is included in the interest of full disclosure. The Final Environmental Impact Statement (FEIS) concludes that the trout tailwater fishery below Bull Shoals and Norfork dams will benefit from the increased wetted perimeter and dissolved oxygen levels resulting from increased minimum flows while negative impacts to hydropower and in-lake recreation will be fully mitigated. The tentatively selected plan calls for the realloction of 5 vertical feet of flood control storage in Bull Shoals Lake and 1.7 vertical feet of flood control storage in Norfork

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Date	Author	Note
6/27/2008	Losak	Lake. Geographical analysis of reallocation of this storage caused impact to recreation resources that are quantified in this feasibility cost estimate.

The construction of these features are to paid by the non-Federal Sponsor, the State of Arkansas.

REFERENCES:

1. ER 1110-1-1300, Cost Engineering Policy and General Requirements, 26 March 1994.

2. ER 1110-2-1302, Civil Works Cost Engineering, 31 March 1994.

3. UFC 3-700-05 Design Guide: Construction Cost Estimating, 3 January 2005.

4. ER 1110-2-1150, Engineering and Design, Engineering and Design for Civil Works Projects, 31 August 1999.

5. EM 1110-1-400, Engineering and Design, Recreation Facility and Customer Services Standards, 1 November 2004.

6. Architectural and Engineering Instruction Manual (AEIM), January 2003.

SOURCE OF LABOR RATES:

1. Labor rates used in SWL cost estimates are from either Federal Davis-Bacon Wage Decisions or state wage decisions for the geographical area where the work is to occur. The two levels of wage decisions are compared by labor craft and the higher wage rate is incorporated into the labor library used by SWL to prepare the cost estimate.

There are times where the work area is so isolated that there are no contractors capable of performing the work with offices nor work crews within the area. Therefore when this situation occurs, the cost estimator will use a wage rate of at least a few key personnel (job superintendent, special equipment operators, and other key skilled personnel) of a higher rate area where the potential contractor will come.

QUOTE SOURCES:

Concrete.
Guy King & Sons, 870-425-3431, 3,000 psi - $75.50; 4,000 psi - $78.50. POC - James. Date of quote - 27 June 2008.

Asphalt:
Twin Lakes Hot Mix, 1-870-425-4510. POC Tony, Asphalt $62.00/ton at plant. Prime coat - $3.00/gallon. Date of quote 30 June 2008.

ASSUMPTIONS:

1. Construction of these features will consist of practices commonly utilized.

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Date	Author	Note
6/27/2008	Losak	2. All work (road, parking(s), swim beach and boat launch ramp, etc) in a park will be done under one contract at one time, therefore only one mobilization and one de-mobilization required by the contractor. 3. Clearing and grubbing quantities are based upon the cost estimator's judgment of the timber conditions (size and quantity) of forests in the Bull Shoals and Norfork Lakes area of Arkansas. 4. All road fill. The amount of fill require is directly proportional to the road length required to be raised by a factor of 0.02 for lengths of zero to 600 feet and .005 for lengths greater than 600 feet per cost estimator's judgement, such as HF = L x 0.02 = 300 x .02 = 6 feet. 5. Mobilization and Demobilization. Average values of 40 hours for mob and 20 hours for demob was assumed by the cost estimator. Most of the work for recreational facilities is common civil work. There are many contractors that can perform the work and therefore, less mob and demob required. 6. E&D and S&A costs. An average rate for this work was included in the cost estimate based on an average experienced. 7. Labor rates used in the cost estimate are from the 2006 labor rate study performed by SWL. It was noted that labor rates do not change drastically for Arkansas since it is a not a labor union state. INCLUSIONS: 1. Contingency of 25 percent due to lack of detailed surveys and other measurements. Quantities derived from common practice. 2. Profit of 10 percent. 3. Job Office Overhead of 15 percent. 4. Home Office Overhead of 7.5 percent.

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Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
Feature Level Report			**17,951,597**	**0**	**4,487,899**	**0**	**22,439,496**
Norfork Lake Mitigation Cost	**EA**	**1.0**	**8,526,500**	**0**	**2,131,625**	**0**	**10,658,125**
04 Federal - Dams	**EA**	**1.0**	**2,828,189**	**0**	**707,047**	**0**	**3,535,237**
06 Federal - Fish and Wildlife Facilities	**EA**	**1.0**	**594,637**	**0**	**148,659**	**0**	**743,296**
14 Non-Federal - Recreational Facilities	**EA**	**1.0**	**3,109,334**	**0**	**777,333**	**0**	**3,886,667**
30 Engineering and Design	**EA**	**1.0**	**1,341,140**	**0**	**335,285**	**0**	**1,676,425**
31 Supervision and Administration	**EA**	**1.0**	**653,200**	**0**	**163,300**	**0**	**816,500**
Bull Shoals Lake Mitigation Cost	**EA**	**1.0**	**9,425,097**	**0**	**2,356,274**	**0**	**11,781,371**
02 Non-Federal - Relocations	**EA**	**1.0**	**1,570,749**	**0**	**392,687**	**0**	**1,963,436**
04 Federal - Dams	**EA**	**1.0**	**178,554**	**0**	**44,638**	**0**	**223,192**
14 Non-Federal - Recreational Facilities	**EA**	**1.0**	**5,349,559**	**0**	**1,337,390**	**0**	**6,686,949**
30 Engineering and Design	**EA**	**1.0**	**1,616,335**	**0**	**404,084**	**0**	**2,020,419**
31 Supervision and Administration	**EA**	**1.0**	**709,900**	**0**	**177,475**	**0**	**887,375**

Currency in US dollars

Description	UOM	Quantity	ContractorOwnCost	ContractCost	Escalation	Contingency	SIOH	ProjectCost
Park Level Report			**17,900,233.61**	**17,951,596.70**	**0.00**	**4,487,899.18**	**0.00**	**22,439,495.88**
Norfork Lake Mitigation Cost	**EA**	**1.0000**	**8,475,136.67**	**8,526,499.76**	**0.00**	**2,131,624.94**	**0.00**	**10,658,124.70**
04 Federal - Dams	**EA**	**1.0000**	**2,828,189.38**	**2,828,189.38**	**0.00**	**707,047.34**	**0.00**	**3,535,236.72**
0402 Spillway	**EA**	**1.0000**	**2,828,189.38**	**2,828,189.38**	**0.00**	**707,047.34**	**0.00**	**3,535,236.72**
040241 Gates. Stoplogs, and Equipment	**EA**	**1.0000**	**2,828,189.38**	**2,828,189.38**	**0.00**	**707,047.34**	**0.00**	**3,535,236.72**
Construction of Bulkhead and Rail	**EA**	**1.0000**	**2,828,189.38**	**2,828,189.38**	**0.00**	**707,047.34**	**0.00**	**3,535,236.72**
06 Federal - Fish and Wildlife Facilities	**EA**	**1.0000**	**543,273.53**	**594,636.62**	**0.00**	**148,659.16**	**0.00**	**743,295.78**
06 1 Fish Facilities at Dams	**EA**	**1.0000**	**543,273.53**	**594,636.62**	**0.00**	**148,659.16**	**0.00**	**743,295.78**
06 159 Water Supply Facilities - Siphon	**EA**	**1.0000**	**543,273.53**	**594,636.62**	**0.00**	**148,659.16**	**0.00**	**743,295.78**
06 15901 Mob, Demob, & Preparatory Work	**EA**	**1.0000**	**64,829.94**	**64,829.94**	**0.00**	**16,207.49**	**0.00**	**81,037.43**
06 15902 Concrete Demolition/Boring	**FT**	**25.0000**	**126,315.51**	**164,628.66**	**0.00**	**41,157.17**	**0.00**	**205,785.83**
06 15903 Concrete	**EA**	**1.0000**	**6,252.54**	**6,252.54**	**0.00**	**1,563.13**	**0.00**	**7,815.67**
06 15905 Metals	**EA**	**1.0000**	**190,083.01**	**190,083.01**	**0.00**	**47,520.75**	**0.00**	**237,603.76**
06 15909 Finishes - Paint Metal	**EA**	**1.0000**	**6,648.44**	**6,648.44**	**0.00**	**1,662.11**	**0.00**	**8,310.55**
06 15915 Mechanical	**EA**	**1.0000**	**106,119.42**	**106,119.42**	**0.00**	**26,529.86**	**0.00**	**132,649.28**
06 15916 Electrical	**EA**	**1.0000**	**43,024.67**	**56,074.61**	**0.00**	**14,018.65**	**0.00**	**70,093.27**
14 Non-Federal - Recreational Facilities	**EA**	**1.0000**	**3,109,333.76**	**3,109,333.76**	**0.00**	**777,333.44**	**0.00**	**3,886,667.20**
1400 Recreational Facilities	**EA**	**1.0000**	**3,109,333.76**	**3,109,333.76**	**0.00**	**777,333.44**	**0.00**	**3,886,667.20**
140022 Parking Lots and Service Roads	**EA**	**1.0000**	**468,328.84**	**468,328.84**	**0.00**	**117,082.21**	**0.00**	**585,411.05**
14002205 Udall Park	**EA**	**1.0000**	**403,019.50**	**403,019.50**	**0.00**	**100,754.88**	**0.00**	**503,774.38**
14002209 Panther Bay Park		**3,040.0000**	**65,309.34**	**65,309.34**	**0.00**	**16,327.33**	**0.00**	**81,636.67**
140072 Day Use Areas	**EA**	**1.0000**	**2,641,004.92**	**2,641,004.92**	**0.00**	**660,251.23**	**0.00**	**3,301,256.15**
14007201 Quarry Park	**EA**	**1.0000**	**211,314.16**	**211,314.16**	**0.00**	**52,828.54**	**0.00**	**264,142.70**
14007202 Robinson Point Park	**EA**	**1.0000**	**630,979.38**	**630,979.38**	**0.00**	**157,744.85**	**0.00**	**788,724.23**
14007203 Panther Bay Park	**EA**	**1.0000**	**202,572.97**	**202,572.97**	**0.00**	**50,643.24**	**0.00**	**253,216.21**
14007204 Cranfield Park	**EA**	**1.0000**	**680,953.12**	**680,953.12**	**0.00**	**170,238.28**	**0.00**	**851,191.40**
14007205 Bidwell Point Park	**EA**	**1.0000**	**194,167.82**	**194,167.82**	**0.00**	**48,541.96**	**0.00**	**242,709.78**

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Description	UOM	Quantity	ContractorOwnCost	ContractCost	Escalation	Contingency	SIOH	ProjectCost
14007206 Gamaliel Park	EA	1.0000	145,974.48	145,974.48	0.00	36,493.62	0.00	182,468.10
14007208 Jordan Park	EA	1.0000	204,592.07	204,592.07	0.00	51,148.02	0.00	255,740.09
14007209 George's Cove	EA	1.0000	74,510.48	74,510.48	0.00	18,627.62	0.00	93,138.10
14007217 Udall Park Launch	EA	1.0000	295,940.43	295,940.43	0.00	73,985.11	0.00	369,925.54
30 Engineering and Design	EA	1.0000	1,341,140.00	1,341,140.00	0.00	335,285.00	0.00	1,676,425.00
30CA Design Costs	EA	1.0000	785,920.00	785,920.00	0.00	196,480.00	0.00	982,400.00
30CA30 Design Cost	EA	1.0000	653,000.00	653,000.00	0.00	163,250.00	0.00	816,250.00
Design Cost For Recreation 14	EA	1.0000	311,500.00	311,500.00	0.00	77,875.00	0.00	389,375.00
Design Cost for Dams 04 (Bulkhead)	EA	1.0000	282,000.00	282,000.00	0.00	70,500.00	0.00	352,500.00
Design Cost for Fish & Wildlife Facilities 6	EA	1.0000	59,500.00	59,500.00	0.00	14,875.00	0.00	74,375.00
30CA40 Surveys & Other Costs	EA	1.0000	100,000.00	100,000.00	0.00	25,000.00	0.00	125,000.00
30CA50 Environmental	EA	1.0000	32,920.00	32,920.00	0.00	8,230.00	0.00	41,150.00
Environmental 04	EA	1.0000	14,400.00	14,400.00	0.00	3,600.00	0.00	18,000.00
Environmental 06	EA	1.0000	2,975.00	2,975.00	0.00	743.75	0.00	3,718.75
Environmental 14	EA	1.0000	15,545.00	15,545.00	0.00	3,886.25	0.00	19,431.25
30CF Cost Estimates	EA	1.0000	65,320.00	65,320.00	0.00	16,330.00	0.00	81,650.00
Cost Estimates 04	EA	1.0000	28,280.00	28,280.00	0.00	7,070.00	0.00	35,350.00
Cost Estimates 06	EA	1.0000	5,950.00	5,950.00	0.00	1,487.50	0.00	7,437.50
Cost Estimates 14	EA	1.0000	31,090.00	31,090.00	0.00	7,772.50	0.00	38,862.50
Contracting Documents	EA	1.0000	65,320.00	65,320.00	0.00	16,330.00	0.00	81,650.00
Engineering & Design During Construction	EA	1.0000	195,960.00	195,960.00	0.00	48,990.00	0.00	244,950.00
Management Documents	EA	1.0000	163,300.00	163,300.00	0.00	40,825.00	0.00	204,125.00
Construction Review of P&S	EA	1.0000	65,320.00	65,320.00	0.00	16,330.00	0.00	81,650.00
31 Supervision and Administration	EA	1.0000	653,200.00	653,200.00	0.00	163,300.00	0.00	816,500.00
3131 Supervision and Administration	EA	1.0000	653,200.00	653,200.00	0.00	163,300.00	0.00	816,500.00
313110 Construction Branch	EA	1.0000	653,200.00	653,200.00	0.00	163,300.00	0.00	816,500.00
Bull Shoals Lake Mitigation Cost	EA	1.0000	9,425,096.94	9,425,096.94	0.00	2,356,274.24	0.00	11,781,371.18

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Description	UOM	Quantity	ContractorOwnCost	ContractCost	Escalation	Contingency	SIOH	ProjectCost
02 Non-Federal - Relocations	EA	1.0000	1,570,749.11	1,570,749.11	0.00	392,687.28	0.00	1,963,436.39
0201 Roads, Construction Activities	EA	1.0000	1,570,749.11	1,570,749.11	0.00	392,687.28	0.00	1,963,436.39
020101 Roads	EA	1.0000	1,570,749.11	1,570,749.11	0.00	392,687.28	0.00	1,963,436.39
020106 Marion County Road 143	FT	193.0000	846,967.95	846,967.95	0.00	211,741.99	0.00	1,058,709.94
020101 Slough Hollow Road. 2 Places.	FT	1,746.0000	723,781.16	723,781.16	0.00	180,945.29	0.00	904,726.45
04 Federal - Dams	EA	1.0000	178,553.89	178,553.89	0.00	44,638.47	0.00	223,192.36
0402 Spillway	EA	1.0000	178,553.89	178,553.89	0.00	44,638.47	0.00	223,192.36
040241 Gates. Stoplogs, and Equipment	EA	1.0000	178,553.89	178,553.89	0.00	44,638.47	0.00	223,192.36
04024109 Finishes	EA	1.0000	178,553.89	178,553.89	0.00	44,638.47	0.00	223,192.36
14 Non-Federal - Recreational Facilities	EA	1.0000	5,349,558.94	5,349,558.94	0.00	1,337,389.73	0.00	6,686,948.67
1400 Recreational Facilities	EA	1.0000	5,349,558.94	5,349,558.94	0.00	1,337,389.73	0.00	6,686,948.67
140004 Permanent Access Roads	EA	1.0000	685,570.55	685,570.55	0.00	171,392.64	0.00	856,963.18
14000414 Tucker Hollow Park	EA	1.0000	74,384.16	74,384.16	0.00	18,596.04	0.00	92,980.19
14000419 Lakeview Park	EA	2.0000	170,588.18	170,588.18	0.00	42,647.04	0.00	213,235.22
14000420 Highway K	EA	1.0000	55,540.27	55,540.27	0.00	13,885.07	0.00	69,425.33
14000421 Theodosia Park	EA	3.0000	385,057.95	385,057.95	0.00	96,264.49	0.00	481,322.43
140022 Parking Lots and Service Roads	EA	1.0000	1,943,621.68	1,943,621.68	0.00	485,905.42	0.00	2,429,527.09
14002205 Point Return Park	EA	2.0000	1,177,654.80	1,177,654.80	0.00	294,413.70	0.00	1,472,068.50
14002209 Oakland Park		1.0000	68,135.46	68,135.46	0.00	17,033.86	0.00	85,169.32
14002220 Pontiac Park	EA	1.0000	76,287.17	76,287.17	0.00	19,071.79	0.00	95,358.96
14002250 Buck Creek Park	EA	1.0000	90,365.35	90,365.35	0.00	22,591.34	0.00	112,956.69
14002255 Lead Hill Park	EA	1.0000	91,635.76	91,635.76	0.00	22,908.94	0.00	114,544.70
14002260 Highway 125 Park	EA	1.0000	117,375.43	117,375.43	0.00	29,343.86	0.00	146,719.29
14002270 Theodosia Park	EA	1.0000	322,167.70	322,167.70	0.00	80,541.93	0.00	402,709.63
140027 Buildings, Public Use	EA	1.0000	254,430.42	254,430.42	0.00	63,607.61	0.00	318,038.03
14002704 Point Return Park	EA	1.0000	254,430.42	254,430.42	0.00	63,607.61	0.00	318,038.03
140072 Day Use Areas	EA	1.0000	2,465,936.29	2,465,936.29	0.00	616,484.07	0.00	3,082,420.36

Currency in US dollars

Description	UOM	Quantity	ContractorOwnCost	ContractCost	Escalation	Contingency	SIOH	ProjectCost
14007201 Point Return Park	EA	1.0000	617,525.24	617,525.24	0.00	154,381.31	0.00	771,906.55
14007202 Dam Site Park	EA	1.0000	58,864.64	58,864.64	0.00	14,716.16	0.00	73,580.80
14007203 Oakland Park	EA	1.0000	116,753.20	116,753.20	0.00	29,188.30	0.00	145,941.50
14007204 Lakeview Park	EA	1.0000	191,709.98	191,709.98	0.00	47,927.49	0.00	239,637.47
14007206 Pontiac Park	EA	1.0000	58,845.61	58,845.61	0.00	14,711.40	0.00	73,557.01
14007209 Beaver Creek Park	EA	1.0000	50,772.41	50,772.41	0.00	12,693.10	0.00	63,465.52
14007210 Tucker Hollow Park	EA	1.0000	46,209.16	46,209.16	0.00	11,552.29	0.00	57,761.45
14007212 River Run Park	EA	1.0000	5,505.97	5,505.97	0.00	1,376.49	0.00	6,882.46
14007213 Lead Hill Park	EA	1.0000	522,999.60	522,999.60	0.00	130,749.90	0.00	653,749.50
14007214 Highway 125 Park	EA	1.0000	200,023.90	200,023.90	0.00	50,005.97	0.00	250,029.87
14007219 Buck Creek Park	EA	1.0000	156,156.98	156,156.98	0.00	39,039.24	0.00	195,196.22
14007220 Theodosia Park	EA	1.0000	440,569.60	440,569.60	0.00	110,142.40	0.00	550,712.01
30 Engineering and Design	EA	1.0000	1,616,335.00	1,616,335.00	0.00	404,083.75	0.00	2,020,418.75
30CA Design Costs	EA	1.0000	977,400.00	977,400.00	0.00	244,350.00	0.00	1,221,750.00
30CA30 Design Cost	EA	1.0000	977,400.00	977,400.00	0.00	244,350.00	0.00	1,221,750.00
30CA40 Surveys & Other Costs	EA	1.0000	298,900.00	298,900.00	0.00	74,725.00	0.00	373,625.00
Design Cost For Recreation 14	EA	1.0000	535,000.00	535,000.00	0.00	133,750.00	0.00	668,750.00
Design Cost for Dams 04 Painting	EA	1.0000	17,900.00	17,900.00	0.00	4,475.00	0.00	22,375.00
Design Cost for Dams 02 Relocations	EA	1.0000	125,600.00	125,600.00	0.00	31,400.00	0.00	157,000.00
30CF Cost Estimates	EA	1.0000	71,000.00	71,000.00	0.00	17,750.00	0.00	88,750.00
Cost Estimates 04	EA	1.0000	1,790.00	1,790.00	0.00	447.50	0.00	2,237.50
Cost Estimates 02	EA	1.0000	15,710.00	15,710.00	0.00	3,927.50	0.00	19,637.50
Cost Estimates 14	EA	1.0000	53,500.00	53,500.00	0.00	13,375.00	0.00	66,875.00
Contracting Documents	EA	1.0000	71,000.00	71,000.00	0.00	17,750.00	0.00	88,750.00
30CA50 Environmental	EA	1.0000	35,500.00	35,500.00	0.00	8,875.00	0.00	44,375.00
Environmental 02	EA	1.0000	7,855.00	7,855.00	0.00	1,963.75	0.00	9,818.75
Environmental 04 Dams	EA	1.0000	895.00	895.00	0.00	223.75	0.00	1,118.75

Currency in US dollars

Description	UOM	Quantity	ContractorOwnCost	ContractCost	Escalation	Contingency	SIOH	ProjectCost
Environmental 14	**EA**	**1.0000**	**26,750.00**	**26,750.00**	**0.00**	**6,687.50**	**0.00**	**33,437.50**
Engineering & Design During Construction	**EA**	**1.0000**	**212,970.00**	**212,970.00**	**0.00**	**53,242.50**	**0.00**	**266,212.50**
Management Documents	**EA**	**1.0000**	**177,475.00**	**177,475.00**	**0.00**	**44,368.75**	**0.00**	**221,843.75**
Construction Review of P&S	**EA**	**1.0000**	**70,990.00**	**70,990.00**	**0.00**	**17,747.50**	**0.00**	**88,737.50**
31 Supervision and Administration	**EA**	**1.0000**	**709,900.00**	**709,900.00**	**0.00**	**177,475.00**	**0.00**	**887,375.00**
3131 Supervision and Administration	**EA**	**1.0000**	**709,900.00**	**709,900.00**	**0.00**	**177,475.00**	**0.00**	**887,375.00**
313110 Construction Branch	**EA**	**1.0000**	**709,900.00**	**709,900.00**	**0.00**	**177,475.00**	**0.00**	**887,375.00**

Currency in US dollars

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
Use Level Report			17,951,596.70	0.00	4,487,899.18	0.00	22,439,495.88
Norfork Lake Mitigation Cost	EA	1.0000	8,526,499.76	0.00	2,131,624.94	0.00	10,658,124.70
04 Federal - Dams	EA	1.0000	2,828,189.38	0.00	707,047.34	0.00	3,535,236.72
0402 Spillway	EA	1.0000	2,828,189.38	0.00	707,047.34	0.00	3,535,236.72
040241 Gates. Stoplogs, and Equipment	EA	1.0000	2,828,189.38	0.00	707,047.34	0.00	3,535,236.72
Construction of Bulkhead and Rail	EA	1.0000	2,828,189.38	0.00	707,047.34	0.00	3,535,236.72
Construction of Maintenance Bulkhead and Rail System	EA	1.0000	2,828,189.38	0.00	707,047.34	0.00	3,535,236.72
06 Federal - Fish and Wildlife Facilities	EA	1.0000	594,636.62	0.00	148,659.16	0.00	743,295.78
06 1 Fish Facilities at Dams	EA	1.0000	594,636.62	0.00	148,659.16	0.00	743,295.78
06 159 Water Supply Facilities - Siphon	EA	1.0000	594,636.62	0.00	148,659.16	0.00	743,295.78
06 15901 Mob, Demob, & Preparatory Work	EA	1.0000	64,829.94	0.00	16,207.49	0.00	81,037.43
06 1590105 Mob	EA	1.0000	43,038.51	0.00	10,759.63	0.00	53,798.13
06 1590107 De-Mob	EA	1.0000	21,791.44	0.00	5,447.86	0.00	27,239.30
06 15902 Concrete Demolition/Boring	FT	25.0000	164,628.66	0.00	41,157.17	0.00	205,785.83
06 1590210 Concrete Demolition/Boring	FT	25.0000	164,628.66	0.00	41,157.17	0.00	205,785.83
06 15903 Concrete	EA	1.0000	6,252.54	0.00	1,563.13	0.00	7,815.67
06 1590330 Joint Filler	EA	1.0000	6,252.54	0.00	1,563.13	0.00	7,815.67
06 15905 Metals	EA	1.0000	190,083.01	0.00	47,520.75	0.00	237,603.76
06 1590510 Metals Pipe Supports	EA	14.0000	19,334.93	0.00	4,833.73	0.00	24,168.66
06 1590520 Metals - Anchor Bolts Installed	EA	112.0000	27,075.80	0.00	6,768.95	0.00	33,844.75
06 1590530 Metals - Attach Pipes to Supports above Water	FT	210.0000	119,574.29	0.00	29,893.57	0.00	149,467.87
06 1590535 Attach Pipes to Supports Underwater	EA	6.0000	24,097.98	0.00	6,024.50	0.00	30,122.48
06 15909 Finishes - Paint Metal	EA	1.0000	6,648.44	0.00	1,662.11	0.00	8,310.55
06 1590910 Paint Pipe	FT	310.0000	823.58	0.00	205.90	0.00	1,029.48
06 1590920 Paint Support Brackets	EA	35.0000	5,824.85	0.00	1,456.21	0.00	7,281.07
06 15915 Mechanical	EA	1.0000	106,119.42	0.00	26,529.86	0.00	132,649.28
06 1591510 Gates	EA	1.0000	11,174.67	0.00	2,793.67	0.00	13,968.34

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Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
06 1591520 Pipes and Fittings	FT	350.0000	57,217.24	0.00	14,304.31	0.00	71,521.55
06 1591530 Valves	EA	1.0000	37,727.51	0.00	9,431.88	0.00	47,159.39
06 15916 Electrical	EA	1.0000	56,074.61	0.00	14,018.65	0.00	70,093.27
06 1591610 Electrical Installation	LS	1.0000	56,074.61	0.00	14,018.65	0.00	70,093.27
14 Non-Federal - Recreational Facilities	EA	1.0000	3,109,333.76	0.00	777,333.44	0.00	3,886,667.20
1400 Recreational Facilities	EA	1.0000	3,109,333.76	0.00	777,333.44	0.00	3,886,667.20
140022 Parking Lots and Service Roads	EA	1.0000	468,328.84	0.00	117,082.21	0.00	585,411.05
14002205 Udall Park	EA	1.0000	403,019.50	0.00	100,754.88	0.00	503,774.38
1400220525 Parking Lot	SF	50,164.0000	403,019.50	0.00	100,754.88	0.00	503,774.38
14002209 Panther Bay Park		3,040.0000	65,309.34	0.00	16,327.33	0.00	81,636.67
1400220925 Parking Lot for Swim Beach	SF	3,040.0000	65,309.34	0.00	16,327.33	0.00	81,636.67
140072 Day Use Areas	EA	1.0000	2,641,004.92	0.00	660,251.23	0.00	3,301,256.15
14007201 Quarry Park	EA	1.0000	211,314.16	0.00	52,828.54	0.00	264,142.70
1400720120 Swim Beach	SF	36,120.0000	183,023.27	0.00	45,755.82	0.00	228,779.09
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
14007202 Robinson Point Park	EA	1.0000	630,979.38	0.00	157,744.85	0.00	788,724.23
1400720215 Boat Launch Ramp	EA	1.0000	400,115.53	0.00	100,028.88	0.00	500,144.41
1400720220 Swim Beach	SF	36,120.0000	202,572.97	0.00	50,643.24	0.00	253,216.21
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
14007203 Panther Bay Park	EA	1.0000	202,572.97	0.00	50,643.24	0.00	253,216.21
1400720320 Swim Beach	SF	36,120.0000	202,572.97	0.00	50,643.24	0.00	253,216.21
14007204 Cranfield Park	EA	1.0000	680,953.12	0.00	170,238.28	0.00	851,191.40
1400720420 Swim Beach	SF	129,115.0000	652,662.24	0.00	163,165.56	0.00	815,827.80
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87

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Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
14007205 Bidwell Point Park	**EA**	**1.0000**	**194,167.82**	**0.00**	**48,541.96**	**0.00**	**242,709.78**
1400720520 Swim Beach	**SF**	**32,702.0000**	**165,876.94**	**0.00**	**41,469.23**	**0.00**	**207,346.17**
Mobilization - Earthwork Contractor	**EA**	**1.0000**	**18,860.59**	**0.00**	**4,715.15**	**0.00**	**23,575.74**
De-Mobilization - Earthwork Contractor	**EA**	**1.0000**	**9,430.29**	**0.00**	**2,357.57**	**0.00**	**11,787.87**
14007206 Gamaliel Park	**EA**	**1.0000**	**145,974.48**	**0.00**	**36,493.62**	**0.00**	**182,468.10**
1400720620 Swim Beach	**EA**	**1.0000**	**117,683.60**	**0.00**	**29,420.90**	**0.00**	**147,104.50**
Mobilization - Earthwork Contractor	**EA**	**1.0000**	**18,860.59**	**0.00**	**4,715.15**	**0.00**	**23,575.74**
De-Mobilization - Earthwork Contractor	**EA**	**1.0000**	**9,430.29**	**0.00**	**2,357.57**	**0.00**	**11,787.87**
14007208 Jordan Park	**EA**	**1.0000**	**204,592.07**	**0.00**	**51,148.02**	**0.00**	**255,740.09**
1400720720 Swim Beach	**SF**	**34,780.0000**	**176,301.19**	**0.00**	**44,075.30**	**0.00**	**220,376.48**
Mobilization - Earthwork Contractor	**EA**	**1.0000**	**18,860.59**	**0.00**	**4,715.15**	**0.00**	**23,575.74**
De-Mobilization - Earthwork Contractor	**EA**	**1.0000**	**9,430.29**	**0.00**	**2,357.57**	**0.00**	**11,787.87**
14007209 George's Cove	**EA**	**1.0000**	**74,510.48**	**0.00**	**18,627.62**	**0.00**	**93,138.10**
1400720915 Boat Launch Ramp #1	**SF**	**3,995.0000**	**46,219.60**	**0.00**	**11,554.90**	**0.00**	**57,774.50**
Mobilization - Earthwork Contractor	**EA**	**1.0000**	**18,860.59**	**0.00**	**4,715.15**	**0.00**	**23,575.74**
De-Mobilization - Earthwork Contractor	**EA**	**1.0000**	**9,430.29**	**0.00**	**2,357.57**	**0.00**	**11,787.87**
14007217 Udall Park Launch	**EA**	**1.0000**	**295,940.43**	**0.00**	**73,985.11**	**0.00**	**369,925.54**
1400721701 Boat Launch Ramp	**SF**	**25,831.0000**	**295,940.43**	**0.00**	**73,985.11**	**0.00**	**369,925.54**
30 Engineering and Design	**EA**	**1.0000**	**1,341,140.00**	**0.00**	**335,285.00**	**0.00**	**1,676,425.00**
30CA Design Costs	**EA**	**1.0000**	**785,920.00**	**0.00**	**196,480.00**	**0.00**	**982,400.00**
30CA30 Design Cost	**EA**	**1.0000**	**653,000.00**	**0.00**	**163,250.00**	**0.00**	**816,250.00**
Design Cost For Recreation 14	**EA**	**1.0000**	**311,500.00**	**0.00**	**77,875.00**	**0.00**	**389,375.00**
Design Cost for Dams 04 (Bulkhead)	**EA**	**1.0000**	**282,000.00**	**0.00**	**70,500.00**	**0.00**	**352,500.00**
Design Cost for Fish & Wildlife Facilities 6	**EA**	**1.0000**	**59,500.00**	**0.00**	**14,875.00**	**0.00**	**74,375.00**
30CA40 Surveys & Other Costs	**EA**	**1.0000**	**100,000.00**	**0.00**	**25,000.00**	**0.00**	**125,000.00**
30CA50 Environmental	**EA**	**1.0000**	**32,920.00**	**0.00**	**8,230.00**	**0.00**	**41,150.00**
Environmental 04	**EA**	**1.0000**	**14,400.00**	**0.00**	**3,600.00**	**0.00**	**18,000.00**

Currency in US dollars

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
Environmental 06	EA	1.0000	2,975.00	0.00	743.75	0.00	3,718.75
Environmental 14	EA	1.0000	15,545.00	0.00	3,886.25	0.00	19,431.25
30CF Cost Estimates	EA	1.0000	65,320.00	0.00	16,330.00	0.00	81,650.00
Cost Estimates 04	EA	1.0000	28,280.00	0.00	7,070.00	0.00	35,350.00
Cost Estimates 06	EA	1.0000	5,950.00	0.00	1,487.50	0.00	7,437.50
Cost Estimates 14	EA	1.0000	31,090.00	0.00	7,772.50	0.00	38,862.50
Contracting Documents	EA	1.0000	65,320.00	0.00	16,330.00	0.00	81,650.00
Engineering & Design During Construction	EA	1.0000	195,960.00	0.00	48,990.00	0.00	244,950.00
Management Documents	EA	1.0000	163,300.00	0.00	40,825.00	0.00	204,125.00
Construction Review of P&S	EA	1.0000	65,320.00	0.00	16,330.00	0.00	81,650.00
31 Supervision and Administration	EA	1.0000	653,200.00	0.00	163,300.00	0.00	816,500.00
3131 Supervision and Administration	EA	1.0000	653,200.00	0.00	163,300.00	0.00	816,500.00
313110 Construction Branch	EA	1.0000	653,200.00	0.00	163,300.00	0.00	816,500.00
Bull Shoals Lake Mitigation Cost	EA	1.0000	9,425,096.94	0.00	2,356,274.24	0.00	11,781,371.18
02 Non-Federal - Relocations	EA	1.0000	1,570,749.11	0.00	392,687.28	0.00	1,963,436.39
0201 Roads, Construction Activities	EA	1.0000	1,570,749.11	0.00	392,687.28	0.00	1,963,436.39
020101 Roads	EA	1.0000	1,570,749.11	0.00	392,687.28	0.00	1,963,436.39
020106 Marion County Road 143	FT	193.0000	846,967.95	0.00	211,741.99	0.00	1,058,709.94
020106 Roads	SF	4,246.0000	818,677.07	0.00	204,669.27	0.00	1,023,346.34
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
020101 Slough Hollow Road. 2 Places.	FT	1,746.0000	723,781.16	0.00	180,945.29	0.00	904,726.45
02010101 Roads	SF	52,380.0000	695,490.27	0.00	173,872.57	0.00	869,362.84
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
04 Federal - Dams	EA	1.0000	178,553.89	0.00	44,638.47	0.00	223,192.36
0402 Spillway	EA	1.0000	178,553.89	0.00	44,638.47	0.00	223,192.36

Currency in US dollars

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
040241 Gates. Stoplogs, and Equipment	EA	1.0000	178,553.89	0.00	44,638.47	0.00	223,192.36
04024109 Finishes	EA	1.0000	178,553.89	0.00	44,638.47	0.00	223,192.36
14 Non-Federal - Recreational Facilities	EA	1.0000	5,349,558.94	0.00	1,337,389.73	0.00	6,686,948.67
1400 Recreational Facilities	EA	1.0000	5,349,558.94	0.00	1,337,389.73	0.00	6,686,948.67
140004 Permanent Access Roads	EA	1.0000	685,570.55	0.00	171,392.64	0.00	856,963.18
14000414 Tucker Hollow Park	EA	1.0000	74,384.16	0.00	18,596.04	0.00	92,980.19
1400041401 Raise Road #1	FT	128.0000	46,093.27	0.00	11,523.32	0.00	57,616.59
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
14000419 Lakeview Park	EA	2.0000	170,588.18	0.00	42,647.04	0.00	213,235.22
1400041901 Raise Road # 1	FT	140.0000	43,346.49	0.00	10,836.62	0.00	54,183.11
1400041902 Raise Road # 2	FT	275.0000	98,950.81	0.00	24,737.70	0.00	123,688.51
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
14000420 Highway K	EA	1.0000	55,540.27	0.00	13,885.07	0.00	69,425.33
1400042001 Raise Road #1	FT	44.0000	27,249.38	0.00	6,812.35	0.00	34,061.73
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
14000421 Theodosia Park	EA	3.0000	385,057.95	0.00	96,264.49	0.00	481,322.43
1400042101 Raise Road #1	FT	361.0000	137,022.64	0.00	34,255.66	0.00	171,278.30
1400042102 Raise Road #2	FT	48.0000	10,859.74	0.00	2,714.93	0.00	13,574.67
1400042103 Raise Road #3	FT	160.0000	208,884.68	0.00	52,221.17	0.00	261,105.85
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
140022 Parking Lots and Service Roads	EA	1.0000	1,943,621.68	0.00	485,905.42	0.00	2,429,527.09
14002205 Point Return Park	EA	2.0000	1,177,654.80	0.00	294,413.70	0.00	1,472,068.50
1400220525 Parking Lot #1 - No Parking Area	SF	38,570.0000	273,650.66	0.00	68,412.67	0.00	342,063.33

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Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
1400220530 Parking Lot #2 - Future Parking - Truck & Boat Trailer	SF	118,304.0000	835,015.12	0.00	208,753.78	0.00	1,043,768.90
1400220535 Parking Lot #3 - Staging Area	SF	5,911.0000	40,698.13	0.00	10,174.53	0.00	50,872.66
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
14002209 Oakland Park		1.0000	68,135.46	0.00	17,033.86	0.00	85,169.32
1400220925 Parking Lot for Swim Beach	SF	2,596.0000	17,873.85	0.00	4,468.46	0.00	22,342.32
1400220930 Parking Lot for Marina	SF	7,300.0000	50,261.61	0.00	12,565.40	0.00	62,827.01
14002220 Pontiac Park	EA	1.0000	76,287.17	0.00	19,071.79	0.00	95,358.96
14002220 01 Parking Lot #1	SF	5,070.0000	76,287.17	0.00	19,071.79	0.00	95,358.96
14002250 Buck Creek Park	EA	1.0000	90,365.35	0.00	22,591.34	0.00	112,956.69
14002250 01 Parking Lot #1	SF	1,501.0000	26,358.92	0.00	6,589.73	0.00	32,948.64
14002250 02 Parking Lot #2	SF	5,222.0000	35,715.55	0.00	8,928.89	0.00	44,644.44
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
14002255 Lead Hill Park	EA	1.0000	91,635.76	0.00	22,908.94	0.00	114,544.70
140022055 Parking Lot #1	SF	12,484.0000	63,344.88	0.00	15,836.22	0.00	79,181.09
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
14002260 Highway 125 Park	EA	1.0000	117,375.43	0.00	29,343.86	0.00	146,719.29
1400220525 Parking Lot	SF	10,831.0000	89,084.55	0.00	22,271.14	0.00	111,355.68
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87
14002270 Theodosia Park	EA	1.0000	322,167.70	0.00	80,541.93	0.00	402,709.63
14002270 01 Parking Lot #1	SF	9,301.0000	65,187.94	0.00	16,296.98	0.00	81,484.92
14002270 02 Parking Lot #2	SF	32,640.0000	228,688.88	0.00	57,172.22	0.00	285,861.10
Mobilization - Earthwork Contractor	EA	1.0000	18,860.59	0.00	4,715.15	0.00	23,575.74
De-Mobilization - Earthwork Contractor	EA	1.0000	9,430.29	0.00	2,357.57	0.00	11,787.87

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Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
140027 Buildings, Public Use	**EA**	**1.0000**	**254,430.42**	**0.00**	**63,607.61**	**0.00**	**318,038.03**
14002704 Point Return Park	**EA**	**1.0000**	**254,430.42**	**0.00**	**63,607.61**	**0.00**	**318,038.03**
1400270410 Restroom	**EA**	**1.0000**	**185,763.82**	**0.00**	**46,440.95**	**0.00**	**232,204.77**
Pavilion. Assumed dimensions 30 ft by 50 ft.	**EA**	**1.0000**	**68,666.61**	**0.00**	**17,166.65**	**0.00**	**85,833.26**
140072 Day Use Areas	**EA**	**1.0000**	**2,465,936.29**	**0.00**	**616,484.07**	**0.00**	**3,082,420.36**
14007201 Point Return Park	**EA**	**1.0000**	**617,525.24**	**0.00**	**154,381.31**	**0.00**	**771,906.55**
1400720115 Boat Launch Ramp #1	**SF**	**255.0000**	**3,075.24**	**0.00**	**768.81**	**0.00**	**3,844.05**
1400720120 Swim Beach	**SF**	**18,980.0000**	**97,040.78**	**0.00**	**24,260.19**	**0.00**	**121,300.97**
1400720115 Boat Launch Ramp #2 MEGA Ramp	**SF**	**38,945.0000**	**517,409.23**	**0.00**	**129,352.31**	**0.00**	**646,761.54**
14007202 Dam Site Park	**EA**	**1.0000**	**58,864.64**	**0.00**	**14,716.16**	**0.00**	**73,580.80**
1400720215 Boat Launch Ramp	**SF**	**1,285.0000**	**30,573.75**	**0.00**	**7,643.44**	**0.00**	**38,217.19**
De-Mobilization - Earthwork Contractor	**EA**	**1.0000**	**9,430.29**	**0.00**	**2,357.57**	**0.00**	**11,787.87**
Mobilization - Earthwork Contractor	**EA**	**1.0000**	**18,860.59**	**0.00**	**4,715.15**	**0.00**	**23,575.74**
14007203 Oakland Park	**EA**	**1.0000**	**116,753.20**	**0.00**	**29,188.30**	**0.00**	**145,941.50**
1400720315 Boat Launch Ramp	**SF**	**1,537.0000**	**88,462.32**	**0.00**	**22,115.58**	**0.00**	**110,577.90**
Mobilization - Earthwork Contractor	**EA**	**1.0000**	**18,860.59**	**0.00**	**4,715.15**	**0.00**	**23,575.74**
De-Mobilization - Earthwork Contractor	**EA**	**1.0000**	**9,430.29**	**0.00**	**2,357.57**	**0.00**	**11,787.87**
14007204 Lakeview Park	**EA**	**1.0000**	**191,709.98**	**0.00**	**47,927.49**	**0.00**	**239,637.47**
1400720415 Boat Launch Ramp	**SF**	**915.0000**	**30,372.49**	**0.00**	**7,593.12**	**0.00**	**37,965.61**
1400720420 Swim Beach	**SF**	**27,900.0000**	**161,337.49**	**0.00**	**40,334.37**	**0.00**	**201,671.86**
14007206 Pontiac Park	**EA**	**1.0000**	**58,845.61**	**0.00**	**14,711.40**	**0.00**	**73,557.01**
1400720601 Boat Launch Ramp	**SF**	**2,024.0000**	**58,845.61**	**0.00**	**14,711.40**	**0.00**	**73,557.01**
14007209 Beaver Creek Park	**EA**	**1.0000**	**50,772.41**	**0.00**	**12,693.10**	**0.00**	**63,465.52**
1400720915 Boat Launch Ramp	**SF**	**1,310.0000**	**50,772.41**	**0.00**	**12,693.10**	**0.00**	**63,465.52**
14007210 Tucker Hollow Park	**EA**	**1.0000**	**46,209.16**	**0.00**	**11,552.29**	**0.00**	**57,761.45**
1400721015 Boat Launch Ramp	**SF**	**1.0000**	**46,209.16**	**0.00**	**11,552.29**	**0.00**	**57,761.45**
14007212 River Run Park	**EA**	**1.0000**	**5,505.97**	**0.00**	**1,376.49**	**0.00**	**6,882.46**

Currency in US dollars

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
New Light Pole	EA	1.0000	5,505.97	0.00	1,376.49	0.00	6,882.46
14007213 Lead Hill Park	EA	1.0000	522,999.60	0.00	130,749.90	0.00	653,749.50
1400721315 Boat Launch Ramp	EA	2.0000	123,999.22	0.00	30,999.80	0.00	154,999.02
1400721320 Swim Beach	SF	53,650.0000	303,333.40	0.00	75,833.35	0.00	379,166.75
1400721320 Handicapped Access Sidewalk	FT	200.0000	95,666.98	0.00	23,916.75	0.00	119,583.73
14007214 Highway 125 Park	EA	1.0000	200,023.90	0.00	50,005.97	0.00	250,029.87
1400721415 Boat Launch Ramp	SF	1,044.0000	47,397.06	0.00	11,849.27	0.00	59,246.33
1400721420 Swim Beach	SF	25,749.0000	152,626.83	0.00	38,156.71	0.00	190,783.54
14007219 Buck Creek Park	EA	1.0000	156,156.98	0.00	39,039.24	0.00	195,196.22
1400721801 Boat Launch Ramp	SF	590.0000	44,870.01	0.00	11,217.50	0.00	56,087.51
1400721820 Swim Beach	SF	17,482.0000	111,286.97	0.00	27,821.74	0.00	139,108.71
14007220 Theodosia Park	EA	1.0000	440,569.60	0.00	110,142.40	0.00	550,712.01
1400722001 Boat Launch Ramp	SF	13,700.0000	345,999.82	0.00	86,499.95	0.00	432,499.77
1400722020 Swim Beach	SF	14,300.0000	94,569.79	0.00	23,642.45	0.00	118,212.23
30 Engineering and Design	EA	1.0000	1,616,335.00	0.00	404,083.75	0.00	2,020,418.75
30CA Design Costs	EA	1.0000	977,400.00	0.00	244,350.00	0.00	1,221,750.00
30CA30 Design Cost	EA	1.0000	977,400.00	0.00	244,350.00	0.00	1,221,750.00
30CA40 Surveys & Other Costs	EA	1.0000	298,900.00	0.00	74,725.00	0.00	373,625.00
Design Cost For Recreation 14	EA	1.0000	535,000.00	0.00	133,750.00	0.00	668,750.00
Design Cost for Dams 04 Painting	EA	1.0000	17,900.00	0.00	4,475.00	0.00	22,375.00
Design Cost for Dams 02 Relocations	EA	1.0000	125,600.00	0.00	31,400.00	0.00	157,000.00
30CF Cost Estimates	EA	1.0000	71,000.00	0.00	17,750.00	0.00	88,750.00
Cost Estimates 04	EA	1.0000	1,790.00	0.00	447.50	0.00	2,237.50
Cost Estimates 02	EA	1.0000	15,710.00	0.00	3,927.50	0.00	19,637.50
Cost Estimates 14	EA	1.0000	53,500.00	0.00	13,375.00	0.00	66,875.00
Contracting Documents	EA	1.0000	71,000.00	0.00	17,750.00	0.00	88,750.00
30CA50 Environmental	EA	1.0000	35,500.00	0.00	8,875.00	0.00	44,375.00

Labor ID: AR3 3 06 EQ ID: EP07R03 Currency in US dollars TRACES MII Version 3.0

Description	UOM	Quantity	ContractCost	Escalation	Contingency	SIOH	ProjectCost
Environmental 02	**EA**	**1.0000**	**7,855.00**	**0.00**	**1,963.75**	**0.00**	**9,818.75**
Environmental 04 Dams	**EA**	**1.0000**	**895.00**	**0.00**	**223.75**	**0.00**	**1,118.75**
Environmental 14	**EA**	**1.0000**	**26,750.00**	**0.00**	**6,687.50**	**0.00**	**33,437.50**
Engineering & Design During Construction	**EA**	**1.0000**	**212,970.00**	**0.00**	**53,242.50**	**0.00**	**266,212.50**
Management Documents	**EA**	**1.0000**	**177,475.00**	**0.00**	**44,368.75**	**0.00**	**221,843.75**
Construction Review of P&S	**EA**	**1.0000**	**70,990.00**	**0.00**	**17,747.50**	**0.00**	**88,737.50**
31 Supervision and Administration	**EA**	**1.0000**	**709,900.00**	**0.00**	**177,475.00**	**0.00**	**887,375.00**
3131 Supervision and Administration	**EA**	**1.0000**	**709,900.00**	**0.00**	**177,475.00**	**0.00**	**887,375.00**
313110 Construction Branch	**EA**	**1.0000**	**709,900.00**	**0.00**	**177,475.00**	**0.00**	**887,375.00**

Labor ID: AR3 3 06 EQ ID: EP07R03 Currency in US dollars TRACES MII Version 3.0

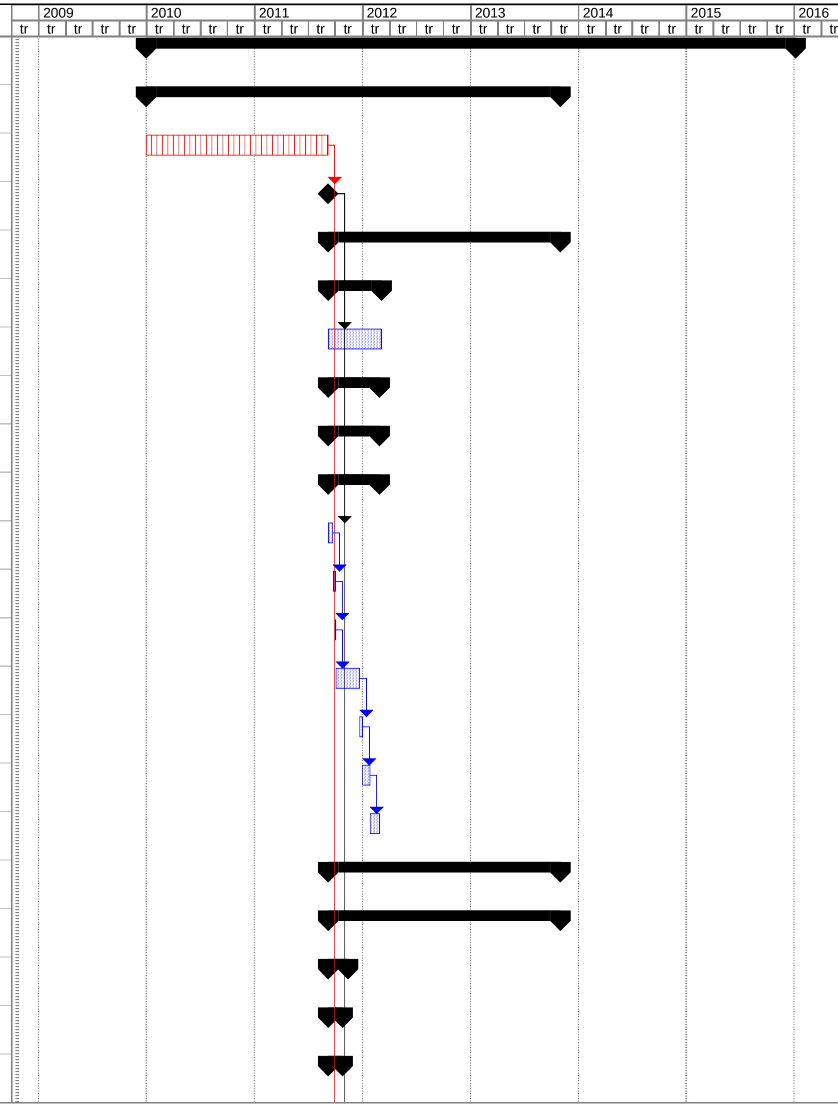
WHITE RIVER MINIMUM FLOWS,
UPPER WHITE RIVER BASIN,
ARKANSAS AND MISSOURI,
FEASIBILITY STUDY

TAB C

- Construction Schedule Network Analysis -

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
1		**TOTAL PROJECT**	**12558 hrs**	**Thu 10/1/09**	**Wed 10/7/15**	
2		**Norfork Lake**	**8011 hrs**	**Thu 10/1/09**	**Fri 8/2/13**	
3		Engineering and Design	20 mons	Thu 10/1/09	Wed 6/8/11	
4		Notice to Proceed	0 hrs	Wed 6/8/11	Wed 6/8/11	3
5		**Construction**	**4491 hrs**	**Thu 6/9/11**	**Fri 8/2/13**	
6		**Dams**	**1032 hrs**	**Thu 6/9/11**	**Tue 12/6/11**	
7		Construction of a Maintenance Bulkhead	129 days	Thu 6/9/11	Tue 12/6/11	4
8		**Fish and Wildlife Facilities**	**988 hrs**	**Thu 6/9/11**	**Tue 11/29/11**	
9		**Fish Facilities at Dams**	**988 hrs**	**Thu 6/9/11**	**Tue 11/29/11**	
10		**Water Supply Facilities - Siphon**	**988 hrs**	**Thu 6/9/11**	**Tue 11/29/11**	
11		Mob, Demob & Preparatory Work	12 days	Thu 6/9/11	Fri 6/24/11	4
12		Concrete Demolition/Boring	44 hrs	Mon 6/27/11	Mon 7/4/11	11
13		Concrete	8 hrs	Mon 7/4/11	Tue 7/5/11	12
14		Metals - Pipe and pipe brackets	465 hrs	Tue 7/5/11	Fri 9/23/11	13
15		Finishes - Paint Metal	48 hrs	Fri 9/23/11	Mon 10/3/11	14
16		Mechanical Components	154 hrs	Mon 10/3/11	Fri 10/28/11	15
17		Electrical	173 hrs	Fri 10/28/11	Tue 11/29/11	16
18		**Recreational Facilities**	**4491 hrs**	**Thu 6/9/11**	**Fri 8/2/13**	
19		**Recreational Facilities**	**4491 hrs**	**Thu 6/9/11**	**Fri 8/2/13**	
20		**Parking Lots and Service Roads**	**379 hrs**	**Thu 6/9/11**	**Mon 8/15/11**	
21		**Udall Park**	**279 hrs**	**Thu 6/9/11**	**Wed 7/27/11**	
22		**Parking Lot**	**279 hrs**	**Thu 6/9/11**	**Wed 7/27/11**	

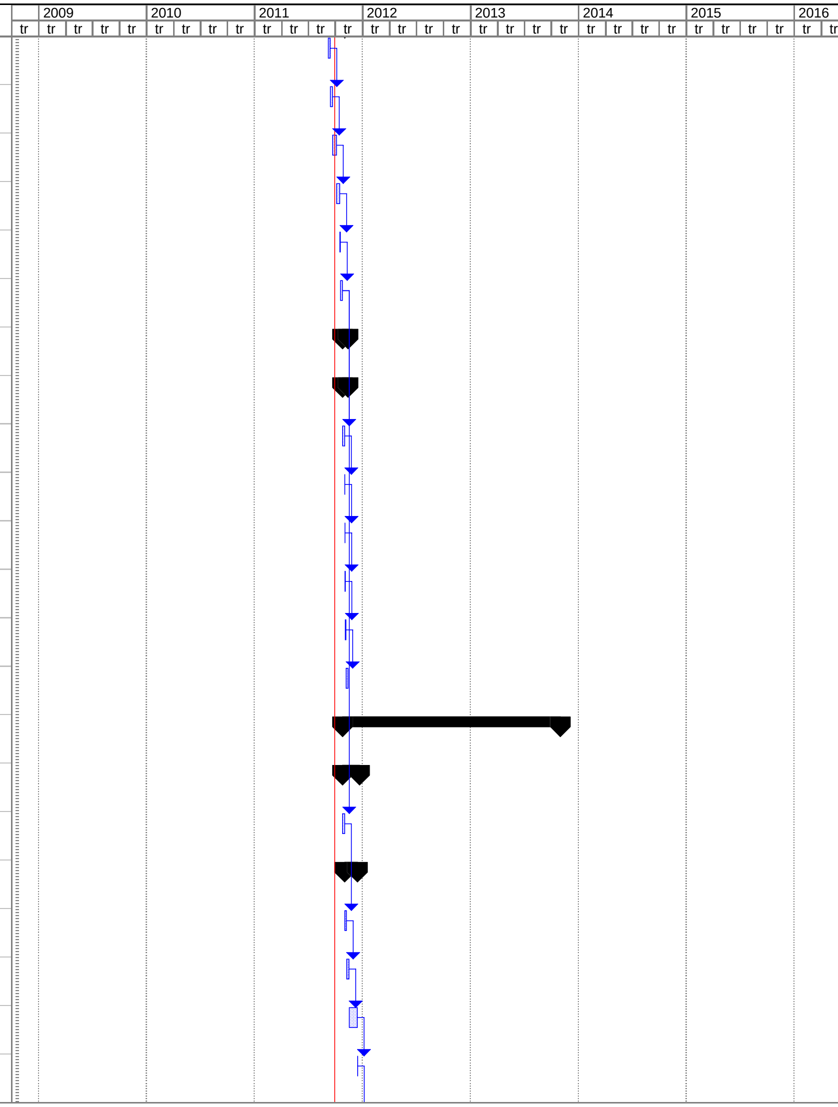


Project: Combined Project WRMF.mpp
Date: Fri 7/18/08

Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID	Indicators	Task Name	Duration	Start	Finish	Predecessors
23		Mobilization - Paving Subcontractor	40 hrs	Thu 6/9/11	Wed 6/15/11	4
24		Clearing	46 hrs	Thu 6/16/11	Thu 6/23/11	23
25		Earthwork	75 hrs	Thu 6/23/11	Thu 7/7/11	24
26		Subbase and Base Material	58 hrs	Thu 7/7/11	Mon 7/18/11	25
27		Asphalt Paving	20 hrs	Mon 7/18/11	Wed 7/20/11	26
28		De-Mobilization - Paving Subcontractor	40 hrs	Wed 7/20/11	Wed 7/27/11	27
29		**Panther Bay Park**	**100 hrs**	**Wed 7/27/11**	**Mon 8/15/11**	
30		**Parking Lot**	**100 hrs**	**Wed 7/27/11**	**Mon 8/15/11**	
31		Mobilization - Paving Subcontractor	40 hrs	Wed 7/27/11	Wed 8/3/11	28
32		Clearing	3 hrs	Wed 8/3/11	Thu 8/4/11	31
33		Earthwork	5 hrs	Thu 8/4/11	Thu 8/4/11	32
34		Subbase and Base Material	4 hrs	Thu 8/4/11	Fri 8/5/11	33
35		Asphalt Paving	8 hrs	Fri 8/5/11	Mon 8/8/11	34
36		De-Mobilization - Paving Subcontractor	40 hrs	Mon 8/8/11	Mon 8/15/11	35
37		**Day Use Areas**	**4212 hrs**	**Wed 7/27/11**	**Fri 8/2/13**	
38		**Quarry Park**	**330 hrs**	**Wed 7/27/11**	**Fri 9/23/11**	
39		Mobilization	40 hrs	Wed 7/27/11	Wed 8/3/11	28
40		**Swim Beach**	**250 hrs**	**Wed 8/3/11**	**Fri 9/16/11**	
41		Clearing and Grubbing	33 hrs	Wed 8/3/11	Tue 8/9/11	39
42		Shape Area Including Compaction	56 hrs	Wed 8/10/11	Thu 8/18/11	41
43		Pea Gravel and Sand Fill for Swim Bea	20 days	Fri 8/19/11	Thu 9/15/11	42
44		Relocate Swim Area Barrier	1 hr	Fri 9/16/11	Fri 9/16/11	43

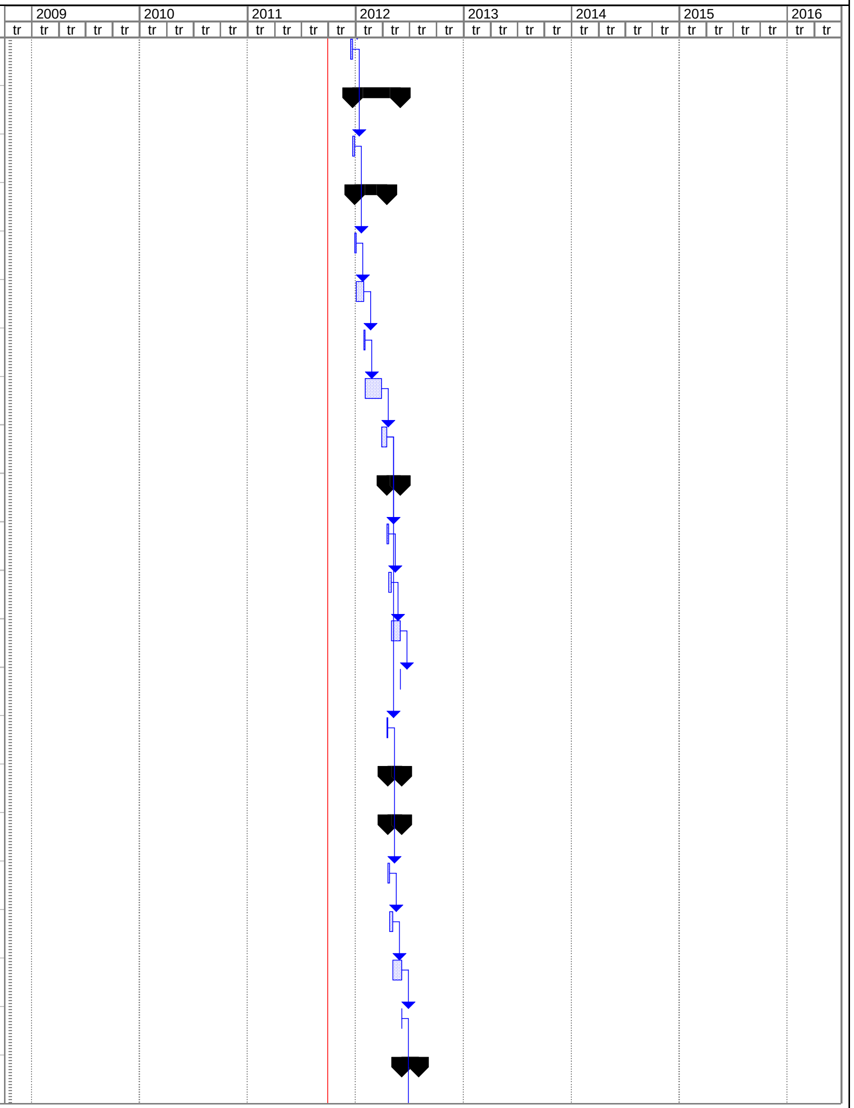


Project: Combined Project WRMF.mpp
Date: Fri 7/18/08

Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
45		De-Mobilization	40 hrs	Fri 9/16/11	Fri 9/23/11	44
46		**Robinson Point Park**	**923 hrs**	**Fri 9/23/11**	**Fri 3/2/12**	
47		Mobilization	40 hrs	Fri 9/23/11	Fri 9/30/11	45
48		**Boat Launch Area**	**616 hrs**	**Fri 9/30/11**	**Tue 1/17/12**	
49		Clearing and Grubbing	26 hrs	Fri 9/30/11	Wed 10/5/11	47
50		Earthwork	145 hrs	Wed 10/5/11	Mon 10/31/11	49
51		Subbase and Base Material	35 hrs	Mon 10/31/11	Fri 11/4/11	50
52		Concrete Paving, 6-inch thick, WWF re	320 hrs	Fri 11/4/11	Fri 12/30/11	51
53		Riprap	90 hrs	Fri 12/30/11	Tue 1/17/12	52
54		**Swim Beach**	**267 hrs**	**Tue 1/17/12**	**Fri 3/2/12**	
55		Clearing and Grubbing	33 hrs	Tue 1/17/12	Mon 1/23/12	53
56		Shape Area Including Compaction	56 hrs	Mon 1/23/12	Wed 2/1/12	55
57		Pea Gravel and Sand Fill for Swim Bea	22 days	Wed 2/1/12	Fri 3/2/12	56
58		Relocate Swim Area Barrier	2 hrs	Fri 3/2/12	Fri 3/2/12	57
59		Demobilization	24 hrs	Tue 1/17/12	Fri 1/20/12	53
60		**Panther Bay Park**	**267 hrs**	**Fri 1/20/12**	**Wed 3/7/12**	
61		**Swim Beach**	**267 hrs**	**Fri 1/20/12**	**Wed 3/7/12**	
62		Clearing and Grubbing	33 hrs	Fri 1/20/12	Thu 1/26/12	59
63		Shape Area Including Compaction	56 hrs	Thu 1/26/12	Mon 2/6/12	62
64		Pea Gravel and Sand Fill for Swim Bea	22 days	Mon 2/6/12	Wed 3/7/12	63
65		Relocate Swim Area Barrier	2 hrs	Wed 3/7/12	Wed 3/7/12	64
66		**Quarry Park**	**331 hrs**	**Wed 3/7/12**	**Thu 5/3/12**	



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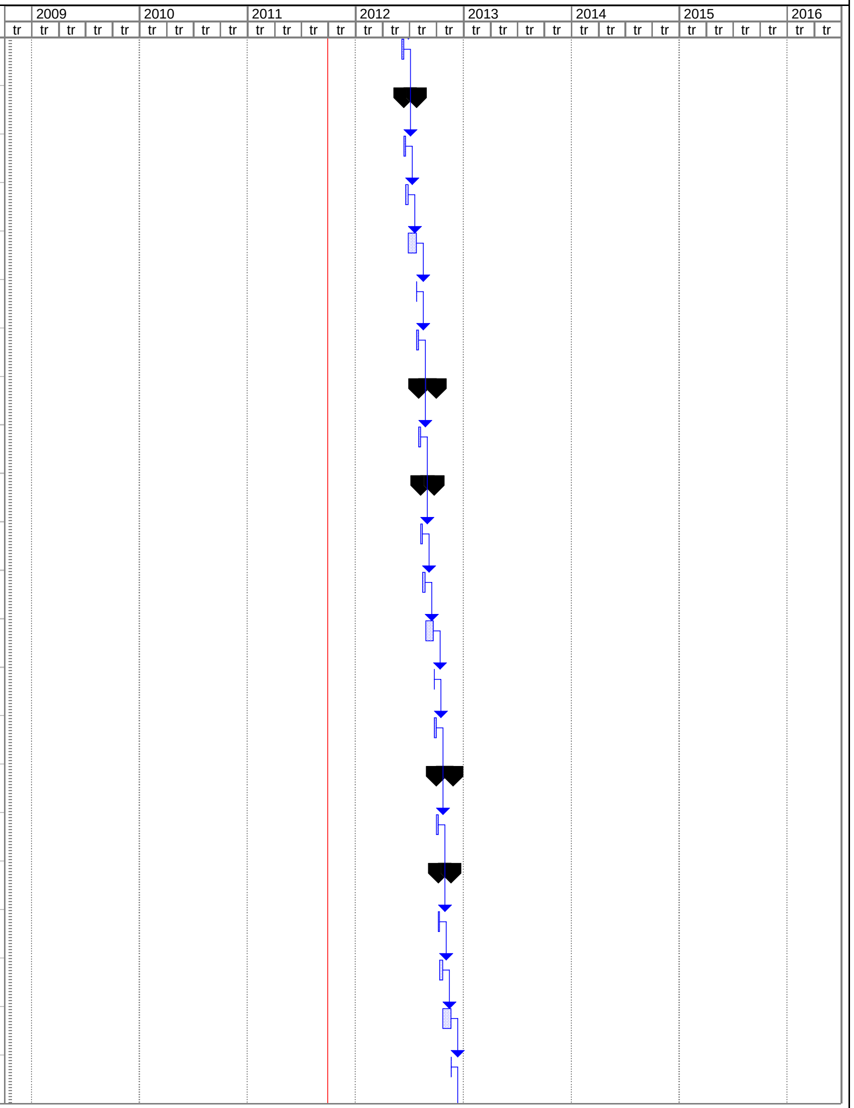
Date: Fri 7/18/08

Task		Milestone		Rolled Up Critical Task		Split		Group By Summary	
Critical Task		Summary		Rolled Up Milestone		External Tasks		Deadline	
Progress		Rolled Up Task		Rolled Up Progress		Project Summary			

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
67		Mobilization	40 hrs	Wed 3/7/12	Wed 3/14/12	65
68		**Swim Beach**	**251 hrs**	**Wed 3/14/12**	**Thu 4/26/12**	
69		Clearing and Grubbing	33 hrs	Wed 3/14/12	Tue 3/20/12	67
70		Shape Area Including Compaction	56 hrs	Tue 3/20/12	Thu 3/29/12	69
71		Pea Gravel and Sand Fill for Swim Bea	20 days	Thu 3/29/12	Thu 4/26/12	70
72		Relocate Swim Area Barrier	2 hrs	Thu 4/26/12	Thu 4/26/12	71
73		De-Mobilization	40 hrs	Thu 4/26/12	Thu 5/3/12	72
74		**Cranfield Park**	**331 hrs**	**Thu 5/3/12**	**Mon 7/2/12**	
75		Mobilization	40 hrs	Thu 5/3/12	Thu 5/10/12	73
76		**Swim Beach**	**251 hrs**	**Thu 5/10/12**	**Mon 6/25/12**	
77		Clearing and Grubbing	33 hrs	Thu 5/10/12	Wed 5/16/12	75
78		Shape Area Including Compaction	56 hrs	Thu 5/17/12	Fri 5/25/12	77
79		Pea Gravel and Sand Fill for Swim Bea	20 days	Mon 5/28/12	Fri 6/22/12	78
80		Relocate Swim Area Barrier	2 hrs	Mon 6/25/12	Mon 6/25/12	79
81		De-Mobilization	40 hrs	Mon 6/25/12	Mon 7/2/12	80
82		**Bidwell Point Park**	**331 hrs**	**Mon 7/2/12**	**Tue 8/28/12**	
83		Mobilization	40 hrs	Mon 7/2/12	Mon 7/9/12	81
84		**Swim Beach**	**251 hrs**	**Mon 7/9/12**	**Tue 8/21/12**	
85		Clearing and Grubbing	33 hrs	Mon 7/9/12	Fri 7/13/12	83
86		Shape Area Including Compaction	56 hrs	Fri 7/13/12	Tue 7/24/12	85
87		Pea Gravel and Sand Fill for Swim Bea	20 days	Tue 7/24/12	Tue 8/21/12	86
88		Relocate Swim Area Barrier	2 hrs	Tue 8/21/12	Tue 8/21/12	87



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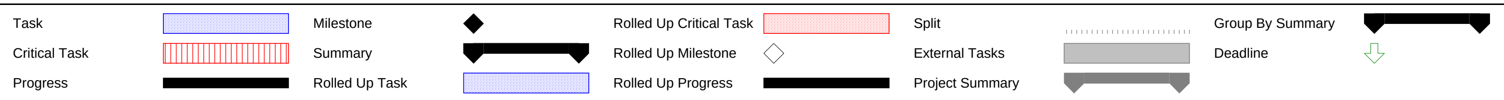
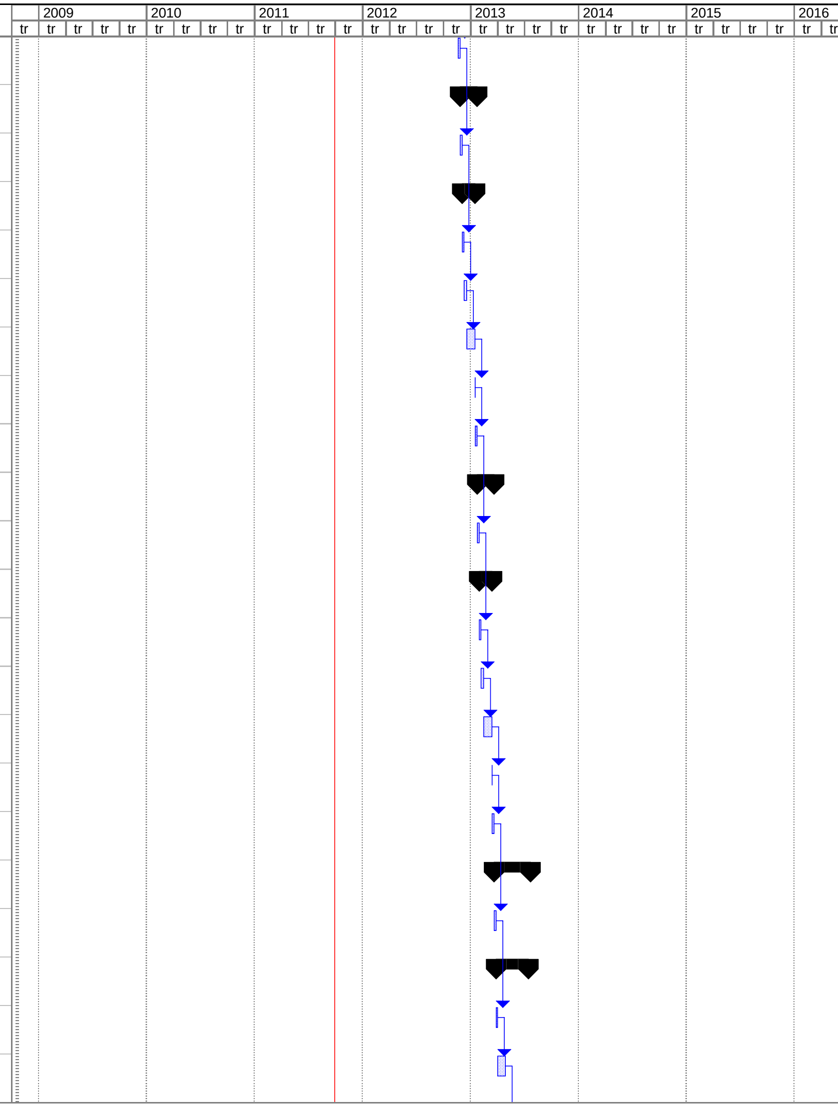


White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
89		De-Mobilization	40 hrs	Tue 8/21/12	Tue 8/28/12	88
90		**Gamaliel Park**	**331 hrs**	**Tue 8/28/12**	**Wed 10/24/12**	
91		Mobilization	40 hrs	Tue 8/28/12	Tue 9/4/12	89
92		**Swim Beach**	**251 hrs**	**Tue 9/4/12**	**Wed 10/17/12**	
93		Clearing and Grubbing	33 hrs	Tue 9/4/12	Mon 9/10/12	91
94		Shape Area Including Compaction	56 hrs	Mon 9/10/12	Wed 9/19/12	93
95		Pea Gravel and Sand Fill for Swim Bea	20 days	Wed 9/19/12	Wed 10/17/12	94
96		Relocate Swim Area Barrier	2 hrs	Wed 10/17/12	Wed 10/17/12	95
97		De-Mobilization	40 hrs	Thu 10/18/12	Wed 10/24/12	96
98		**Jordan Park**	**331 hrs**	**Thu 10/25/12**	**Fri 12/21/12**	
99		Mobilization	40 hrs	Thu 10/25/12	Wed 10/31/12	97
100		**Swim Beach**	**251 hrs**	**Thu 11/1/12**	**Fri 12/14/12**	
101		Clearing and Grubbing	33 hrs	Thu 11/1/12	Wed 11/7/12	99
102		Shape Area Including Compaction	56 hrs	Wed 11/7/12	Fri 11/16/12	101
103		Pea Gravel and Sand Fill for Swim Bea	20 days	Fri 11/16/12	Fri 12/14/12	102
104		Relocate Swim Area Barrier	2 hrs	Fri 12/14/12	Fri 12/14/12	103
105		De-Mobilization	40 hrs	Fri 12/14/12	Fri 12/21/12	104
106		**George's Cove Park**	**696 hrs**	**Fri 12/21/12**	**Tue 4/23/13**	
107		Mobilization	40 hrs	Fri 12/21/12	Fri 12/28/12	105
108		**Boat Launch Area**	**616 hrs**	**Fri 12/28/12**	**Tue 4/16/13**	
109		Clearing and Grubbing	26 hrs	Fri 12/28/12	Wed 1/2/13	107
110		Earthwork	145 hrs	Wed 1/2/13	Mon 1/28/13	109



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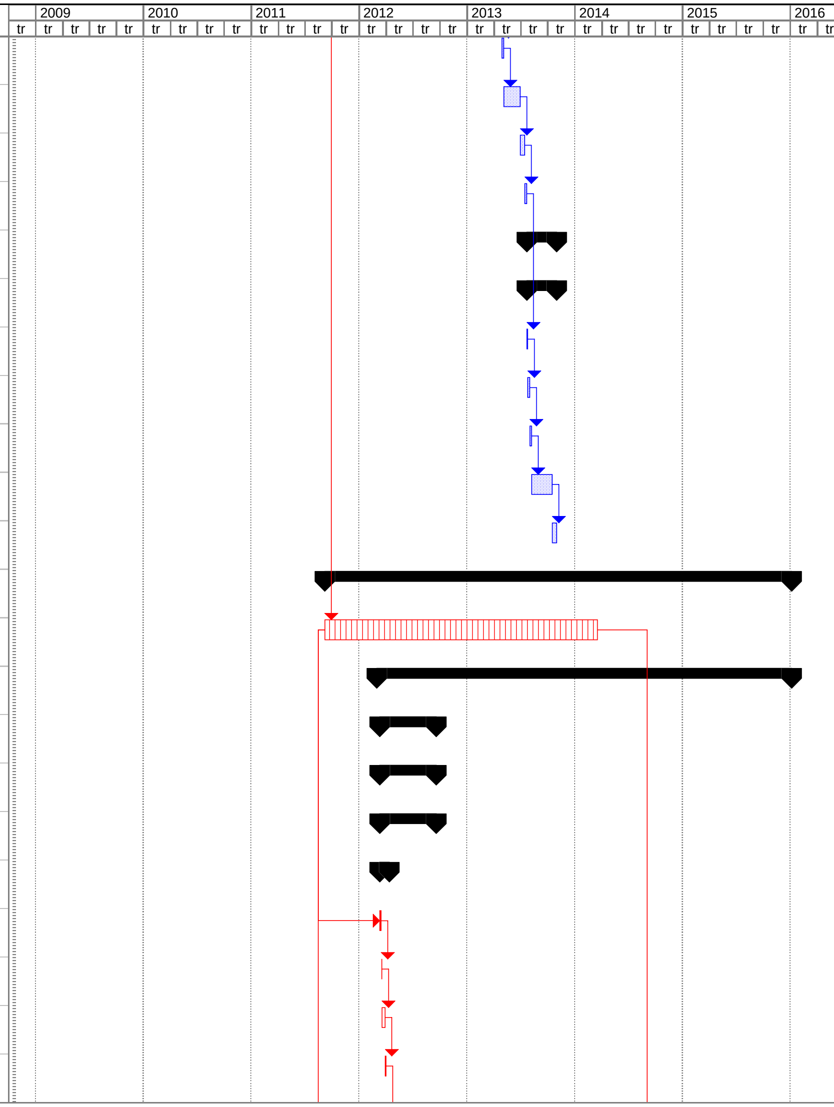
Task		Milestone		Rolled Up Critical Task		Split		Group By Summary	
Critical Task		Summary		Rolled Up Milestone		External Tasks		Deadline	
Progress		Rolled Up Task		Rolled Up Progress		Project Summary			

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
111		Subbase and Base Material	35 hrs	Mon 1/28/13	Mon 2/4/13	110
112		Concrete Paving, 6-inch thick, WWF re	320 hrs	Mon 2/4/13	Mon 4/1/13	111
113		Riprap	90 hrs	Mon 4/1/13	Tue 4/16/13	112
114		De-Mobilization	40 hrs	Tue 4/16/13	Tue 4/23/13	113
115		**Udal Park Boat Launc**	**584 hrs**	**Tue 4/23/13**	**Fri 8/2/13**	
116		**Boat Launch Area**	**584 hrs**	**Tue 4/23/13**	**Fri 8/2/13**	
117		Clearing and Grubbing	23 hrs	Tue 4/23/13	Fri 4/26/13	114
118		Earthwork	39 hrs	Fri 4/26/13	Fri 5/3/13	117
119		Subbase and Base Material	32 hrs	Fri 5/3/13	Thu 5/9/13	118
120		Concrete Paving, 6-inch thick, WWF re	400 hrs	Thu 5/9/13	Thu 7/18/13	119
121		Riprap	90 hrs	Thu 7/18/13	Fri 8/2/13	120
122		**Bull Shoals Lake**	**9038 hrs**	**Thu 6/9/11**	**Wed 10/7/15**	
123		Engineering and Design	30 mons	Thu 6/9/11	Wed 12/18/13	3
124		**Construction**	**8030 hrs**	**Fri 12/2/11**	**Wed 10/7/15**	
125		**Relocations**	**1100 hrs**	**Mon 12/12/11**	**Wed 6/20/12**	
126		**Roads, Construction Activities**	**1100 hrs**	**Mon 12/12/11**	**Wed 6/20/12**	
127		**Roads**	**1100 hrs**	**Mon 12/12/11**	**Wed 6/20/12**	
128		**Marion County Road 143**	**198 hrs**	**Mon 12/12/11**	**Fri 1/13/12**	
129		Mobilization - Earthwork Contractor	40 hrs	Mon 12/12/11	Fri 12/16/11	123SS+132 days
130		Clearing & Grubbing including Off-Site dispc	4 hrs	Mon 12/19/11	Mon 12/19/11	129
131		Earthwork	74 hrs	Mon 12/19/11	Fri 12/30/11	130
132		Culvert	7 hrs	Fri 12/30/11	Mon 1/2/12	131



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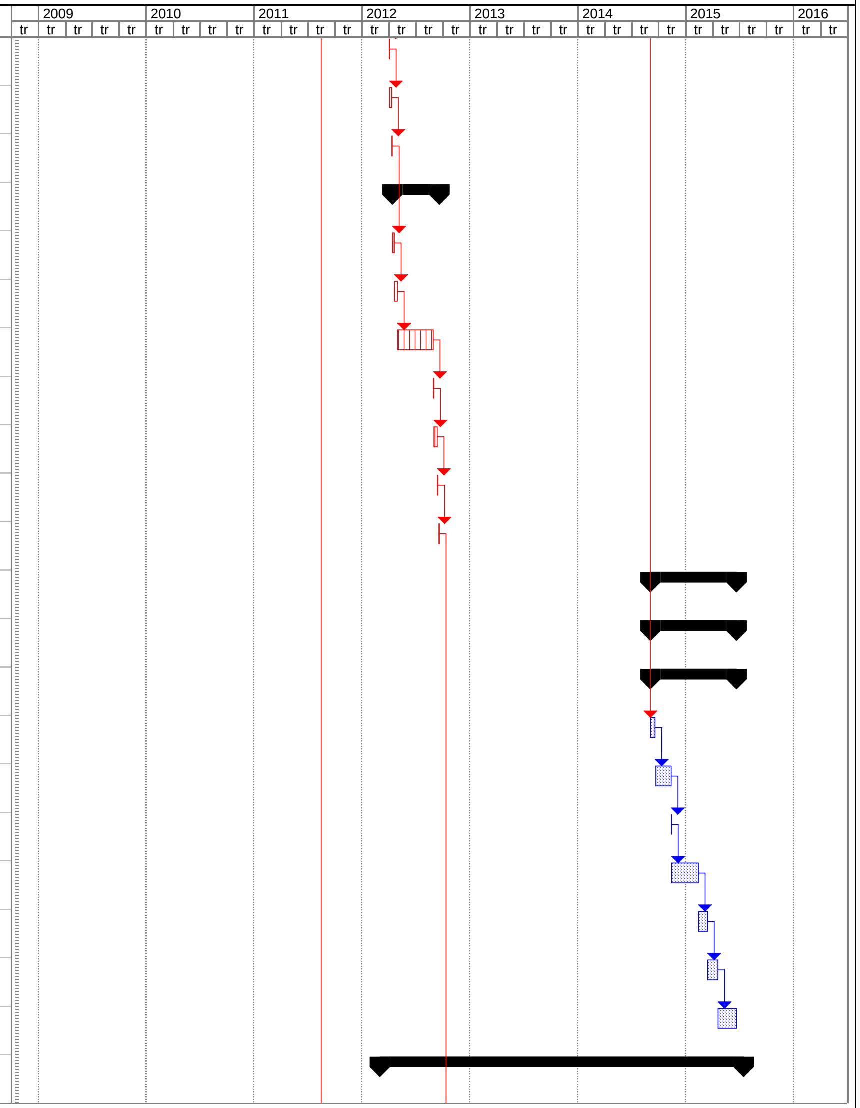
Progress		Rolled Up Task		Rolled Up Progress		Project Summary			

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
133		Subbase and Base Material	5 hrs	Mon 1/2/12	Tue 1/3/12	132
134		Concrete Amour Paving. 4 inch layer	48 hrs	Tue 1/3/12	Wed 1/11/12	133
135		De-Mobilization - Earthwork Contractor	20 hrs	Wed 1/11/12	Fri 1/13/12	134
136		**Slough Hollow Road**	**902 hrs**	**Fri 1/13/12**	**Wed 6/20/12**	
137		Mobilization - Earthwork Contractor	40 hrs	Fri 1/13/12	Fri 1/20/12	135
138		Clearing & Grubbing including Off-Site dispc	48 hrs	Fri 1/20/12	Mon 1/30/12	137
139		Earthwork	700 hrs	Mon 1/30/12	Thu 5/31/12	138
140		Culvert	13 hrs	Thu 5/31/12	Fri 6/1/12	139
141		Subbase and Base Material	60 hrs	Fri 6/1/12	Wed 6/13/12	140
142		Asphalt Paving	21 hrs	Wed 6/13/12	Fri 6/15/12	141
143		De-Mobilization - Earthwork Contractor	20 hrs	Mon 6/18/12	Wed 6/20/12	142
144		**Fish and Wildlife Facilities**	**1664 hrs**	**Thu 6/5/14**	**Mon 3/23/15**	
145		**Fish Facilities at Dams**	**1664 hrs**	**Thu 6/5/14**	**Mon 3/23/15**	
146		**Water Supply Facilities - Siphon**	**1664 hrs**	**Thu 6/5/14**	**Mon 3/23/15**	
147		Mob, Demob & Preparatory Work	12 days	Thu 6/5/14	Fri 6/20/14	123FS+120 days
148		Concrete Demolition/Boring	312 hrs	Mon 6/23/14	Thu 8/14/14	147
149		Concrete	4 hrs	Fri 8/15/14	Fri 8/15/14	148
150		Metals - Pipe and pipe brackets	521 hrs	Fri 8/15/14	Fri 11/14/14	149
151		Finishes - Paint Metal	168 hrs	Fri 11/14/14	Mon 12/15/14	150
152		Mechanical Components	200 hrs	Mon 12/15/14	Mon 1/19/15	151
153		Electrical	363 hrs	Mon 1/19/15	Mon 3/23/15	152
154		**Recreational Facilities**	**7038 hrs**	**Fri 12/2/11**	**Thu 4/16/15**	



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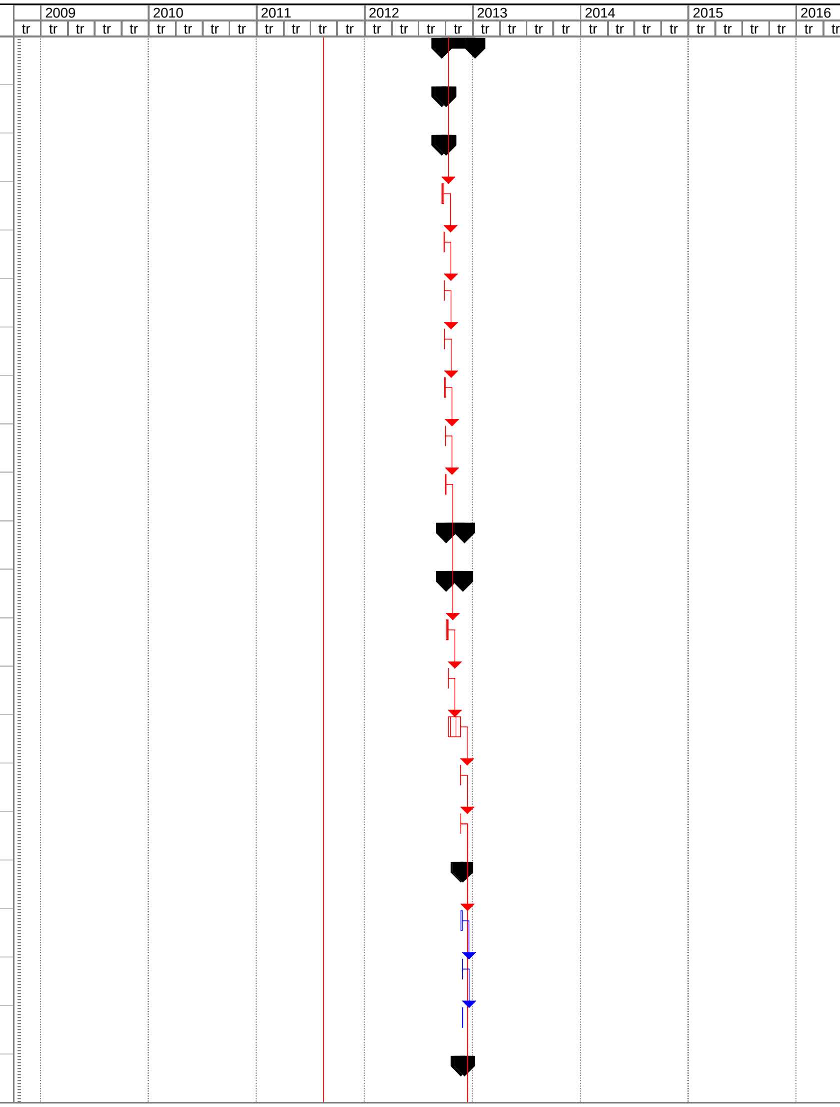
Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
155		**Permanent Access Roads**	**645 hrs**	**Wed 6/20/12**	**Thu 10/11/12**	
156		**Tucker Hollow Park**	**86 hrs**	**Wed 6/20/12**	**Thu 7/5/12**	
157		**Road 1**	**86 hrs**	**Wed 6/20/12**	**Thu 7/5/12**	
158		Mobilization - Earthwork Contractor	40 hrs	Wed 6/20/12	Wed 6/27/12	143
159		Clearing & Grubbing including Off-Site dispc	9 hrs	Wed 6/27/12	Thu 6/28/12	158
160		Earthwork	6 hrs	Thu 6/28/12	Fri 6/29/12	159
161		Culvert	3 hrs	Fri 6/29/12	Fri 6/29/12	160
162		Subbase and Base Material	4 hrs	Fri 6/29/12	Mon 7/2/12	161
163		Asphalt Paving, 2 inch layer	4 hrs	Mon 7/2/12	Mon 7/2/12	162
164		De-Mobilization - Earthwork Contractor	20 hrs	Mon 7/2/12	Thu 7/5/12	163
165		**Lakeview Park**	**355 hrs**	**Thu 7/5/12**	**Wed 9/5/12**	
166		**Road 1**	**327 hrs**	**Thu 7/5/12**	**Fri 8/31/12**	
167		Mobilization - Earthwork Contractor	40 hrs	Thu 7/5/12	Thu 7/12/12	164
168		Clearing & Grubbing including Off-Site dispc	4 hrs	Thu 7/12/12	Thu 7/12/12	167
169		Earthwork	235 hrs	Thu 7/12/12	Thu 8/23/12	168
170		Culvert	4 hrs	Thu 8/23/12	Thu 8/23/12	169
171		Subbase and Base Material	4 hrs	Thu 8/23/12	Fri 8/24/12	170
172		**Asphalt Paving, 2 inch layer**	**40 hrs**	**Fri 8/24/12**	**Fri 8/31/12**	
173		Mob - Paving	24 hrs	Fri 8/24/12	Wed 8/29/12	171
174		Paving	4 hrs	Wed 8/29/12	Wed 8/29/12	173
175		De-Mob Paving	12 hrs	Wed 8/29/12	Fri 8/31/12	174
176		**Road 2**	**68 hrs**	**Fri 8/24/12**	**Wed 9/5/12**	



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Task
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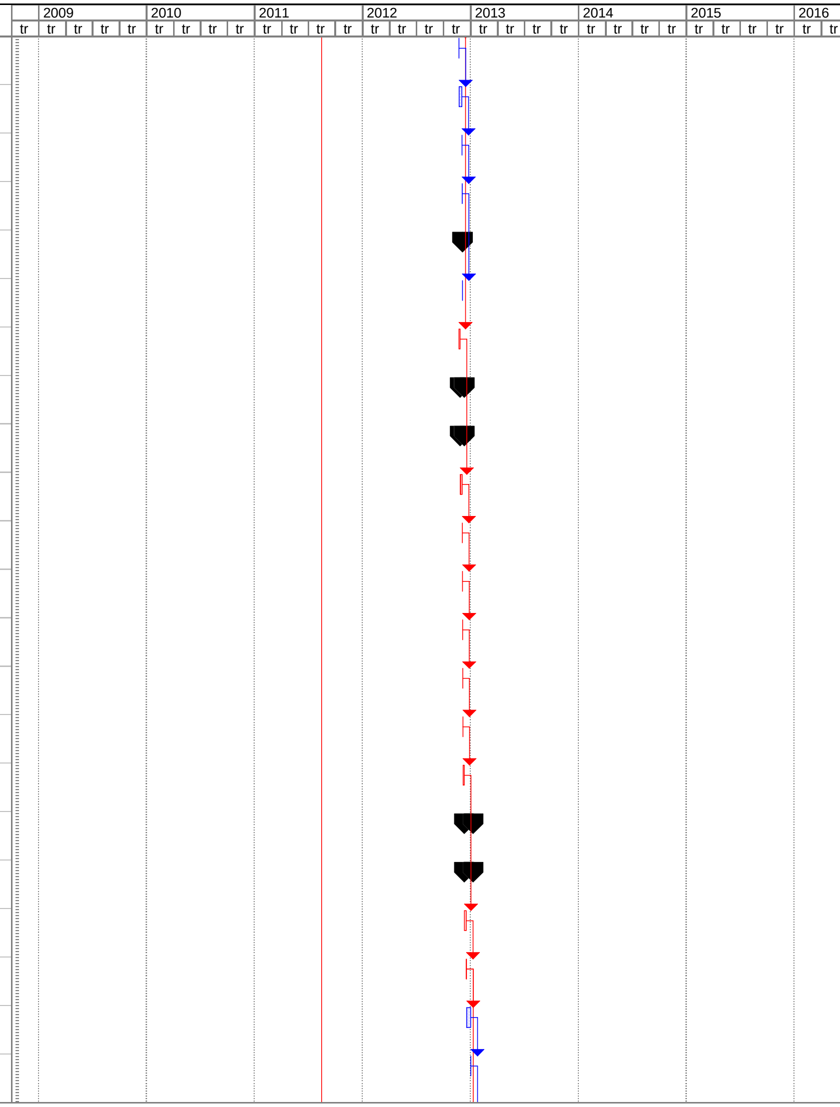
White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
177		Clearing & Grubbing including Off-Site dispc	4 hrs	Fri 8/24/12	Fri 8/24/12	171
178		Earthwork	47 hrs	Fri 8/24/12	Mon 9/3/12	177
179		Culvert	4 hrs	Mon 9/3/12	Mon 9/3/12	178
180		Subbase and Base Material	8 hrs	Tue 9/4/12	Tue 9/4/12	179
181		**Asphalt Paving, 2 inch layer**	**5 hrs**	**Wed 9/5/12**	**Wed 9/5/12**	
182		Paving	5 hrs	Wed 9/5/12	Wed 9/5/12	180
183		De-Mobilization - Earthwork Contractor	20 hrs	Fri 8/24/12	Tue 8/28/12	171
184		**Highway K Park**	**79 hrs**	**Tue 8/28/12**	**Tue 9/11/12**	
185		**Road 1**	**79 hrs**	**Tue 8/28/12**	**Tue 9/11/12**	
186		Mobilization - Earthwork Contractor	40 hrs	Tue 8/28/12	Tue 9/4/12	183
187		Clearing & Grubbing including Off-Site dispc	4 hrs	Tue 9/4/12	Wed 9/5/12	186
188		Earthwork	4 hrs	Wed 9/5/12	Wed 9/5/12	187
189		Culvert	3 hrs	Wed 9/5/12	Wed 9/5/12	188
190		Subbase and Base Material	4 hrs	Thu 9/6/12	Thu 9/6/12	189
191		Asphalt Paving, 2 inch layer	4 hrs	Thu 9/6/12	Thu 9/6/12	190
192		De-Mobilization - Earthwork Contractor	20 hrs	Fri 9/7/12	Tue 9/11/12	191
193		**Highway K Park**	**173 hrs**	**Tue 9/11/12**	**Thu 10/11/12**	
194		**Road 1**	**173 hrs**	**Tue 9/11/12**	**Thu 10/11/12**	
195		Mobilization - Earthwork Contractor	40 hrs	Tue 9/11/12	Tue 9/18/12	192
196		Clearing & Grubbing including Off-Site dispc	8 hrs	Tue 9/18/12	Wed 9/19/12	195
197		Earthwork	81 hrs	Wed 9/19/12	Wed 10/3/12	196
198		Culvert	3 hrs	Wed 10/3/12	Wed 10/3/12	197



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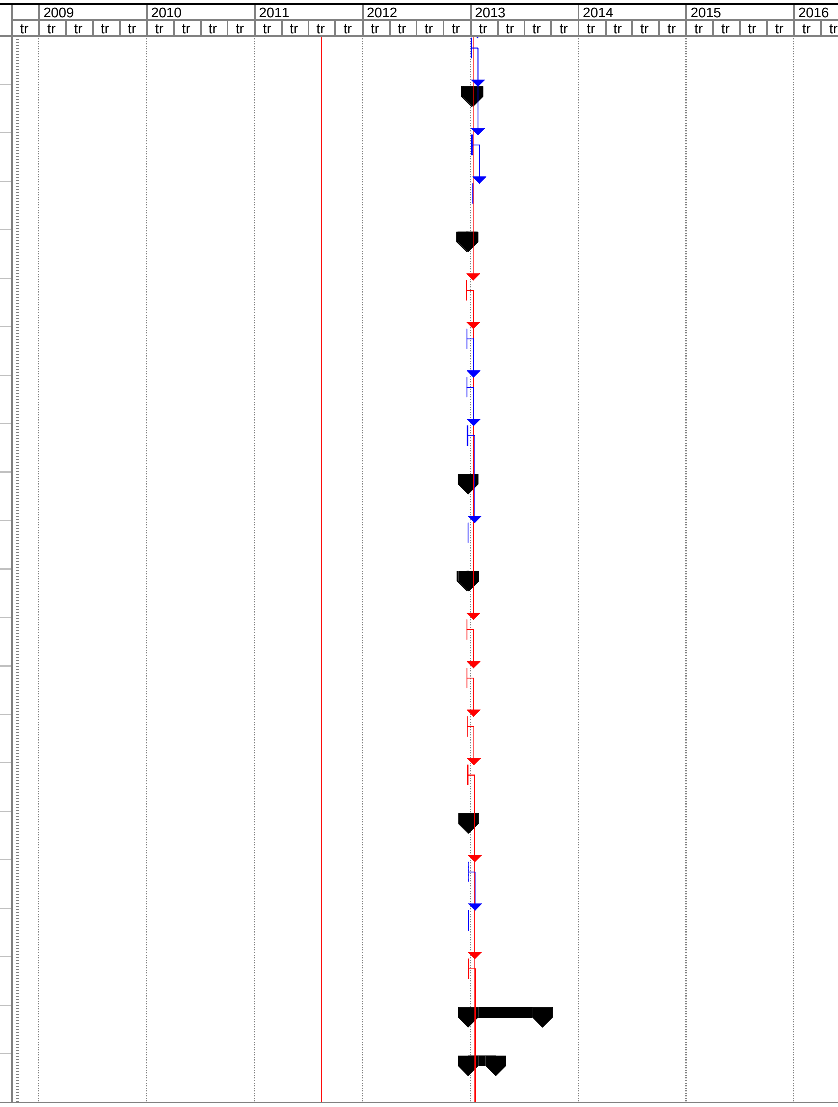
Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
199		Subbase and Base Material	10 hrs	Thu 10/4/12	Fri 10/5/12	198
200		**Asphalt Paving, 2 inch layer**	**31 hrs**	**Fri 10/5/12**	**Thu 10/11/12**	**199**
201		Mob - Paving	24 hrs	Fri 10/5/12	Wed 10/10/12	199
202		Asphalt Paving, 2 inch layer	7 hrs	Wed 10/10/12	Thu 10/11/12	201
203		**Road 2**	**25 hrs**	**Wed 9/19/12**	**Mon 9/24/12**	
204		Clearing & Grubbing including Off-Site dispc	4 hrs	Wed 9/19/12	Wed 9/19/12	196
205		Earthwork	4 hrs	Thu 9/20/12	Thu 9/20/12	204
206		Culvert	3 hrs	Thu 9/20/12	Thu 9/20/12	205
207		Subbase and Base Material	10 hrs	Thu 9/20/12	Mon 9/24/12	206
208		**Asphalt Paving, 2 inch layer**	**4 hrs**	**Mon 9/24/12**	**Mon 9/24/12**	
209		Asphalt Paving, 2 inch layer	4 hrs	Mon 9/24/12	Mon 9/24/12	207
210		**Road 3**	**41 hrs**	**Thu 9/20/12**	**Thu 9/27/12**	
211		Clearing & Grubbing including Off-Site dispc	4 hrs	Thu 9/20/12	Thu 9/20/12	204
212		Earthwork	4 hrs	Thu 9/20/12	Thu 9/20/12	211
213		Culvert	3 hrs	Fri 9/21/12	Fri 9/21/12	212
214		Subbase and Base Material	10 hrs	Fri 9/21/12	Mon 9/24/12	213
215		**Asphalt Paving, 2 inch layer**	**16 hrs**	**Mon 9/24/12**	**Wed 9/26/12**	
216		Asphalt Paving, 2 inch layer	4 hrs	Mon 9/24/12	Tue 9/25/12	214
217		De-Mob Paving	12 hrs	Tue 9/25/12	Wed 9/26/12	216
218		De-Mobilization - Earthwork Contractor	20 hrs	Mon 9/24/12	Thu 9/27/12	214
219		**Parking Lots and Service Roads**	**1438 hrs**	**Mon 9/24/12**	**Mon 6/3/13**	
220		**Point Return Park**	**544 hrs**	**Mon 9/24/12**	**Thu 12/27/12**	



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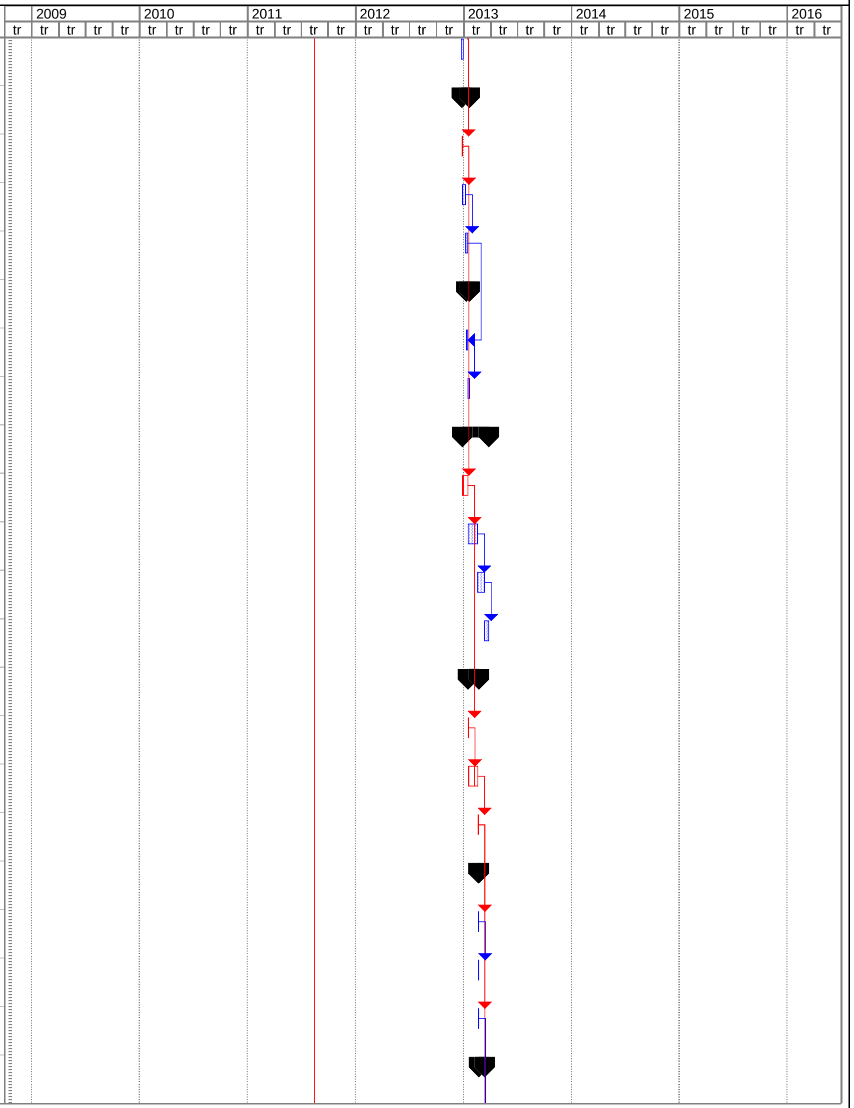
White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
221		Mobilization - Earthwork Contractor	40 hrs	Mon 9/24/12	Mon 10/1/12	214
222		**Parking Lot 1, No Parking Area**	**142 hrs**	**Thu 9/27/12**	**Mon 10/22/12**	
223		Grubbing including Off-Site disposal of debri	11 hrs	Thu 9/27/12	Fri 9/28/12	218
224		Earthwork	58 hrs	Fri 9/28/12	Tue 10/9/12	223
225		Subbase and Base Material	44 hrs	Tue 10/9/12	Wed 10/17/12	224
226		**Asphalt Paving, 2 inch layer**	**53 hrs**	**Fri 10/12/12**	**Mon 10/22/12**	
227		Mob - Paving	24 hrs	Fri 10/12/12	Wed 10/17/12	225FF
228		Asphalt Paving, 2 inch layer	29 hrs	Wed 10/17/12	Mon 10/22/12	227
229		**Parking Lot 2, Boat & Truck Parking**	**513 hrs**	**Fri 9/28/12**	**Thu 12/27/12**	
230		Grubbing including Off-Site disposal of debri	107 hrs	Fri 9/28/12	Wed 10/17/12	223
231		Earthwork	180 hrs	Wed 10/17/12	Mon 11/19/12	230
232		Subbase and Base Material	136 hrs	Mon 11/19/12	Wed 12/12/12	231
233		Asphalt Paving, 2 inch layer	90 hrs	Wed 12/12/12	Thu 12/27/12	232
234		**Parking Lot 3, Staging Area**	**216 hrs**	**Wed 10/17/12**	**Fri 11/23/12**	
235		Grubbing including Off-Site disposal of debri	9 hrs	Wed 10/17/12	Thu 10/18/12	230
236		Earthwork	180 hrs	Fri 10/19/12	Tue 11/20/12	235
237		Subbase and Base Material	7 hrs	Tue 11/20/12	Wed 11/21/12	236
238		**Asphalt Paving, 2 inch layer**	**20 hrs**	**Wed 11/21/12**	**Fri 11/23/12**	
239		Asphalt Paving, 2 inch layer	8 hrs	Wed 11/21/12	Thu 11/22/12	237
240		De-Mob Paving	12 hrs	Thu 11/22/12	Fri 11/23/12	239
241		De-Mobilization - Earthwork Contractor	20 hrs	Wed 11/21/12	Fri 11/23/12	237
242		**Oakland Park**	**108 hrs**	**Fri 11/23/12**	**Thu 12/13/12**	



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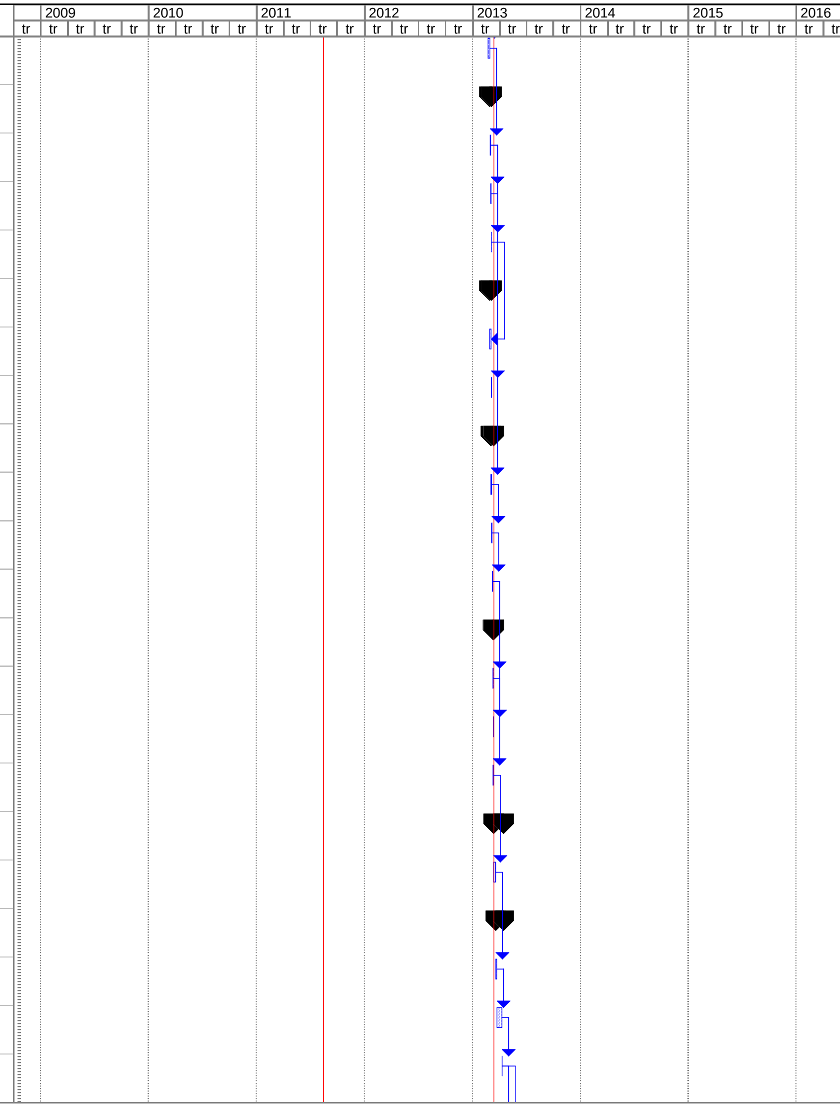
White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
243		Mobilization - Earthwork Contractor	40 hrs	Fri 11/23/12	Fri 11/30/12	241
244		**Parking Lot for Swim Area**	**28 hrs**	**Thu 11/29/12**	**Wed 12/5/12**	
245		Grubbing including Off-Site disposal of debri	8 hrs	Fri 11/30/12	Mon 12/3/12	243
246		Earthwork	4 hrs	Mon 12/3/12	Tue 12/4/12	245
247		Subbase and Base Material	4 hrs	Tue 12/4/12	Tue 12/4/12	246
248		**Asphalt Paving, 2 inch layer**	**28 hrs**	**Thu 11/29/12**	**Wed 12/5/12**	
249		Mob - Paving	24 hrs	Thu 11/29/12	Tue 12/4/12	247FF
250		Asphalt Paving, 2 inch layer	4 hrs	Tue 12/4/12	Wed 12/5/12	249
251		**Parking Lot for Marina**	**58 hrs**	**Mon 12/3/12**	**Thu 12/13/12**	
252		Grubbing including Off-Site disposal of debri	21 hrs	Mon 12/3/12	Thu 12/6/12	245
253		Earthwork	11 hrs	Thu 12/6/12	Fri 12/7/12	252
254		Subbase and Base Material	8 hrs	Fri 12/7/12	Mon 12/10/12	253
255		**Asphalt Paving, 2 inch layer**	**18 hrs**	**Mon 12/10/12**	**Thu 12/13/12**	
256		Asphalt Paving, 2 inch layer	6 hrs	Mon 12/10/12	Tue 12/11/12	254
257		De-Mob Paving	12 hrs	Tue 12/11/12	Thu 12/13/12	256
258		De-Mobilization - Earthwork Contractor	20 hrs	Mon 12/10/12	Thu 12/13/12	254
259		**Pontiac Park**	**184 hrs**	**Thu 12/13/12**	**Tue 1/15/13**	
260		Mobilization - Earthwork Contractor	40 hrs	Thu 12/13/12	Thu 12/20/12	258
261		**Parking Lot**	**142 hrs**	**Thu 12/20/12**	**Tue 1/15/13**	
262		Grubbing including Off-Site disposal of debri	15 hrs	Thu 12/20/12	Mon 12/24/12	260
263		Earthwork	103 hrs	Mon 12/24/12	Thu 1/10/13	262
264		Subbase and Base Material	6 hrs	Thu 1/10/13	Thu 1/10/13	263



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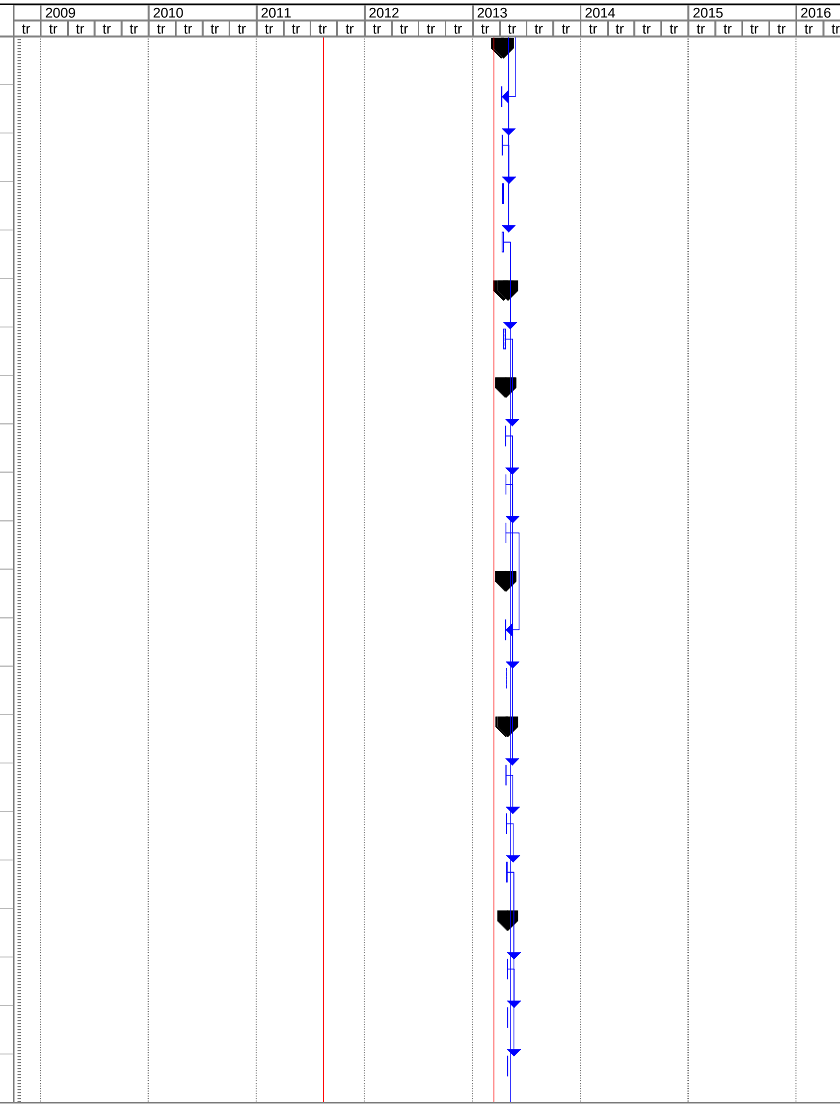
White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
265		**Asphalt Paving, 2 inch layer**	**42 hrs**	**Mon 1/7/13**	**Tue 1/15/13**	
266		Mob - Paving	24 hrs	Mon 1/7/13	Thu 1/10/13	264FF
267		Asphalt Paving, 2 inch layer	6 hrs	Thu 1/10/13	Fri 1/11/13	266
268		De-Mob Paving	12 hrs	Fri 1/11/13	Tue 1/15/13	267
269		De-Mobilization - Earthwork Contractor	20 hrs	Thu 1/10/13	Tue 1/15/13	264
270		**Buck Creek Park**	**91 hrs**	**Tue 1/15/13**	**Wed 1/30/13**	
271		Mobilization - Earthwork Contractor	40 hrs	Tue 1/15/13	Tue 1/22/13	269
272		**Parking Lot #1**	**28 hrs**	**Mon 1/21/13**	**Thu 1/24/13**	
273		Grubbing including Off-Site disposal of debri	5 hrs	Tue 1/22/13	Tue 1/22/13	271
274		Earthwork	4 hrs	Wed 1/23/13	Wed 1/23/13	273
275		Subbase and Base Material	4 hrs	Wed 1/23/13	Wed 1/23/13	274
276		**Asphalt Paving, 2 inch layer**	**28 hrs**	**Mon 1/21/13**	**Thu 1/24/13**	
277		Mob - Paving	24 hrs	Mon 1/21/13	Wed 1/23/13	275FF
278		Asphalt Paving, 2 inch layer	4 hrs	Thu 1/24/13	Thu 1/24/13	277
279		**Parking Lot #2**	**42 hrs**	**Wed 1/23/13**	**Wed 1/30/13**	
280		Grubbing including Off-Site disposal of debri	12 hrs	Wed 1/23/13	Thu 1/24/13	273
281		Earthwork	8 hrs	Thu 1/24/13	Fri 1/25/13	280
282		Subbase and Base Material	6 hrs	Fri 1/25/13	Mon 1/28/13	281
283		**Asphalt Paving, 2 inch layer**	**16 hrs**	**Mon 1/28/13**	**Wed 1/30/13**	
284		Asphalt Paving, 2 inch layer	4 hrs	Mon 1/28/13	Mon 1/28/13	282
285		De-Mob Paving	12 hrs	Mon 1/28/13	Wed 1/30/13	284
286		De-Mobilization - Earthwork Contractor	20 hrs	Mon 1/28/13	Wed 1/30/13	282



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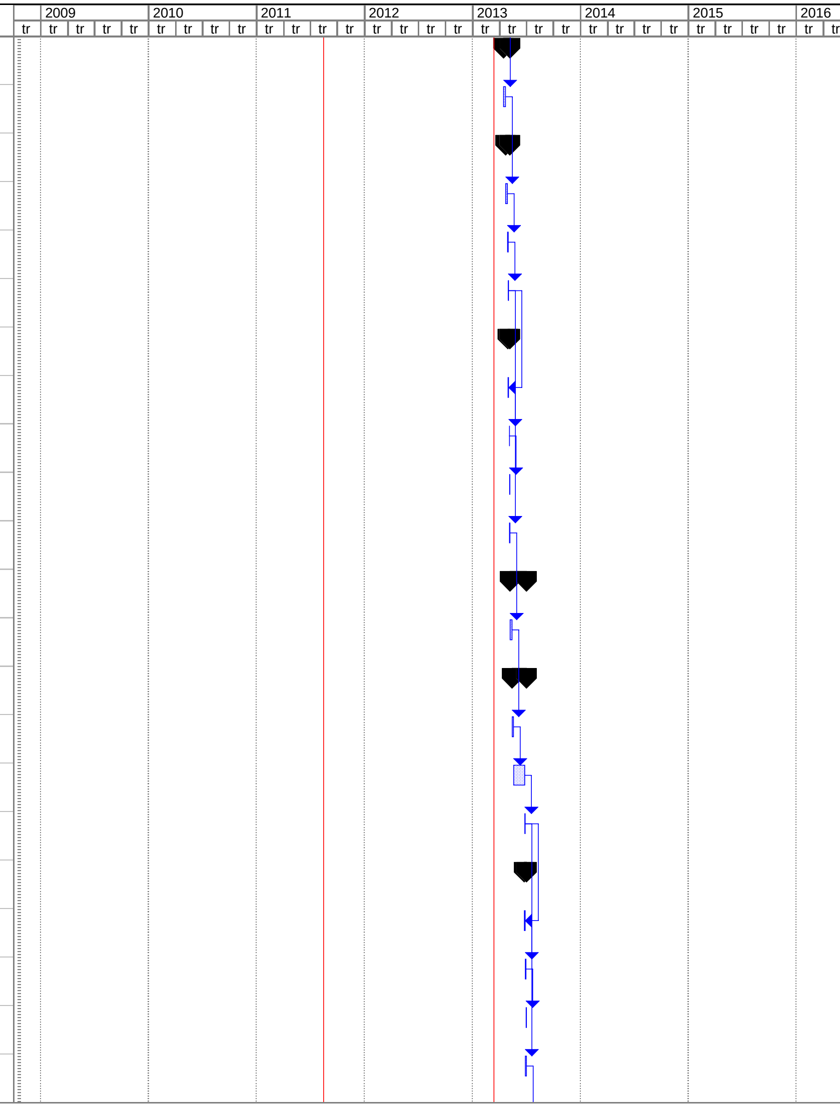
White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
287		**Lead Hill Park**	**129 hrs**	**Tue 1/15/13**	**Wed 2/6/13**	
288		Mobilization - Earthwork Contractor	40 hrs	Tue 1/15/13	Tue 1/22/13	269
289		**Parking Lot**	**85 hrs**	**Tue 1/22/13**	**Tue 2/5/13**	
290		Grubbing including Off-Site disposal of debri	36 hrs	Tue 1/22/13	Mon 1/28/13	288
291		Earthwork	19 hrs	Mon 1/28/13	Thu 1/31/13	290
292		Subbase and Base Material	14 hrs	Thu 1/31/13	Fri 2/1/13	291
293		**Asphalt Paving, 2 inch layer**	**40 hrs**	**Wed 1/30/13**	**Tue 2/5/13**	
294		Mob - Paving	24 hrs	Wed 1/30/13	Fri 2/1/13	292FF
295		Asphalt Paving, 2 inch layer	4 hrs	Mon 2/4/13	Mon 2/4/13	294
296		De-Mob Paving	12 hrs	Mon 2/4/13	Tue 2/5/13	295
297		De-Mobilization - Earthwork Contractor	20 hrs	Mon 2/4/13	Wed 2/6/13	292
298		**Highway 125 Park**	**318 hrs**	**Wed 2/6/13**	**Wed 4/3/13**	
299		Mobilization - Earthwork Contractor	40 hrs	Wed 2/6/13	Wed 2/13/13	297
300		**Parking Lot**	**278 hrs**	**Wed 2/13/13**	**Wed 4/3/13**	
301		Grubbing including Off-Site disposal of debri	25 hrs	Wed 2/13/13	Mon 2/18/13	299
302		Earthwork	220 hrs	Mon 2/18/13	Thu 3/28/13	301
303		Subbase and Base Material	13 hrs	Thu 3/28/13	Fri 3/29/13	302
304		**Asphalt Paving, 2 inch layer**	**44 hrs**	**Tue 3/26/13**	**Wed 4/3/13**	
305		Mob - Paving	24 hrs	Tue 3/26/13	Fri 3/29/13	303FF
306		Asphalt Paving, 2 inch layer	8 hrs	Fri 3/29/13	Mon 4/1/13	305
307		De-Mob Paving	12 hrs	Mon 4/1/13	Wed 4/3/13	306
308		De-Mobilization - Earthwork Contractor	20 hrs	Fri 3/29/13	Wed 4/3/13	303



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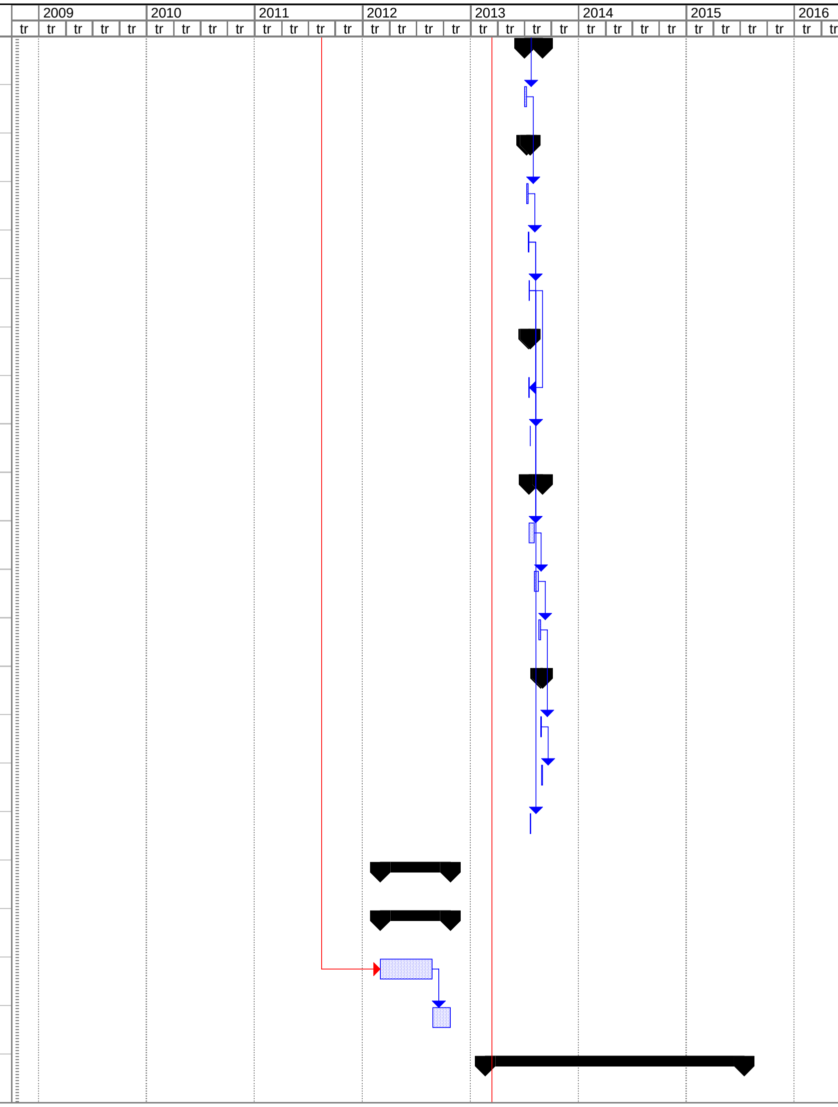
White River Minimum Flows, Implementation Schedule

ID	Task Name	Duration	Start	Finish	Predecessors
309	**Theodosia Park**	**345 hrs**	**Wed 4/3/13**	**Mon 6/3/13**	
310	Mobilization - Earthwork Contractor	40 hrs	Wed 4/3/13	Wed 4/10/13	308
311	**Parking Lot #1**	**70 hrs**	**Wed 4/10/13**	**Mon 4/22/13**	
312	Grubbing including Off-Site disposal of debri	27 hrs	Wed 4/10/13	Mon 4/15/13	310
313	Earthwork	24 hrs	Mon 4/15/13	Thu 4/18/13	312
314	Subbase and Base Material	11 hrs	Thu 4/18/13	Fri 4/19/13	313
315	**Asphalt Paving, 2 inch layer**	**32 hrs**	**Wed 4/17/13**	**Mon 4/22/13**	
316	Mob - Paving	24 hrs	Wed 4/17/13	Fri 4/19/13	314FF
317	Asphalt Paving, 2 inch layer	8 hrs	Mon 4/22/13	Mon 4/22/13	316
318	**Parking Lot #2**	**254 hrs**	**Thu 4/18/13**	**Mon 6/3/13**	
319	Grubbing including Off-Site disposal of debri	95 hrs	Thu 4/18/13	Mon 5/6/13	313
320	Earthwork	84 hrs	Mon 5/6/13	Mon 5/20/13	319
321	Subbase and Base Material	38 hrs	Tue 5/21/13	Mon 5/27/13	320
322	**Asphalt Paving, 2 inch layer**	**37 hrs**	**Mon 5/27/13**	**Mon 6/3/13**	
323	Asphalt Paving, 2 inch layer	25 hrs	Mon 5/27/13	Thu 5/30/13	321
324	De-Mob Paving	12 hrs	Thu 5/30/13	Mon 6/3/13	323
325	De-Mobilization - Earthwork Contractor	20 hrs	Mon 4/22/13	Wed 4/24/13	314
326	**Buildings, Public Use**	**1360 hrs**	**Fri 12/2/11**	**Thu 7/26/12**	
327	**Point Return Park**	**1360 hrs**	**Fri 12/2/11**	**Thu 7/26/12**	
328	Restroom	126 days	Fri 12/2/11	Fri 5/25/12	123SS+126 days
329	Picnic Pavilion	44 days	Mon 5/28/12	Thu 7/26/12	328
330	**Day Use Areas**	**5011 hrs**	**Wed 11/21/12**	**Thu 4/16/15**	

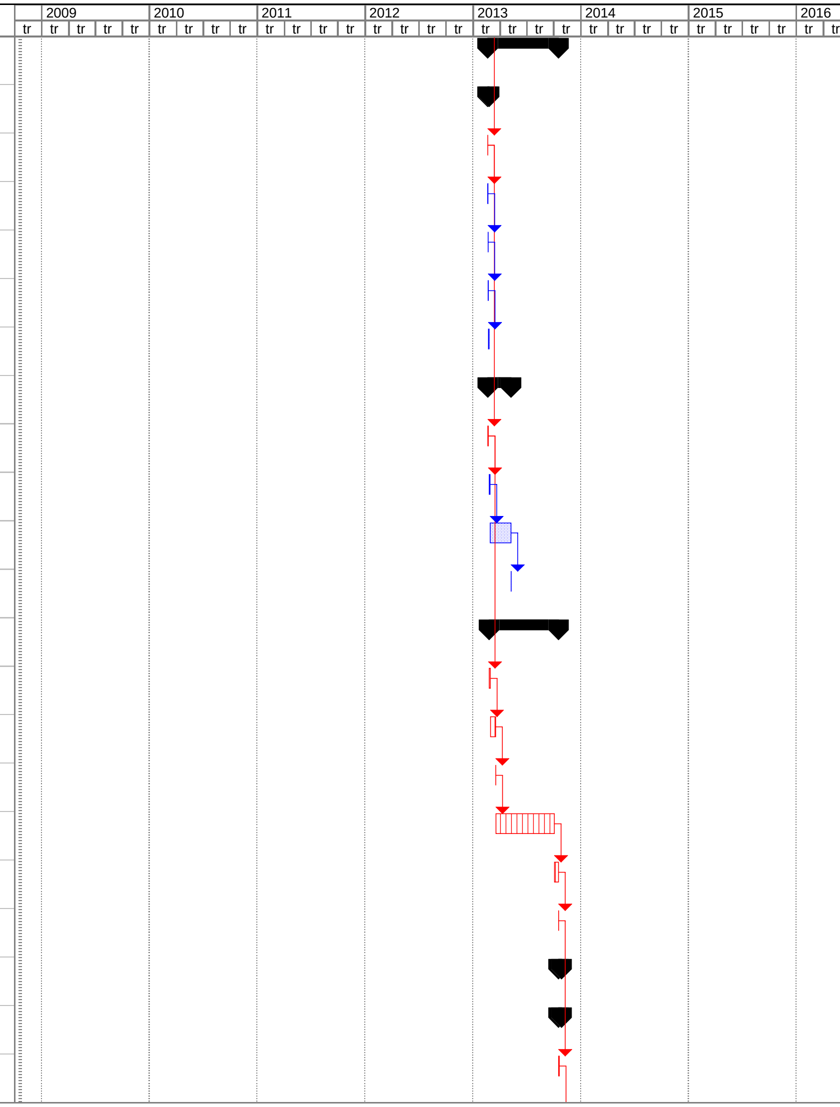


Project: Combined Project WRMF.mpp
Date: Fri 7/18/08

Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID	Task Name	Duration	Start	Finish	Predecessors
331	**Point Return Park**	**1379 hrs**	**Wed 11/21/12**	**Fri 7/19/13**	
332	**Boat Launch Ramp #1**	**24 hrs**	**Wed 11/21/12**	**Mon 11/26/12**	
333	Clearing and Grubbing	4 hrs	Wed 11/21/12	Wed 11/21/12	237
334	Earth Work	4 hrs	Wed 11/21/12	Thu 11/22/12	333
335	Subbase and Base Material	4 hrs	Thu 11/22/12	Thu 11/22/12	334
336	Concrete Paving	8 hrs	Thu 11/22/12	Fri 11/23/12	335
337	Riprap	4 hrs	Fri 11/23/12	Mon 11/26/12	336
338	**Swim Beach**	**457 hrs**	**Wed 11/21/12**	**Fri 2/8/13**	
339	Clearing and Grubbing	17 hrs	Wed 11/21/12	Fri 11/23/12	333
340	Shape Area Including Compaction	30 hrs	Mon 11/26/12	Thu 11/29/12	339
341	Pea Gravel and Sand Fill for Swim Beach	408 hrs	Thu 11/29/12	Fri 2/8/13	340
342	Relocate Swim Barrier	2 hrs	Fri 2/8/13	Fri 2/8/13	341
343	**Boat Launch Ramp #2**	**1358 hrs**	**Mon 11/26/12**	**Fri 7/19/13**	
344	Clearing and Grubbing	35 hrs	Mon 11/26/12	Fri 11/30/12	339
345	Earth Work	100 hrs	Fri 11/30/12	Tue 12/18/12	344
346	Subbase and Base Material	4 hrs	Tue 12/18/12	Wed 12/19/12	345
347	Concrete Paving	1135 hrs	Wed 12/19/12	Fri 7/5/13	346
348	Position Slab	80 hrs	Fri 7/5/13	Fri 7/19/13	347
349	Riprap	4 hrs	Fri 7/19/13	Fri 7/19/13	348
350	**Dam Site Park**	**50 hrs**	**Fri 7/19/13**	**Mon 7/29/13**	
351	**Boat Launch Ramp**	**50 hrs**	**Fri 7/19/13**	**Mon 7/29/13**	
352	Clearing and Grubbing	4 hrs	Fri 7/19/13	Mon 7/22/13	349



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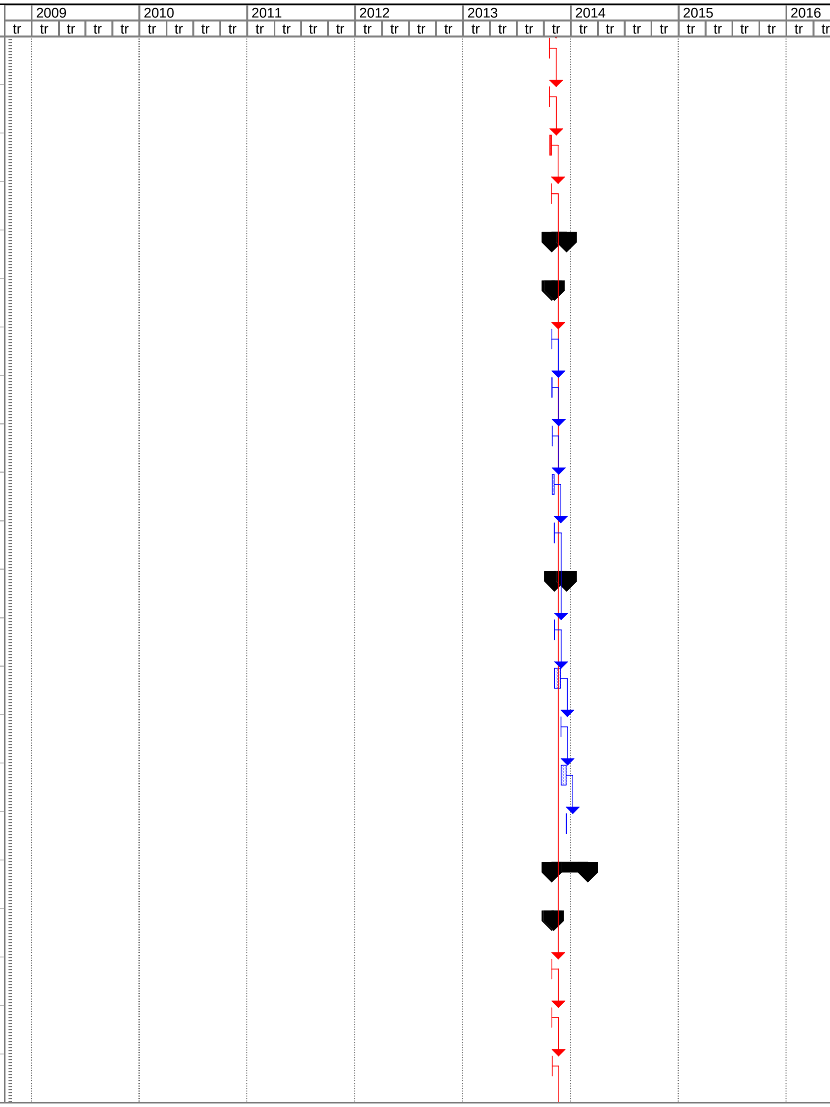
Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
353		Earth Work	4 hrs	Mon 7/22/13	Mon 7/22/13	352
354		Subbase and Base Material	4 hrs	Mon 7/22/13	Tue 7/23/13	353
355		Concrete Paving	34 hrs	Tue 7/23/13	Mon 7/29/13	354
356		Riprap	4 hrs	Mon 7/29/13	Mon 7/29/13	355
357		**Oakland Park**	**292 hrs**	**Tue 7/30/13**	**Wed 9/18/13**	
358		**Boat Launch Ramp #1**	**59 hrs**	**Tue 7/30/13**	**Thu 8/8/13**	
359		Clearing and Grubbing	5 hrs	Tue 7/30/13	Tue 7/30/13	356
360		Earth Work	4 hrs	Tue 7/30/13	Wed 7/31/13	359
361		Subbase and Base Material	4 hrs	Wed 7/31/13	Wed 7/31/13	360
362		Concrete Paving	41 hrs	Wed 7/31/13	Wed 8/7/13	361
363		Riprap	5 hrs	Wed 8/7/13	Thu 8/8/13	362
364		**Boat Launch Ramp #2**	**233 hrs**	**Thu 8/8/13**	**Wed 9/18/13**	
365		Clearing and Grubbing	4 hrs	Thu 8/8/13	Thu 8/8/13	363
366		Earth Work	121 hrs	Thu 8/8/13	Thu 8/29/13	365
367		Subbase and Base Material	4 hrs	Fri 8/30/13	Fri 8/30/13	366
368		Concrete Paving	92 hrs	Fri 8/30/13	Mon 9/16/13	367
369		Riprap	12 hrs	Tue 9/17/13	Wed 9/18/13	368
370		**Lakeview Park**	**711 hrs**	**Tue 7/30/13**	**Fri 11/29/13**	
371		**Boat Launch Ramp**	**40 hrs**	**Tue 7/30/13**	**Mon 8/5/13**	
372		Clearing and Grubbing	4 hrs	Tue 7/30/13	Tue 7/30/13	356
373		Earth Work	4 hrs	Tue 7/30/13	Tue 7/30/13	372
374		Subbase and Base Material	4 hrs	Wed 7/31/13	Wed 7/31/13	373



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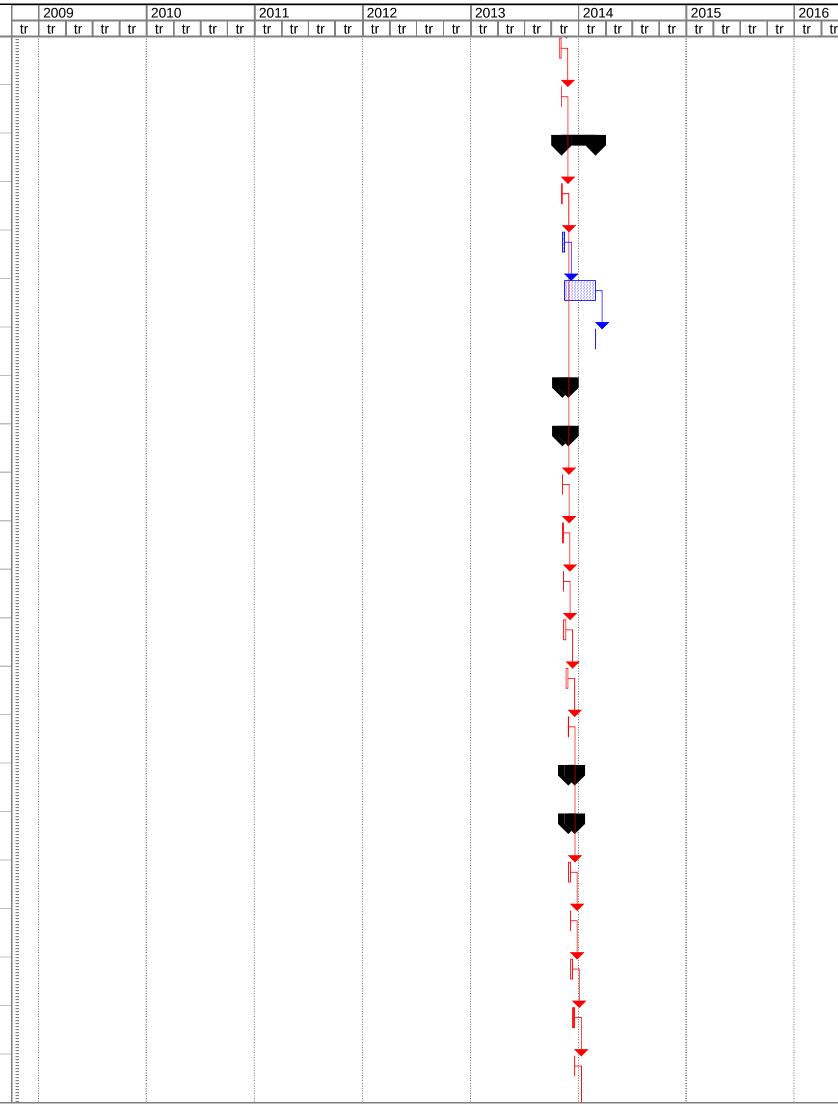
Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
375		Concrete Paving	24 hrs	Wed 7/31/13	Mon 8/5/13	374
376		Riprap	4 hrs	Mon 8/5/13	Mon 8/5/13	375
377		**Swim Beach**	**671 hrs**	**Tue 8/6/13**	**Fri 11/29/13**	
378		Clearing and Grubbing	25 hrs	Tue 8/6/13	Fri 8/9/13	376
379		Shape Area Including Compaction	44 hrs	Fri 8/9/13	Fri 8/16/13	378
380		Pea Gravel and Sand Fill for Swim Beach	600 hrs	Fri 8/16/13	Fri 11/29/13	379
381		Relocate Swim Barrier	2 hrs	Fri 11/29/13	Fri 11/29/13	380
382		**Pontiac Park**	**113 hrs**	**Fri 8/9/13**	**Thu 8/29/13**	
383		**Boat Launch Ramp**	**113 hrs**	**Fri 8/9/13**	**Thu 8/29/13**	
384		Grubbing	6 hrs	Fri 8/9/13	Fri 8/9/13	378
385		Earth Work	5 hrs	Fri 8/9/13	Mon 8/12/13	384
386		Subbase and Base Material	4 hrs	Mon 8/12/13	Mon 8/12/13	385
387		Concrete Paving	54 hrs	Tue 8/13/13	Wed 8/21/13	386
388		Push Slab into Deeper Water	40 hrs	Wed 8/21/13	Wed 8/28/13	387
389		Riprap	4 hrs	Wed 8/28/13	Thu 8/29/13	388
390		**Beaver Creek Park**	**129 hrs**	**Thu 8/29/13**	**Fri 9/20/13**	
391		**Boat Launch Ramp**	**129 hrs**	**Thu 8/29/13**	**Fri 9/20/13**	
392		Earth Work	42 hrs	Thu 8/29/13	Thu 9/5/13	389
393		Subbase and Base Material	4 hrs	Thu 9/5/13	Thu 9/5/13	392
394		Concrete Paving	38 hrs	Fri 9/6/13	Thu 9/12/13	393
395		Push Slab into Deeper Water	40 hrs	Thu 9/12/13	Thu 9/19/13	394
396		Riprap	5 hrs	Thu 9/19/13	Fri 9/20/13	395

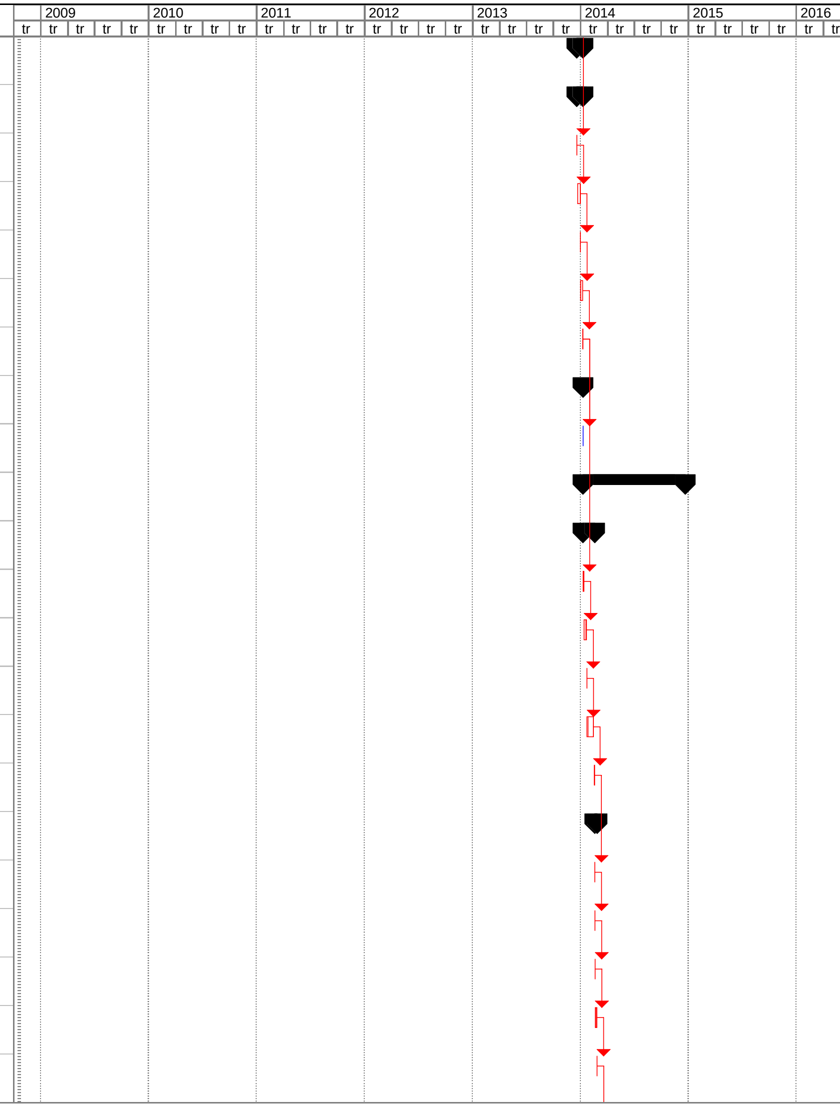


Project: Combined Project WRMF.mpp
Date: Fri 7/18/08

Task	Milestone	Rolled Up Critical Task	Split	Group By Summary	
Critical Task	Summary	Rolled Up Milestone	External Tasks	Deadline	
Progress	Rolled Up Task	Rolled Up Progress	Project Summary		

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
397		**Tucker Hollow Park**	**118 hrs**	**Fri 9/20/13**	**Fri 10/11/13**	
398		**Boat Launch Ramp**	**118 hrs**	**Fri 9/20/13**	**Fri 10/11/13**	
399		Grubbing	5 hrs	Fri 9/20/13	Fri 9/20/13	396
400		Earth Work	58 hrs	Mon 9/23/13	Wed 10/2/13	399
401		Subbase and Base Material	4 hrs	Wed 10/2/13	Wed 10/2/13	400
402		Concrete Paving	45 hrs	Wed 10/2/13	Thu 10/10/13	401
403		Riprap	6 hrs	Thu 10/10/13	Fri 10/11/13	402
404		**River Run Park**	**6 hrs**	**Fri 10/11/13**	**Fri 10/11/13**	
405		New Lighting	6 hrs	Fri 10/11/13	Fri 10/11/13	403
406		**Lead Hill Park**	**1971 hrs**	**Fri 10/11/13**	**Mon 9/22/14**	
407		**Boat Launch Ramp # 1**	**224 hrs**	**Fri 10/11/13**	**Wed 11/20/13**	
408		Grubbing	13 hrs	Fri 10/11/13	Mon 10/14/13	403
409		Earth Work	58 hrs	Mon 10/14/13	Wed 10/23/13	408
410		Subbase and Base Material	6 hrs	Thu 10/24/13	Thu 10/24/13	409
411		Concrete Paving	130 hrs	Thu 10/24/13	Fri 11/15/13	410
412		Riprap	17 hrs	Mon 11/18/13	Wed 11/20/13	411
413		**Boat Launch Ramp # 2**	**49 hrs**	**Wed 11/20/13**	**Thu 11/28/13**	
414		Grubbing	5 hrs	Wed 11/20/13	Wed 11/20/13	412
415		Earth Work	4 hrs	Wed 11/20/13	Thu 11/21/13	414
416		Subbase and Base Material	4 hrs	Thu 11/21/13	Thu 11/21/13	415
417		Concrete Paving	32 hrs	Thu 11/21/13	Wed 11/27/13	416
418		Riprap	4 hrs	Wed 11/27/13	Thu 11/28/13	417



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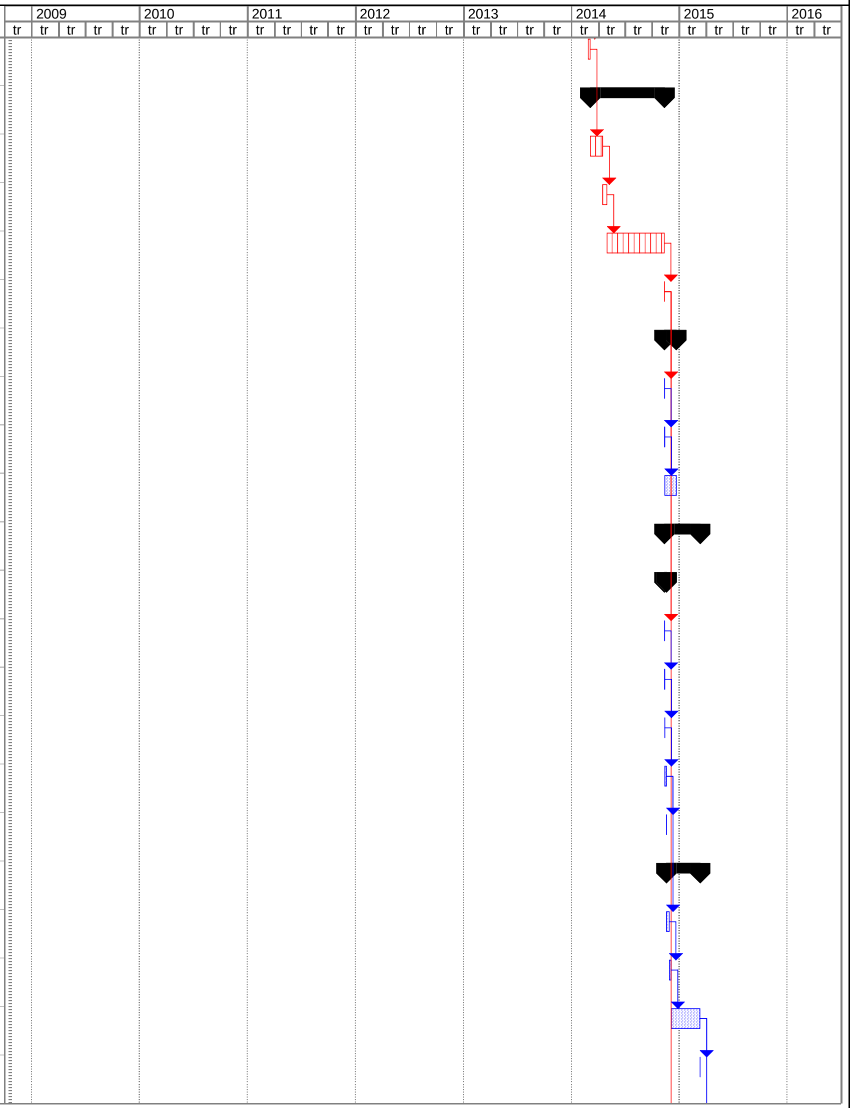
Task | Milestone | Rolled Up Critical Task | Split | Group By Summary
Critical Task | Summary | Rolled Up Milestone | External Tasks | Deadline
Progress | Rolled Up Task | Rolled Up Progress | Project Summary

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
419		Push Slabs into deeper Water	40 hrs	Thu 11/28/13	Thu 12/5/13	418
420		**Swim Beach**	**1431 hrs**	**Thu 12/5/13**	**Wed 8/13/14**	
421		Grubbing	245 hrs	Thu 12/5/13	Thu 1/16/14	419
422		Shape Area Including Compaction	84 hrs	Thu 1/16/14	Fri 1/31/14	421
423		Pea Gravel and Sand Fill for Swim Beach	1100 hrs	Fri 1/31/14	Tue 8/12/14	422
424		Relocate Swim Barrier	2 hrs	Tue 8/12/14	Wed 8/13/14	423
425		**Handicapped Access Sidewalk**	**227 hrs**	**Wed 8/13/14**	**Mon 9/22/14**	
426		Earthwork	4 hrs	Wed 8/13/14	Wed 8/13/14	424
427		Subbase and Base Material	4 hrs	Wed 8/13/14	Thu 8/14/14	426
428		Concrete Sidewalk with Handrails	219 hrs	Thu 8/14/14	Mon 9/22/14	427
429		**Tucker Hollow Park**	**696 hrs**	**Wed 8/13/14**	**Fri 12/12/14**	
430		**Boat Launch Ramp**	**44 hrs**	**Wed 8/13/14**	**Wed 8/20/14**	
431		Grubbing	4 hrs	Wed 8/13/14	Wed 8/13/14	424
432		Earth Work	4 hrs	Wed 8/13/14	Thu 8/14/14	431
433		Subbase and Base Material	4 hrs	Thu 8/14/14	Thu 8/14/14	432
434		Concrete Paving	28 hrs	Thu 8/14/14	Wed 8/20/14	433
435		Riprap	4 hrs	Wed 8/20/14	Wed 8/20/14	434
436		**Swim Beach**	**656 hrs**	**Wed 8/20/14**	**Fri 12/12/14**	
437		Grubbing	61 hrs	Wed 8/20/14	Fri 8/29/14	434
438		Shape Area Including Compaction	40 hrs	Fri 8/29/14	Fri 9/5/14	437
439		Pea Gravel and Sand Fill for Swim Beach	553 hrs	Fri 9/5/14	Thu 12/11/14	438
440		Relocate Swim Barrier	2 hrs	Thu 12/11/14	Fri 12/12/14	439



Project: Combined Project WRMF.mpp
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Task | Milestone | Rolled Up Critical Task | Split | Group By Summary
Critical Task | Summary | Rolled Up Milestone | External Tasks | Deadline
Progress | Rolled Up Task | Rolled Up Progress | Project Summary

White River Minimum Flows, Implementation Schedule

ID	Task Name	Duration	Start	Finish	Predecessors
441	**Buck Creek Park**	**505 hrs**	**Thu 12/11/14**	**Tue 3/10/15**	
442	**Boat Launch Ramp**	**50 hrs**	**Thu 12/11/14**	**Mon 12/22/14**	
443	Clearing and Grubbing	4 hrs	Thu 12/11/14	Fri 12/12/14	439
444	Earth Work	21 hrs	Fri 12/12/14	Tue 12/16/14	443
445	Subbase and Base Material	4 hrs	Wed 12/17/14	Wed 12/17/14	444
446	Concrete Paving	17 hrs	Wed 12/17/14	Fri 12/19/14	445
447	Riprap	4 hrs	Fri 12/19/14	Mon 12/22/14	446
448	**Swim Beach**	**455 hrs**	**Mon 12/22/14**	**Tue 3/10/15**	
449	Grubbing	51 hrs	Mon 12/22/14	Tue 12/30/14	447
450	Shape Area Including Compaction	27 hrs	Tue 12/30/14	Fri 1/2/15	449
451	Pea Gravel and Sand Fill for Swim Beach	375 hrs	Fri 1/2/15	Tue 3/10/15	450
452	Relocate Swim Barrier	2 hrs	Tue 3/10/15	Tue 3/10/15	451
453	**Theodosia Park**	**1413 hrs**	**Wed 8/13/14**	**Thu 4/16/15**	
454	**Boat Launch Ramp**	**1040 hrs**	**Wed 8/13/14**	**Wed 2/11/15**	
455	Clearing and Grubbing	12 hrs	Wed 8/13/14	Thu 8/14/14	424
456	Earth Work	561 hrs	Thu 8/14/14	Thu 11/20/14	455
457	Subbase and Base Material	17 hrs	Thu 11/20/14	Mon 11/24/14	456
458	Concrete Paving	363 hrs	Mon 11/24/14	Tue 1/27/15	457
459	Push Slab into Deeper Water	40 hrs	Tue 1/27/15	Tue 2/3/15	458
460	Riprap	47 hrs	Tue 2/3/15	Wed 2/11/15	459
461	**Swim Beach**	**373 hrs**	**Wed 2/11/15**	**Thu 4/16/15**	
462	Grubbing	42 hrs	Wed 2/11/15	Wed 2/18/15	460

2009 2010 2011 2012 2013 2014 2015 2016

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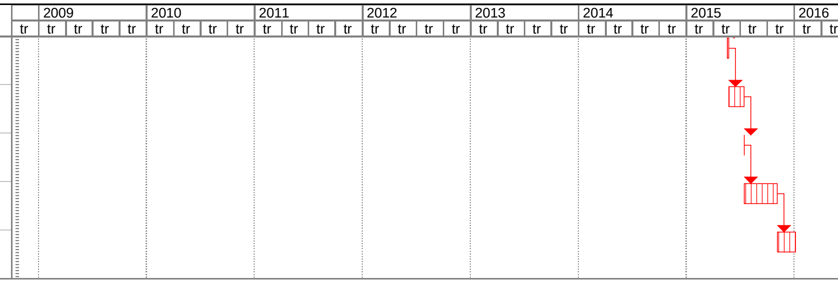
Task | Critical Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Critical Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

White River Minimum Flows, Implementation Schedule

ID		Task Name	Duration	Start	Finish	Predecessors
463		Shape Area Including Compaction	22 hrs	Wed 2/18/15	Mon 2/23/15	462
464		Pea Gravel and Sand Fill for Swim Beach	307 hrs	Mon 2/23/15	Thu 4/16/15	463
465		Relocate Swim Barrier	2 hrs	Thu 4/16/15	Thu 4/16/15	464
466		Weather Delays	80 days	Thu 4/16/15	Thu 8/6/15	465
467		Contract Closeout	44 days	Thu 8/6/15	Wed 10/7/15	466



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White River Basin, Arkansas, Minimum Flows
Project Report

Lakeside Facilities

APPENDIX F

1. LAKESIDE FACILITY INTRODUCTION

1.1 General. Section 132 of the FY 2006 Energy and Water Development Appropriations Act (P.L. 109-103) (EWDAA) authorizes and directs the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes. Section 132 states that the non-Federal interest must provide relocations or modifications for public and private lake facilities to allow for reasonable continued use. The Arkansas Game & Fish Commission, for the State of Arkansas, has been identified as the non-Federal interests, and has agreed to provide relocations or modifications for public and private lake facilities to allow for reasonable continued use relative to the change of operations at Bull Shoals and Norfork Lakes.

1.1.1 Impacts to Lake Recreation. Under the original Water Resources Development Act authorization, lakeside facilities modifications did not qualify as a Federal expense according to the Planning Principals and Guidelines (P&G). The annual loss to lake recreation was calculated using SWD's SUPER model. The SUPER model analyzed historical information to estimate damages based on changes to stage and duration levels. There is a negative correlation between high and low water conditions and visitor accessibility. SUPER model used historical data and unit day values to determine the change in recreation benefits. The unit day values were obtained by using Economic Guidance Memorandum (EGM) 01-01, Unit Day Values for Recreation, fiscal year 2001. EGM 01-01 describes the unit day value method as the following:

> "The unit day value method for estimating recreation benefits relies on expert or informed opinion and judgment to approximate the average willingness to pay of users of Federal or Federally assisted recreation resources. … By applying a carefully thought-out and adjusted unit day value to estimated use, an approximation is obtained that may be used as an estimate of project recreation benefits."

The unit day value estimate was based on a point scale in the guidance memorandum. Points were assigned by a PHD Economist to five different categories: Recreation Experience, Availability of Opportunity, Carrying Capacity, Accessibility, and Environmental Quality. The unit day value was used in conjunction with the SUPER model's stage duration and visitor data to determine the change in recreation benefits due to a change in stage and duration from the implementation of minimum flows. If no lakeside facilities are modified, annual recreation losses at Bull Shoals and Norfork Lakes due to the proposed minimum flows would be $139,000 and $26,000 respectively. The non-Federal costs to avoid these impacts are $12,494,000 at Bull Shoals and $5,609,000 Norfork. The lake recreation losses are disproportional with regards to cost of modifications necessary to avoid these impacts. However, the Congressional delegation and the Arkansas Game & Fish Commission recognized the importance of recreation to the Arkansas and Missouri Ozark region, and their desire to minimize possible adverse affects related to White River Minimum Flows (WRMF) resulted in the lakeside facility provisions contained in Section 132 EWDAA.

1.2 **Study Constraints and Assumptions**.

- Lakeside facilities is a specific term used in section 132(a) EWDAA, in assigning cost-sharing responsibilities. With the exception of "minimum flow project facilities" and the facilities of FERC Project No. 2221, "lakeside facilities" are any man-made improvements, including but not limited to structures, roads, and utilities, that are located in, at the shoreline or within an area of project effect adjacent to Bull Shoals and Norfork Lakes;

- Project facilities is a specific term used in section 132(a) in assigning cost-sharing responsibilities. These are new facilities or modifications, fully federally funded, to existing project facilities described in BS-3 and NF-7 of the July 2004 Report that are directly necessary to provide the minimum flow releases. There are no LERRD's required for modifications as the Corps owns all property below the spillway crest at Bull Shoals and Norfork Lakes in fee simple. No increased shoreline erosion will occur because the proposed storage reallocation will not result in permanent, static lake elevations, and the lakes are in a mountainous region with natural stone beaches and cliffs.

- Visitation numbers for 2007 were used to determine peak monthly park visitation, 2007 had near record visitation due to moderate water levels and were considered representative of an optimum recreation year;

- Comparison of lake elevation frequency and duration were used to determine the change in lake hydraulics between current lake conditions to the minimum flows' lake conditions. Lake elevation duration was determined to control impacts to lakeside facilities, peak monthly visitation and corresponding monthly lake elevation duration figures were used to measure reasonable continued use. The elevation were incremental change in duration peaked, followed by a decline in incremental change in duration at the next higher elevation is defined as the "filter elevation". All Lakeside facilities above the filter elevation do not qualify to be evaluated for reasonable continued use because the change in elevation duration will not change significantly with the minimum flows operation;

- Lake frequency, in layman's terms, measures how often an elevation is equaled or exceeded and duration measures how long an elevation is equaled or exceeded;

- Due to record rainfall and flooding at Bull Shoals and Norfork Lakes, LIDAR was not flown, instead an aerial photograph (flown March 2008) of lake elevation 660 was used to evaluate facility impacts at Bull Shoals Lake, existing aerial photographs and surveys were used to calculate feasibility level impacts to lakeside facilities at Norfork Lake;

- LIDAR will be flown over both lakes during the Construction phase to ascertain final lakeside facility impacts at Norfork Lake, as well as final quantities used for facility design;

- The Little Rock District Project Delivery Team (PDT) included Mtn Home Project Office personnel. PDT members inspected all public and private lakeside facilities during the study process;

2. EXISTING LAKESIDE FACILITIES

2.1 <u>Location</u>. Bull Shoals and Norfork Reservoirs are primarily in Arkansas with some upstream portions in Missouri. The tailwater trout habitats are located in north central Arkansas in the heart of the Ozarks.

2.2 <u>Existing Lakeside Facilities</u>. Lakeside facilities are any man-made improvements, including but not limited to structures, roads, and utilities, that are located in, at the shoreline or within an area of project effect adjacent to Bull Shoals and Norfork Lakes. The PDT visually inventoried all lakeside facilities at Bull Shoals and Norfork Lakes, using aerial photography and site visits at Bull Shoals and Norfork Lakes.

There are 11 marinas, 48 private resorts, and 20 Corps parks at Bull Shoals Lake. The marinas are all located on Corps parks. There are 687 private boat docks permitted on Bull Shoals Lake. Around Bull Shoals Lake, 183 county, state, and, Federal roads were evaluated. For complete lists of parks, marinas, roads, and boat docks evaluated during the study process are included in Appendix F-A.

There are10 marinas, 21 private resorts, and 21 Corps parks at Norfork Lake. The marinas are all located on Corps parks. There are 314 private boat docks permitted on Norfork Lake. Around Norfork Lake, 125 county, state, and, Federal roads were evaluated. For complete lists of parks, marinas, roads, and boat docks evaluated during the study process are included in Appendix F-A.

2.3 <u>Existing Conditions Affecting Lakeside Facilities</u>. Currently lakeside facilities are affected by a range of lake conditions. At Bull Shoals, the lake levels can range from as low as 628.5 up to as high as 695.0. At Norfork, the lake levels can range from as low as 510.0 up to as high as 580.0. Recreation is adversely affected by both drought and flooding.

<u>2.3.1 Flooding.</u> Using SUPER model, five historic flood events (1945, 1957, 1973, 1990, and 2002) were investigated to determine how the proposed minimum flows operation would have affected the pool elevation.

At Bull Shoals, the proposed minimum flows plan increased the pool elevation for each flood event. The increase ranged from a minimum change 0.01 feet for the 1957 event to a maximum of 0.88 feet for the 2002 event. None of the maximum pool elevations exceeded top of dam, although three events did exceed the flood pool for both existing operation and the proposed minimum flows operation. The duration of storage in flood pool either had no change or the number of days above conservation pool was reduced. For the 1957 and 1973 events simulating the proposed minimum flows operation, the number of days above conservation pool was reduced by 10 and 15 days respectively. The impact of the proposed project on pool elevation for these events is that there will be an expected increase in the maximum pool for the extreme events but no increase in the duration that the pool is above conservation pool. Therefore, there is no significant loss of recreation opportunity to lake recreation.

At Norfork, the proposed minimum flows plan increased the pool elevation for four of the five flood events. The increase ranged from 0.01 feet for the 1945 event to 1.26 feet for the 1990 event. For the 1957 event, the maximum pool elevation was 0.25 feet lower than the existing conditions simulation. None of the maximum pool elevations exceeded top of dam, although three events exceeded the flood pool under existing conditions and two events exceeded the flood pool under the minimum flows plan. The duration of storage in flood pool was reduced slightly for the 1990 and 2002 events for the simulated proposed project, but for the 1945, 1957 and 1973 events, the number of days above conservation pool was increased by 2, 30, and 2 days respectively. In other words, if the 1957 flood event were to occur again when operating the project according to the proposed reallocation plan, Norfork Lake would be in flood control operations for approximately an additional month. The impact of the proposed project on pool elevation for these events is that there will be an expected increase in the maximum pool for the extreme events and some increase in the duration that the pool is above conservation pool. Therefore, there is no significant loss of recreation opportunity to lake recreation.

2.3.2 Drought. Similar to flood events, the impacts of the proposed minimum flows project was analyzed for impacts upon operations at each project for drought events. For this study, four time periods were analyzed: 1953-1957, 1962-1965, 1980-1982, and 1999-2002.

For Bull Shoals Lake, simulating the proposed minimum flows' plan for the 1953-1957 drought would have increased the number of days that the pool elevation remained below conservation pool by more than two months, but the lake level would not have reached as low an elevation as it did under simulated existing conditions. This drought period produced the lowest elevation and longest duration below top of conservation pool for both existing conditions and the proposed project. The 1999-2002 drought would have produced a lower elevation than existing conditions had the proposed plan been in operation; however, the lowest elevation would have been higher than the 1953-1957 drought. The proposed plan would have increased the number of days the lake was below top of conservation pool by about two months. The impact of the proposed project on pool elevation and duration for these events is that that although the minimum pool elevation may not be as severe; it would be expected to take about 6 percent longer to refill the lake to conservation pool. SUPER model did not include a minimum flows drought contingency plan.

For Norfork Lake, the 1953-1957 drought would have had similar impacts to the impacts at Bull Shoals Lake. Simulating the proposed project increased the number of days that the pool elevation remained below conservation pool by about two months, but the lake level would not have reached as low an elevation as it did under simulated existing conditions, ending about 0.15 higher. Likewise, this drought period produced the lowest elevation and longest duration below top of conservation pool. The 1999-2002 drought would have produced a lower elevation, about -0.33 feet, than existing conditions had the proposed plan been in operation, but the lowest elevation would have been about 4.25 feet higher than the 1953-1957 drought. The 1962-1965 drought showed a lower minimum pool than the proposed plan by 2.64 feet, but still above the 1953-1957 minimum pool. The proposed plan would not have significantly increased the number of days the lake was below top of conservation pool for the 1980s or 1990s drought. The impact of the proposed project on pool elevation and duration for these events is that the minimum pool may be lower and will take about 3 percent longer to refill the lake to conservation pool.

In summary, from a hydrologic and hydraulic perspective, the proposed minimum flows operation would have slightly higher flood pool elevations with minimum impacts to the duration that the pools are above conservation pool at both Bull Shoals and Norfork Lakes when considering operations during extreme flood events. During droughts it would be expected that Bull Shoals would have less severe minimums and Norfork would have slightly lower minimum pool elevations. At both lakes it would be expected that it will take longer to refill the lakes to conservation pool.

3. ANALYSIS CRITERIA.

3.1 Visitation. Daily visitation is measured by month at each Corps park, and stored in Visitation Estimation Reporting System (VERS). Due to hydrologic and hydraulic conditions, calendar year 2007 was considered a representative recreation year, therefore visitation numbers from 2007 were used to identify the peak visitation month. June was the peak visitation month for Bull Shoals (246,903 total visits) and July was the peak visitation month for Norfok (154,818). Appendix F-A, Table 10 contains visitation data for each month in 2007.

3.2 Hydrology & Hydraulics (H&H). The White River Minimum Flow Study examined both the beneficial and the adverse effects that could result from reallocating storage in Bull Shoals and Norfork reservoirs to maintain minimum flows for the purpose of improving tailwater trout fishing. In order to accomplish the maintenance of tailwater flow, existing reservoir storage allocations must be altered. Storage allocations studied were:

- 3.5 feet in Norfork Lake (50% from conservation pool and 50% from flood pool),
- 5 feet in Bull Shoals Lake, 100% from flood pool.

Bull Shoals and Norfork Lakes, as identified in EWDAA Section 132 (P.L. 109-103), are multipurpose projects. Each project has flood control, hydropower, water supply, recreation, and fish & wildlife purposes. Little Rock District used the existing Southwestern Division Reservoir Regulation Computer Model (commonly referred to as SUPER) reservoir routing model to simulate 64 years of experienced rainfall runoff in order to determine the impacts of the proposed minimum flows operations to other authorized purposes. The SUPER program simulates, on a daily basis, the regulation of a system of multipurpose reservoirs based on a specified plan of regulation including seasonal pools, and hydropower loadings as defined by the operation guide curve. The White River Minimum Flows SUPER model runs include seasonal tops of conservation pools of 662 and 555.75 at Bull Shoals and Norfork, respectively. The hydrologic output is presented in average daily values such as average daily lake level elevations. Project releases and river flows are given as daily average flows. Pool elevations are given as midnight elevations. For the White River Minimum Flows Study, SWL modified the SUPER model algorithm to include a function that allowed SUPER to stop minimum flows releases when EWRDA authorized storage was depleted and restart releases once storage was recharged. Consistent with other SWL uses of SUPER, the impacts to lakeside facilities related to the White River Minimum Flows operation were measured using lake elevation duration and frequency data.

SUPER model output was used to develop annual, seasonal, and monthly series lake elevation frequency and duration curves for the both the current operation and the proposed minimum flows operation. Due to the seasonal nature of recreation, the PDT determined monthly lake elevation duration as the best measure for comparing reasonable continued use at lakeside facilities. The current operation duration curve provided the baseline for existing recreational use, and the minimum flows duration curve provided a measure for future recreational use. The incremental change in recreation use was calculated by subtracting the current conditions duration from the minimum flows duration. Incremental change to the monthly elevation duration was used to measure the average number of days a lakeside facility was not available for use under the current operation and under the proposed minimum flows operation.

At Bull Shoals the April through June season had the greatest increase in flooding based on analysis of elevation-duration. Table 1 contains lake elevation duration comparisons for Bull Shoals Lake. The data in Table 1 indicates that facilities at elevation 660 potentially lose 11 days of recreation opportunity in an average June. As the elevations increase, facilities at 662 potentially lose 6 days and facilities at 670 potentially lose 1 day of recreation. The trends for lake elevation-durations for minimum flows conditions begin to converge with current operational trends at the filter elevation. Simply stated, as the pool elevations get higher the differences in pool elevations-durations begin to get smaller, meaning the effects of the minimum flows operations are becoming less noticeable when compared to current operations.

Bull Shoals Lake				
June Pool Elevation-Duration for Pool Elevations of Interest				
Elevation (feet)	Current (W01X01R)	BS-3&NF-7 (W06X03)	Difference (%)	Days Difference
654	87.9	92.3	4.3	1
657	62.6	88.9	26.3	8
659	48.8	84.7	35.9	11
660	44.1	81.8	37.7	11
662	37.6	57.9	20.3	6
670	28.3	32.0	3.8	1
675	22.0	26.7	4.8	1
690	8.5	10.3	1.8	1
695	2.5	2.5	0.0	0

Table 1 Bull Shoals Lake June Duration Comparison

Norfork Lake				
July Pool Elevation-Duration for Pool Elevations of Interest				
Elevation (feet)	Current (W01X01R)	BS-3&NF-7 (W06X03)	Difference (%)	Days Difference
553.75	49.9	66.6	16.7	5
554.5	39.5	59.3	19.8	6
555	37.8	53.6	15.7	5
556.75	33.4	36.5	3.1	1
580	0.0	0.0	0.0	0

Table 2 Norfork Lake July Duration Comparison

At Norfork the April through June season also had the greatest increase in flooding based on analysis of elevation-duration. Table 2 contains lake elevation duration comparisons for Norfork Lake. The data in Table 2 indicates that facilities at elevation 554.5 potentially lose 6 days of recreation opportunity in an average July. As the elevations increase, facilities at 555 potentially lose 5 days and facilities at 556.75 potentially lose 1 days of recreation. The trends for lake elevation-durations for minimum flows conditions begin to converge with current operational trends at the filter elevation. Simply stated, as the pool elevations get higher the differences in pool elevations-durations begin to get smaller, meaning the effects of the minimum flows operations are becoming less noticeable when compared to current operations.

The PDT, including the Arkansas Game & Fish Commission, Missouri Department of Conservation, and Missouri Department of Natural Resources identified lake level elevations to be used to measure the incremental change in elevation duration and frequency for with project and without project conditions. It was determined that elevation duration, the number of days a facility is or is not available, was the best way to measure reasonable continued use. Based on the peak loss of potential recreation days of 11 for facilities at 660 and below, 660 became the filter elevation for lakeside facility modifications and relocations at Bull Shoals. Similarly, the peak loss of 6 days for facilities at 554.5 and below, 554.5 became the filter elevation for lakeside facility modifications and relocations at Norfork.

3.3 **Seasonal Pool**. The dependence of these trout fisheries upon hydropower releases has required considerations to downstream water temperatures when scheduling releases. The largest of the fisheries is below Bull Shoals and it extends downstream about 78 miles to Sylamore Creek. The North Fork River below Norfork is also a cold water fishery. At Bull Shoals and Norfork a combined 2,000 day-second-feet (DSF) 3-day running average release is made when air temperatures at Calico Rock are forecasted at or above 85 degrees F and pool elevations are above 649 at Bull Shoals and 545 at Norfork. To provide additional storage for the 2,000 DSF releases, the Bull Shoals and Norfork Lakes operations guide curves include a seasonal conservation pool elevations 657 and 555 respectively. Therefore, the current top of conservation pool at Bull Shoals is 654 from January through April, then transitions up to elevation 657 in May. The seasonal top of conservation pool is 657 from May until October then transitions back down to elevation 654. Similarly, Nofork has a current top of conservation pool of 552 from January through April, then transitions up to elevation 555 in May. The seasonal top of conservation pool is 555 from May until October then transitions back down to elevation 552. These requirements are part of a Memorandum of Understanding (MOU) between the Corps and SWPA. The Corps regulator must monitor the temperature sensors; these sensors are located below each of the hydropower projects and near the towns of Fairview, Calico Rock, Sylamore, and Pangburn. The sensor readings guide supplementary releases or changes in timing of releases as needed to keep water temperatures from exceeding 75 degrees F. The worst case scenario is a hot, dry 3-day weekend when generation requirements are at a minimum. At such times, pools in the river may be isolated by shoals and the fish may be unable to seek refuge in cooler waters. Currently, the seasonal guide curves providesan additional 138,000 acre-feet of storage at Bull Shoals and an additional 67,000 acre-feet of storage at Norfork for SWPA. The White River Minimum Flows SUPER model runs include seasonal tops of conservation pools of 662 and 555.75 at Bull Shoals and Norfork, respectively. The effects of the lake levels associated with the seasonal guide curves are included in the computation of the lake elevation frequency and duration numbers used to measure impacts to lakeside facilities.

3.4 Hydroelectric Power. The demand for electric power varies from hour to hour, from day to day, and from season to season in response to the needs and living patterns of the power users. The daily demand for power is at a low point in the early morning hours, when most of the population is at rest. The daily demand increases markedly at 6 am, as people get up and begin going to work, and reaches a peak in the late morning hours. The daily demand remains high through the daytime hours, often reaching another peak about suppertime, and then decreases in the evening hours, as activity drops off. The daily demand, which is at a high level during the five weekdays, is somewhat lower on Saturdays and at their lowest levels on Sundays and holidays, reflecting the impact of industrial and commercial activity on power demand.

Hydropower produced at Corps dams in this region is marketed by the region's power marketing agency, Southwestern Power Administration, SWPA. The degree to which SWPA exercises control on the quantity and timing of hydropower releases depends on the elevation of the water stored and the stages at the downstream regulating control points. When the lake elevations are in the flood pool, the Corps of Engineers has absolute control on the quantity and timing of its releases. The one exception is the daily release volume needed for the generation of firm power. Normally, hydropower production is constrained during downstream flood conditions. As it is, hydropower demands are met minimally through the provision of firm power, also known as "firm energy." Table 7-09, page 7-21 of the White River Master Manual, lists minimum daily hydropower release volumes. During flood control operations, hydropower will be reduced to a minimum provided by firm power. When restricted to firm power, the firm energy remaining for that day is computed by prorating the number of hours left in the day. If flooding conditions warrant greater restrictions, the Corps will declare a flood emergency and notify SWPA in accordance with the guidelines set forth in the draft Operating Arrangement between the Corps and SWPA. When in the flood pool, the primary objective of generation is to provide releases for recovery of flood storage space and operation requirements are forwarded to SWPA each weekday. The resultant energy provides an additional benefit to the flood control operation. Once in the conservation pool SWPA determines the amount and timing of releases based on power needs unless there is an overriding flood control or project need. Routine turbine releases are established at rates which will not exceed downstream regulating criteria. The effects of the lake levels associated with hydropower operations are captured by SUPER model in the computation of the lake elevation frequency and duration numbers used to measure impacts to lakeside facilities.

3.5 Reasonable Continued Use. In the context of implementing WRMF, all Corps, private and public lake facilities, including but not limited to structures, roads, and utilities within the lake level elevations of 660 and below at Bull Shoals and 554.5 and below at Norfork qualified for modification or relocation if they were significantly impacted. Under utilized, non-maintained, facilities with the availability of substantively equal alternative facilities, or abandoned facilities were not eligible for modification or relocation. The Corps (the Little Rock District) and stakeholders decided on a case by case basis if modification or relocation was appropriate based on significance of the impact. Significance was defined using the VERS 2007 visitation data, potential impacts to O&M costs, incremental loss of visitation days, regional loss of recreation opportunity, and safety at the lakeside facilities. In Appendix F-A, Table 3 for Bull Shoals and Table 4 for Norfork, contain itemized list of modifications and relocations identified during the lakeside facility evaluation process.

The visual inventory of impacted facilities, evaluation criteria, reasonable use definition and its site by site application were coordinated and approved by State, County, and Corps stakeholders. Appendix F-B contains plates with photos of lake facilities considered to be impacted by the proposed Minimum Flows operation, Appendix F-C contains the M2 cost estimate for modifying or relocating impacted facilities, and Appendix F-D contains letter from the Arkansas Game & Fish Commission notifying the Corps of their intention of serving as the non-Federal sponsor for the White River Minimum Flows project. Coordination letters with County Judges and Commissionaires are also included in Appendix F-D. Stakeholders and State agencies lakeside facility coordination meetings were held in Mtn Home, AR on 12 July 2007, Bull Shoals, AR on 9 January 2008, and Forsythe, MO on 29 January 2008 & 11 July 2008. The meetings were used to develop lakeside facility inventory, evaluation criteria, and to disseminate status and findings.

At Bull Shoals, public facilities at 12 recreation sites will be relocated or modified, including: 11 boat ramps, 6 swim beaches, 1 light pole, 9 parking lots, 3 Corps roads, and 2 County roads. Evaluations determined that all private facilities at the lake, such as marinas, concessions, docks could accommodate the pool raise and operational changes and maintain reasonable continued use without any modifications or relocations. The cost to relocate roads and park facilities is estimated to be approximately $12,494,000, and is a non-Federal cost. For detailed information, reference Tables 3 of Appendix F, Lakeside Facilities.

At Norfork Lake, public facilities at 9 recreation sites will be relocated or modified, including: 3 boat ramps, 7 swim beaches, and 2 parking lots. Evaluations determined that all private facilities at the lake, such as marinas, concessions, docks could accommodate the pool raise and operational changes and maintain reasonable continued use without any modifications or relocations. The construction cost to relocate park facilities is estimated to be approximately $5,609,000, and is a non-Federal cost. For detailed information, reference Tables 4 of Appendix F, Lakeside Facilities.

3.5.1 Proposed Mega Ramps. The lakeside facility evaluation process required stakeholders and the Corps to evaluate impacts to recreation from a regional perspective. Also considered was the non-Federal Sponsors desire for phased construction implementation. Following the compilation of the existing lakeside facility inventory, the PDT identified two sites that could meet the requirements of providing reasonable continued use on a regional basis. The two sites, Theodosia, MO and Point Return, AR could have multi-lane boat ramps, and corresponding parking capacity to provide compensation for lost recreation opportunity at the adversely impacted existing lakeside facilities. The proposed mega ramps could be constructed instead of modifying the existing lakeside facilities at Corps parks that are regionally close, see Table 9 in Appendix F-A for lakeside facilities tied to mega ramps. During construction of the mega ramps the Corps facilities would be able to remain open, allowing for storage to be captured prior to completion of the mega ramps. Part of the design during construction phase, will include negotiations between the non-Federal sponsor, the Corps of Engineers, and local stakeholders to determine if the mega ramp proposal is a viable alternative. If the mega ramp option is not agreed to by participating entities, the Corps lakeside facilities will be modified. A signed Project Participation Agreement (PPA) will document the final lakeside facilities to be modified.

3.5.2 Ozark Beach Hydroelectric Project. Ozark Beach hydroelectric project (Empire Electric) has no plant or facility downstream of Dam Site. Empire Electric requested modification to an existing, un-maintained road that they use to visually inspect the downstream face of their dam. The road in question was originally constructed by the Corps of Engineers, but was abandoned and not maintained since 1985. Empire Electric has no Right of Entry or Permit with regards to the road. Therefore, the subject road did not qualify for modification with regards to reasonable continued use.

White River Basin, Arkansas, Minimum Flows
Project Report
Lakeside Facility Tables

APPENDIX F-A

TABLE 3. BULL SHOALS LAKE FACILITY MODIFICATIONS & RELOCATIONS

PARK	FEATURE	LENGTH	AREA	CONDITION	COMMENT	FIGURE
BEAVER CREEK	BOAT RAMP	30 FT	1308 sq ft	MODIFICATION	CORPS OWNED	**F-1**
BUCK CREEK	SWIM BEACH		17482 sq ft	RELOCATION	CORPS OWNED	**F-2**
BUCK CREEK	PARKING		1501 sq ft	MODIFICATION	CORPS OWNED	**F-2**
BUCK CREEK	PARKING LOT		5221 sq ft	MODIFICATION	CORPS OWNED	**F-2**
BUCK CREEK	BOAT RAMP	20 FT	589 sq ft	MODIFICATION	CORPS OWNED	**F-2**
DAM SITE	BOAT RAMP	30 FT	1285 sq ft	MODIFICATION	CORPS OWNED	**F-4**
HIGHWAY 125	PARKING		10830 sq ft	MODIFICATION	CORPS OWNED	**F-5**
HIGHWAY 125	SWIM BEACH		25749 sq ft	RELOCATION	CORPS OWNED	**F-5**
HIGHWAY 125	BOAT RAMP		1044 sq ft	MODIFICATION	CORPS OWNED	**F-5**
HIGHWAY K	ROAD		1053 sq ft	MODIFICATION	CORPS OWNED	**F-6**
LAKEVIEW	ROAD	140 FT	2248 sq ft	MODIFICATION	CORPS OWNED	**F-7**
LAKEVIEW	ROAD	275 FT	9662 sq ft	MODIFICATION	CORPS OWNED	**F-7**
LAKEVIEW	SWIM BEACH		27891 sq ft	MODIFICATION	CORPS OWNED	**F-7**
LAKEVIEW	BOAT RAMP	30 FT	914 sq ft	MODIFICATION	CORPS OWNED	**F-7**
LEAD HILL	BOAT RAMP		4888 sq ft	MODIFICATION	CORPS OWNED	**F-8**
LEAD HILL	HANDICAP ACCESS		453 sq ft	MODIFICATION	CORPS OWNED	**F-8**
LEAD HILL	SWIM BEACH		53642 sq ft	RELOCATION	CORPS OWNED	**F-8**
LEAD HILL	PARKING LOT		12484 sq ft	MODIFICATION	CORPS OWNED	**F-8**
LEAD HILL	BOAT RAMP	40 FT	1178 sq ft	MODIFICATION	CORPS OWNED	**F-8**
MARION CO ROAD 143	ROAD	192.928 ft	4101 sq ft	MODIFICATION	MARION CO.	**F-16**
OAKLAND	BOAT RAMP	40 FT	1536 sq ft	MODIFICATION	CORPS OWNED	**F-9**
OAKLAND	PARKING LOT		2595 sq ft	MODIFICATION	CORPS OWNED	**F-9**
OAKLAND	PARKING		7299 sq ft	MODIFICATION	CORPS OWNED	**F-9**
POINT RETURN	PARKING LOT		13628 sq ft	MODIFICATION	CORPS OWNED	**F-10**
POINT RETURN	SWIM BEACH		18979 sq ft	RELOCATION	CORPS OWNED	**F-10**
POINT RETURN	BOAT RAMP	15 FT	254 sq ft	MODIFICATION	CORPS OWNED	**F-10**
POINT RETURN	PARKING /LAUNCH		38569 sq ft	RELOCATION	PROPOSED MEGA RAMP	**F-10**
POINT RETURN	WATERBORNE TOILET		1018 sq ft	RELOCATION	PROPOSED MEGA RAMP	**F-10**
POINT RETURN	PARKING		118304 sq ft	RELOCATION	PROPOSED MEGA RAMP	**F-10**

TABLE 3 BULL SHOALS LAKE FACILITY MODIFICATIONS & RELOCATIONS (Continued)						
PARK	FEATURE	LENGTH	AREA	CONDITION	COMMENT	FIGURE
POINT RETURN	BOAT RAMP	300 FT	38943 sq ft	RELOCATION	PROPOSED MEGA RAMP	F-10
POINT RETURN	STAGING AREA		5911 sq ft	RELOCATION	PROPOSED MEGA RAMP	F-10
POINT RETURN	PAVILION		2338 sq ft	RELOCATION	PROPOSED MEGA RAMP	F-10
PONTIAC	BOAT RAMP	50 FT	2024 sq ft	MODIFICATION	CORPS OWNED	F-11
PONTIAC	PARKING		5070 sq ft	MODIFICATION	CORPS OWNED	F-11
RIVER RUN	LIGHT POLE		NA	RELOCATION	LOCATE ABOVE 653	F-12
SLOUGH HOLLOW ROAD	ROAD	721.701 ft	17775 sq ft	MODIFICATION	TANEY CO.	F-17
SLOUGH HOLLOW ROAD	ROAD	1024.028 ft	25030 sq ft	MODIFICATION	TANEY CO.	F-17
THEODOSIA	PARKING LOT		9301 sq ft	MODIFICATION	CORPS OWNED	F-14
THEODOSIA	SWIM BEACH		14284 sq ft	RELOCATION	CORPS OWNED	F-14
THEODOSIA	BOAT RAMP		13700 sq ft	MODIFICATION	PROPOSED MEGA RAMP	F-14
THEODOSIA	ROAD		8664 sq ft	MODIFICATION	PROPOSED MEGA RAMP	F-14
THEODOSIA	PARKING LOT		32639 sq ft	MODIFICATION	PROPOSED MEGA RAMP	F-14
TUCKER HOLLOW	BOAT RAMP	50 FT	1677 sq ft	MODIFICATION	CORPS OWNED	F-15
TUCKER HOLLOW	ROAD		3063 sq ft	MODIFICATION	CORPS OWNED	F-15

TABLE 4. NORFORK LAKE MODIFICATIONS & RELOCATIONS

PARK	FEATURE	LENGTH	AREA	CONDITION	COMMENT	FIGURE
BIDWELL POINT	SWIM BEACH		32536 sq ft	RELOCATION	CORPS OWNED	**F-18**
CRANFIELD	SWIM BEACH		110327 sq ft	RELOCATION	CORPS OWNED	**F-19**
GAMALIEL	SWIM BEACH		22669 sq ft	RELOCATION	CORPS OWNED	**F-20**
GEORGES COVE	BOAT RAMP		1752 sq ft	MODIFICATION	CORPS OWNED	**F-21**
JORDAN	SWIM BEACH		34226 sq ft	RELOCATION	CORPS OWNED	**F-22**
PANTHER BAY	SWIM BEACH		48248 sq ft	RELOCATION	CORPS OWNED	**F-23**
PANTHER BAY	PARKING		3040 sq ft	MODIFICATION	CORPS OWNED	**F-23**
QUARRY	SWIM BEACH		37890 sq ft	RELOCATION	CORPS OWNED	**F-24**
ROBINSON POINT	SWIM BEACH		28736 sq ft	RELOCATION	CORPS OWNED	**F-25**
ROBINSON POINT	BOAT RAMP		1042 sq ft	MODIFICATION	CORPS OWNED	**F-25**
UDALL	PARKING		50164 sq ft	MODIFICATION	CORPS OWNED	**F-26**
UDALL	BOAT RAMP		25831 sq ft	MODIFICATION	CORPS OWNED	**F-26**

Table 5. Bull Shoals Roads				
Frisco Hills	County Road 141	Diamond Blvd	Lakeview	Rivercliff
452 Mo	County Road 142	Doc Fowler	Lead Hill City	Roberts
Arena	County Road 15	Dock	Lead Hill Park	Shadbush
Ash	County Road 163	Dove	Lead Hill Road	Shoals Lake
B Rodgers Circle	County Road 164-140	Downing	Lead Hill School	Shore Line Drive
Barker Hole	County Road 213	Dunlap	Leawood	Sister Creek
Beaver Creek Park	County Road 215	Elbow	Locust Road	Spring Creek Park
Ben Riddle	County Road 228	Evergreen	Lone Tree	State Park
Benton	County Road 229	Fawn Ridge	Lower Place	Strawberry
Blackwell Ferry	County Road 265	Ferncliff	Lowery	Theodosia Park
Blou Clower	County Road 271	Fisherman Friend	Main Street	Theosia Park
Boatdock	County Road 503	Fisherman's Nose	Mallard Drive	Thunder
Brass Lantern	County Road 505	Frost Point	Marina	Trout Dock
Bright Elbow	County Road 651	Goat Bluff	Marina Road	Troute Pound
Broadway	County Road 669	Grady	Marion County 8119	Tucker Hollow Park
Buck Creek Park	County Road 803	Hammerschmidt	McBride	Tulley's
Buckmaster Estates	County Road 807	Hammerschmidt Road	McDonald	Turner Road
Bull Shoals Dam	County Road 813	Highland Road	Nave Hill	US Hwy 160
Bull Shoals State Park	County Road 814	Highway 125	Norman	Warren
C S Woods	County Road 827	Highway 125 Park	Oakland Cutoff	West
Camp Galilee Church Camp	County Road 828	Highway 14	Oakland Park	Westview
Casey	County Road 829	Highway 160	Old Hart	Westwood
Cedar	County Road 833	Highway 178	Old Highway 14	Wilderness Point
Cedar Crest	County Road 834	Highway 76	Old Lowery	Winkle Creek
Cedar Crest Road	County Road 838	Highway K Park	Ozark Isle	Wolf Creek
Cedar Road	County Road 859	Highway OO	Pace's Ferry	Woodard Park
Central	County Road 873	Highway Y	Park	Yocum Bend
Coleman Road	County Road 883	Hollyhock	Parksley	Zaner
Copper	County Road 885	Homar	Penix	
Copperhead	County Road 888	Horseshoe Bend	Perry Road	
Cord	County Road 891	Howard Creek	Persimmon Point Road	
County Road 104	County Road 892	Jimmy Creek	Pontiac Park	
County Road 105	Coy	Johnson	Possum Trot	
County Road 106	Cribbs	Katdydid	Promise Land	
County Road 118	Cross Timber	Kissee	Qry Mountain	
County Road 120	Dam Site Park	Kissee Mills Park	Resort	
County Road 121	Davidson	Kissee Mills Park Lake	Risley Road	
County Road 123	Deshields Creek Road	Lake Lane	River Run Park	
County Road 126	Devils Teatable	Lakeland		

Table 5. Norfork Roads				
101 Park	County Road 38	County Road 583	County Roadanfield Park	Robinson Point
3 Oak	County Road 386	County Road 763	Cranfield Park	Robinson Point Park
Autumn Leaf	County Road 387	County Road 766	Doe Run	Rocky Ridge
Belle Cove	County Road 396	County Road 769	Driftwood	Seward Point
Bidwell Point Park	County Road 396	County Road 803	Elizabeth	Smith Drive
Big County Roadeek	County Road 416	County Road 805	Fish and Fiddle	State Highway 177
Black Forest	County Road 43	County Road 806	Forrest Hills	State Highway 62
Blue Wing	County Road 44	County Road 807	Fout	State Highway O
Buzzard Roost	County Road 442	County Road 810	Gamaliel Park	State Hwy 101
County Road 1264	County Road 46	County Road 814	Greentree	Sycamore Springs
County Road 1281	County Road 47	County Road 815	Henderson Park	Tanglewood
County Road 136	County Road 470	County Road 820	Highway 201	Teal Point
County Road 138	County Road 477	County Road 821	Highway 62	The Bluff
County Road 139	County Road 48	County Road 822	Howard Cove	Tracy Ferry Park
County Road 140	County Road 480	County Road 830	Jordan Landing	Udall Park
County Road 147	County Road 483	County Road 832	Jordan Park	US Highway 160
County Road 149	County Road 483	County Road 833	Kingswood	Water Oak
County Road 153	County Road 484	County Road 835	Lake	Water Plant
County Road 156	County Road 486	County Road 840	Mallard Point	Wilderness Point
County Road 173	County Road 522	County Road 852	Misty	Wilderness Point Park
County Road 175	County Road 542	County Road 857	Norfork	Woods Point
County Road 24	County Road 551	County Road 857	Panther Bay Park	Woods Point Park
County Road 2480	County Road 555	County Road 91	Pigeon County Roadeek Park	
County Road 30	County Road 556	County Road 93	Quarry Park	
County Road 318	County Road 569	County Road 94	Red Bank	
County Road 33	County Road 578	County Road 989	River ACounty Roades	

TABLE 6. CORPS PARKS TABLES

NORFORK PARKS		
Park Name	**Owner**	**Notes**
Bidwell Point	Corps of Engineers	
Boggy Creek	Corps of Engineers	Leased to Fulton Co., AR
Buzzard Roost	Corps of Engineers	Leased to Buzzard Roost Marina
Cranfield	Corps of Engineers	
Curley Point	Corps of Engineers	Access Only
Gamaliel	Corps of Engineers	
George’s Cove	Corps of Engineers	
Hand	Corps of Engineers	Access Only
Henderson	Corps of Engineers	
Howard Cove	Corps of Engineers	Leased to 101 Boat Dock Marina
Jordan	Corps of Engineers	
Panther Bay	Corps of Engineers	
Pigeon Creek	Corps of Engineers	
Quarry	Corps of Engineers	
Red Bank	Corps of Engineers	Access Only
Robinson Point	Corps of Engineers	
Talbert	Corps of Engineers	Access Only
Tecumseh	Corps of Engineers	
Tracy	Corps of Engineers	Leased to Tracy Ferry Marina
Udall	Corps of Engineers	
Woods Point	Corps of Engineers	

TABLE 6. CORPS PARKS TABLES (Continued)

BULL SHOALS PARKS		
Bull Shoals	**Owner**	**Notes**
Beaver Creek	Corps of Engineers	
Buck Creek	Corps of Engineers	
Bull Shoals	Corps of Engineers	Leased to Bull Shoals Lake Dock Marina
Bull Shoals State Park	Corps of Engineers	Leased to State of Arkansas
Dam Site	Corps of Engineers	
Highway 125	Corps of Engineers	
Highway K	Corps of Engineers	Access Only
Kissee Mills	Corps of Engineers	Operated by Taney County, MO
Lakeview	Corps of Engineers	
Lead Hill	Corps of Engineers	
Lowery	Corps of Engineers	Access Only
Oakland	Corps of Engineers	
Ozark Isle	Corps of Engineers	Leased to Oakland Marina
Point Return	Corps of Engineers	Leased to City of Bull Shoals
Pontiac	Corps of Engineers	
River Run	Corps of Engineers	
Shadow Rock	Corps of Engineers	Leased to City of Forsyth, MO
Spring Creek	Corps of Engineers	Access Only
Theodosia	Corps of Engineers	
Tucker Hollow	Corps of Engineers	
Woodard	Corps of Engineers	Access Only

TABLE 7. BULL SHOALS RESORTS									
NAME	POC	ADDRESS	PHONE NO	Lease #	Lease Exp	Overnight	Boat Slips	Parking	Annual Rent
BS/MIDWAY/LAKEVIEW									
Bull Shoal Lake Resort	Stan Polit	327 Westview Rd; Midway AR	870-431-5377	04-3724	2013	19	18+ Swim	C 254	$645
Cedar Oaks Resorts	Robert Laurence	1429 Nubbin Ridge Road; Lakeview AR	870-431-5351	04-3725	2013	8	3+ Swim	C 205	$395
Evergreen Resort	William Murray	13 Evergreen Drive; Bull Shoals	870-445-4440	04-3741	2013	6	2	B132	$245
Holiday Shores Resort	Ray Coahran	943 Howard Creek Road; Midway	870-431-5370	04-3728	2013	13	10	C241	$445
Howard Creek Resort	Paul Swanson	887 Howard Creek Road; Midway	870-431-5371	04-3785	2013	10	8	C241	$395
Red Arrow Resort	Jeffery Johnson	16 Golden Acres Road Midway	870-431-5375	04-3729	2013	10	8	C241	$395
Ridgecrest Resort	Robert Martin	971 Howard Creek Road; Midway	870-431-5376	04-3727	2013	8	12	C241	$495
Rocky Hollow Lodge	William Richardson	1306 Lake Street; box 212 Bull Shoals AR	870-445-4400	04-3742	2013	6	2	E405	$245
Waterfront Resort (residential)	James Smakal	317 Waterfront Cir; Lakeview AR	870-431-5356	04-3726	2013	8	12+ Swim	C245	$495
PEEL/PROTEM/LEADHILL									
Blue Water's Resort	Kenneth Alexander	4962 McBride Road; Protem, MO	417-785-4375	04-3748	2013	7	8	N 1301	$495
Captain Jack's	Mrs Char Cameron	PO Box 292; Lead Hill AR	870-436-5939	04-3745	2013	5	4	N 1342	$295
Coon Creek Resort	Patricia Dell	Box 36; Peel AR	870-436-5405	04-3744	2013	12	12	I 840	$495
Lakewoods Resort	Kevin E Schubert	10425 S State Hwy 125	417-785-4325	04-3753	2013	23	20 + Swim	M 1201	$595
L-Bo Bend	Stephan D Behnen	3690 Elbow Road; Protem AR	417-785-4350	04-3747	2013	7	8	V 2110	$395
Pinder Resort (residential)	Ronald Pelka	520 Pender Road, Protem	417-785-4491	04-3749	2013	11	10	M 1232	$445
Robert's Resort	Ron Mallory	PO Box 1076; Diamond City AR	870-422-7515	04-3746	2013	7	12	O 1415	$470
Trimble Creek Lodge	Michael Richardson	1605 MC 2066; Peel AR	870-436-3222	05-1836	2013	3	6		$345
CEDAR CREEK									
Brass Lantern	James Petersen	5133 Brass Lantern Rd; Cedar Creek MO	417-794-3761	04-3752	2013	6	5 + Swim	W 2225	$320
THEODOSIA									
Noland Point Resort	Ronald M. Lease	HC 4 Boz 4408; Theodosia MO	417-273-4323	04-3751	2013	6	12 + swim Dock	S 1822	$495
Salat's Resort (residential)	Craig Bucheit	586 Schrader Farm Dr Saint Peters MO	417-273-4433	04-3750	2013	4	3	S 1844	$270
Big Creek Resort	Tim Matthews	PO Box 231; Theodosia MO	417-679-3321	04-3754	2013	5	4	S 1822	$295
Cedar Creek Cove Resort	Ronald Misek	HC3 Box 3770; Theodosia MO	417-273-4927	04-3756	2013	7	7 + swim	L 1124	$370
Turkey Creek Resort	Richard/ Robert Edwards	HC 3 Box 3180; Theodosia MO	417-273-4362	04-3757	2013	25	25 +32X40 fishing	U2000	$820

TABLE 7. BULL SHOALS RESORTS (Continued)									
NAME	POC	ADDRESS	PHONE NO	Lease #	Lease Exp	Overnight	Boat Slips	Parking	Annual Rent
ISABELLA									
Biltmore Resort	Tom Hilger	HCR 1 Box 1245; Isabella MO	417-273-4499	04-3760	2013	8	12	R1771	$495
Lone Pine Resort	Albert Flynn	HC 1 Box 1127; Isabella MO	417-273- 4232	04-3755	2013	4	4	R 1748	$295
Ridgewood Resort	Virginia Matyska	Rt 1 Box 1125; Isabella MO	417-273-4300	04-3758	2013	6	4	R 1748	$295
Spring Creek	Rocky Daffron	HCR 1 1235; Isabella MO	417-273-4333	04-3763	2013	10	15	R 1743	$570
Thunder Bay Resort	Jerry Gallagher	HCR 1 Box 1300; Isabella MO	417-273-4222	04-3759	2013	6	8	R1743	$395
Twin Forks	Bruno Ochner	HCR 1 Box 1275; Isabella MO	417-273-4344	04-3762	2013	12	9	R1774	$420
Wing and Fin Resort	Bruno Jeziorski	HC 1 Box 1290; Isabella MO	417-273-4242	04-3761	2013	6	9	R1775	$420
PROMISE LAND									
Deer Run Cabins	David Pearson	273 CR 106 Mountain Home AR	870-431-4252	04-3780	2013	5	5	D315	$320
Batty's Resort	Richard J Keller	790 CR 505 Mountain Home AR	870-431-5561	04-3766	2013	13	16	B132	$595
Chit Chat Chaw	Charles Herlien	9476 Promise Land Road; MH AR	870-431-5584	04-3775	2013	8	9	D315	$420
Edgewater Resort	Withold Dembski	10108 Promise Land Rdl MH AR	870-431-5222	04-3778	2013	14	18 + Swim	D318	$645
North Shore Resort	Fabian Janecek	1462 CR 19; Mountain Home AR	870-431-5564	04-3765	2013	6	6	C 210	$345
Oak Ridge Resort & Spa	Michael Engenfelder	275 CR 106	870-431-5575	04-3781	2013	9	13	D 337	$470
Promise Land Resort	Larry Smith	323 CR 107	870-431-5576	05-1511	2013	10	2	D 315	$245
Razorback residential	Robert Griffith	9496 Promise Land Roadl MH AR	870-431-8585	04-3776	2013	3	4	D315	$295
Sister Creek Resort	Carl Lauer	9833 Promise Land Road MH	870-431-5587	04-3779	2013	14	10 + Swim	D316	$445
Wood's Landing	James R Wood	10470 Promise Land Rd; MH; AR	870-431-8456	04-3764	2013	5	6+ Swim	D315	$345
OAKLAND									
Black Oak Resort	Mike Scrima	PO Box 100; Oakland AR	870-431-8363	04-3770	2013	9	14 + swim	B132	$545
Fin N' Feather	Glen F Clark	765 CR 126; Oakland AR	870-431-5621	04-3774	2013	8	8 + Swim	G629	$395
Fish un Time	Jeanette Eidson	1009 CR 123; Oakland AR	870-431-5745	04-3777	2013	4	3+ swim	G 631	$270
Hidden Bay Resort	Daniel Twist	5091 Highway N; Robertsville MO	314-799-4974	04-3768	2013	6	3	D 339	$270
Persimmon Point Resort	Vang Bach	8594 Oakland Rd, Oakland AR	870-431-8877	04-3769	2013	7 w 5 RV sites	12 + 2 swim	B132	$495
Southern Comfort	Ron Reineri	6401 Grayhawk Drive; Parcific MO	314-575-0162	04-3772	2013	5	3+ swim	G629	$270
Tall Timbers	Linda Borne	1239 CR 124; Oakland AR	870-431-5622	04-3771	2013	8	9	G629	$420

TABLE 7. NORFORK RESORTS									
NAME	POC	ADDRESS	PHONE NO	Lease No.	Expires	Overnight	Boat Slips	Parking	Annual Rent
BETWEEN 62 & HWY 5									
Blackburn's Resort	Steve Street	734 CR 989: MH	870-492-5115	03-1476	2013	14	14	NF 283-1	$545
Buzzard Roost Inn	Dennis Dymek	4271 Buzzard Roost Road	870-492-5187	03-1493	2013	10	6+Swim	NF 170	$345
Blue Heaven	Diane Edwards	4398 Buzzard Roost	870-492-5123	03-1492	2013	7	4+ Swim	NF 170	$295
Blue Lady of the Ozark	Brian Roelands	149 Blue Lady Dr	870-467-5115	03-1481	2013	9	15 + Swim	NF 263	$570
Mockingbird Bay	Frank B. Zortman III	217 Sycamore Springs Circle	870-491-5151	03-1478	2013	7	9	A	$420
Crystal Cove Resort	Robert Niemeyer	1453 CR 832 Henderson AR	870-488-5373	03-1490	2013	10	12 + Swim	NF 232	$495
Driftwood Resort	Bruce Grisham	2201 October Lane; West Plans, MO	417-256-7949	03-1488	2013	6	10	NF 334	$445
Echo Point Resort	Andrew Stewart	1296 CR 806; Gamaliel, AR 72537	870-467-5244	03-1491	2013	8	4	NF 279-1	$295
Fish & Fiddle	Roger Boskus	880 Fish & Fiddle Road; MH AR	870-491-5161	03-1494	2013	15	16	NF 140-1	$595
HWY 62 E of Lake									
Hand Cove Resort	Greg Weinmann	8885 Hand Cove Road;Elizabeth AR	870-488-5367	03-1484	2013	6 + 5RV	11	NF 120	$470
Holiday Hills	Fank Snellgrove	Box 1346; Jonesboro AR 72403	870-488-5303	03-1483	2013	16	22+swim*fish	NF 102-C	$745
Whispering Deer	Ralph Lowe	219 CR 148; Elizabeth AR 72531	870-488-5187	03-1489	2013	8	11+fish	NF 190 NF 184A	$470
Keller's Kove	Robert Elster	141 CR 851 Elizabeth AR	870-488-5360	03-1486		7	8	NF 122 A	$395
N Hwy 62 W of Lake									
Hummingbird Hideaway	Louis Gabric	1034 CR 989 MH	870-492-5113	03-1485	2013	17	16	NF 283-1	$595
Rocking Chair	Robert Domagalski	278 CR 783; MH AR	870-492-5157	03-1482	2013	15	20+Swim	NF 203	$695
Crooked Hook	Chuck Menschik	3483 Rocky Ridge Rd; MH	870-491-5665	03-1479	2013	7	6+Swim	NF 170	$345
Sunrise Point	Kevin Wintle	88 Sunrise Point Lane; MH	870-491-5188	03-1495	2013	12	12	NF 170/ A	$495
Take It Easy	John Van Eps	168 CR 12; Gamaiel AR	870-467-5284	03-1480	2013	8	10	NF 279A NF 279A-2	$445
Teal Point	Karl Nigemann	715 Teal Point Rd; MH AR	870-492-5145	03-1477	2013	9 + 2RV	26+2 swim	NF 276	$895
Three Oaks	Michael Roe	1034 County Rd 806; Gamaiel AR	870-656-6760	03-1487	2013	13	12	NF 279-1	$495
Treasure Cove	Paul Pierski	902 CR 470; Clarkridge, AR 72623	870-425-4325	03-1496	2013	8	9+swim	B	$420

TABLE 8. BULL SHOALS LAKE MARINAS		
BS Marinas	**Owner**	**Ph. No.**
Beaver Creek	Art Hale	417-546-5121
Buck Creek	Farris & Teresa Brotherton	870-436-5390
Bull Shoals	John Eastwold	870-445-4424
Hwy 125	Farris & Teresa Brotherton	870-436-5390
Hwy K	Scott Hansen	417-334-2880
Lakeview	Kevin & Terri Lorenz	870-431-5291
Lead Hill	Steve Bernard	870-422-7444
Oakland	Doug and Heidi Potts	870-431-5381
Pontiac	Tim Morgan	417-679-3676
Theodosia	Bill Cook	417-273-4444
Tucker Hollow	Steve Bernard	870-436-5564

TABLE 8. NORFORK LAKE MARINAS		
NF Marinas	**Owner**	**Ph. No.**
Buzzard Roost	Chuck & Paula Thitoff	870-492-5346
Cranfield	Bob & Kathy Grace	870-492-5191
Fout	Glenn Cox	870-467-5341
Jordan	Dan & Denise Weber	870-499-7348
Lake Norfork	Doug Cooper	870-488-5229
101	Bob & Kathy Griffin	870-467-5252
Panther Bay	Gerald & Ann Kenyeri	870-492-5151
Quarry	Richard Hanson	870-499-5388
Tracy Ferry	Seth Bemis	870-491-5335
Udall	Teri & Dale Rhodes	417-284-3584

TABLE 9. MEGA RAMP/CORPS PARKS TABLES

NORFORK PARKS		
Park Name	**Owner**	**Notes**
Bidwell Point	Corps of Engineers	not tied to mega ramp
Boggy Creek	Corps of Engineers	Leased to Fulton Co., AR, no impacts identified
Buzzard Roost	Corps of Engineers	Leased to Buzzard Roost Marina, no impacts identified
Cranfield	Corps of Engineers	not tied to mega ramp
Curley Point	Corps of Engineers	Access Only, no impacts identified
Gamaliel	Corps of Engineers	not tied to mega ramp
George’s Cove	Corps of Engineers	not tied to mega ramp
Hand	Corps of Engineers	Access Only, no impacts identified
Henderson	Corps of Engineers	no impacts identified
Howard Cove	Corps of Engineers	Leased to 101 Boat Dock Marina, no impacts identified
Jordan	Corps of Engineers	not tied to mega ramp
Panther Bay	Corps of Engineers	not tied to mega ramp
Pigeon Creek	Corps of Engineers	no impacts identified
Quarry	Corps of Engineers	not tied to mega ramp
Red Bank	Corps of Engineers	Access Only, no impacts identified
Robinson Point	Corps of Engineers	not tied to mega ramp
Talbert	Corps of Engineers	Access Only, no impacts identified
Tecumseh	Corps of Engineers	no impacts identified
Tracy	Corps of Engineers	Leased to Tracy Ferry Marina, no impacts identified
Udall	Corps of Engineers	not tied to mega ramp
Woods Point	Corps of Engineers	no impacts identified

TABLE 9. MEGA RAMP/CORPS PARKS TABLES

BULL SHOALS PARKS		
Bull Shoals	**Owner**	**Notes**
Beaver Creek	Corps of Engineers	not tied to mega ramp
Buck Creek	Corps of Engineers	Impacts replaced by Point Return Mega Ramp
Bull Shoals	Corps of Engineers	no identified impacts
Bull Shoals State Park	Corps of Engineers	no identified impacts
Dam Site	Corps of Engineers	Impacts replaced by Point Return Mega Ramp
Highway 125	Corps of Engineers	Impacts replaced by Point Return Mega Ramp
Highway K	Corps of Engineers	not tied to mega ramp
Kissee Mills	Corps of Engineers	Operated by Taney County, MO, no impacts
Lakeview	Corps of Engineers	Impacts replaced by Point Return Mega Ramp
Lead Hill	Corps of Engineers	not tied to mega ramp
Lowery	Corps of Engineers	Access Only, no identified impacts
Oakland	Corps of Engineers	Impacts replaced by Point Return Mega Ramp
Ozark Isle	Corps of Engineers	Leased to Oakland Marina, no identified impacts
Point Return	Corps of Engineers	Impacts replaced by Point Return Mega Ramp
Pontiac	Corps of Engineers	Impacts replaced by Theodosia Mega Ramp
River Run	Corps of Engineers	not tied to mega ramp
Shadow Rock	Corps of Engineers	Leased to City of Forsyth, MO, no identified impacts
Spring Creek	Corps of Engineers	Access Only, no identified impacts
Theodosia	Corps of Engineers	Impacts replaced by Theodosia Mega Ramp
Tucker Hollow	Corps of Engineers	not tied to mega ramp
Woodard	Corps of Engineers	Access Only, no identified impacts

Table 10. Bull Shoals Visitation (2007)

Bull Shoals Visitation 2007												
	January	February	March	April	May	June	July	August	September	October	November	December
Lakeview	2874	3237	4592	3654	7849	13588	15495	11321	7839	5572	2789	2981
Oakland/Ozark Isle	674	1545	1977	3401	3387	9263	5156	2557	5520	3273	956	1332
Pontiac	1705	1625	2775	6118	4471	12350	12028	9477	5630	3412	2498	2031
Spring Creek Access	842	1102	2136	1803	3642	4040	6338	3860	2419	1813	769	1241
Theodosia	5663	8321	25888	21864	27696	53432	27387	20758	12468	11471	12427	6045
Buck Creek	635	910	1080	1840	1770	2664	7540	5110	3258	1162	664	503
Woodard Access	230	1242	754	829	1808	1493	3347	2479	2306	0	0	1637
Kissee Mills Park	1920	2825	5216	3506	5021	3720	5669	582	2822	2103	1609	1252
Bull Shoals State Park	16369	12681	21940	17708	26538	36515	36515	19067	25086	23684	13497	11112
Shadow Rock	4653	5627	11598	11329	15075	12858	8276	12523	13477	10000	4051	3400
River Run	1462	1388	1521	3078	2067	5656	4879	3541	3813	1189	1137	1958
Highway K Access	1567	1818	4767	4242	6833	1503	3590	4125	3345	5176	2006	2788
Tucker Hollow	884	1007	1365	1579	2587	5452	5053	3649	3754	2080	1364	600
Lead Hill	6912	7804	4994	11262	12554	19177	23796	13995	13536	7198	6249	8279
Highway 125	2836	1833	2028	4733	5016	13691	11021	7874	7106	5700	4046	5659
Bull Shoals Park	2958	3911	3375	8232	16253	12592	14738	10201	8609	8659	5348	2899
Point Return	1470	1302	2747	3281	7947	9427	7527	8647	5018	2512	1535	353
Dam Site	913	1061	2028	1948	4673	8867	10941	6451	5697	2243	1048	578
Beaver Creek	1661	6736	2528	3670	3933	7637	3176	6801	1168	2030	1233	842
Bull Shoals City Park	1137	1195	1953	6908	12068	12978	13074	11690	10614	15123	7889	3666
Totals	57365	67170	105262	120985	171188	246903	225546	164708	143485	114400	71115	59156

Table 10. Norfork Visitation (2007)

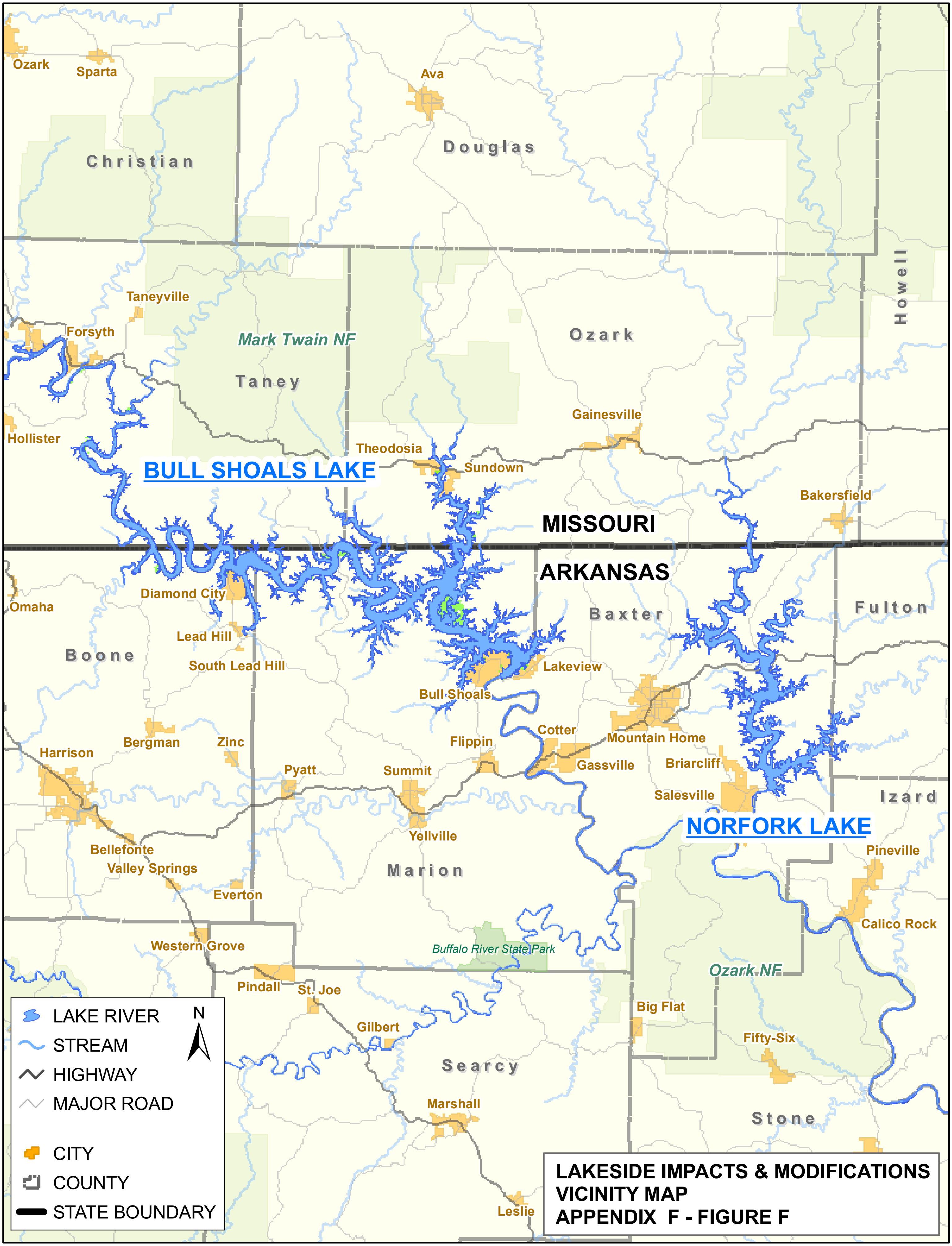
Norfork Visitation 2007	January	February	March	April	May	June	July	August	September	October	November	December
Tecumseh	1014	1152	1161	1588	2309	3960	3969	4145	1081	897	584	1097
Udall Park	865	742	1755	1032	1702	2681	3161	2594	1061	630	326	2061
Howard Cove	779	498	1023	1127	1938	6353	7394	5090	861	615	272	152
Henderson	1393	857	2458	2643	7274	10462	12053	4688	5439	12942	3777	1364
Panther Bay	868	2256	1562	1994	4768	14168	15736	10983	6179	3791	2395	953
Cranfield	2722	3434	3317	2846	5076	13861	13570	10321	9836	5594	6517	2872
Pigeon Creek Access	2409	2319	3434	5595	2964	9721	7486	6561	1860	2031	1518	3011
Tracy	1692	1460	1399	1537	2635	4572	5658	5306	726	362	149	93
Dam-Quarry	970	1087	3435	2874	1333	19578	18739	1447	5233	4681	3723	2711
Jordan	567	1063	1442	1904	2105	11770	13103	5747	5337	2789	1308	256
Robinson Point	552	674	407	1079	1310	8438	8727	6165	4220	2978	1297	707
Buzzard Roost	1957	2086	1730	1536	2036	4925	5493	4422	571	92	444	1539
Red Bank Access	328	294	1085	757	1025	4305	3563	374	236	132	290	406
Bidwell Point	0	0	0	477	1110	7724	9395	5466	2979	0	0	0
Talbert Point Access	197	196	388	365	714	3560	2966	2359	591	1287	737	981
Hand Cove Access	389	317	786	1011	1450	7290	8845	5425	1852	1225	657	977
Gamaliel	81	1142	1855	1968	2266	15747	10255	6648	5074	9440	1977	753
Wood's Point Access	217	184	544	510	663	2270	2169	1350	391	389	211	109
George's Cove Access	291	170	345	482	672	2778	2536	2899	344	464	102	54
Totals	17291	19931	28126	31325	43350	154163	154818	91990	53871	50339	26284	20096

Table 11. Numeration of boat docks at Norfork and Bull Shoals Lakes

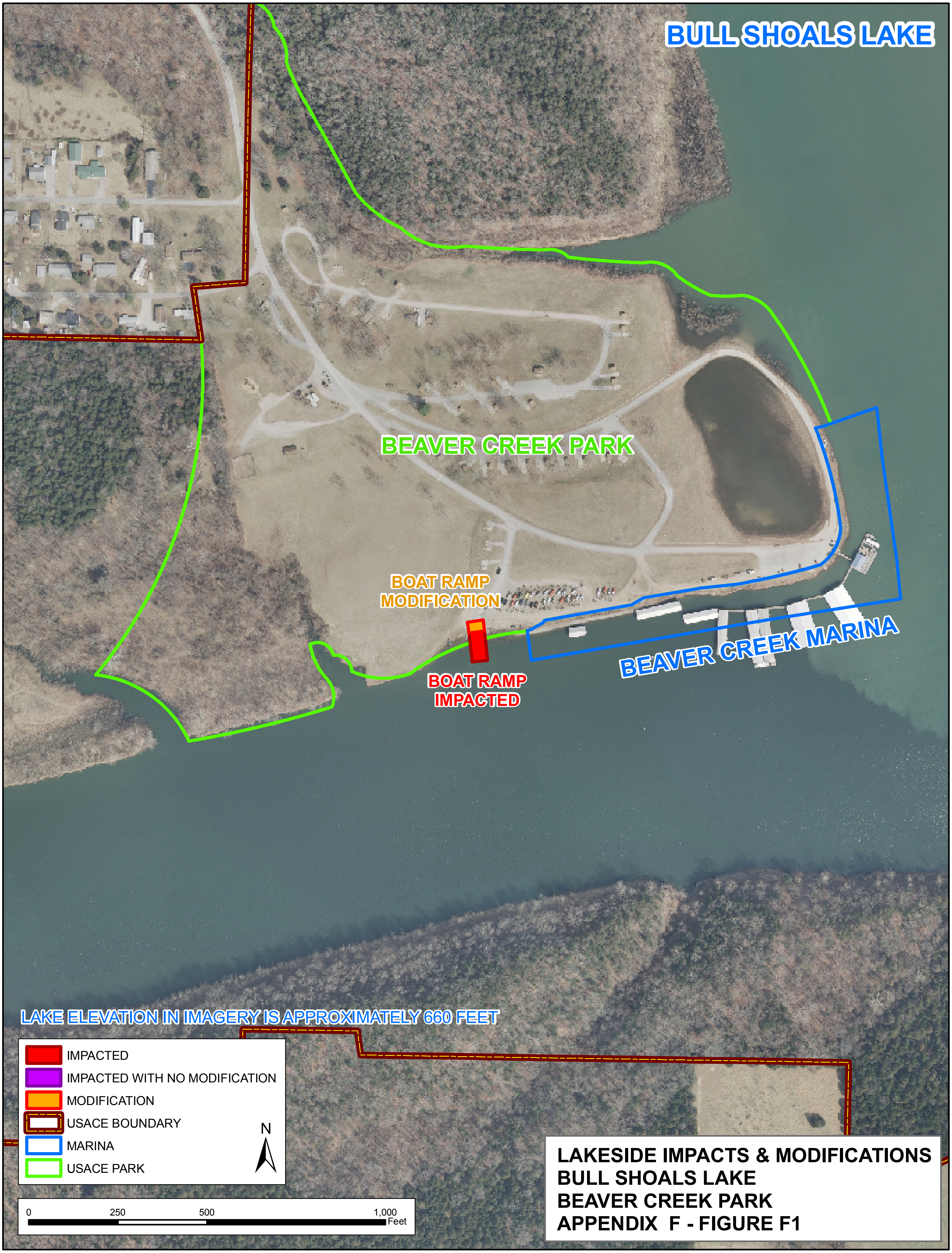
Norfork and Bull Shoals Combined Private boat dock Permits			
	Combined Permits	Bull Shoals Permits	Nofork Permits
Ozark County	88	85	3
Taney County	103	103	
Boone County	62	62	
Marion County	381	381	
Baxter County	357	56	301
Fulton County	10		10
Totals	1001	687	314

White River Basin, Arkansas, Minimum Flows
Project Report
Site Plates

APPENDIX
F-B

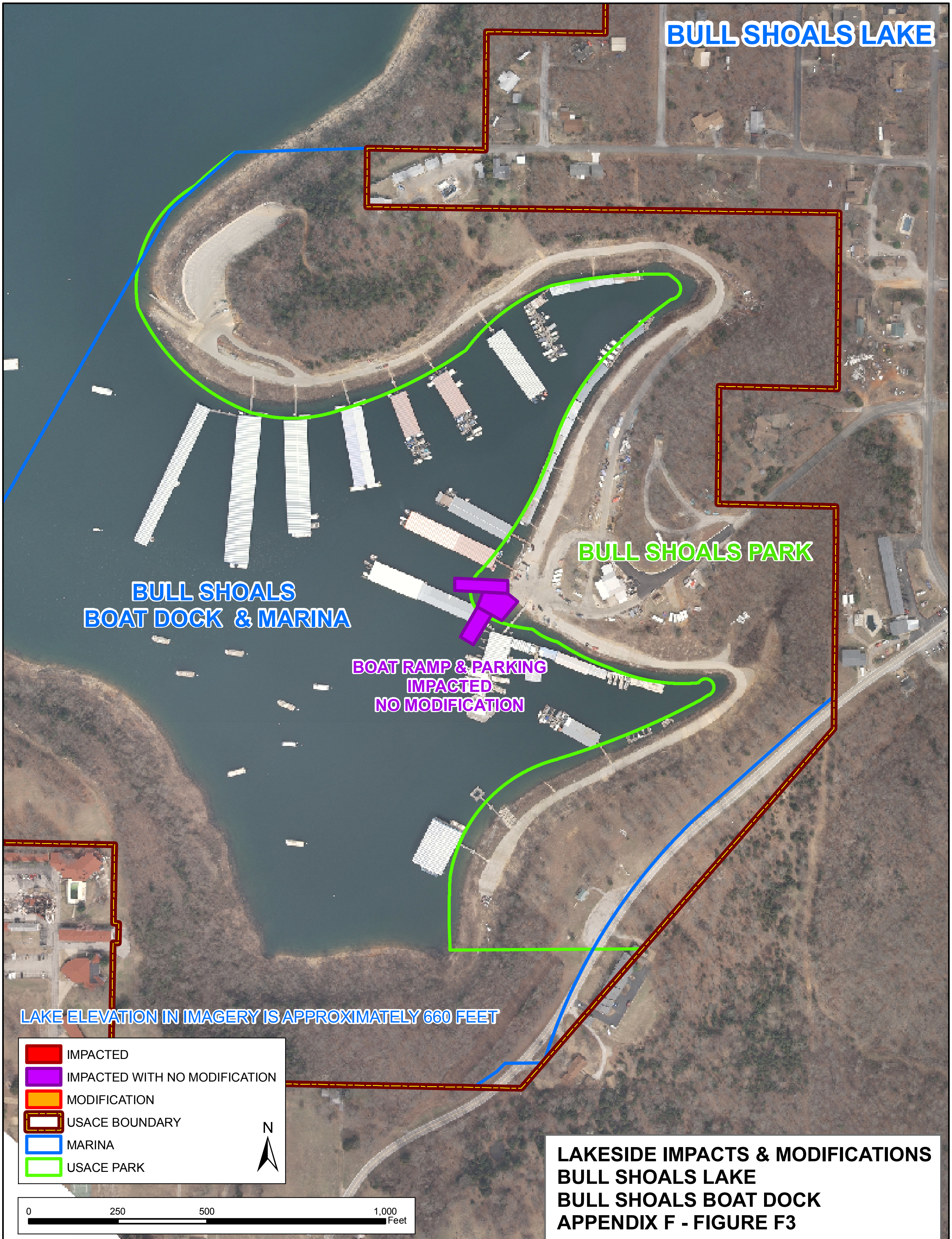


LAKESIDE IMPACTS & MODIFICATIONS
VICINITY MAP
APPENDIX F - FIGURE F

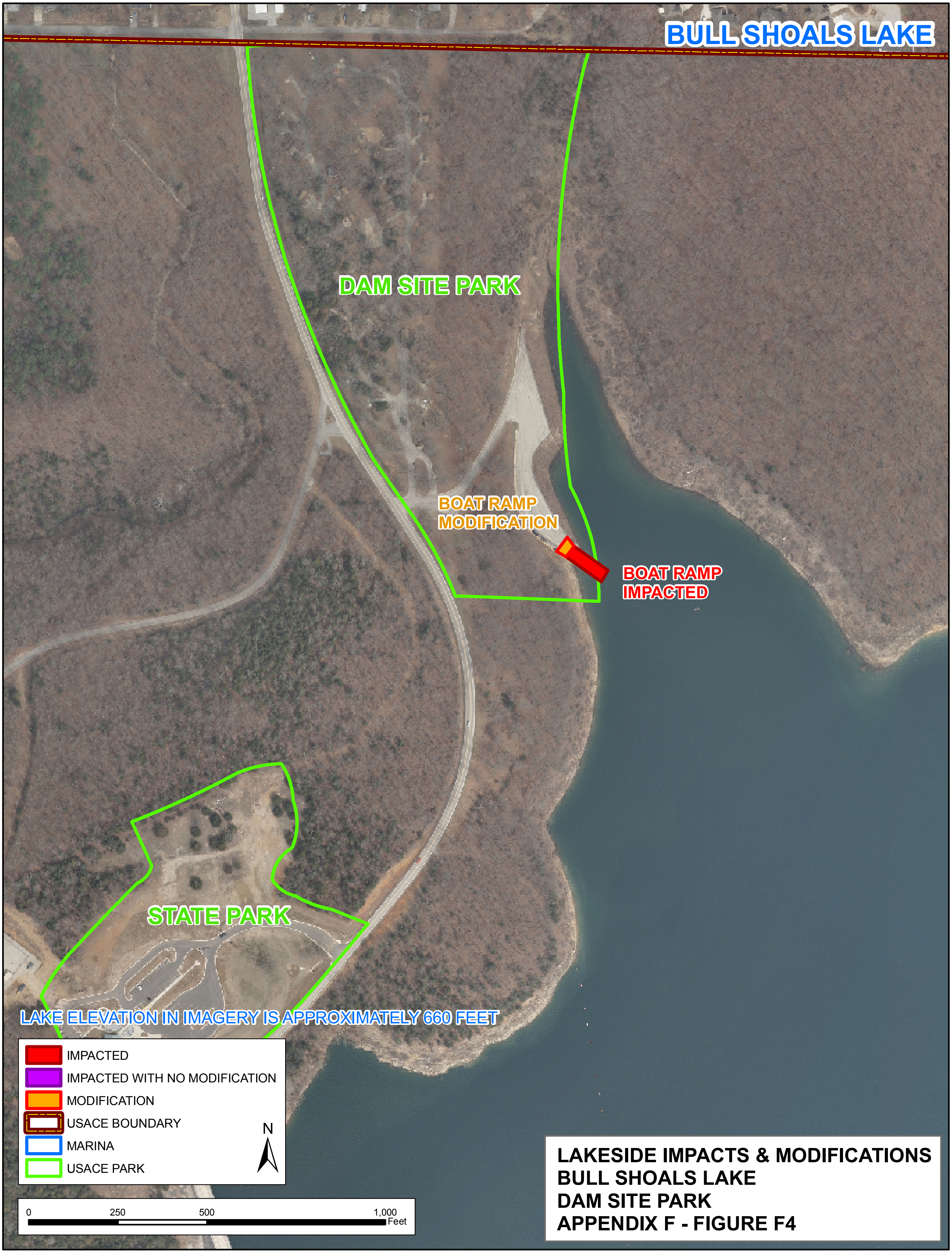


LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
BEAVER CREEK PARK
APPENDIX F - FIGURE F1

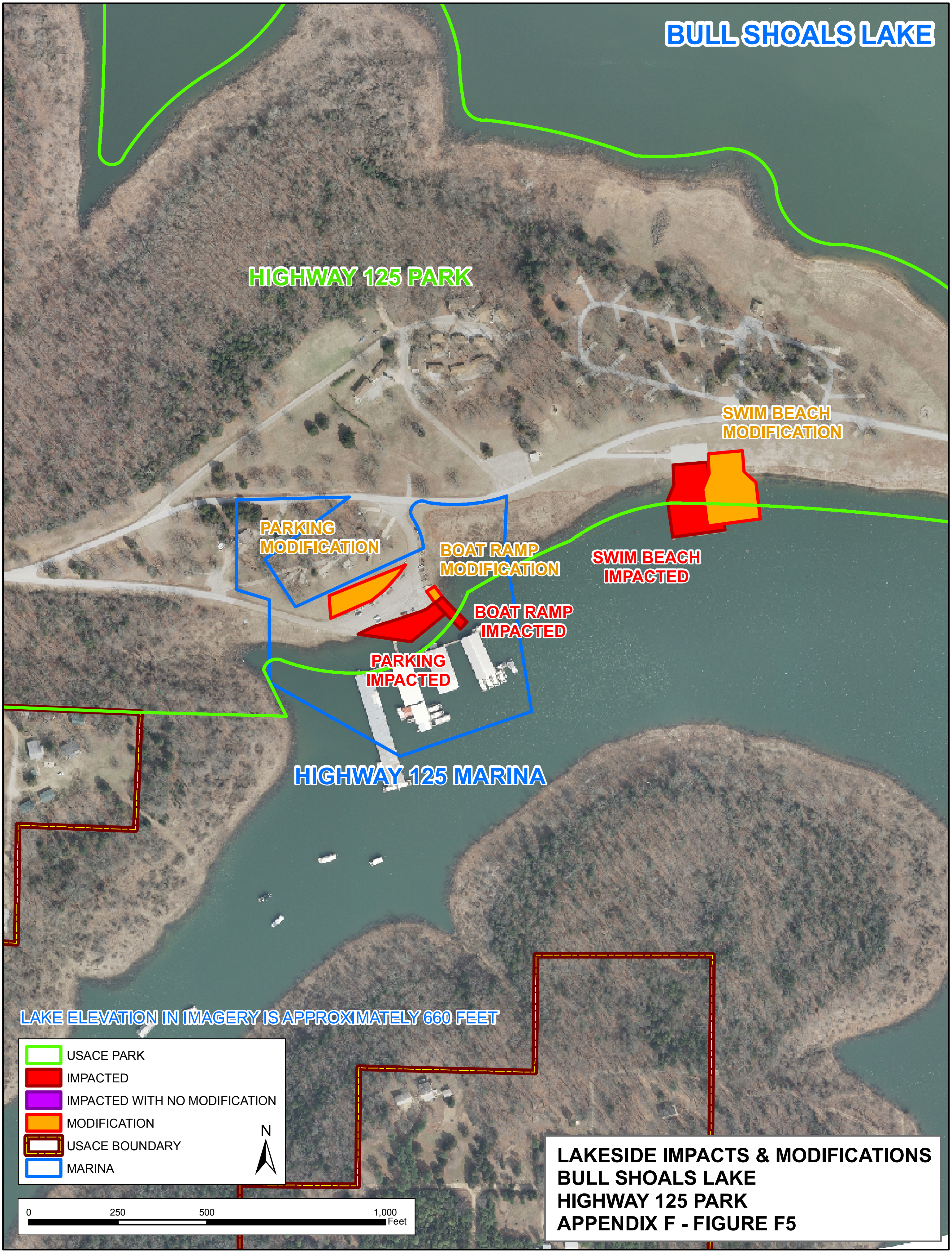
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
BUCK CREEK PARK
APPENDIX F - FIGURE F2



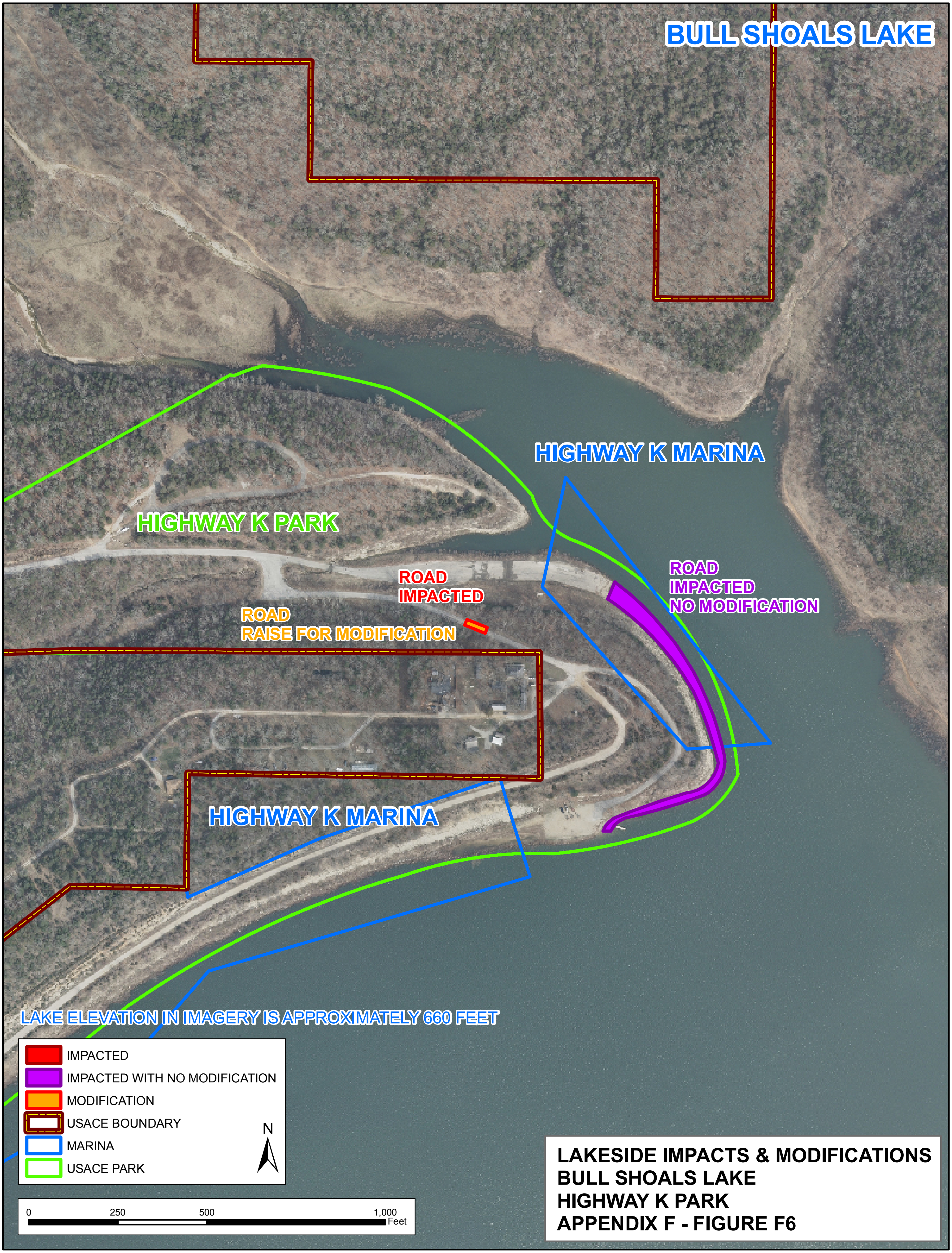
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
BULL SHOALS BOAT DOCK
APPENDIX F - FIGURE F3



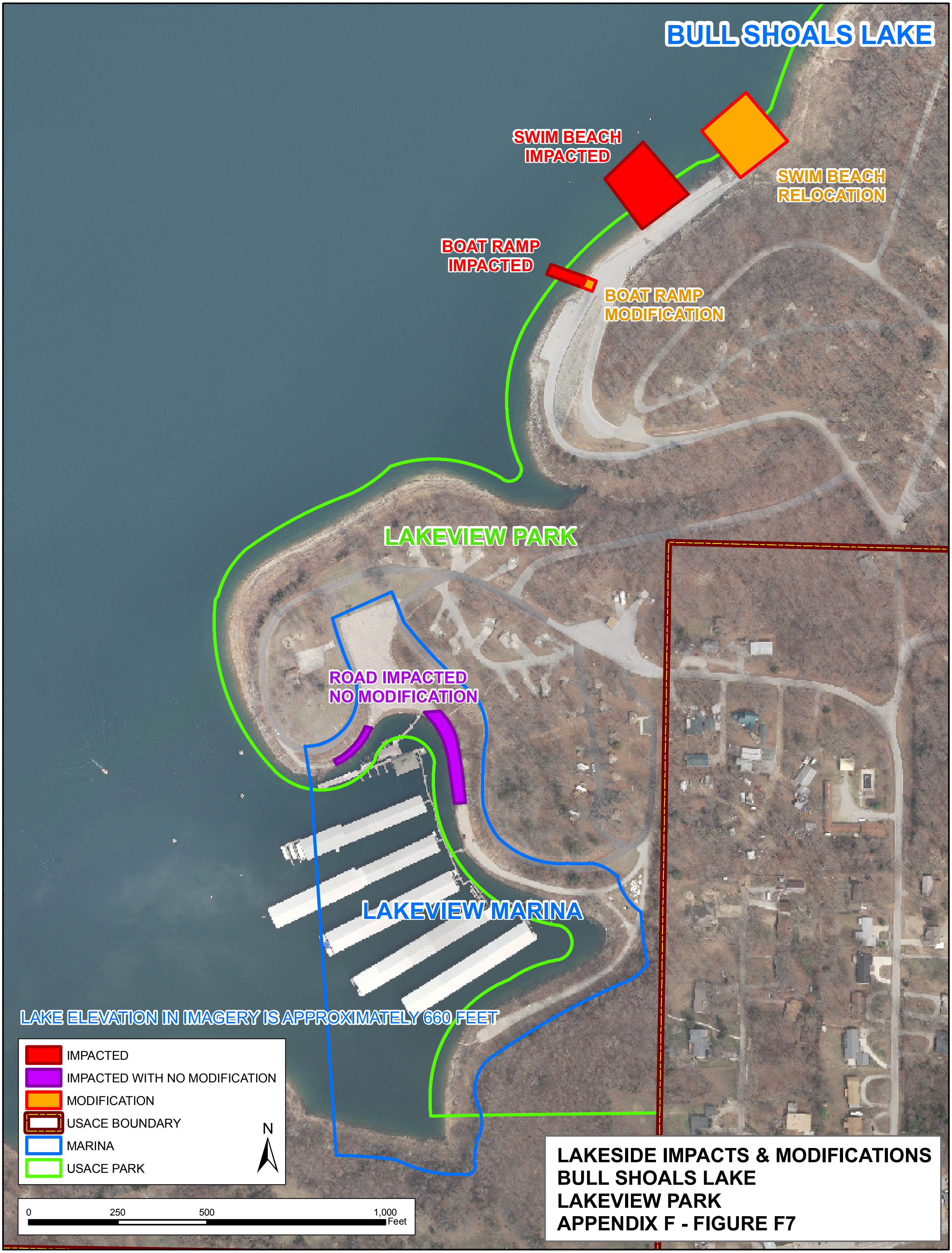
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
DAM SITE PARK
APPENDIX F - FIGURE F4



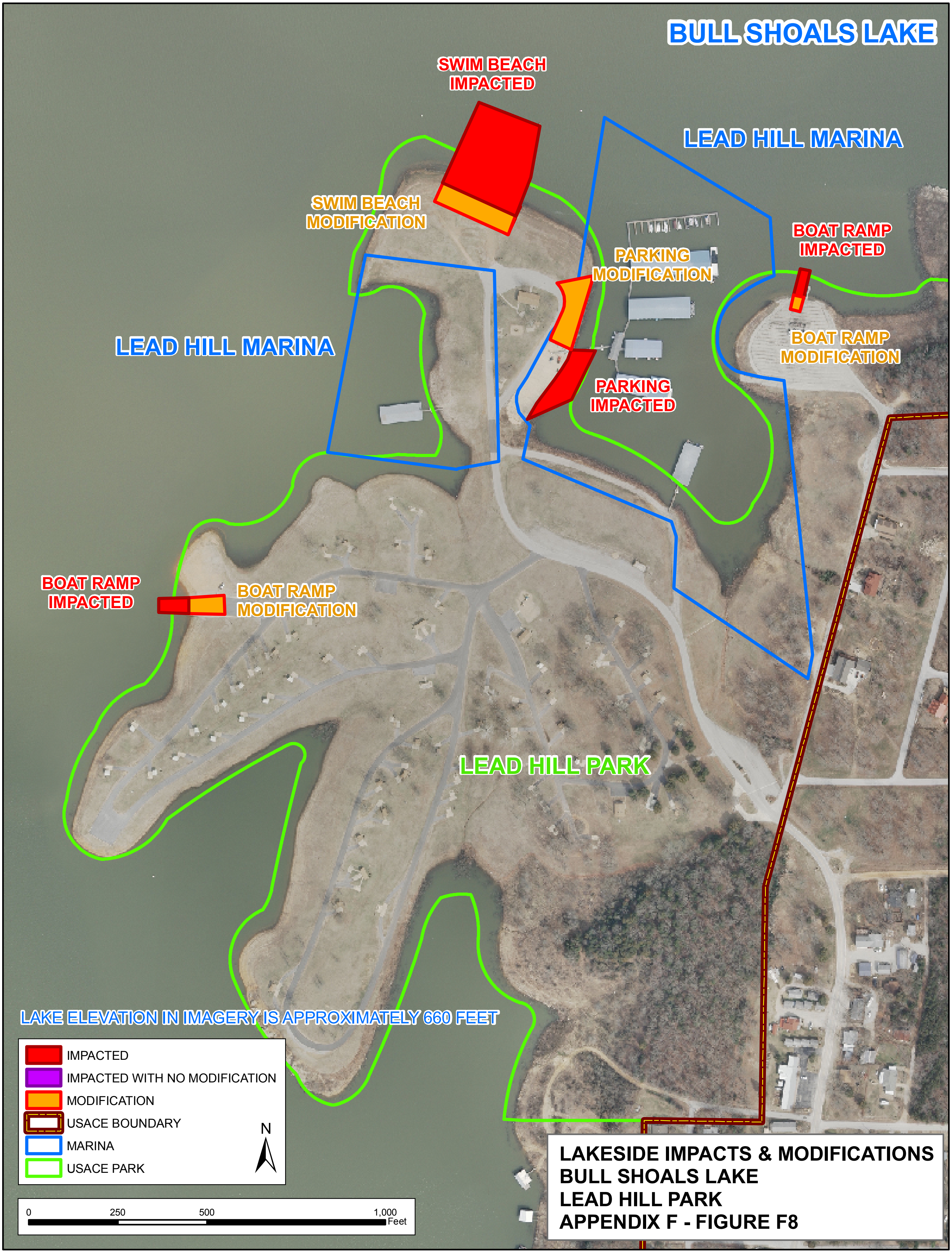
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
HIGHWAY 125 PARK
APPENDIX F - FIGURE F5



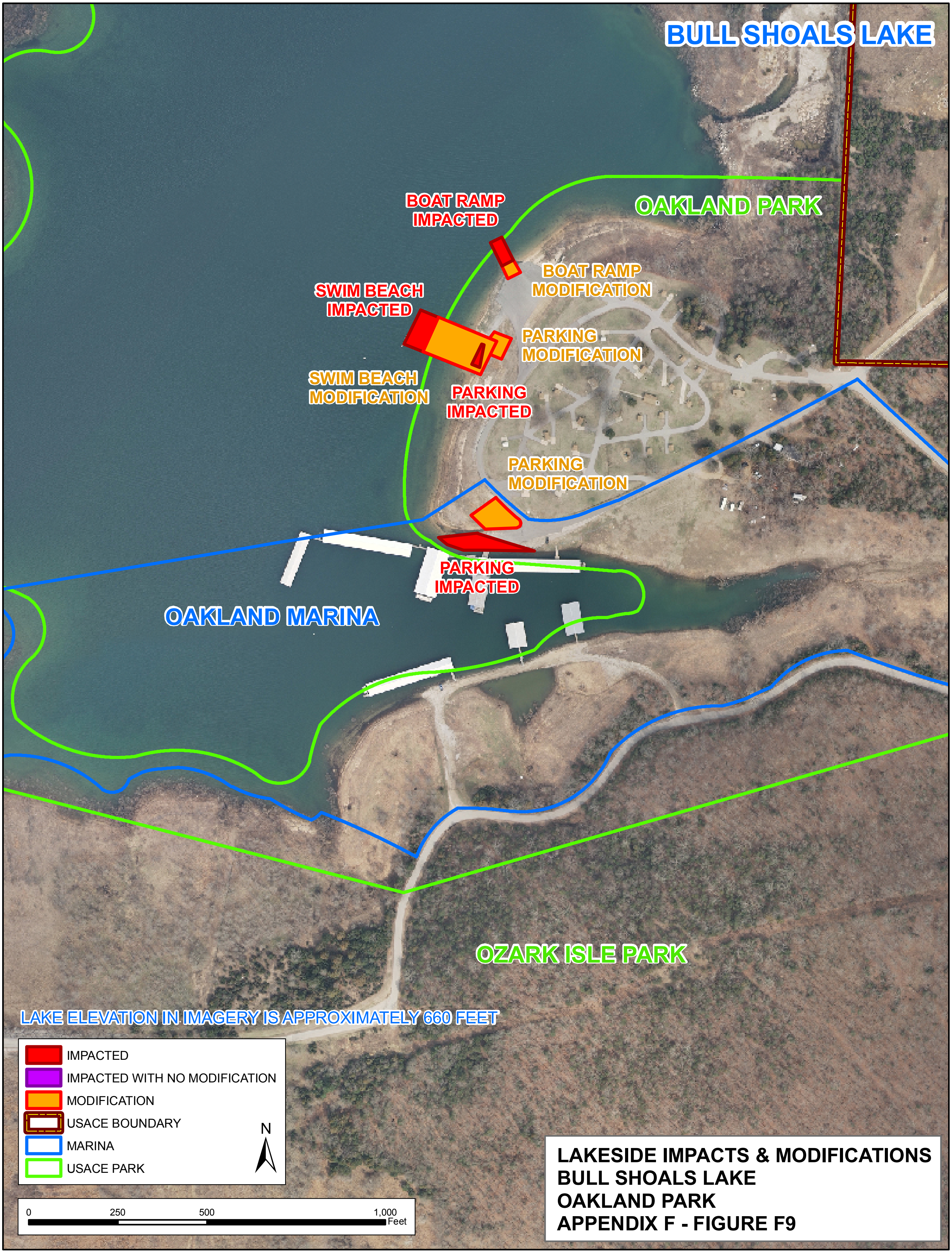
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
HIGHWAY K PARK
APPENDIX F - FIGURE F6



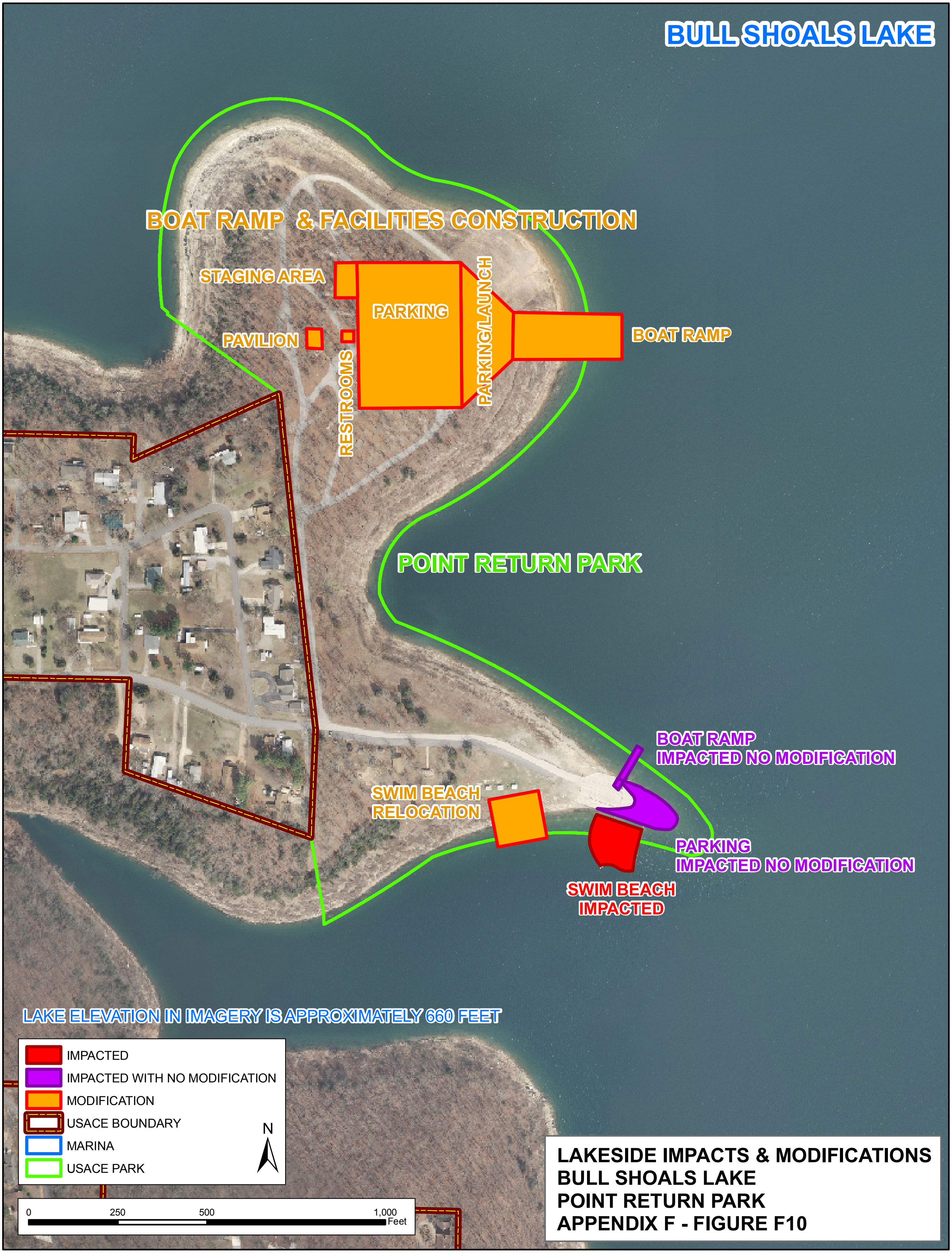
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
LAKEVIEW PARK
APPENDIX F - FIGURE F7



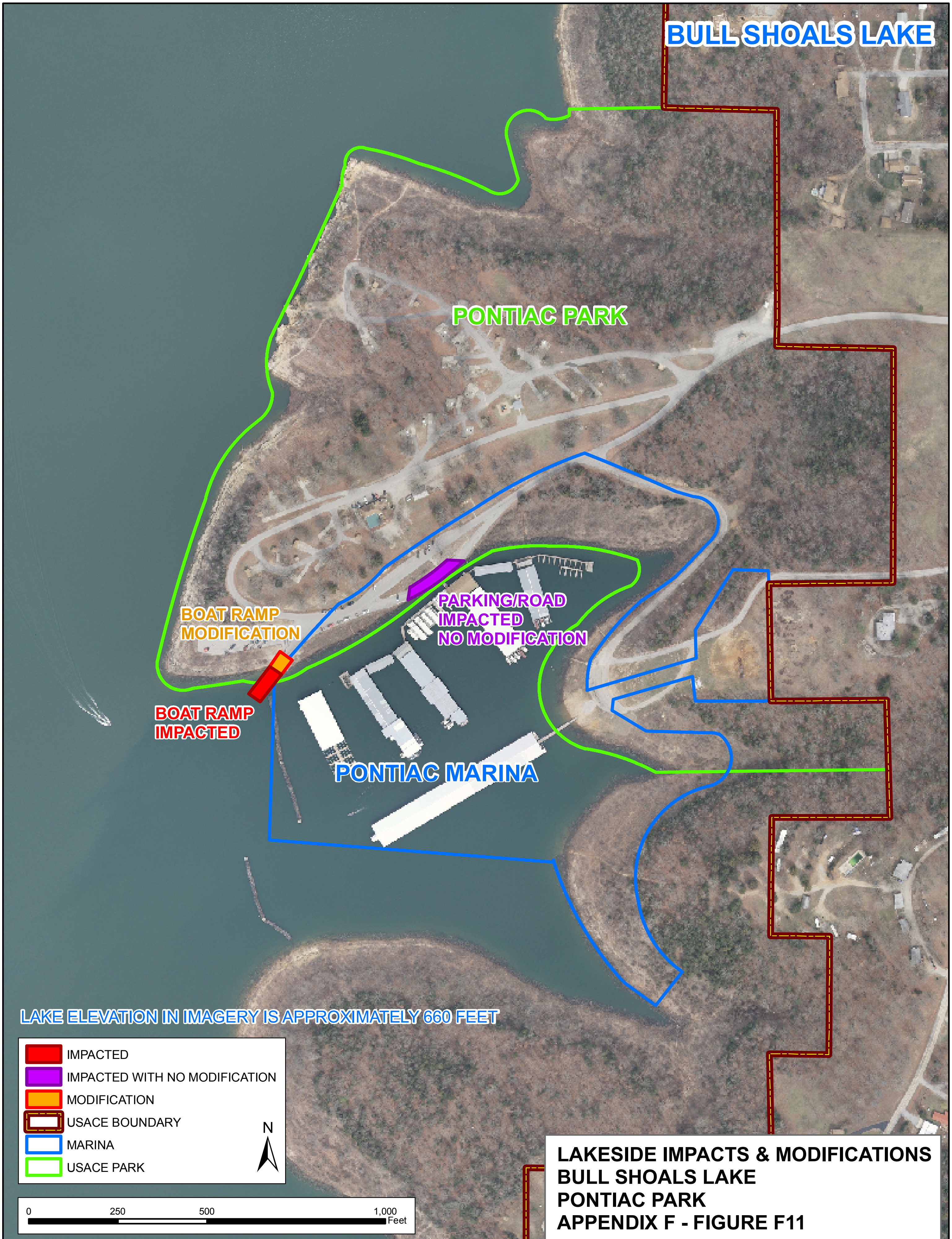
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
LEAD HILL PARK
APPENDIX F - FIGURE F8



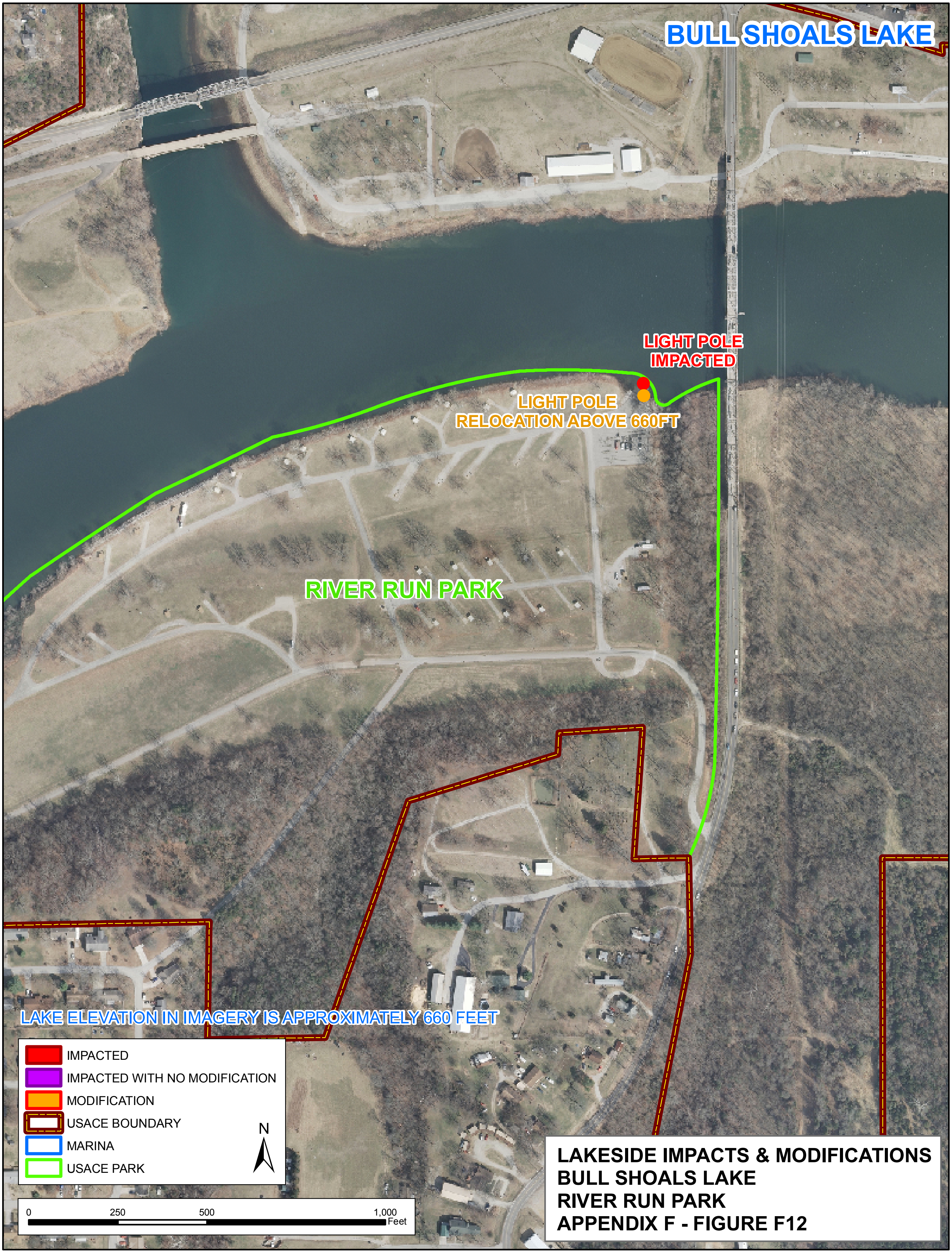
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
OAKLAND PARK
APPENDIX F - FIGURE F9



LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
POINT RETURN PARK
APPENDIX F - FIGURE F10

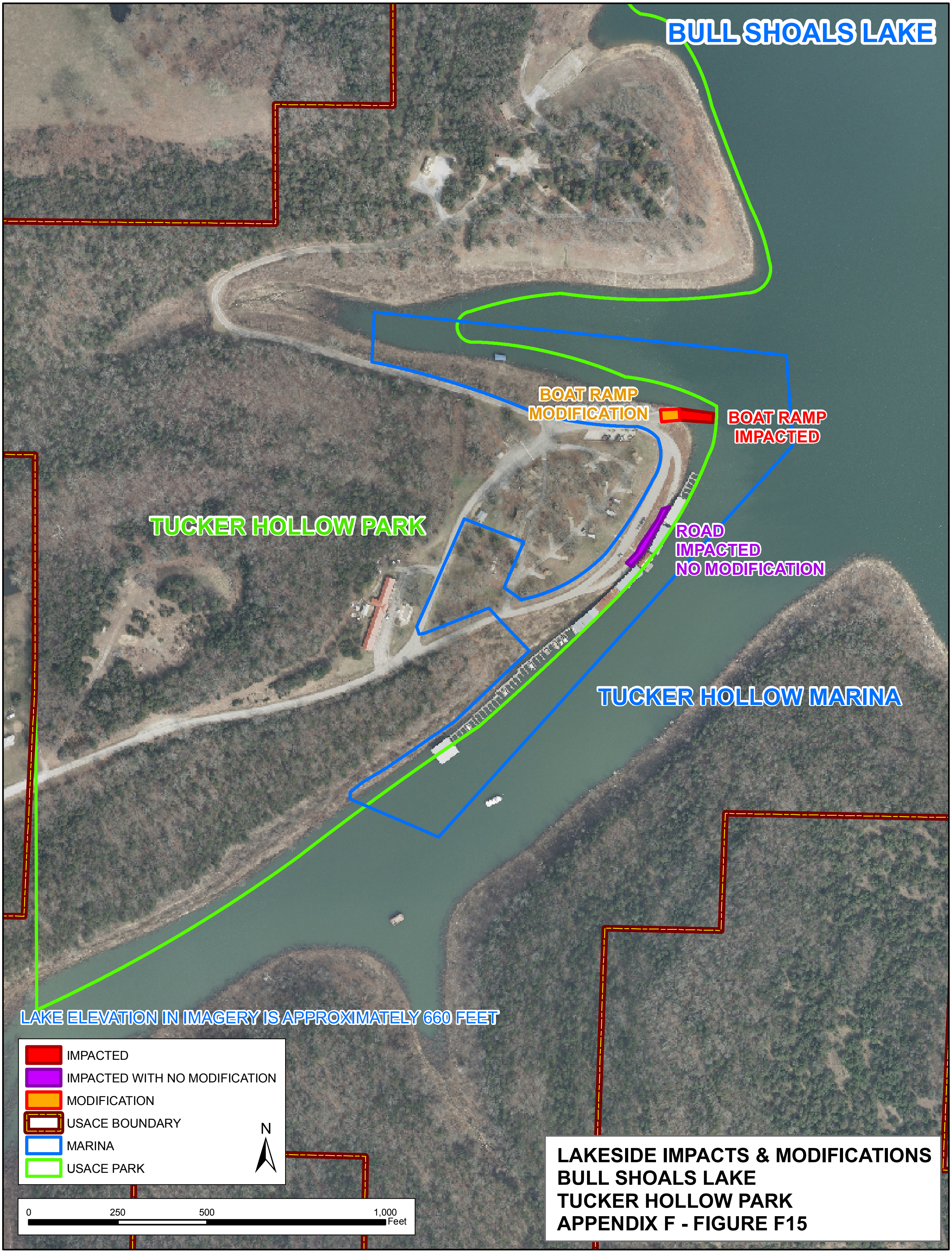


LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
PONTIAC PARK
APPENDIX F - FIGURE F11

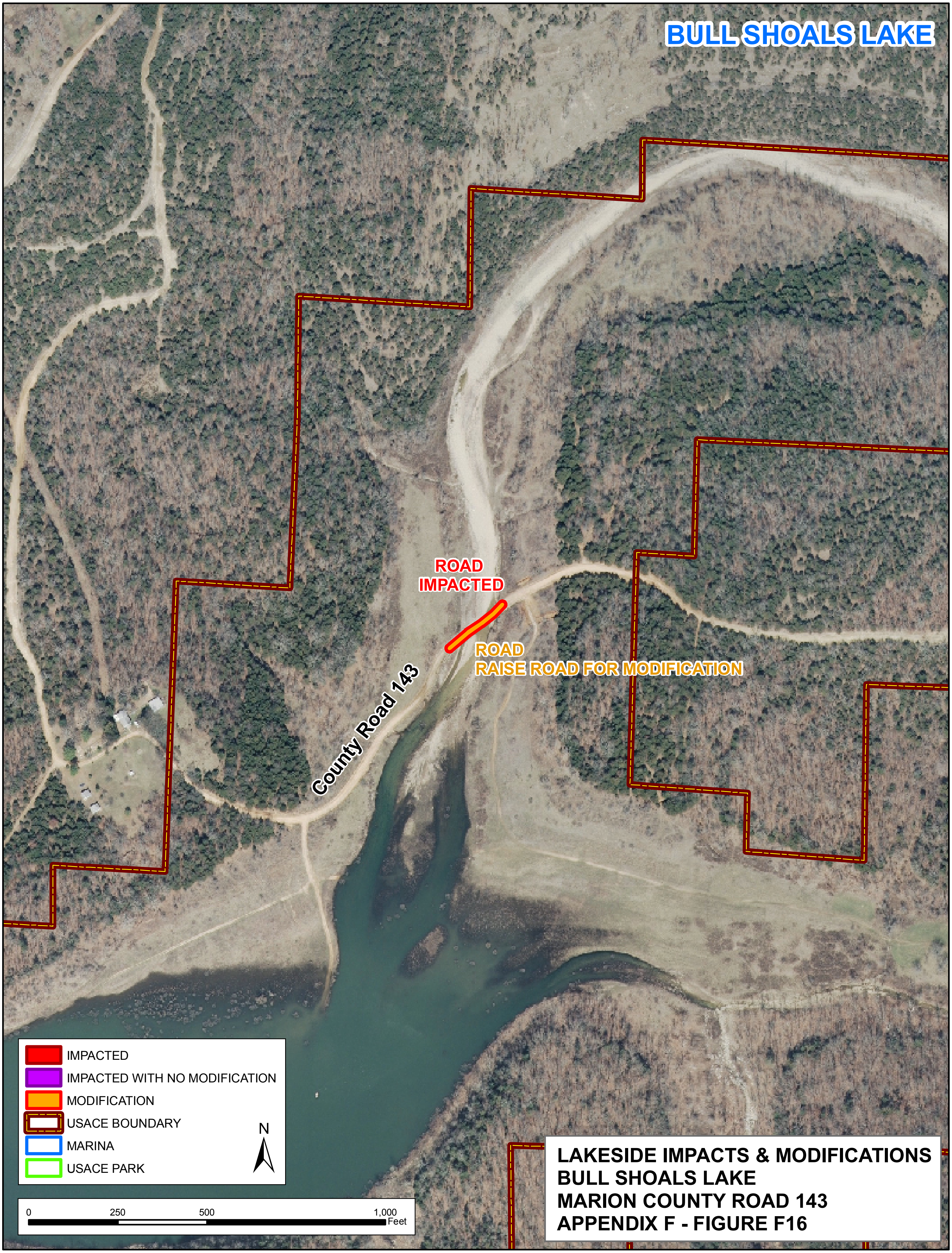


LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
RIVER RUN PARK
APPENDIX F - FIGURE F12

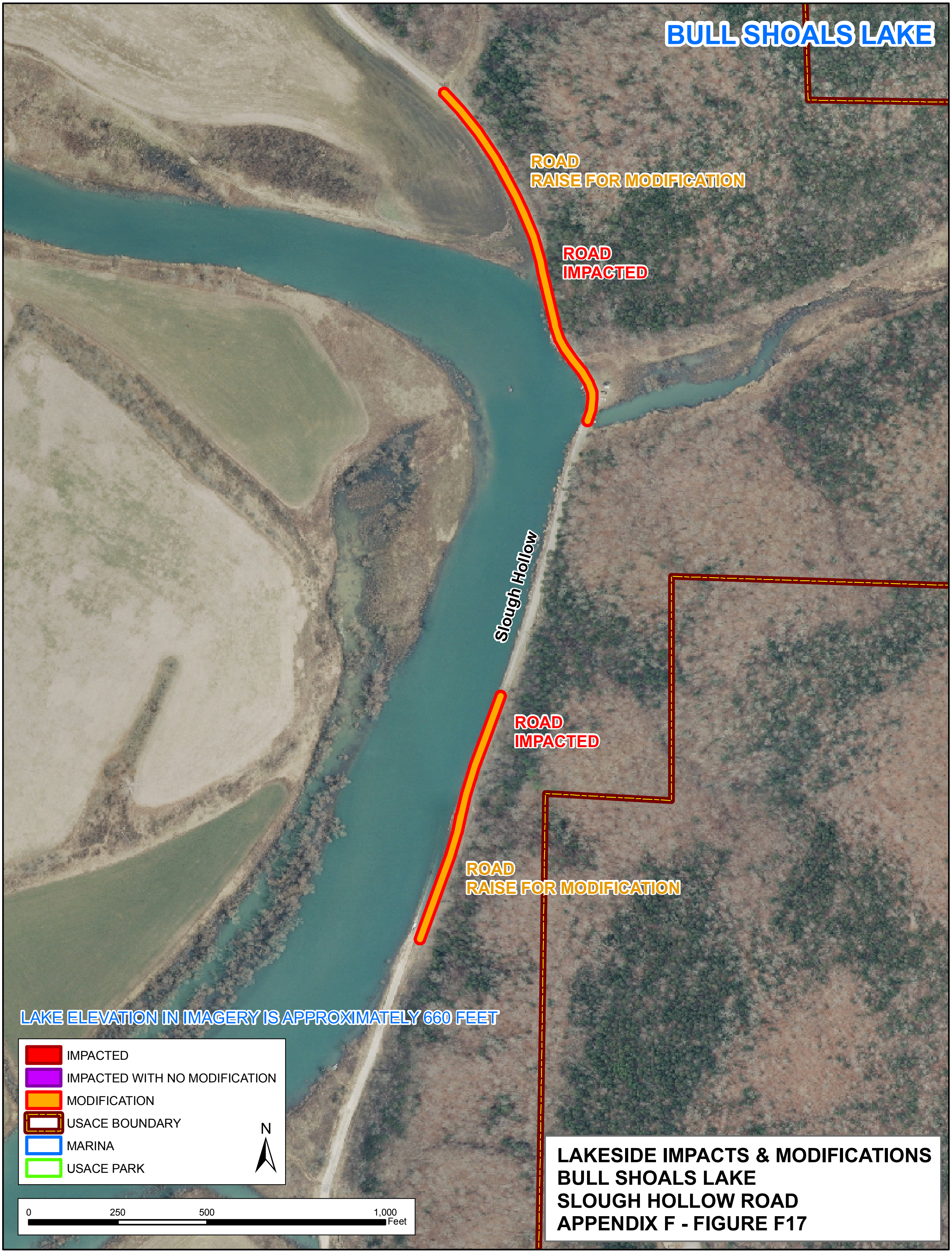
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
THEODOSIA PARK
APPENDIX F - FIGURE F14



LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
TUCKER HOLLOW PARK
APPENDIX F - FIGURE F15



LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
MARION COUNTY ROAD 143
APPENDIX F - FIGURE F16



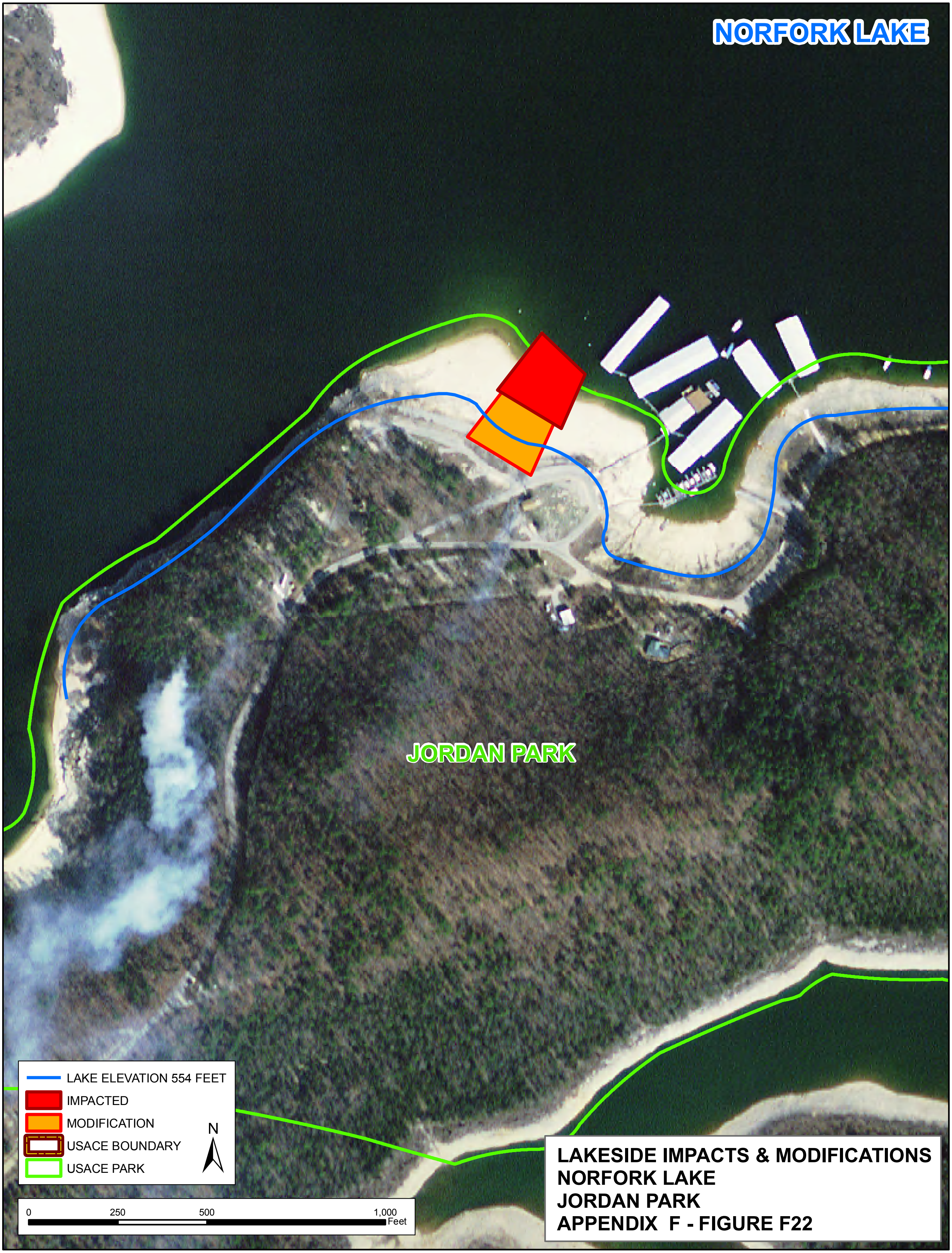
LAKESIDE IMPACTS & MODIFICATIONS
BULL SHOALS LAKE
SLOUGH HOLLOW ROAD
APPENDIX F - FIGURE F17

LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
BIDWELL POINT PARK
APPENDIX F - FIGURE F18

LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
CRANFIELD PARK
APPENDIX F - FIGURE F19


NORFORK LAKE
GAMALIEL PARK
LAKE ELEVATION 554 FEET
IMPACTED
MODIFICATION
USACE BOUNDARY
USACE PARK
N
0
250
500
1,000
Feet
LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
GAMALIEL PARK
APPENDIX F - FIGURE F20

LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
GEORGES COVE PARK
APPENDIX F - FIGURE F21



NORFORK LAKE
JORDAN PARK
LAKE ELEVATION 554 FEET
IMPACTED
MODIFICATION
USACE BOUNDARY
USACE PARK
N
0
250
500
1,000
Feet
LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
JORDAN PARK
APPENDIX F - FIGURE F22


NORFORK LAKE
PANTHER BAY PARK
LAKE ELEVATION 554 FEET
IMPACTED
MODIFICATION
USACE BOUNDARY
USACE PARK
N
0
250
500
1,000
Feet
LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
PANTHER BAY PARK
APPENDIX F - FIGURE F23


NORFORK LAKE
QUARRY PARK
LAKE ELEVATION 554 FEET
IMPACTED
MODIFICATION
USACE BOUNDARY
USACE PARK
N
0
250
500
1,000
Feet
LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
QUARRY PARK
APPENDIX F - FIGURE F24

LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
ROBINSON POINT PARK
APPENDIX F - FIGURE F25

LAKESIDE IMPACTS & MODIFICATIONS
NORFORK LAKE
UDALL PARK
APPENDIX F - FIGURE F26

White River Basin, Arkansas, Minimum Flows
Project Report
Coordination Letters

APPENDIX
F-C

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867
www.swl.usace.mil/

REPLY TO
ATTENTION OF

July 25, 2007

Honorable Dan Hall
County Judge
Baxter County, AR
1 E. 7th St., Suite 303
Mountain Home, AR 72653

Dear Judge Hall:

The U.S Army Corps of Engineers, Little Rock District will be completing the Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project in August 2008. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also requires non-Federal interests (Arkansas Game & Fish Commission, Missouri Department of Conservation, Missouri Department of Natural Resources) to mitigate lakeside facilities impacted in order to ensure "Reasonable Continued Use" of the facilities. The Act also establishes the procedures for the Administrator of the Southwestern Power Administration to determine the costs for compensating Empire Electric (non-Federal FERC operator) for loss of electrical generation.

I would like to extend an invitation for you or your representative to participate in this phase of the project as a Project Delivery Team (PDT) member since lakeside facilities located in your County could be affected by implementation of the White River Minimum Flows Project.

My staff will coordinate with your office, outlining the status of the project and the roles and responsibilities of the PDT members. We would like to schedule a meeting to discuss the overall project. The district's point of contact is the Project Manager, Mr. Michael Biggs. He can be reached by phone at 501-324-5842 x1071, or by email at mike.l.biggs@usace.army.mil.

Sincerely,

Donald E. Jackson, Jr
Colonel, US Army
District Commander

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867
www.swl.usace.mil/

REPLY TO
ATTENTION OF

July 25, 2007

Honorable Mike Moore
County Judge
Boone County, AR
100 N. Main St., Suite 300
Harrison, AR 72601

Dear Judge Moore:

The U.S Army Corps of Engineers, Little Rock District will be completing the Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project in August 2008. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also requires non-Federal interests (Arkansas Game & Fish Commission, Missouri Department of Conservation, Missouri Department of Natural Resources) to mitigate lakeside facilities impacted in order to ensure "Reasonable Continued Use" of the facilities. The Act also establishes the procedures for the Administrator of the Southwestern Power Administration to determine the costs for compensating Empire Electric (non-Federal FERC operator) for loss of electrical generation.

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Sincerely,

Donald E. Jackson, Jr
Colonel, US Army
District Commander

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867
www.swl.usace.mil/

REPLY TO
ATTENTION OF

July 25, 2007

Honorable Charles Willett
County Judge
Fulton County, AR
P.O. Box 278
Salem, AR 72576

Dear Judge Willett:

The U.S Army Corps of Engineers, Little Rock District will be completing the Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project in August 2008. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also requires non-Federal interests (Arkansas Game & Fish Commission, Missouri Department of Conservation, Missouri Department of Natural Resources) to mitigate lakeside facilities impacted in order to ensure "Reasonable Continued Use" of the facilities. The Act also establishes the procedures for the Administrator of the Southwestern Power Administration to determine the costs for compensating Empire Electric (non-Federal FERC operator) for loss of electrical generation.

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Sincerely,

Donald E. Jackson, Jr
Colonel, US Army
District Commander

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867
www.swl.usace.mil/

REPLY TO
ATTENTION OF

July 25, 2007

Honorable Kenneth Oxford
County Judge
Marion County, AR
P.O. Box 545
Yellville, AR 72687

Dear Judge Oxford:

The U.S Army Corps of Engineers, Little Rock District will be completing the Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project in August 2008. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also requires non-Federal interests (Arkansas Game & Fish Commission, Missouri Department of Conservation, Missouri Department of Natural Resources) to mitigate lakeside facilities impacted in order to ensure "Reasonable Continued Use" of the facilities. The Act also establishes the procedures for the Administrator of the Southwestern Power Administration to determine the costs for compensating Empire Electric (non-Federal FERC operator) for loss of electrical generation.

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Sincerely,

Donald E. Jackson, Jr
Colonel, US Army
District Commander

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867
www.swl.usace.mil/

REPLY TO
ATTENTION OF

July 25, 2007

Commissioner David Morrison
Presiding Commissioner
Ozark County, MO
P.O. Box 247
Gainesville, MO 65655

Dear Commissioner Morrison:

The U.S Army Corps of Engineers, Little Rock District will be completing the Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project in August 2008. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also requires non-Federal interests (Arkansas Game & Fish Commission, Missouri Department of Conservation, Missouri Department of Natural Resources) to mitigate lakeside facilities impacted in order to ensure "Reasonable Continued Use" of the facilities. The Act also establishes the procedures for the Administrator of the Southwestern Power Administration to determine the costs for compensating Empire Electric (non-Federal FERC operator) for loss of electrical generation.

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Sincerely,

Donald E. Jackson, Jr
Colonel, US Army
District Commander

REPLY TO
ATTENTION OF

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867
www.swl.usace.mil/

July 25, 2007

Commissioner Chuck Pennel
Presiding Commissioner
Taney County, MO
P.O. Box 1086
Forsyth, MO 65653

Dear Commissioner Pennel:

The U.S Army Corps of Engineers, Little Rock District will be completing the Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project in August 2008. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also requires non-Federal interests (Arkansas Game & Fish Commission, Missouri Department of Conservation, Missouri Department of Natural Resources) to mitigate lakeside facilities impacted in order to ensure "Reasonable Continued Use" of the facilities. The Act also establishes the procedures for the Administrator of the Southwestern Power Administration to determine the costs for compensating Empire Electric (non-Federal FERC operator) for loss of electrical generation.

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Sincerely,

Donald E. Jackson, Jr
Colonel, US Army
District Commander

White River Basin, Arkansas, Minimum Flows
Project Report

Real Estate

APPENDIX G

REAL ESTATE PLAN
WHITE RIVER MINIMUM FLOW STUDY PROJECT
BULL SHOALS AND NORFORK LAKES
ARKANSAS AND MISSOURI

November 4, 2008

PREPARED BY
RONALD BRIDGES
REAL ESTATE BRANCH
U.S. ARMY CORPS OF ENGINEERS
LITTLE ROCK DISTRICT

REAL ESTATE PLAN
WHITE RIVER MINIMUM FLOW STUDY PROJECT
BULL SHOALS AND NORFORK LAKES
ARKANSAS AND MISSOURI

Table of Contents

Attachments:

Maps Exhibit A: Bull Shoals Lake
Exhibit B: Norfork Lake

Exhibit C: Assessment of Non-Federal Sponsor

Prepared By: Ronald Bridges
Real Estate Branch

Revised Date: November 4, 2008

REAL ESTATE PLAN
WHITE RIVER MINIMUM FLOW STUDY PROJECT
BULL SHOALS LAKE AND NORFORK LAKE
ARKANSAS AND MISSOURI

[1] Purpose

The purpose of this Real Estate Plan (REP) is to outline any real estate acquisition requirements for the completion of the White River Minimum Flow Study at Bull Shoals and Norfork Lakes in northern Arkansas and southern Missouri.

The authority for the study is Public Law 109-103, Section 132, Energy and Water Resources Development Act. Work under this authority directs the implementation of alternatives involving the reallocation of the conservation and flood pool storages at Bull Shoals Lake and Norfork Lake.

[2] Description of lands, easements and rights-of-way (LER's)

The project study is located at Bull Shoals and Norfork Lakes. Both lakes are located in northern Arkansas and southern Missouri. Bull Shoals Lake and Norfork Lake were authorized for construction by the Flood Control Act of 1938 as two of the original six lakes developed for flood control and other purposes in the White River Basin. Bull Shoals Lake and Norfork Lake are operated for the primary purposes of flood control and hydropower with secondary consideration to water supply, recreation, fish and wildlife. All lands, easements, and rights-of-way required for the project on Bull Shoals and Norfork Lakes are US Government owned and are managed by the US Army Corps of Engineers, Little Rock District. On the two lakes addressed above, reallocation from the conservation and flood pool storages of each project lake is preferred as there are no additional LER acquisition requirements. On Bull Shoals Lake, the 654-foot contour is the top of the conservation pool elevation and the 695-foot contour is the top of the flood pool elevation. On Norfork Lake, the 554-foot contour is the top of the conservation pool elevation and the 580-foot contour is the top of the flood pool elevation. The conservation and the flood pool storage elevation contour levels are below the fee acquisition line of both lakes.

[3] LER owned by non-federal sponsor

None of the land for this project is owned by the non-federal sponsor, the Arkansas Game and Fish Commission. However, the Missouri Department of Conservation has an interest in this study as it pertains to improving trout fishing conditions on the White River.

[4] Non-standard estates

There are no non-standard estates needed for this project.

[5] Any existing federal projects

The minimum flow study involves Bull Shoals and Norfork Lakes. Bull Shoals Lake and Norfork Lake were authorized for constructed in 1938. Both lakes were constructed with federal funds.

[6] Any federally owned land

The lands for the minimum flow study are owned by the US Government and managed by the US Army Corps of Engineers.

[7] LER that lies below the ordinary high water mark

The lands for the proposed minimum flow study lie between the conservation pool elevations and the flood control pool elevations at Bull Shoals and Norfork. On Bull Shoals Lake, the 654-foot contour is the top of the conservation pool elevation and the 695-foot contour is the top of the flood pool elevation. On Norfork Lake, the 554-foot contour is the top of the conservation pool elevation and the 580-foot contour is the top of the flood pool elevation.

[8] Maps

The maps depicting the location of the Bull Shoals Lake and Norfork Lake are shown in Exhibits A and B.

[9] Any possible flooding

No induced flooding of privately owned land is to occur for this project. However, as the non-federal sponsor, the Arkansas Game and Fish Commission will provide any relocations or modifications for public and private lake facilities as a result of the reallocation of water levels between the conservation and flood pools of Bull Shoals and Norfork Lakes.

[10] Cost estimate

No real estate cost estimate is needed as additional lands, easements or rights-of-way will not be acquired for this project.

[11] Relocation benefits

No relocation benefits will be required for this project for private individuals or residences outside the lake boundaries.

[12] Mineral activity

There is no mineral activity in the vicinity of either lake for the proposed project.

[13] Assessment of non-federal sponsor

The Arkansas Game and Fish Commission is capable of accomplishing the relocations or modifications of any public and private lake facilities as a result of the reallocation of water levels between the conservation and flood pools of Bull Shoals and Norfork Lakes. (See Exhibit C)

[14] Application of zoning ordinances

The land area is not subject any municipal zoning ordinances.

[15] Land acquisition milestones

Not applicable as the lands for this project are owned by the US Government and managed by the US Army Corps of Engineers, Little Rock District.

[16] Facility or utility relocations

Cost estimates are being determined for the potential relocations of park amenities, roads, and structure modifications because of the changes involving the conservation and flood pool storages capacity at the parks and other areas of Bull Shoals and Norfork Lakes. If the construction phase of the project is approved, the Arkansas Game and Fish Commission will bear the costs of relocations of park amenities, roads, and structure modifications at the Bull Shoals Lake and Norfork Lake for this project.

[17] Known contaminants

No visible contaminants were noted on or adjacent to the LER's required for the proposed minimum flow project.

[18] Support or opposition to the project

The Arkansas Game and Fish Commission and the Missouri Department of Conservation are in favor of this study because the possibility of improvement to trout habitat. Opposition to this project may arise from the marina owners and agriculture and grazing lessees at Bull Shoals and Norfork Lakes due to the possible affect of the reallocation may have on their respective lease areas.

[19] Statement that non-federal sponsor has been notified in writing about the risks associated with acquiring land.

Not applicable as additional lands will not be acquired by the non-federal sponsor for this project. The proposed project lands are owned by the US Government and managed by the US Army Corps of Engineers.

[20] Other real estate issues

No modifications to lease agreements need be made between the lessees and the US Government, i.e. the US Army Corps of Engineers, at the project lakes. The necessary rights-of-entry permits will be issued to the non-federal sponsor for construction involving this project upon US Government owned land.