Lake Ouachita, Arkansas

**US Army Corps
of Engineers
Vicksburg District**

WATER SUPPLY STORAGE REALLOCATION REPORT

Reallocation of Storage at Lake Ouachita, Arkansas for the Mid-Arkansas Water Alliance

September 2016

Executive Summary

Mid-Arkansas Water Alliance
Water Supply Storage Reallocation from Lake Ouachita, Arkansas

This report presents the results of a study to reallocate storage in Lake Ouachita, Arkansas, to the Mid-Arkansas Water Alliance (MAWA) for municipal and industrial (M&I) water supply. This reallocation study comes at the request of MAWA to purchase storage in Lake Ouachita capable of yielding 30 million gallons per day (mgd). This report includes an environmental assessment, as directed by the National Environmental Policy Act (NEPA), which is included in Appendix E.

The Hydrology and Hydraulics (H&H) analysis concluded that 49,983 acre-feet of storage in the conservation pool is available and would be required to supply MAWA's 30 mgd of demand. However, reallocating water from the conservation pool would require forgoing a portion of authorized hydropower production at Lake Ouachita.

To provide the remaining discretionary storage for MAWA, a new water storage agreement between MAWA and the United States Government will be required. This report will be submitted to Headquarters, U.S. Army Corps of Engineers, in Washington, D.C. for approval. Upon approval, the new water storage agreement will be executed, and the reallocation of the immediate need for storage will be made.

A conservation pool reallocation was determined as the best alternative due to Blakely Mountain's Dam Safety Action Classification (DSAC) rating. Blakely Mountain Dam currently has a Corps of Engineers' DSAC III rating. Corps policy prohibits reallocation of flood pool storage to other purposes if a dam has a DSAC rating of I, II, or III. Reallocation of conservation pool storage (below normal pool) is acceptable for a dam with a DSAC III rating under the policy.

The user's cost for storage will be based on the lost hydropower benefits which were determined to be the highest of the foregone benefits. Lost hydropower benefits were calculated at $484,000 annually, compared to an annual storage cost of $342,000. An annual power marketing agency (PMA) credit of $174,000 will be made based on the estimated loss of power outputs and the current rates charged by Southwestern Power Administration (SWPA).

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LIST OF TERMS, REFERENCES, AND ACRONYMS

AF, or Acre-Foot - a unit for measuring the volume of water. It is equal to the quantity of water required to cover 1.0 acre to a depth of 1.0 foot and is equal to 43,560 cubic feet. It is used in measuring volumes of water used or stored.

Construction Cost - the total expenditures to physically build the project including the cost of lands, relocations, engineering, design, administration, and supervision. This cost is sometimes referred to as the "first cost."

Cost Allocation - a systematic distribution of costs among the project purposes of a multipurpose project.

Cost Sharing - the division of cost among various entities which gain benefit including Federal, state, local, or private interests.

CWCCIS, or Civil Works Construction Cost Index System - this refers to the cost index used to inflate construction costs to present day values.

DYMS, or dependable yield mitigation storage, or mitigation storage - the storage necessary to keep existing users whole to compensate for the reduction in the dependable yield which occurs when the conservation pool is expanded into the flood pool.

EA - Environmental Assessment.

ENR - Engineering News Record is used to adjust construction costs to present day values.

ER 1105-2-100 - Policy and Planning Guidance For Conducting Civil Works Planning Studies, 22 April 2000.

Financial Feasibility - criterion of project acceptability, based upon the financial value of the returns to the sponsoring entity exceeding the financial value of the costs to the sponsoring entity.

Government fiscal year - October 1 to September 30.

GPM, or gallons per minute – a unit for measuring the flow or discharge of a volume of water over a period of time.

HQUSACE - or Headquarters, United States Army Corps of Engineers.

Immediate need - is that storage that the local sponsor must begin payment on immediately upon final approval of the water supply agreement, whether or not it is needed.

Investment or investment cost - the construction cost plus interest during construction. In water supply agreements, this is the construction cost allocated to that portion of the water supply storage space plus interest during construction for those projects paid out over time, but does not include (if there is any) interest on the unpaid balance.

Joint-use Costs - total project costs less all specific costs.

MGD, or million gallons per day - a unit for measuring the flow or discharge of a volume of water over a period of time.

M&I, or municipal and industrial - while not defined in legislative history, the term has been defined by the Corps to mean supply for uses customarily found in the operation of municipal water systems and for uses in industrial processes. Industrial processes can include thermal power generation and mining operations.

NED, or National Economic Development Plan - the plan with the greatest excess benefits over costs.

O&M - operation and maintenance.

Period of Analysis - the period determined by the estimated point in time at which the combined effect of physical depreciation, obsolescence, changing requirements for project services, and time and discount allowances will cause the cost of continuing the project to exceed the benefits to be expected from continuation. It may be equal to or greater than the amortization period and may be equal to, but is generally less than, the physical life.

PMA's - Power Marketing Agencies.

Public Law 85-500, Title III, Water Supply Act of 1958, as amended - 1958 River and Harbor Act, 3 July 1958. Title III of this act is entitled The Water Supply Act of 1958. Section 301 provided that storage may be included for present and future municipal or industrial water supply in Corps projects and that the costs plus interest must be repaid by non-Federal entities within the life of the project but not to exceed 50 years after first use for water supply. No more than 30 percent of total project costs may be allocated to future demands. An interest-free period, until supply is first used, but not to exceed ten years, was permitted (72 Stat. 319, 43, U.S.C. 390b). These provisions were modified by Section 10 of Public Law 87-88 and Section 932 of Public Law 99-662.

Safe, dependable or critical period yield - the maximum quantity of water reliably available throughout the most severe drought of record.

Storage - the volume in a reservoir project between two different elevations. The normal unit of storage space is acre-feet. There may or may not be any water available within this space.

SWPA - Southwestern Power Administration.

Water Supply Handbook - IWR Report 96-PS-4 (Revised).

WRDA, or Water Resource Development Act - an act of Congress to provide for the conservation and development of water and related resources.

Yield - The quantity of water which can be taken, continuously, for any particular economic use. For municipal and industrial water supply purposes, this is normally taken as the flow which can be guaranteed during the 50-year drought on a 98 percent dependability.

LAKE OUACHITA ANALYSIS

WATER SUPPLY STORAGE REALLOCATION REPORT AT LAKE OUACHITA FOR THE MID-ARKANSAS WATER ALLIANCE

1. PURPOSE

A. REALLOCATION REQUEST

A U.S. Army Corps of Engineers study, The Mid-Arkansas Water Resource Study, was completed in November 2002 for the Mid-Arkansas Water Discussion Group to evaluate future water needs of central Arkansas and identify sources to meet those needs through the year 2050. Based upon the results of this study, the group decided that the best alternative for obtaining water for the central Arkansas area south of the Arkansas River would be to purchase the remaining Corps of Engineers discretionary storage in Lake Ouachita. On April 4, 2003, the Mid-Arkansas Water Discussion Group evolved into the Mid-Arkansas Water Alliance (MAWA) and was incorporated.

Another U.S. Corps of Engineers Study, Mid-Arkansas Water Resource Study Update, was completed in December 2004 to update the needs of the eight counties in central Arkansas that comprise MAWA because the member utilities doubled since the initial report was completed. The purpose of this study was primarily to consider the population and demand based on the new members. Furthermore, this study took into consideration the existing raw water sources that were available to Central Arkansas Water, which were not considered in the initial study. Based on these findings and after meetings with the Little Rock District, MAWA decided their goals could be met through the year 2025 by reducing their initial request. A letter requesting the purchase of storage to provide 30 million gallons per day (mgd) from Lake Ouachita was submitted to the Little Rock District on May 9, 2005, by MAWA.

B. REALLOCATION AUTHORITY

Authority for the Corps to reallocate existing storage space to municipal and industrial (M&I) water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended. The Secretary of the Army is authorized to cooperate with local interests in providing storage space for M&I water supply in Corps projects as long as the local interests agree to pay the costs associated with the storage space. The Chief of Engineers has the discretionary authority to reallocate provided the reallocation has no significant effect on other authorized purposes and will not involve major structural or operational changes. If so, Congressional authorization is required.

C. DAM SAFETY ACTION CLASSIFICATION

Blakely Mountain Dam currently has a Corps of Engineers Dam Safety Action Classification (DSAC) III rating. The DSAC III rating is for dams with confirmed and unconfirmed dam safety issues where the combination of life or economic consequences with probability of failure relative to other dams is moderate to high. The Corps of Engineers policy prohibits reallocation of flood pool storage to other purposes if a dam has a DSAC rating of I, II, or III. Reallocation of conservation pool storage (below normal pool) is acceptable for DSAC III under the policy.

2. PROJECT BACKGROUND

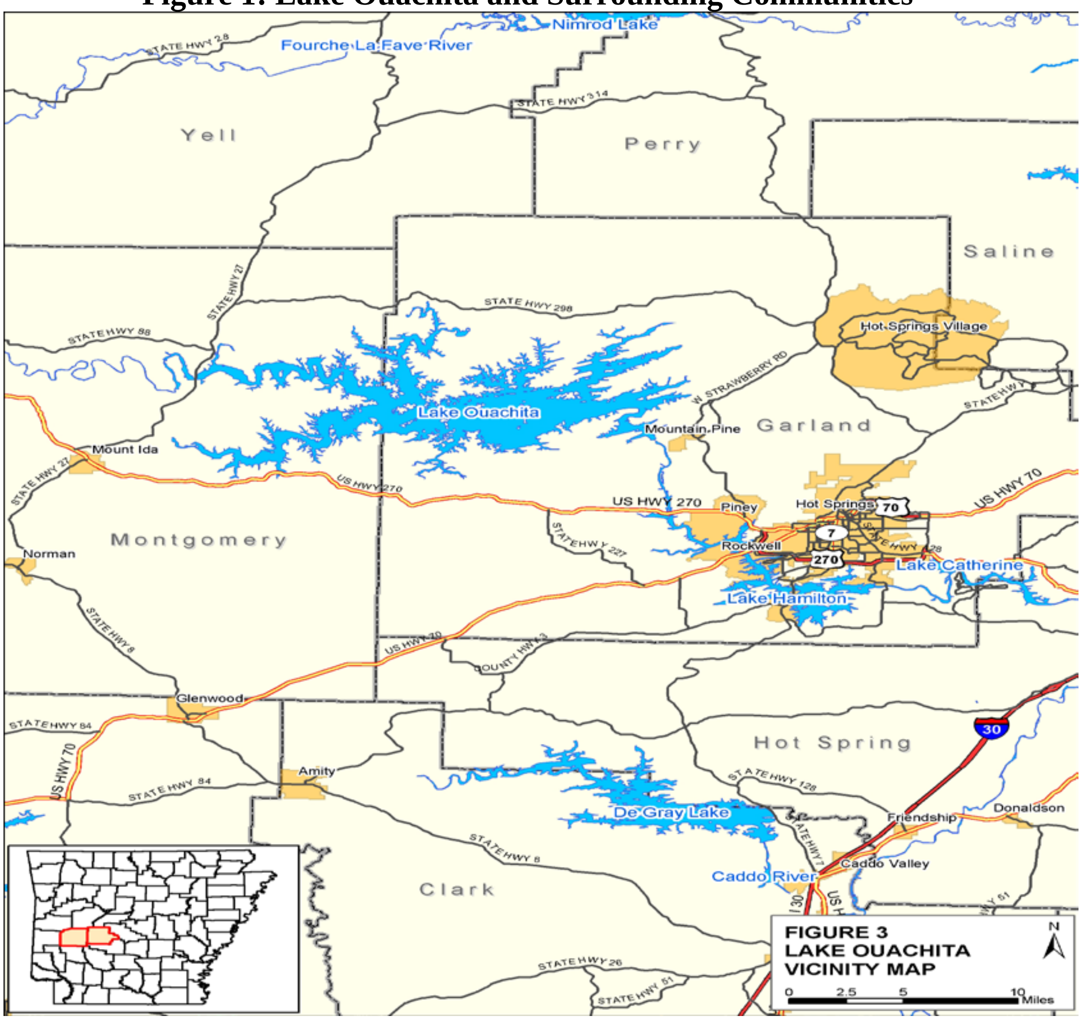
A. PROJECT HISTORY

House Document No. 647, 78th Congress, 2d Session, recommended the construction of Blakely Mountain Dam – Lake Ouachita Project, Arkansas, for flood control, hydroelectric power, and other purposes. The Flood Control Act of 1944 (Public Law 534, 78th Congress, 2nd Session) authorized the construction, operation and maintenance of this project.

B. PROJECT PURPOSES AND LOCATION

Blakely Mountain Dam that impounds Lake Ouachita is located at mile 430.4, approximately 10 miles northwest of Hot Springs in Garland County, Arkansas, and 487 miles above the mouth of Black River. The project is a feature of the comprehensive plan for water resources development in the Ouachita River Basin. Specifically authorized project purposes are flood control and hydroelectric power. Other functions benefiting from the project include recreation, fish and wildlife, and navigation. Below in Figure 1 is a vicinity map of Lake Ouachita.

Figure 1: Lake Ouachita and Surrounding Communities



Spillway construction began in August 1947 and the powerhouse was completed in October 1955. Blakely Mountain Dam consists of an earth fill dam, spillway, intake structure, flood control conduit and stilling basin, power conduit, surge tank, penstocks, powerhouse, switchyard, appurtenant structures, and hydroelectric, power generating facilities. The dam is approximately 235 feet in height above the streambed and 1,100 feet in length at the crest elevation of 616 feet, mean sea level (MSL). The reservoir has a total capacity of 2,768,000 acre-feet below spillway crest, of which 864,900 acre-feet are below minimum pool. Of the total, 1,286,000 acre-feet are for power production and 617,000 acre-feet are for flood control.

Current physical features of Blakely Mountain Dam and Lake Ouachita Reservoir are shown below in Table 1.

TABLE 1
CURRENT PROJECT PHYSICAL FEATURES

Feature	Elevation[1]		Area (acres)	Storage Volume (acre-feet)	Equiv. Runoff[2] (inches)
Top of dam	616.00		----	----	
Top of flood control pool	592.00		48,300	2,768,000	47.0
Top of conservation pool	578.00		40,100	2,151,000	36.5
Top of inactive pool	535.00		20,900	865,000	14.7
Flood control storage	578.00 -	592.00	----	617,000	
Conservation Storage	535.00 -	578.00	----	1,286,000	
Inactive storage	Below elev.	535.00	----	865,000	

[1] Above the National Geodetic Vertical Datum (NGVD29).
[2] From 1,105 square miles of drainage area upstream from dam.

The power storage is contained between elevation 535.0 and 578.1 feet MSL, with average fluctuations of approximately 10 feet below elevation 578.1. The flood control pool has sufficient storage to manage risk of the flood of record, and its operation will reduce flooding below the dam and along the Ouachita River to the vicinity of Moro Bay, Arkansas.

The hydroelectric facility has two conventional units of 37,500-kilowatt capacity, which were both placed online in October 1955, with the usual control, switching, transforming, and operating equipment. Two other Federal projects (Narrows and DeGray Dams) are operated by remote facilities located in the Blakely Mountain powerhouse. Power generated at Blakely Mountain’s powerhouse is marketed by the Southwestern Power Administration (SWPA). Listed below in Table 2 is the pertinent data for Blakely Mountain Dam and Lake Ouachita Reservoir.

TABLE 2
BLAKELY MOUNTAIN DAM AND LAKE OUACHITA
RESERVOIR PERTINENT DATA

Dam Location	
State:	Arkansas
County:	Garland
Nearest Community:	Royal
River:	Ouachita River
Mile:	430.4
Latitude:	34.573
Longitude:	-93.188
Upstream Federal Projects:	N/A
Federal Projects Downstream:	N/A
Other Non-Federal Projects:	Carpenter Dam Remmel Dam
Drainage Area:	1,105 square miles
Authorization, Project Purposes, and History of Construction	
Authorizing Legislation:	Flood Control Act of 1944, Public Law 53, 78th Congress, 2nd Session
Project Purposes:	Flood Control, Water Supply, Hydroelectric, Recreation
History of Construction:	
Construction Began:	August 1947
Closure of Embankment:	September 1953
Project Completed:	October 1955
Type of Structure	
Earth filled dam with a center core of impervious material and random fill material upstream and downstream of the impervious core	
Total Dam Length	1,100 feet
Concrete Spillway, uncontrolled (saddle)	1,400 feet
Spillway and Outlet Works	
Spillway	Net operating width 200 feet
Tunnels	Power tunnel is 30 feet in diameter and 1,440 feet. Flood control tunnel is 19 feet in diameter and 1,640 feet long.

C. WATER REALLOCATION

Storage for water supply has been reallocated once since the construction of Blakely Mountain Dam – Lake Ouachita. This water supply agreement was executed on February 14, 1996, between the North Garland County Regional Water District (NGCRWD) and the United States Government. The agreement was for 1,575 acre-feet (current yield analysis data requires 1,668 acre-feet to provide 1 mgd) of storage to provide a yield of 1 mgd.

The Hydrology and Hydraulics (H&H) analysis (See Appendix B) concluded that 49,983 acre-feet of storage in the conservation pool would be required to supply MAWA's 30 mgd of demand. However, reallocating water from the conservation pool would require forgoing a portion of authorized hydropower production at Lake Ouachita. Reallocation from the conservation pool would not create a significant effect on hydropower production at the project and will be further addressed in the hydropower analysis.

While the Corps reallocation authority is for storage and not safe yield, the intent and actual calculations are based on using the safe yield requested by the customer to determine the amount of storage that will provide that yield. As stated in the Water Supply Handbook, IWR Report 96-PS-4 (Revised), page 2-3, "Repayment agreements for storage space will base the amount of storage to be provided on the yield required by the non-Federal sponsor."

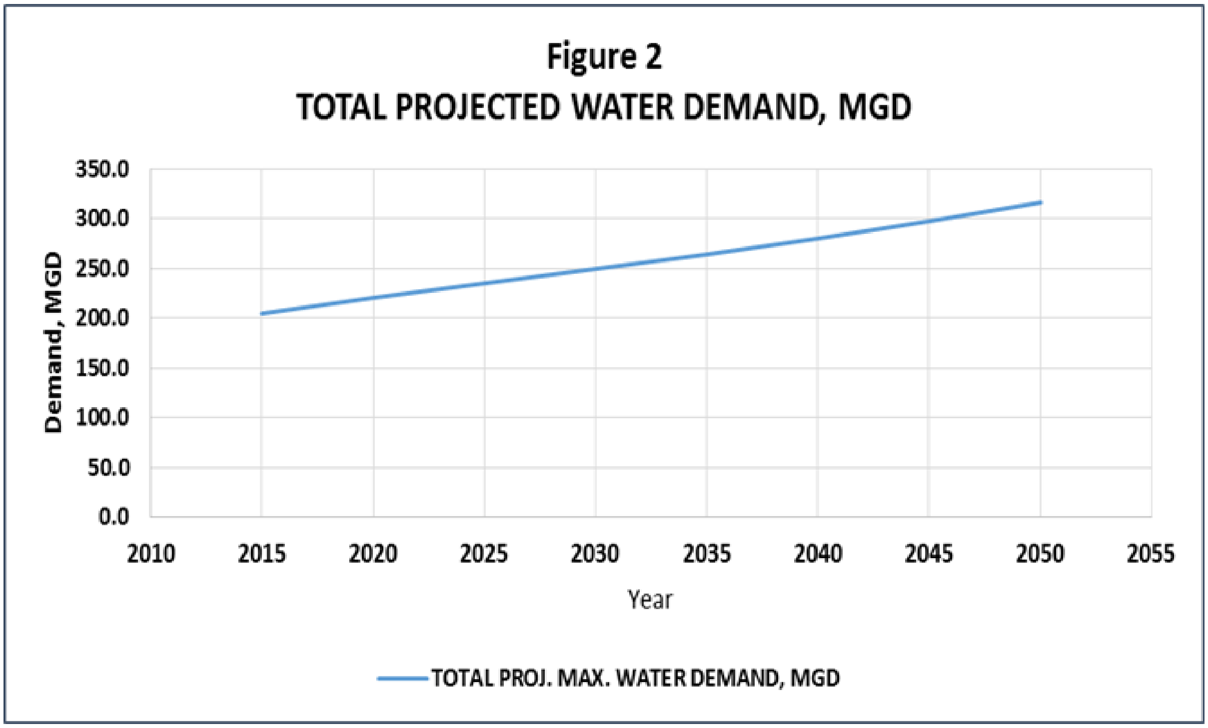
3. ECONOMIC ANALYSIS

A. WATER SUPPLY DEMAND ANALYSIS

The Mid-Arkansas Water Resource Demand Model, February 2016, was provided to USACE by the non-Federal sponsor. Data inputs into this detailed model included population data, growth projections, and water demand by entity. The model also included the variability associated with climate change. The model was approved for use by a USACE Headquarters panel in June 2016.

The presented data show the population of 27 participating entities of 875,400 in year 2015 and is projected to be approximately 1,400,000 in the year 2050. Some of the larger cities benefiting from this water reallocation include Hot Springs, Heber Springs, and Benton, Arkansas. Water usage within central Arkansas averaged 129 mgd in 2015, with a peak usage of 235 mgd in the summer months.

The current safe yield for water supply available in central Arkansas is 175 mgd which may not currently meet peak usage during a drought. Central Arkansas has experienced rapid growth and development. As population in the area continues to increase, manufacturing and service industries will most surely follow. Figure 2 displays a graph of Central Arkansas' historical and projected water demand. The maximum projected water demand for the study area shows a demand of 233 mgd for 2015 and approximately 355 mgd in 2050.



B. ANALYSIS OF WATER SUPPLY ALTERNATIVES
Five alternatives were considered during Lake Ouachita water reallocation study. A description of each alternative is listed below.

(1) Alternative 1 - No Action.
The no-action alternative does not allow for the future water supply needs for members of MAWA. This would be inconsistent with existing and future water supply needs for the association and could severely impact the safety and health of their customers.

(2) Alternative 2 - Reallocate from Conservation Pool.
This alternative would reallocate 49,983 acre-feet from the conservation pool of Lake Ouachita. Reallocation of the conservation pool storage from Lake Ouachita allows for the following: provide a feasible local alternative for water supply, help sustain economic growth and development in the area. This reallocation will not alter the operations that was envisioned by Congress when originally authorized, and will have no significant impact on hydropower production. The loss in capability for the conservation pool shows an average generation capacity loss of 1.22 megawatts, which is a minimal impact on the project's hydropower production. This will be further discussed in the report. If a reallocation was to occur from the conservation pool, the power marketing authority would receive accounting credits for any impacts.

(3) Alternative 3 - Groundwater
Groundwater in central Arkansas is drawn from two aquifer systems--the alluvial aquifer system and the Mississippi Embayment aquifer system. The alluvial system consists of the Arkansas River aquifer and the more extensive Mississippi River Valley aquifer.

The Mississippi Embayment aquifer underlies the alluvial aquifers although these aquifers are connected to each other throughout eastern Arkansas. The alluvial aquifers can yield large quantities of water; properly constructed wells can yield 500 gallons per minute (gpm) almost anywhere in the system. Wells in the Mississippi River Valley system have been reported to yield as much as 5,000 gpm. The Mississippi Embayment aquifer system is comprised of several aquifers—the Nacatoch, the Wilcox, the Sparta, and the Cockfield. The Sparta, the most productive aquifer, is capable of producing yields in excess of 1,000 gpm.

As a result of large scale groundwater withdrawals primarily for rice farming, groundwater levels in the state are declining. Declining aquifer water levels create a multitude of problems. Because of the excessive withdrawals of groundwater, the safe yield has been approached or exceeded in the alluvial and Sparta aquifers. The Arkansas Soil and Water Conservation Commission have declared these aquifers as "critical groundwater levels" due to the safe yield concerns relating to poor water quality and to saline intrusions consistent with declining groundwater levels. Several of the existing entities currently use groundwater and are experiencing difficulty in obtaining adequate water from their sources. Therefore, alternatives utilizing groundwater sources are not considered as a viable option.

(4) Alternative 4 - Reallocate from Flood Control Pool.
This alternative would reallocate 49,983 acre-feet from the flood control pool of Lake Ouachita. The Corps of Engineers policy prohibits reallocation of flood pool storage to other purposes if a dam has a DSAC rating of I, II, or III. Currently, this project has an assigned DSAC III rating. In order for this alternative to be considered as an option, the dam's DSAC rating would have to be a DSAC IV. Based on information provided by Vicksburg District Engineer's, it would cost an estimated $ 2.5 million in modifications to potentially reach a DSAC IV rating. Actions include performing a Phase 2 Issues Evaluation Study (IES), construct emergency power tunnel bulkheads, update the emergency action plan (EAP), improved warning system downstream of the project, load rate the Powerhouse Bridge, and additional improvements to the dam's instrumentation. Performing these updates and modifications would not guarantee an improvement to a DSAC IV project. Due to the estimated cost and the uncertainty of the dam being reclassified as a DSAC IV, this alternative is not considered a viable option.

(5) Alternative 5 – Development of New Surface Reservoirs.
For this alternative, MAWA would find a suitable location within the watershed and construct a new reservoir to supply their storage needs. Estimating a cost for a project of this magnitude that provides both water supply and flood control is not easily quantifiable. However, for this example, it is assumed that the cost to construct a new dam would be comparable as the recent built Portuguese Dam near Ponce, Puerto Rico. Portuguese Dam is 220 feet tall at the crest with a length of 1,230 feet. In comparison, Blakely Mountain Dam is 231 feet tall at the crest and 1,110 feet long. Portuguese Dam was put into operation in 2015 at a construction cost of $375 million which does not include mitigation or lands, easements, right-a-ways, and disposal areas

(LERRDS). It was assumed that construction of Alternative 5 would take three years to complete with operation and maintenance (O&M) cost being accounted for once the dam was put into operation. The total capital expenditure and O&M cost were annualized over a 50 year life cycle at the Federal Discount rate of 3.125%. The first ten years would have annual O&M cost of $150,000 for minimum maintenance, but that cost would increase to $3,000,000 per year from year eleven to fifty. The results of this analysis gives a total present value of $403.5 million or $17.8 million in annual average cost. Due to the estimated cost and the potential environmental uncertainty associated with constructing a dam, this alternative is not considered a viable option.

4. DERIVATION OF USER COST

A. YIELD/STORAGE ANALYSIS

(1) General

Due to the high cost of modifications to reach a DSAC IV rating and the current DSAC III rating, the only option evaluated for reallocation of storage in Lake Ouachita was using storage from the conservation pool. Current storage and yields from the conservation pool are between elevations 535.00 and 578.00 which contains 1,286,000 acre-feet of storage. MAWA's request of 49,983 acre-feet would result in remaining space of 1,236,017 acre-feet for hydropower usage. The safe yield of this storage during the drought of record is 794 mgd.

(2) Conservation Pool

When storage is reallocated from the conservation pool there is no change in the yield of the pool. The reallocation is made directly from hydropower storage causing both a reduction in their existing storage and a reduction in their yield.

B. HYDROPOWER EFFECTS

The hydropower section of the report was prepared by the Corps of Engineers Hydropower Analysis Center (HAC) in Portland, Oregon. See Appendix A for the complete analysis. The procedures for computing the cost of reallocating water from hydropower to water supply use are outlined in ER 1105-2-100, *Planning Guidance Notebook* (22 April 2000), Appendix E, paragraph E-57, d(2). These procedures require that the reallocation cost charged to water supply customers be the highest of the following:

- power benefits foregone
- power revenues foregone
- replacement costs of power
- updated cost of storage

Power benefits foregone, power revenue foregone, and the replacement costs of power are impacts to hydropower. Power benefits foregone and power revenue foregone are calculated in this report. The replacement cost of power is equal to power benefits foregone and therefore is not calculated separately.

Benefits Foregone Overview

Hydropower benefits are based on the cost of the most likely alternative source of power. When storage is reallocated for water supply and an impact occurs to hydropower, the power benefits foregone are equivalent to the cost of replacing the lost power with the most likely alternative source of power.

The power benefits foregone can be divided into two components--the lost energy benefits and capacity benefits. In the case of water supply withdrawals, there is usually a loss of energy benefits, and lost energy benefits are based on the loss in generation (both at-site and downstream) as a result of water being diverted from the reservoir for water supply rather than passing through the hydro plant. In addition, there could be a loss of capacity benefits as a result of a loss in dependable capacity at the project. Dependable capacity could be lost as a result of:

- A loss in head due to lower post-withdrawal reservoir elevations;
- A reduction in the usability of the capacity due to inadequate energy to support the full capacity during low-flow periods.

Energy benefits foregone are computed by multiplying the expected monthly loss in megawatt-hours (MWh) by the average monthly price of energy in dollars per megawatt-hour ($/MWh) over the period of analysis, differentiating for on-peak and off-peak. Energy prices are based on the marginal cost of energy from the existing regional generation resources expected to replace the energy lost from hydropower generation.

For each month of the year, the present value of forecast energy prices (values) over the 50-year period of analysis is amortized to produce annualized monthly prices. The product of the annualized monthly energy price and the average monthly energy loss due to water withdrawals represents the annualized energy benefits foregone for that alternative.

Capacity benefits foregone are computed by first determining a composite cost per megawatt representing the annualized fixed cost of the combination of thermal power plants most likely to replace the power lost to the Ouachita River system as a result of the reallocation alternatives. Next, the loss of generating capability for each alternative is calculated using the average availability method. Capacity benefits foregone are the product of the loss of generating capability and the composite fixed cost of the most likely mix of replacement thermal power plants.

(1) ENERGY BENEFITS FOREGONE

The amount of flow through the Blakely Mountain powerhouse under existing conditions and under the reallocation of storage for water supply at Lake Ouachita was simulated by the Little Rock District for Vicksburg District using stream flows from the historical period of record (1961–2012) in RESSIM, a sequential stream flow routing model.

The regional definition of on-peak hours of generation is 6 a.m. to 10 p.m. on weekdays and Saturdays. The off-peak hours of generation are the remaining hours on weekdays and all hours on Sunday. However, because generation by plants in the Ouachita River system is concentrated in a subset of the highest-value weekday peak hours to fulfill power contracts, these hours were evaluated separately as contract on-peak hours in order not to understate their value. Table 3 presents the distribution of contract-peak hours, non-contract peak hours, and off-peak hours for each month of the year, and also for weekends. A schedule of contract peak hours was provided by Southwestern Power Association (SWPA), an agency of the U.S. Department of Energy.

TABLE 3
YEAR GENERATION SCHEDULE FOR THE LAKE OUACHITA HYDROPOWER PLANT

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours
Weekdays			
January	5	11	8
February	3	13	8
March	3	13	8
April	3	13	8
May	3	13	8
June	5	11	8
July	9	7	8
August	9	7	8
September	4	12	8
Weekdays			
October	3	13	8
November	3	13	8
December	5	11	8
Weekends (All Year)			
Saturdays	0	16	8
Sundays	0	0	24

As an example of how energy production is allocated between on-peak and off-peak designations, Table 4 below shows the simulated energy production for Lake Ouachita for the week of April 2, 1962, under existing (baseline) conditions. The capability is constant so the maximum on-peak production Monday through Friday would be 16 hours per day of generation at the plant capability of about 88 megawatt (1,408 MWh), of which three hours would be contract generation (~264 MWh) and the remaining 13 hours would be non-contract generation (~1,144 MWh). Generation in excess of 16 hours on weekdays and Saturdays is off-peak energy. All power generated on Sunday is also off-peak energy.

TABLE 4
ON-PEAK AND OFF-PEAK ENERGY ALLOCATION

DATE	Day	Capability (MW)	Energy Production (MWh)	On-Peak Energy (contract) (MWh)	On-Peak Energy (non-contract) (MWh)	Off-Peak Energy (MWh)
2-Apr-62	Monday	88.56	946.2	265.7	680.5	0.0
3-Apr-62	Tuesday	88.63	946.2	265.9	680.3	0.0
4-Apr-62	Wednesday	88.29	2,297.2	264.9	1,147.8	884.6
5-Apr-62	Thursday	88.19	2,299.8	264.6	1,146.5	888.8
6-Apr-62	Friday	88.06	2,303.1	264.2	1,144.8	894.2
7-Apr-62	Saturday	87.94	1,226.3	0.0	1,226.3	0.0
8-Apr-62	Sunday	88.13	490.9	0.0	0.0	490.9

Table 5 is a summary of monthly corresponding energy loss from the conservation pool alternative. For clarity, losses are expressed as negative numbers, and increases in generation are presented as positive numbers. Each monthly condition (e.g., Weekdays, Off-Peak; Saturdays On-Peak, etc.) was calculated and summed in the subtotal row. Each subtotal was then summed together to provide the total expected yearly loss of energy at Blakely Mountain.

TABLE 5
AVERAGE MONTHLY ENERGY LOSSES (MWh) AT LAKE OUACHITA, BLAKELY MOUNTAIN HYDROPOWER PLANT

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	On-Peak (non-contract)	Off-Peak	Off-Peak
Jan	-224.30	-464.22	-389.61	-143.00	-79.68	-187.82
Feb	-73.14	-383.08	-147.25	-45.55	2.45	-100.35
Mar	-69.05	-464.01	-99.44	-103.38	-33.70	-78.53
Apr	-117.21	-423.27	-118.72	-90.12	-32.70	-52.88
May	-67.86	-241.55	-73.87	-76.42	-62.73	-47.77
Jun	-78.87	-231.08	-60.64	-69.36	-29.42	-76.78
Jul	-333.47	-27.12	-8.12	-60.17	0.12	-64.53
Aug	-410.90	-2.23	0.00	-85.04	0.00	-113.07
Sep	-52.92	-0.20	-5.12	-15.99	0.13	-34.72
Oct	-165.32	-36.16	-17.99	-45.82	0.00	-44.51
Nov	-208.73	-155.33	-29.35	-47.73	-19.10	-59.26
Dec	-176.37	-130.81	-71.83	-46.22	-9.12	-59.66
subtotal	-1,978.15	-2,559.06	-1,021.94	-828.79	-263.76	-919.87
TOTAL	-7,571.57					

The average annual loss of contract on-peak energy resulting from the conservation pool alternative is about 1,978 MWh. If SWPA loses the ability to generate an average of approximately 1,978 MWh each year during on-peak contract hours, they will necessarily need to reduce the capacity they market for contract on-peak hours by approximately

1.65 megawatts (1,978 MWh loss divided by 1,200 hours firm energy per megawatt of marketed capacity) once the current contract expires in 2031. This will cause a reduction in annual capacity revenue of approximately $91,000 per year at current rates.

COMPUTATION OF ENERGY PRICES

Energy benefits are computed as the product of the energy loss in megawatt-hours and an energy unit value price ($/MWh). The energy price is based on the cost of energy that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

A forecast of future energy prices is needed to evaluate the resulting changes in hydropower benefits over a 50-year period of analysis. These forecasted prices also need to reflect seasonal variation of both peak (contract and non-contract) and off-peak prices.

To estimate regional future energy prices that reflect both seasonal peak and off-peak variation, two sources of data are required. The first data source is the Energy Information Administration (EIA) long term energy forecast, while the second data source is the Southwestern Power Pool historical Locational Imbalance Price (LIP) for SWPA pricing node.

Table 6 shows the average annual energy prices in 2016 dollars from the analysis. A more detailed description is listed in Appendix B.

TABLE 6
AVERAGE ANNUAL ENERGY PRICES (2016 DOLLARS)

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	On-Peak (non-contract)	Off-Peak	Off-Peak
Jan	$66.00	$46.86	$31.52	$55.77	$40.03	$40.18
Feb	$63.07	$45.22	$31.73	$49.60	$35.43	$33.12
Mar	$56.72	$37.70	$25.26	$41.00	$29.09	$33.69
Apr	$58.72	$41.22	$25.46	$43.35	$26.04	$31.24
May	$61.37	$39.77	$22.05	$51.15	$26.33	$33.34
Jun	$57.55	$42.70	$24.39	$53.25	$30.85	$36.71
Jul	$64.06	$45.94	$30.57	$59.71	$37.89	$42.43
Aug	$58.63	$42.20	$29.67	$63.93	$33.30	$39.46
Sep	$52.73	$38.04	$22.65	$47.17	$29.00	$32.14
Oct	$56.95	$38.93	$25.90	$41.94	$29.93	$32.31
Nov	$62.45	$35.17	$25.74	$39.10	$26.44	$30.07
Dec	$51.34	$35.66	$27.51	$37.46	$28.32	$33.99

The final step is to multiply the total average monthly generation of contract on-peak, on-peak and off-peak energy in Table 5 by the average annual energy prices by month in Table 6 to obtain energy benefits foregone by month which are then summed.

Foregone energy benefits based on 2016 dollars are shown below in Table 7. Based on the analysis, it was estimated that $337,000 of energy benefits would be foregone by reallocating 49,983 acre-feet of water from the conservation pool.

TABLE 7
FOREGONE ENERGY BENEFITS (2016 DOLLARS)

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	On-Peak (non-contract)	Off-Peak	Off-Peak
Jan	($14,802.73)	($21,752.04)	($12,282.12)	($7,974.73)	($3,189.65)	($7,547.25)
Feb	($4,613.51)	($17,322.92)	($4,672.49)	($2,259.30)	$86.84	($3,323.85)
Mar	($3,916.95)	($17,491.01)	($2,511.60)	($4,238.03)	($980.40)	($2,645.78)
Apr	($6,881.77)	($17,445.18)	($3,022.90)	($3,906.83)	($851.69)	($1,651.86)
May	($4,164.86)	($9,606.62)	($1,628.55)	($3,908.46)	($1,652.04)	($1,592.65)
Jun	($4,539.59)	($9,866.84)	($1,479.17)	($3,693.49)	($907.62)	($2,819.03)
Jul	($21,362.41)	($1,245.67)	($248.17)	($3,592.43)	$4.55	($2,737.76)
Aug	($24,089.37)	($94.11)	$0.00	($5,435.91)	$0.00	($4,461.28)
Sep	($2,790.37)	($7.48)	($115.97)	($754.14)	$3.88	($1,115.90)
Oct	($9,414.97)	($1,407.52)	($465.77)	($1,921.81)	$0.00	($1,438.28)
Nov	($13,035.04)	($5,462.67)	($755.59)	($1,866.40)	($505.14)	($1,782.15)
Dec	($9,054.51)	($4,664.47)	($1,975.76)	($1,731.38)	($258.37)	($2,027.81)
subtotal	($118,666.08)	($106,366.52)	($29,158.09)	($41,282.92)	($8,249.64)	($33,143.60)
TOTAL	**($336,866.85)**					

(2) CAPACITY BENEFITS FOREGONE

Capacity benefits foregone are defined as the product of the loss in power plant capability and a capacity unit value, which represents the capital cost of constructing replacement thermal capacity.

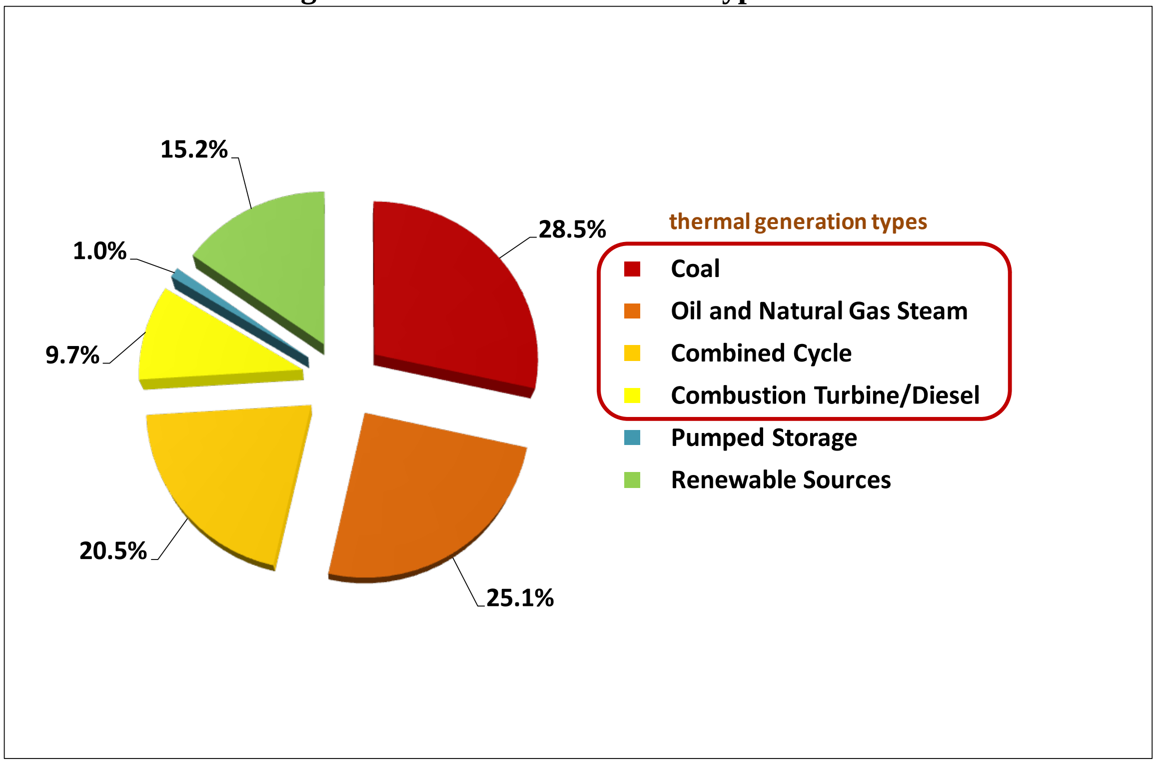
A hydropower project's capability is a measure of the amount of energy that the project can reliably contribute towards meeting system peak power demands. If a hydropower project always maintains approximately the same head, and there is always an adequate supply of stream flow so that there is enough generation for the full capability to be usable in the system load, the full installed capacity can be considered to be the capability. In some cases even the overload capacity can be used as its capability.

However, at storage projects, normal reservoir drawdown can result in a loss of capability due to a loss in head. At other times, stream flows in low flow periods may result in insufficient generation to support the available capability in the load. Capability accounts for these factors by giving a measure of the amount of capability that can be provided with some degree of reliability during peak demand periods.

The most appropriate method for evaluating a hydropower plant’s capability in a predominantly thermal-based power system is the average availability method, as described in Section 6-7g of EM 1110-2-1701, *Hydropower*, dated December 31, 1985. The occasional unavailability of a portion of hydro project's generating capability due to hydrologic variations is treated in the same manner as the occasional unavailability of all or part of a thermal plant's generating capacity due to forced outages. The average availability method attempts to measure the average capability available during the peak demand periods of the year.

The Southwest Power Pool (SPP) (SPP-southern sub-region) is primarily a thermal-based power system with only a small amount of hydropower, as illustrated in Figure 3. Consequently, the average availability method is the most appropriate method for measuring capability for this analysis.

Figure 3. Thermal Generation Type for SPP



Source: Annual Energy Outlook 2013, Energy Information Agency, U.S Department of Energy

HYDROLOGIC PERIOD OF ANALYSIS

In order to evaluate the average capability of a project during its peak demand season, a long-term record of project operation must be used. Actual project operating records can be used, but the period of operation may not be long enough to give a statistically reliable value. Furthermore, operating changes may have occurred over the life of the project, which would make actual data somewhat inconsistent.

An alternative method is the use of a period-of-record computer simulation of system operation. As previously described, the Little Rock District provided a daily simulation of the Ouachita River projects over the period of record of 52 years, from 1961 through 2012. This simulation, which was performed using the RESSIM stream flow routing model, served as the basis of this study’s dependable capacity computations. Because reallocation of water at Lake Ouachita changes the amount of water available for power, capability calculations were performed for each project and then summed to estimate changes in capability for Lake Ouachita.

The initial step is to calculate the project's contribution (average weekly generating hours) to the system's capacity for the regional critical year. That contribution estimate was determined by first calculating the project's average weekly energy produced (MWh) for the peak demand months of June through September in 1964, which appears to be a critical year for water availability and power generation. That number was then divided by the marketable capacity (megawatt), giving an estimate of average weekly generating hours during the peak demand months. These values, as well as the marketable capacity and machine capability (i.e., the overload capacity) for Lake Ouachita, are presented in Table 8.

TABLE 8
GENERATION CAPABILITY FOR LAKE OUACHITA

Machine Capability (MW)	88.59
Average Weekly Energy (MW) (critical period)	2,548.14
Marketable Capacity (MW)	75
Average Weekly Generation Hours (critical period of 1964)	33.98

Next, the project's average weekly energy (MWh) produced during the peak demand months was calculated for each simulated year. Dividing those values by the project's average weekly generating hours from the critical period, as determined in the previous step, yields an array of yearly potential supportable capacity values. However, energy produced is limited by the machine capability of the project. The actual supportable capacity for any given year is consequently the lesser of the potential supportable capacity or the machine capability. With the average availability method, capability is the average actual supportable capacity over the period of record.

As an example of how dependable capacity is calculated, Table 9 shows the values described in the previous paragraphs for the baseline, or no-action, alternative for Lake Ouachita for the years 1961 through 2012 (the years 1974-1999 are not shown for brevity). The average actual supportable capacity for the years 1961 through 2012 for Lake Ouachita is 83.96 megawatts. For most years, the actual supportable capacity is equal to the machine capability (overload capacity) of the project. This is not surprising because the capability is calculated based on the average number of generating hours per week in a critical year in which water was scarce.

TABLE 9
CAPABILITY CALCULATIONS FOR EXISTING CONDITIONS, LAKE OUACHITA, 1961-2012 PERIOD OF RECORD

Year	Average Weekly Energy (MWh)	Potential Supportable Capacity (MW)	Machine Capability (MW)	Actual Supportable Capacity (MW)
1961	3,414.93	100.5	88.55	88.55
1962	2,654.21	78.1	89.29	78.12
1963	2,873.58	84.6	88.58	84.58
1964	2,548.14	75.0	88.65	75.00
1965	3,404.78	100.2	88.57	88.57
1966	3,125.40	92.0	88.57	88.57
1967	4,024.04	118.4	88.47	88.47
1968	7,484.12	220.3	88.46	88.46
1969	3,928.07	115.6	88.39	88.39
1970	3,022.04	88.9	88.63	88.63
1971	2,686.62	79.1	88.65	79.08
1972	2,295.11	67.6	88.69	67.55
1973	6,126.21	180.3	88.27	88.27
…	…	…	…	…
2000	5,207.35	153.3	88.48	88.48
2001	2,713.50	79.9	88.58	79.87
2002	3,100.56	91.3	88.65	88.65
2003	4,469.53	131.6	88.52	88.52
2004	3,777.85	111.2	88.54	88.54
2005	2,167.63	63.8	88.79	63.80
2006	2,470.76	72.7	88.69	72.72
2007	3,398.84	100.0	88.52	88.52
2008	5,600.89	164.9	88.27	88.27
2009	7,703.01	226.7	88.30	88.30
2010	4,502.63	132.5	88.60	88.60
2011	6,019.26	177.2	88.60	88.60
2012	1,969.92	58.0	88.79	57.98
			Capability	83.96

Table 10 summarizes the capability for Lake Ouachita under the no-action, reallocation from the conservation pool alternatives. The loss in capability for the conservation pool is also presented, and shows an average generation capacity loss of 1.22 megawatts, which is a minimal impact on the project’s hydropower production.

TABLE 10
SUMMARY OF LAKE OUACHITA GENERATION CAPABILITY

Under No Action Plan	83.96 MW
Allocation from Conservation Pool	82.74 MW
Change in Capability Due to Allocation	-1.22 MW

COMPUTATION OF CAPACITY VALUES

Capacity benefits are an estimate of the investment cost of thermal generating plant capacity that would be needed to replace the lost capacity due to the water withdrawals from the reservoir. Capacity benefits are computed as the product of the capability loss and a capacity unit value, which is based on the unit cost of constructing the most likely thermal generating alternative.

A screening curve analysis was conducted to determine the mix of thermal resources that would be the most likely (least-cost) generation plant alternatives for each of the White River hydropower plants. The type of alternative plants considered were coal-fired steam (base loads displacement), gas-fired combined cycle (intermediate loads displacement), and gas-fired combustion turbine (peak loads displacement). Appendix A provides a more detailed summary concerning the screening curve.

A composite capacity value (see Appendix A) is then converted to dollars per megawatt-year and multiplied by the respective changes in capability from Table 10 to give capacity benefits foregone. The effect of the conservation pool alternative on project capability is a small loss. Composite capacity values and capacity benefits foregone are summarized in Table 11.

TABLE 11
CAPACITY BENEFITS FOREGONE FOR THE CONSERVATION POOL
(2016 DOLLARS)

	Lake Ouachita
Change in Capability (MW)	-1.22 MW
Composite Capacity Values ($/kW-year)	$94.52
Average Annual Capacity Benefits Foregone	$115,300

(3) SUMMARY OF BENEFITS FOREGONE

Table 12 summarizes power benefits foregone for Lake Ouachita hydropower project due to water reallocation from conservation pool storage. Results of power benefits foregone, shown in Table 12, are a summation of foregone energy and capacity benefits discussed earlier in the report. The results indicate that $452,000 in annual power benefits would be foregone by reallocating storage from the conservation pool.

TABLE 12
SUMMARY OF AVERAGE ANNUAL POWER BENEFITS FOREGONE
(2016 DOLLARS)

Energy Benefits Foregone	$337,000
Capacity Benefits Foregone	$115,000
Total Hydropower Benefits Foregone	$452,000

(1) Hydropower Revenues Forgone

Revenue foregone is to be based on the current SWPA contract rates applicable to power generation by Lake Ouachita hydropower plant.

The SWPA developed the composite revenue rate from the current power sales contract rates which are--firm energy rate of $15.30 for on-peak production, and $9.40/MWh for off peak production and on-peak production (non-contract).

To compute energy revenues foregone, the contract peaking energy rate is applied to the average annual on-peak contract energy losses, and the supplemental peaking energy rate is applied to on-peak non-contract energy losses and off-peak energy losses. Below in Table 13, is an overview of foregone power revenue. When applying the current rates and energy losses, there is an expected revenue loss of $174,000.

TABLE 13
POWER REVENUE FOREGONE SUMMARY (2016 DOLLARS)

	Energy Loss	SWPA Composite Revenue Rate	Power Revenue Foregone
On-Peak Energy (Contract)	1,978 MWh	$15.30/MWh	$30,000
On-Peak Energy (Non-Contract)	3,388 MWh	$9.40/MWh	$32,000
Off-Peak Energy	2,206 MWh	$9.40/MWh	$21,000
Capability/ Capacity	1.65 MW	$55,190/MW	$91,000
Total			$174,000

(2) Hydropower Replacement Cost

The replacement cost of power as used for computing the cost of reallocated storage is an economic or National Economic Development (NED) cost. In the case of hydropower, the NED cost of replacement power is, by definition, identical to the power benefits foregone. Power benefits foregone are based on the cost of the most likely alternative, which in fact is the cost of replacement power. Therefore, the replacement cost of power is the value of the power benefits foregone as shown in Table 12, or $452,000.

F. FLOOD CONTROL BENEFITS FOREGONE

(1) Dependable Yield Mitigation Storage

The purpose of providing dependable yield mitigation storage is to maintain the current yield of existing users. When storage is reallocated from flood storage, the yield/storage ratio decreases. This means that the acre-feet of storage the existing water supply user is contracted for will provide fewer yields (mgd). Typically, when dependable yield mitigation storage (DYMS) is provided to existing water users the requesting entity would be required to purchase additional storage to keep the existing users whole, i.e. maintain the yield for existing users. Since this request is for storage in the conservation pool, DYMS would not be provided from MAWA's requested storage.

(2) Lost Flood Control Benefits

Blakely Mountain Dam currently has a Corps of Engineers DSAC III rating. Corps of Engineers policy prohibits reallocation of flood pool storage to other purposes if a dam has a DSAC rating of I, II, or III. In the case of this analysis, the flood control pool would not be impacted; therefore, there are no expected lost flood control benefits.

G. UPDATED COST OF STORAGE

The value of the 49,983 acre-feet of storage is estimated at $5,904,000 based on the standard method for calculating updated cost of storage. Total usable storage is calculated as the flood pool plus the conservation pool. The value of the storage was determined by first computing the cost at the midpoint of construction by using the use of facilities cost allocation procedure as follows:

Project Joint-Use Cost x (Storage Reallocation (AF)/ Total Usable Storage (AF))

Calculations to determine the value of the 49,983 ac-ft of reallocation storage are:

$224,768,000 (FY2016) x (49,983 / 1,903,000) = $5,904,000

The storage cost updates for fiscal year 2016 for Lake Ouachita are shown in Table 14. These costs are adjusted to the current rates at the time the water supply agreements are signed and cost indexed to the appropriate fiscal year and interest rate. The costs were then inflated to 2016 price levels by use of the Engineering News Record (ENR) Construction Cost Index and the Corps of Engineers Civil Works Construction Cost Index System (CWCCIS).

TABLE 14
UPDATED PROJECT COST ESTIMATE

Categories	Initial Project Cost 1957 Prices	1957 ENR Index[2]	Jul 67 ENR Index	Jul 67 CWCCIS Index	FY 16 CWCCIS Index [1]	FY 16 Project Cost	
Land and Damages	2,361,600	477	1,078	100		41,881,000	J
Relocation	1,083,700	477	1,078	100	832.09	20,379,000	J
Reservoir	2,009,900	477	1,078	100	876.67	39,821,000	J
Dam and Spillway							
Main Dam	6,306,500	477	1,078	100	794.69	113,263,000	J
Power Intake Works	6,724,900	477	1,078	100	794.69	120,777,000	P
Flood Control Outlet Works	3,275,300	477	1,078	100	794.69	58,823,000	F
Powerplant	7,479,800	477	1,078	100	739.84	125,063,000	P
Roads	347,200	477	1,078	100	810.02	6,356,000	J
Buildings	169,200	477	1,078	100	790.52	3,023,000	J
Equipment	1,091,900	477	1,078	100	739.84	18,257,000	P
TOTAL	30,850,000					547,688,000	
SUMMARY							
Specific Costs							
Flood Control	3,275,300					58,823,000	FC
Power	15,296,600					264,097,000	P
SUBTOTAL	18,571,900					322,920,000	
Joint-Use Cost	12,278,100					224,768,000	
TOTAL PROJECT COST	30,850,000					547,688,000	

[1] CWCCIS factors are taken from EM1110-2-1304, dated 30 March 2014.
[2] ENR factors are taken from Engineering News Record, http://enr.construction.com/, 30 March 2014.

TABLE 15
ANNUAL REPAYMENT COST FOR REALLOCATION STORAGE

ITEM	AMOUNT
Storage Required, (AF)	49,983
Water Supply Yield, (mgd)	30
Interest Rate, (percent)	3.50%
Repayment Period, (years)	30
Usable Project Storage	
Flood Control (AF)	617,000
Power Drawdown and Water Supply, (AF)	1,286,000
TOTAL	1,903,000
Percent of Usable Project Storage	2.6257%
Joint-Use Project Cost	$224,768,000
O&M (FY16)	$1,201,000
Allocated Water Supply Storage Cost	$5,904,000
Flood Control Benefits Foregone	$0
Annual Cost of Storage	
Investment [1]	$310,000
O&M [2]	$32,000
TOTAL	$342,000

Calculations for the value of the storage are shown in Table 15. If an agreement between MAWA and the United States Government was executed for this water supply storage reallocation, and the cost of storage was more than the foregone project benefits, the annual cost would be $310,000, which includes annual O&M costs of $32,000.

H. USER'S COSTS

In accordance with ER 1105-2-100, paragraph 3-8.b.(5)(a), the cost of reallocation storage will normally be established as the highest of the benefits or revenues foregone, the replacement cost, or the updated cost of storage in the Federal project. Table 16 lists these costs.

TABLE 16
COMPARISONS TO OBTAIN USER'S COST FOR ALTERNATIVE 2-CONSERVATION POOL REALLOCATION

ITEM	Capital Cost (Annual $'s)	O&M Cost (Annual $'s)	User Cost (Annual $'s)
Lost Hydropower Benefits	$452,000	$32,000	$484,000
Lost Hydropower Revenues	174,000	32,000	206,000
Replacement Cost of Hydropower	452,000	32,000	484,000
Updated Cost of Storage	310,000	32,000	342,000

For this reallocation, the user's cost will be the value of the lost hydropower benefits which were determined to be the highest of these costs. Therefore, MAWA will be required to make annual payments based on the value of lost hydropower benefits of $484,000 which includes annual O&M cost of $32,000.

5. COST ACCOUNT ADJUSTMENTS/CREDITS TO POWER MARKETING AGENCY (PMA)

A water supply reallocation from Lake Ouachita will have an effect on the hydropower purposes. Therefore, a credit to the accounting records could be made based on the estimated loss of power outputs and the current rates charged by SWPA. Contract information provided by the PMA indicated that current contracts for all power marketed from the SWPA system will expire in 2031, and the credit for firm power (i.e., contract on-peak power) is based on the costs of replacement firm power until that date. Following 2031, the PMA credit for firm energy losses is based on revenue foregone.

The PMA credit for loss of supplemental power generation (i.e., non-contract on peak power and off-peak power) is based on revenue foregone for the entire period of analysis. The PMA has no obligation to make up losses of supplemental generation to its customers in excess of its marketed capacity. The estimated annual credit to the accounting records is $174,000. This credit is based on capacity credits and energy credits.

6. SELECTED ALTERNATIVE

Alternative 2 is the selected alternative. This Alternative requires MAWA to pay total foregone hydropower benefits of $484,000 (includes $32,000 O&M) on an annual basis, which is more economically preferred from a quantitative and qualitative standpoint compared to the other Alternatives. Unlike Alternatives 1 (No Action) and Alternative 3 (groundwater), Alterative 2 provides a reliable source of water storage for Central Arkansas users to meet the demand of the area's population growth.

Regulations do not allow reallocations from the flood control pool for a DSAC III structure. The estimated modification cost to potentially improve the rating to a DSAC IV is $2.5 million, but with potential life safety aspects there are no guarantees the structure would be upgraded and remain a DSAC IV through the life of the storage contract. Finally, Alternative 5's (New Reservoir) annual average cost of $17.8 million substantially exceeds Alternative 2's yearly cost of $484,000. For this reallocation study, Alternative 2 (Reallocation from the Conservation Pool) will be the selected alternative.

7. OTHER CONSIDERATIONS

A. TEST OF FINANCIAL FEASIBILITY

The second most likely alternative to consider was Alternative 4 (Reallocation from Flood Control Pool). This alternative would cost an estimated $2.5 million to modify the structure to a DSAC IV, however there are numerous risk to account for with this alternative. As mentioned, there are no guarantees that the modifications would allow the structure to improve its DSAC rating. Based on analyzing all five of the listed alternatives, the proposed storage reallocation from the conservation pool (Alternative 2) is the best alternative.

B. NATIONAL ENVIRONMENTAL POLICY ACT (NEPA) DOCUMENTATION

The proposed storage reallocation will not significantly affect the Lake Ouachita project. Storage currently allocated to the power pool will be reallocated to municipal and industrial water supply; therefore, the current size of the conservation pool and flood pool will not change. This is considered to have no impact on the natural or cultural resources listed as being present. A determination of "no significant impacts" was made, and a finding to that effect was prepared as part of the NEPA documentation. The completed Environmental Assessment (EA) and Finding of No Significant Impact are attached in Appendix F.

C. PUBLIC COMMENT

Federal law and Corps of Engineers regulations require a 30-day public comment period for this reallocation of storage report. The 30-day comment period will begin October 5, 2016, and end November 5, 2016. NEPA and Section 5 of Public Law 100-676 required a public review and comment period for the NEPA documentation, and this was held beginning December 3, 2014 and ending January 5, 2015. The public review was accomplished by running a news release in local newspapers, providing inspection copies of the draft reallocation report and draft EA at the project office, and sending a copy of the EA to interested state and Federal agencies and interested parties that requested a copy of the draft documents.

VIEWS OF FEDERAL, STATE AND LOCAL INTERESTS

A Public Notice was distributed on 3 December 2014, informing the public of the proposed reallocation. Copies of the draft EA report were distributed to the Environmental Protection Agency, U.S. Fish and Wildlife Service (FWS), SWPA, the State of Arkansas and other interested parties for review.

Comment: By letter, 30 December 2014, The City of Hot Springs Deputy City Manager indicated they were in agreement with the conclusion in this EA.

Response: Concur

Comment: By letter, 31 December 2014, The Department of Arkansas Heritage indicated by letter that they concurred that the proposed undertaking has no potential to impact cultural resources and that they have no objection to it.

Response: Concur

Comment: By email, 27 January 2015, the district EPA office indicated that they had reviewed the EA and concurred with the Finding of no Significant Impact.

Response: Concur

Comment: On 23 December 2014 and 5 January 2015, letters were received from the Department of Energy and the Southwestern Power Resources Association, respectively. Both of the entities expressed concern about reallocation of water storage from the hydropower pool to water supply.

Response: These concerns will be addressed in reviewing the main reallocation report for this project.

Comment: By email, 5 January 2015, the Historic Preservation Department of the Choctaw Nation of Oklahoma notified that they determined the area was outside the Choctaw Nation of Oklahoma area of historic interest.

Response: Concur

Comment: On 22 January 2015, a letter was received from the Osage Nation Tribal Historic Preservation Office. The Osage Nation does not anticipate that this project will adversely impact any cultural resources or human remains protected under any currents laws. They did ask that if any artifacts or human remains are discovered during project construction that work cease immediately and they be contacted.

Response: Concur

Comment: By letter, 22 April 2015, the U.S. Fish and Wildlife Service indicated that they had reviewed the EA and concurred with the Finding of no Significant Impact.

Response: Concur

Comment: By letter, on 28 May 2015 the Jena Band of Choctaw Indians indicated that they had reviewed the EA and concurred with the Finding of no Significant Impact. Their office should be contacted if any cultural impacts as a result of the project.

Response: Concur

A Public Notice was distributed on 1 May 2014, informing the public of the draft reallocation report for the proposed reallocation. Copies of the draft reallocation report were distributed to the Environmental Protection Agency, U.S. Fish and Wildlife Service (FWS), SWPA, the State of Arkansas and other interested parties for review.

Comment: By letter, May 2015, Mid-Arkansas Water Alliance, The City of Hot Springs, and North Garland County Regional Water District provided comments based on the reallocation report. Questions and concerns included what the agreement language would be in the agreement between the parties of interest, when payments would start for the reallocated water, a question concerning Southwestern Power Association marketing of peak power from hydropower facilities, and whether or not hydropower benefits foregone apply when the lake is in flood pool.

Response: Comments and concerns will be addressed before final water storage agreement is executed.

Comment: By letter, 7 May 2015, Arkansas Game and Fish Commission provided comments based on the reallocation report. They concluded that “no negative impacts to the lake fishery are expected from this municipal water use”.

Response: Concur

Comment: By letter, 11 May 2015, Southwestern Power Administration (Department of Energy) provided comments based on the reallocation report. They concluded that hydropower will suffer the greatest impact from the proposed reallocation. SWPA’s biggest concern was that the proposed reallocation would exceed the Corps’ discretionary authority at Lake Ouachita. The Corps must take into consideration previous allocations to ensure the discretionary limit was not exceeded. Otherwise, Congressional approval would be required. SWPA also believes that value of hydropower benefits foregone are underestimated as presented.

Response: The Corps will look into the reallocation limit concern and determine the appropriate action to resolve the issue. Foregone hydropower benefits were estimated by USACE’s HAC located in Portland, OR. Cost and benefits are based on the following, per the HAC: “Both costs and benefits are expressed in estimated 2014 (FY2014) price levels. Some prices, such as annual wholesale generation prices in the Energy Information Agency’s Annual Energy Outlook forecasts, are based on a calendar year price level rather than fiscal year. Because the fiscal year overlaps three-quarters of the calendar year, these prices are used as if they were fiscal year prices, without adjustment. Capacity unit value and energy costs and prices in this report are reported in FY2014 constant dollars. Because constant value dollars are used for all calculations, inflation and price escalation are not included in the analysis, as would be the case with nominal dollars.”

Comment: By letter, 11 May 2015, Southwestern Power Resource Association (SPRA) provided comments based on the reallocation report. They concluded that a reallocation at Lake Ouachita cannot be accomplished without Congressional approval and should be reconsidered. SPRA also felt that they should be the entity to calculate hydropower benefits losses, since they are experts in the field.

Response: The Corps will look into the reallocation limit concern and determine the appropriate action to resolve the issue. Foregone hydropower benefits were estimated by USACE's HAC located in Portland, OR. The estimated value may not mirror what SPRA would provide, but the HAC's values are based on accepted assumptions and provide a solid approximated value. The Corps Agency Technical Review (ATR) will also provide an opportunity to the HAC's values to be further reviewed.

Comment: By letter, 19 May 2015, The Choctaw Nation of Oklahoma indicated this project lies outside of the Nation's area of historic interest.

Response: Concur

7. CONCLUSIONS

This report concludes that 49,983 acre-feet of storage in the conservation pool of Lake Ouachita is available and may be reallocated to MAWA to meet the water needs of central Arkansas through the year 2050. This reallocation does not constitute a fundamental departure from the Congressional intent for Lake Ouachita and, therefore, does not constitute a major operational change.

The user's cost for storage will be based on the lost hydropower benefits, which are the highest of the foregone benefits. Lost hydropower benefits were calculated at $484,000 annually, compared to lost hydropower revenues of $206,000 annually and the updated storage cost of $342,000 annually. An annual PMA credit of $174,000 would be made based on the estimated loss of power outputs and the current rates charged by SWPA.

8. REFERENCES

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APPENDIX A

HYDROPOWER ANALYSIS

HYDROPOWER ANALYSIS
LAKE OUACHITA WATER REALLOCATION STUDY

Hydropower Analysis Center
Portland District
U.S. Army Corps of Engineers

November 2014
Updated 16 September 2016
Dollar values are not rounded as shown in report

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1. INTRODUCTION

1.1. Purpose and Scope

This report, prepared by the Hydropower Analysis Center (HAC) for the Vicksburg Rock District (MVK), Corps of Engineers, presents an analysis of the hydropower benefits and costs of reallocating reservoir storage to serve local municipal and industrial water supply needs. The quantity of reservoir storage to reallocated will be sufficient to meet current requests but will be limited to the amount that is within the Chief of Engineers authority.

1.2. Reallocation Authority.

Authority for the Corps to reallocate existing storage space to M&I water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended. The Secretary of the Army is authorized to cooperate with local interests in providing storage space for M&I water supply in U.S. Army Corps of Engineers projects as long as the local interests agree to pay the costs associated with the storage space. The Chief of Engineers has the discretionary authority to reallocate 50,000 acre feet of the total storage capacity in Lake Ouachita provided the reallocation has no severe effect on other authorized purposes and will not involve major structural or operational changes. If so, Congressional authorization is required.

1.3. Project Description

Blakely Mountain Dam that impounds Lake Ouachita is located at mile 430.4, approximately 10 miles northwest of Hot Springs in Garland County, Arkansas, and 487 miles above the mouth of Black River. The project is a feature of the comprehensive plan for water resources development in the Ouachita River Basin. Entergy Power Company owns and operates two hydroelectric dams (Carpenter and Remmel Dams) immediately downstream from Blakely Mountain Dam, shown in Figure 1-1 below.

In addition to the authorized purposes of Lake Ouachita for flood control and hydroelectric power generation, the multiple-purpose project provides collateral benefits of water supply and to recreation and to industry and navigation downstream from the dam through regulation of low flows in the Ouachita River.

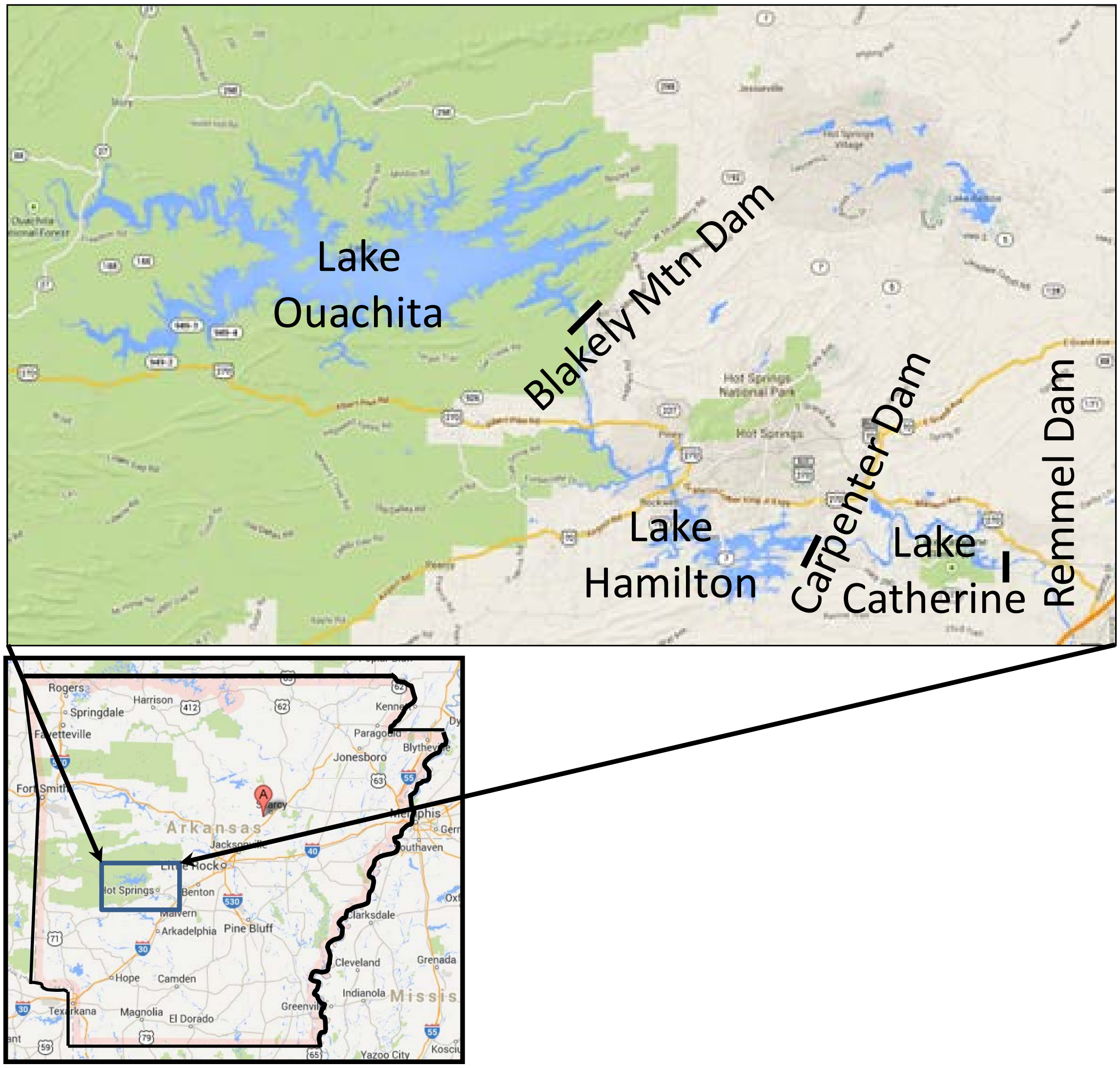


Figure 1-1. Location of Ouachita River Basin Projects

Lake Ouachita (Blakely Mountain Dam)

Spillway construction began in August 1947 and the powerhouse was completed in October 1955. Blakely Mountain Dam consists of an earthfill dam, spillway, intake structure, flood control conduit and stilling basin, power conduit, surge tank, penstocks, powerhouse, switchyard, appurtenant structures, and hydroelectric, power generating facilities;

The dam is approximately 235 feet in height above the streambed, 1,100 feet in length at the crest elevation of 616 feet, mean sea level.

The reservoir has a total capacity of 2,768,500 acre-feet below spillway crest, of which, 864,900 acre-feet are below minimum pool; 1,286,200 acre-feet are for power production; and 617,400 acre-feet are for flood control.

The power storage is contained between elevation 535.0 and 578.1 feet mean sea level, with average fluctuations of about 10 feet below elevation 578.1.

The flood control pool has sufficient storage to control the flood of record, and its operation will reduce flooding below the dam and along the Ouachita River to the vicinity of Moro Bay, Arkansas.

The hydroelectric facility has two conventional units of 37,500-kilowatt capacity which were both place online in October 1955, with the usual control, switching, transforming, and operating equipment. Two other federal projects (Narrows Dam and DeGray Dam) are operated by remote facilities located in Blakely Mountain powerhouse.

Lake Hamilton (Carpenter Dam)

About 19 miles downstream from Blakely Mountain Dam is Carpenter Dam which is owned and operated by Entergy Power Company. It forms the pool of Lake Hamilton that extends to the foot of Blakely Mountain Dam. The plant capacity is 56,000 KW with a power discharge of about 8,600 cfs. The shores of Lake Hamilton have become highly developed over the past years with a constant pool elevation of about 400 ft. msl. Entergy maintains this elevation during the recreation season, but lowers the lake to elevation 395 msl during the winter and early spring to provide additional downstream flood control benefits.

Lake Catherine (Remmel Dam)

The next dam downstream is also owned and operated by Entergy Power Company. Remmel Dam is about 12 miles downstream from Carpenter Dam and forms the pool of Lake Catherine. The plant capacity is 9,300 KW with a power flow of about 3,200 cfs. The lake extends to Carpenter Dam. Storage in Lake Catherine is small, and releases at Carpenter Dam are passed through Remmel Dam with little change in the flow. Releases from Remmel Dam are the contributing flows to the downstream Ouachita River. The power company notifies the operators at Blakely Mountain Dam of the time and discharge when spillway gates are opened. The Corps does not require information on release at Carpenter Dam. The Arkansas Power and Light Company has agreed to cause minor fluctuations in the pool elevation of Lake Catherine, lake behind Remmel Dam, as recommended by the Arkansas Game and Fish Commission to control aquatic growth.

2. GENERAL

This section describes some of the terminology, basic assumptions, and methodology of the analysis.

2.1. Period of Analysis

The economic period of analysis for this study is 50 years. The “Period of Analysis” as defined in *Planning Guidance Notebook*, Section 2-4j, for a multiple-purpose reservoir project, is not to exceed 100 years. Section E-63 i(1)(a)(1), “Benefits Foregone”, defines the period of analysis for storage reallocations as the greater of (a) the remaining economic life of the project, or (b) 50 years. Benefits foregone for this analysis are computed assuming the water supply contract will be implemented in 2016. The power on-line date and total economic life for the project are shown in Table 2-1.

Table 2-1. Pertinent Hydropower and Economic Parameters

Power	**Blakely Mountain Dam**
Overload Capacity	86.0
Power-on-Line (POL)	1955
Marketable Capacity	75.0
Economic	
Total Project Life	100
Interest Rate	3.5%
Period of Analysis	50

2.2. Discount Rate.

Costs and benefits occurring at different points in time are converted to an average annual equivalent basis over a 50-year period of analysis using the federal discount rate prescribed for water resources projects. This rate is currently 3.125 percent.

2.3. Price Level.

Both costs and benefits are expressed at an estimated July 2016 (FY2016) price level. Some prices, such as annual wholesale generation prices in the Energy Information Agency Annual Energy Outlook forecasts, are based on a calendar year price level rather than fiscal year. Because the fiscal year overlaps three-quarters of the calendar year, these prices are used as if they were fiscal year prices, without adjustment. Capacity unit value and energy costs and prices in this report are reported in FY2016 constant dollars. Because constant value dollars are used for all calculations, inflation and price escalation are not included in the analysis, as would be the case with nominal dollars.

2.4. Rounding and Totals.

Some parts of the study analysis were performed using spreadsheet software. Arithmetic operations and totals were taken to full decimal accuracy within the spreadsheet. Some tables found within this report have been rounded after the mathematical computations were performed; as a consequence, rounded totals may not equal the summation of rounded values.

2.5. Simulation with RESSIM Streamflow Routing Model.

The RESSIM sequential streamflow routing model was used to simulate the operation of Blakely Mountain Dam project on the Ouachita River according to existing guidelines for reservoir and system operation. The simulations used in the analysis were based on a period of record of 52 years, from 1961 through 2012. Modeling results are described elsewhere in the main report. Daily average power plant discharge and daily lake elevations were used to compute power output for this project.

2.6. Water Supply Withdrawal Alternatives Considered.

The full use of existing water supply contracts are accounted for in the base case (no-action) alternative. Vicksburg District (MVK) requested that the Hydropower Analysis Center (HAC) evaluate the following alternative reservoir storage reallocations:

- Existing condition - No action
- Water Supply Reallocation - from the conservation pool

2.7. Study Assumptions.

The evaluation of energy benefits foregone due to water supply withdrawals from Lake Ouachita was performed based on the following assumptions;

- The RESSIM Model simulations used in this analysis include updated hydrology and power plant discharge are described elsewhere.
- Water supply withdrawals are not considered "consumptive use," implying that all of the withdrawal amount taken from Lake Ouachita will be returned to the stream reach below the reservoir.
- The water supply withdrawal rates from Lake Ouachita are made at a uniform rate throughout the year.

2.8. Hydropower Effects.

The procedures for computing the cost of reallocating water from hydropower to water supply use are outlined in ER 1105-2-100, *Planning Guidance Notebook* (22 April 2000), Appendix E, paragraph E-57, d(2). These procedures require that the reallocation cost charged to water supply customers be the highest of the following:

- power benefits foregone
- power revenues foregone
- replacement costs of power
- updated cost of storage

Power benefits foregone, power revenue foregone, and the replacement costs of power are impacts to hydropower. Power benefits foregone and power revenue foregone are calculated in this report. The replacement costs of power is equal to power benefits foregone and is not calculated separately. The updated cost of storage is not power related and will be computed by the Vicksburg District based on the storage necessary to yield the requested withdrawals.

3. POWER BENEFITS FOREGONE

Hydropower benefits are based on the cost of the most likely alternative source of power. When conservation storage is reallocated for water supply, the usual assumption is that the lost hydropower will be replaced with power generated from thermal sources.

The power benefits foregone can be divided into two components, energy benefits foregone and capacity benefits foregone. Energy benefits foregone are based on the loss in generation (both at-site and downstream) as a result of water being diverted from the reservoir for water supply rather than passing through the hydropower plant. In addition, there could be a loss of capacity benefits as a result of a loss in generating capability at the project. Loss of generating capability could be a result of:

- a loss in head due to lower post-withdrawal reservoir elevations
- inadequate water to support full capability during low-flow periods (i.e., low-flow periods that reduce the amount of water that can be passed through the generators)

Energy benefits foregone are computed by multiplying the expected monthly loss in megawatt-hours (MWh) of on-peak and off-peak generation by the average monthly prices of on-peak and off-peak energy in dollars per megawatt-hour ($/MWh) over the period of analysis. These energy prices are based on the marginal cost of energy from the existing regional generation resources that would replace the energy lost from hydropower generation.

For each month of the year, the present value of forecast energy prices (values) over the fifty-year period of analysis is amortized to produce annualized monthly prices. The product of the annualized monthly energy price and the average monthly energy loss due to water withdrawals represents the annualized energy benefits foregone for that alternative. The calculation of energy benefits foregone is presented in detail in Section 4.

Capacity benefits foregone are computed by first determining a composite cost per MW representing the annualized fixed cost of the combination of thermal power plants most likely to replace the power lost to the Ouachita River system as a result of the reallocation alternatives. Next, the loss of generating capability for each alternative is calculated using the average availability method. Capacity benefits foregone are the product of the loss of generating capability and the composite fixed cost of the most likely mix of replacement thermal power plants. Calculations of composite cost, generating capability, and a description of the average availability method are presented in Section 5.

4. ENERGY BENEFITS FOREGONE

The amount of flow through the Blakely Mountain powerhouse under existing conditions and under the reallocation of storage for water supply at Lake Ouachita was simulated by the Little Rock District for Vicksburg District using stream flows from the historical period of record (1961–2012) in RESSIM, a sequential streamflow routing model.

The regional definition of on-peak hours of generation is 6 a.m. to 10 p.m. on weekdays and Saturdays. The off-peak hours of generation are the remaining hours on weekdays and all hours on Sunday. However, because generation by plants in the Ouachita River system is concentrated in a subset of the highest-value weekday peak hours to fulfill power contracts, these hours were evaluated separately as contract on-peak hours in order not to understate the their value. Table 4-1 presents the distribution of contract-peak hours, non-contract peak hours, and off-peak hours for each month of the year, and also for weekends. A schedule of contract peak hours was provided by the Southwestern Power Administration (SWPA), an agency of the U.S. Department of Energy.

Table 4-1. 1,200 Hours/Year Generation Schedule for the Lake Ouachita Hydropower Plant

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours
Weekdays			
January	5	11	8
February	3	13	8
March	3	13	8
April	3	13	8
May	3	13	8
June	5	11	8
July	9	7	8
August	9	7	8
September	4	12	8
October	3	13	8
November	3	13	8
December	5	11	8
Weekends (All Year)			
Saturdays	0	16	8
Sundays	0	0	24

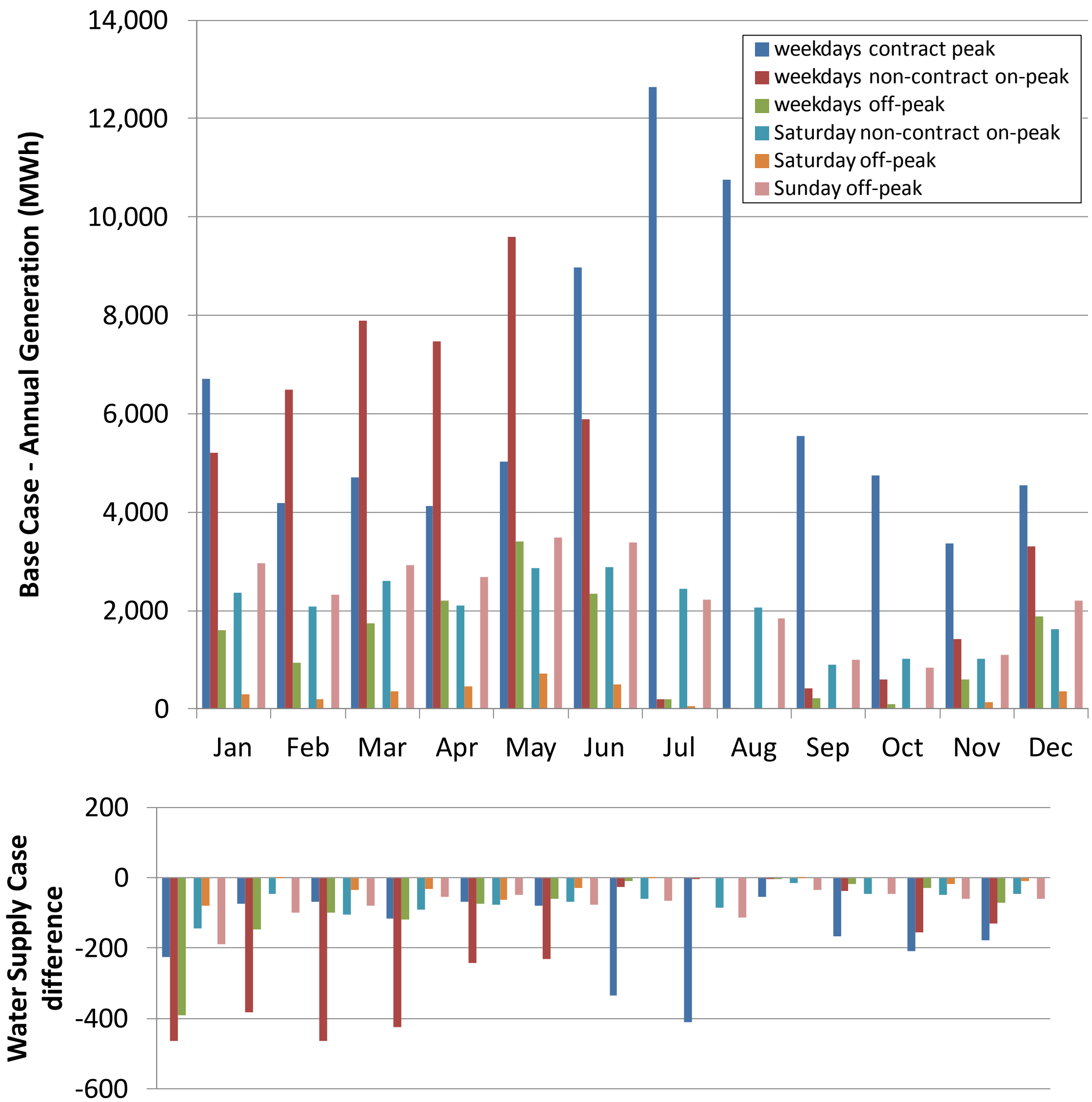
As an example of how energy production is allocated between on-peak and off-peak designations, Table 4-2 below shows the simulated energy production for Lake Ouachita for the week of April 2, 1962 under existing (baseline) conditions. The capability is constant so the maximum on-peak production Monday through Friday would be 16 hours per day of generation at the plant capability of about ~88 MW (~1,408 MWh), of which 3 hours would be contract generation (~264 MWh) and the remaining 13 hours would be non-contract generation (~1,144 MWh). Generation in excess of 16 hours on weekdays and Saturdays is off-peak energy. All power generated on Sunday is also off-peak energy.

Table 4-2. On-Peak & Off-Peak Energy Allocation

DATE	Day	Capability (MW)	Energy Production (MWh)	On-Peak Energy (contract) (MWh)	On-Peak Energy (non-contract) (MWh)	Off-Peak Energy (MWh)
2-Apr-62	Monday	88.56	946.2	265.7	680.5	0.0
3-Apr-62	Tuesday	88.63	946.2	265.9	680.3	0.0
4-Apr-62	Wednesday	88.29	2,297.2	264.9	1,147.8	884.6
5-Apr-62	Thursday	88.19	2,299.8	264.6	1,146.5	888.8
6-Apr-62	Friday	88.06	2,303.1	264.2	1,144.8	894.2
7-Apr-62	Saturday	87.94	1,226.3	0.0	1,226.3	0.0
8-Apr-62	Sunday	88.13	490.9	0.0	0.0	490.9

Average monthly on-peak (contract and non-contract) and off-peak energy for each project under existing condition is shown on the next page in Figure 4-1.

Figure 4-1. Average monthly energy generation at Lake Ouachita (1961 – 2012)



In the lower portion of Figure 4-1 above is the monthly loss in generation (MWh) under the water supply reallocation.

Table 4-3, on the next page, summarizes the corresponding energy loss from the conservation pool alternative. For clarity, losses are expressed as negative numbers and increases in generation are presented as positive numbers.

Table 4-3. Average Monthly Energy Losses (MWh) at Lake Ouachita, Blakely Mountain hydropower plant

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	On-Peak (non-contract)	Off-Peak	Off-Peak
Jan	-224.30	-464.22	-389.61	-143.00	-79.68	-187.82
Feb	-73.14	-383.08	-147.25	-45.55	2.45	-100.35
Mar	-69.05	-464.01	-99.44	-103.38	-33.70	-78.53
Apr	-117.21	-423.27	-118.72	-90.12	-32.70	-52.88
May	-67.86	-241.55	-73.87	-76.42	-62.73	-47.77
Jun	-78.87	-231.08	-60.64	-69.36	-29.42	-76.78
Jul	-333.47	-27.12	-8.12	-60.17	0.12	-64.53
Aug	-410.90	-2.23	0.00	-85.04	0.00	-113.07
Sep	-52.92	-0.20	-5.12	-15.99	0.13	-34.72
Oct	-165.32	-36.16	-17.99	-45.82	0.00	-44.51
Nov	-208.73	-155.33	-29.35	-47.73	-19.10	-59.26
Dec	-176.37	-130.81	-71.83	-46.22	-9.12	-59.66
subtotal	-1,978.15	-2,559.06	-1,021.94	-828.79	-263.76	-919.87
TOTAL	-7,571.57					

4.1. Computation of Energy Prices.

Energy benefits are computed as the product of the energy loss in megawatt-hours and an energy unit value price ($/MWh). The energy price is based on the cost of energy that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

A forecasts of future energy prices is needed to evaluate the resulting changes in hydropower benefits over a 50-year period of analysis, These forecasted prices also need to reflect seasonal variation of both peak (contract and non-contract) and off-peak prices.

To estimate regional future energy prices that reflect both seasonal peak and off-peak variation two sources of data are required. The first data source is the EIA long term energy forecast, while the second data source is the Southwestern Power Pool historical LIP (Locational Imbalance Price) for the SPA (Southwest Power Administration) pricing node.

EIA AEO 2016 annual forecast generation prices were used to shape a forecast for hourly LIP values.

EIA Long-Term Forecast

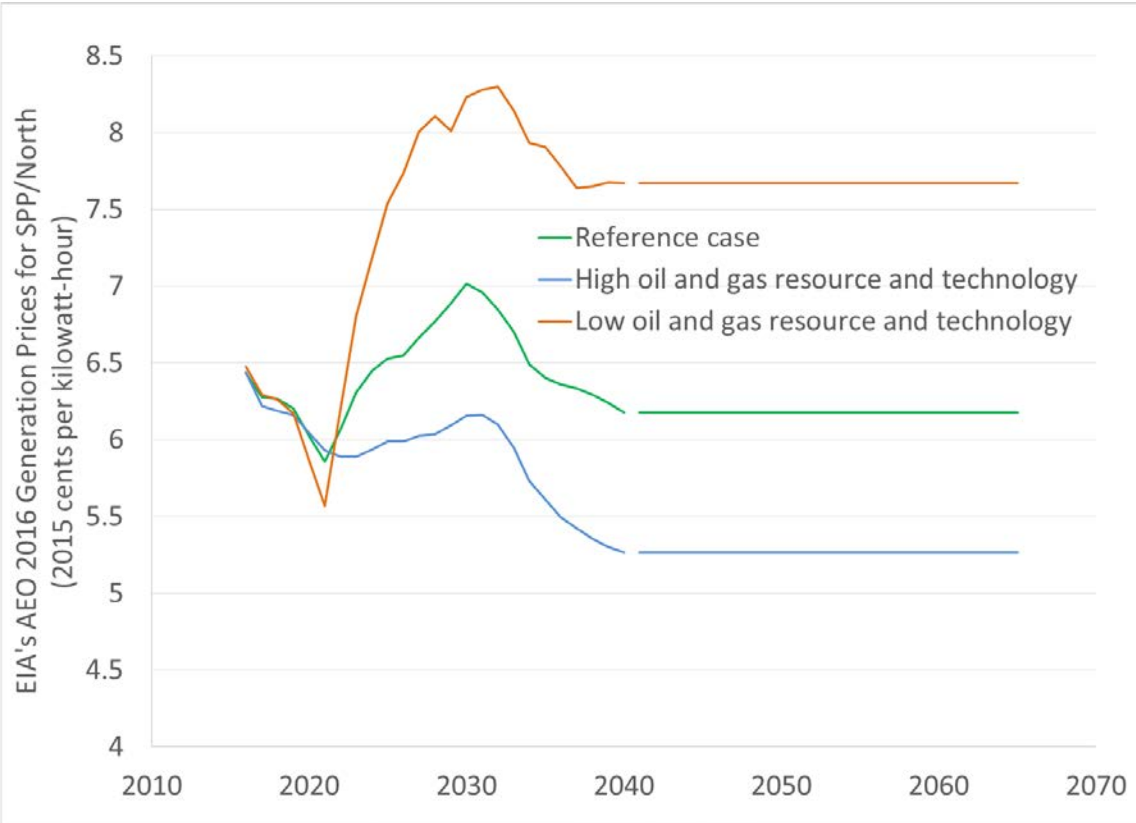
Future and historical energy values in this analysis are based on EIA forecasts from the supplemental tables of “Annual Energy Outlook” (AEO 2016). The EIA forecasts are developed with the Electricity Market Model (EMM) as part of the National Energy Modeling System (NEMS). The following description is from the model documentation report available on the EIA website:

> *The National Energy Modeling System (NEMS) was developed to provide 20-to-25 year forecasts and analyses of energy-related activities. The NEMS uses a central database to store and pass inputs and outputs between the various components. The NEMS Electricity Market Module (EMM) provides a major link in the NEMS framework (Figure 1). In each model year, the EMM receives electricity demand from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module. The EMM estimates the actions taken by electricity producers (electric utilities and nonutilities) to meet demand in the most economical manner. The EMM then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the integrating module, and capital requirements to the macroeconomic module. The model iterates until a solution is reached for each forecast year.*

In addition to providing average annual energy forecasts of electrical generation prices through 2040, AEO 2016 also includes regional forecasts corresponding to North American Electric Reliability Corporation (NERC) regional entity sub-regions. Discussions with SWPA confirmed that most of the electrical generation from Lake Ouachita is marketed through Southwestern Power Pool (SPP).

AEO 2016 reports several forecast cases. In addition to the ‘Reference’ case, used for this study, the ‘high oil and gas resource’ and low oil and gas resource’ cases are included to illustrate a range in forecast generation prices.

Figure 4-2. EIA AEO 2016 forecast electrical power generation prices.



Locational Imbalance Price

The LIP value represents the price to serve the next increment of energy at a Pricing Node. LIPs are calculated every five minutes and averaged to hourly settlement prices. Following is an example of the calculation of LIP;

> Consider:
> Generator A offers 10 MWh at $15/MWh
> Generator B offers 10 MWh at $30/MWh
> Generator C offers 10 MWh at $20/MWh
>
> To supply 15 MWh of energy in an hour to a load in an unconstrained system, the market selects the most economical generation within current reliability standards.

> In this case, Generator A would supply 10 MW at $15/MWh and Generator C would supply 5 MW at $20/MWh, which sets the price as providing the “next” increment of energy. Generators A and C would get paid $20/MWh to serve 15 MWh of load.

From a calculation process there is little difference between the current LIP and LMP (Locational Marginal Price). The following explanation of how LMP (lambda) was calculated is from the FERC Form 714 report, Part II, Schedule 6, filed for 2012 by American Electric Power Company, Inc.:

> *The American Electric Power Company, Inc. system’s calculation of the firm-load lambda is based on the after-the-fact search for the generating unit that could have theoretically served ‘one’ MW of additional firm demand, in addition to the actual firm demand. If more than one generating unit were to be candidates to serve that additional MW, the one with the lowest incremental cost would be the one considered.*
>
> *The incremental energy cost, in $/MWh, to raise that unit’s loading by one MW above its actual loading is defined as the AEP System’s firm-load lambda. Such determination and calculation are carried out on an hourly basis.*
>
> *Prior to determining that incremental generating unit and the associated incremental cost, the computer program is coded to take into consideration all appropriate realities and obligations encountered while the AEP System’s generation resources are operating on real-time. These are: consideration of each operating generating unit’s seasonal capability, including condition deratings and partial outages, if any; exclusion of capacity blocks actually allocated to unit-power sales commitments; exclusion of the Donald C. Cook Nuclear Units #1 & #2 and conventional hydroelectric units from ‘incremental’ consideration, in as much as those units generally operate to their physical and regulatory limits; and inclusion of the 3% spinning reserve requirement over firm demand, as mandated by the ECAR (East Central Area Reliability Coordination Agreement) Document No. 2.*

LIP hourly values for 2010, 2011, and 2012 were obtained from SPP’s historical database for the Southwestern Power Administration node (SPA).

Methodology for energy price shaping

To forecast the LIP using the EIA forecasted generation values the following ratio is assumed:

$$\frac{LIP_{Future}}{LIP_{Past}} = \frac{EIA\_Generation_{Future}}{EIA\_Generation_{Past}}$$

This can be rewritten as:

$$LIP_{Future} = EIA\_Generation_{Future} * \frac{LIP_{Past}}{EIA\_Generation_{Past}}$$

Future LMP values can then be computed by the product of the EIA generation forecast and a shaping ratio defined as:

$$ShapingRatio = \frac{LIP_{Past}}{EIA\_Generation_{Past}}$$

To replicate the peak and off peak variation, daily LIP values are sorted from high to low and are averaged using the peak and off peak periods described in the Energy Benefits Calculation section below. Seasonal variability is taken into account by computing shaping ratios for each month. These shaping ratios are computed as averages among dates with like month and peak and off-peak classification using the equation:

Table 4-4. Shaping Factors for SPP/South

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non contract)	Off-Peak	On-Peak (non contract)	Off-Peak	Off-Peak
Jan	1.0235	0.7267	0.4889	0.8649	0.6208	0.6232
Feb	0.9782	0.7013	0.4921	0.7693	0.5495	0.5137
Mar	0.8797	0.5846	0.3917	0.6358	0.4512	0.5225
Apr	0.9106	0.6392	0.3949	0.6723	0.4039	0.4845
May	0.9518	0.6168	0.3419	0.7932	0.4084	0.5171
Jun	0.8926	0.6622	0.3783	0.8258	0.4785	0.5694
Jul	0.9935	0.7124	0.4741	0.9260	0.5877	0.6580
Aug	0.9092	0.6544	0.4601	0.9914	0.5165	0.6119
Sep	0.8178	0.5899	0.3512	0.7316	0.4497	0.4985
Oct	0.8832	0.6037	0.4016	0.6505	0.4642	0.5011
Nov	0.9685	0.5454	0.3992	0.6064	0.4101	0.4664
Dec	0.7962	0.5530	0.4266	0.5809	0.4392	0.5271

The proportions in Table 4-4 were then multiplied by the EIA annualized forecast energy value for each year to obtain estimates of monthly on-peak and off-peak values.

The EIA forecast energy values in Figure 4-2 were converted to 2016 dollars using the GDP (chain-type) Index then annualized over the 50-year period using the federal discount rate of three and a half percent.

Table 4-5. Annualized electrical power generation price.

EIA forecast cases	Annualized Value (2012 cents per kilowatt-hour)
low oil and gas resource	$7.46
reference	$6.45
high oil and gas resource	$5.82

The resulting annualized prices for the EIA Reference Case are shown in Table 4-6.

Table 4-6. Average Annual Energy Prices - EIA Reference Case (2016 Dollars)

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	On-Peak (non-contract)	Off-Peak	Off-Peak
Jan	$66.00	$46.86	$31.52	$55.77	$40.03	$40.18
Feb	$63.07	$45.22	$31.73	$49.60	$35.43	$33.12
Mar	$56.72	$37.70	$25.26	$41.00	$29.09	$33.69
Apr	$58.72	$41.22	$25.46	$43.35	$26.04	$31.24
May	$61.37	$39.77	$22.05	$51.15	$26.33	$33.34
Jun	$57.55	$42.70	$24.39	$53.25	$30.85	$36.71
Jul	$64.06	$45.94	$30.57	$59.71	$37.89	$42.43
Aug	$58.63	$42.20	$29.67	$63.93	$33.30	$39.46
Sep	$52.73	$38.04	$22.65	$47.17	$29.00	$32.14
Oct	$56.95	$38.93	$25.90	$41.94	$29.93	$32.31
Nov	$62.45	$35.17	$25.74	$39.10	$26.44	$30.07
Dec	$51.34	$35.66	$27.51	$37.46	$28.32	$33.99

Energy Benefits

The final step is to multiply the total average monthly generation of contract on-peak, on-peak and off-peak energy in Table 4-3 by the average annual energy prices by month in Table 4-5 to obtain energy benefits foregone by month which are then summed. In Table 4-7 values in red and enclosed by brackets are negative benefits (losses) or benefits foregone.

Table 4-7. Energy Benefits - Reference case (2016 Dollars)

	Weekdays			Saturdays		Sundays
	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	On-Peak (non-contract)	Off-Peak	Off-Peak
Jan	($14,802.73)	($21,752.04)	($12,282.12)	($7,974.73)	($3,189.65)	($7,547.25)
Feb	($4,613.51)	($17,322.92)	($4,672.49)	($2,259.30)	$86.84	($3,323.85)
Mar	($3,916.95)	($17,491.01)	($2,511.60)	($4,238.03)	($980.40)	($2,645.78)
Apr	($6,881.77)	($17,445.18)	($3,022.90)	($3,906.83)	($851.69)	($1,651.86)
May	($4,164.86)	($9,606.62)	($1,628.55)	($3,908.46)	($1,652.04)	($1,592.65)
Jun	($4,539.59)	($9,866.84)	($1,479.17)	($3,693.49)	($907.62)	($2,819.03)
Jul	($21,362.41)	($1,245.67)	($248.17)	($3,592.43)	$4.55	($2,737.76)
Aug	($24,089.37)	($94.11)	$0.00	($5,435.91)	$0.00	($4,461.28)
Sep	($2,790.37)	($7.48)	($115.97)	($754.14)	$3.88	($1,115.90)
Oct	($9,414.97)	($1,407.52)	($465.77)	($1,921.81)	$0.00	($1,438.28)
Nov	($13,035.04)	($5,462.67)	($755.59)	($1,866.40)	($505.14)	($1,782.15)
Dec	($9,054.51)	($4,664.47)	($1,975.76)	($1,731.38)	($258.37)	($2,027.81)
subtotal	($118,666.08)	($106,366.52)	($29,158.09)	($41,282.92)	($8,249.64)	($33,143.60)
TOTAL	**($336,866.85)**					

This procedure was repeated for the other two price cases to indicate a range of energy benefits foregone due to variation in significant price factors, Table 4-8.

Table 4-8. Energy benefits foregone of other 'price cases'

EIA forecast cases	**Annual Energy Benefits Foregone (2016 dollars)**
low oil and gas resource	$389,790
reference	**$336,867**
high oil and gas resource	$304,162

5. CAPACITY BENEFITS FOREGONE

Capacity benefits foregone are defined as the product of the loss in power plant capability and a capacity unit value, which represents the capital cost of constructing replacement thermal capacity.

5.1. Hydropower Project's Capability

A hydropower project's capability is a measure of the amount of capability that the project can reliably contribute towards meeting system peak power demands. If a hydropower project always maintains approximately the same head, and there is always an adequate supply of stream flow so that there is enough generation for the full capability to be usable in the system load, the full installed capacity can be considered to be the capability. In some cases even the overload capacity can be used as its capability.

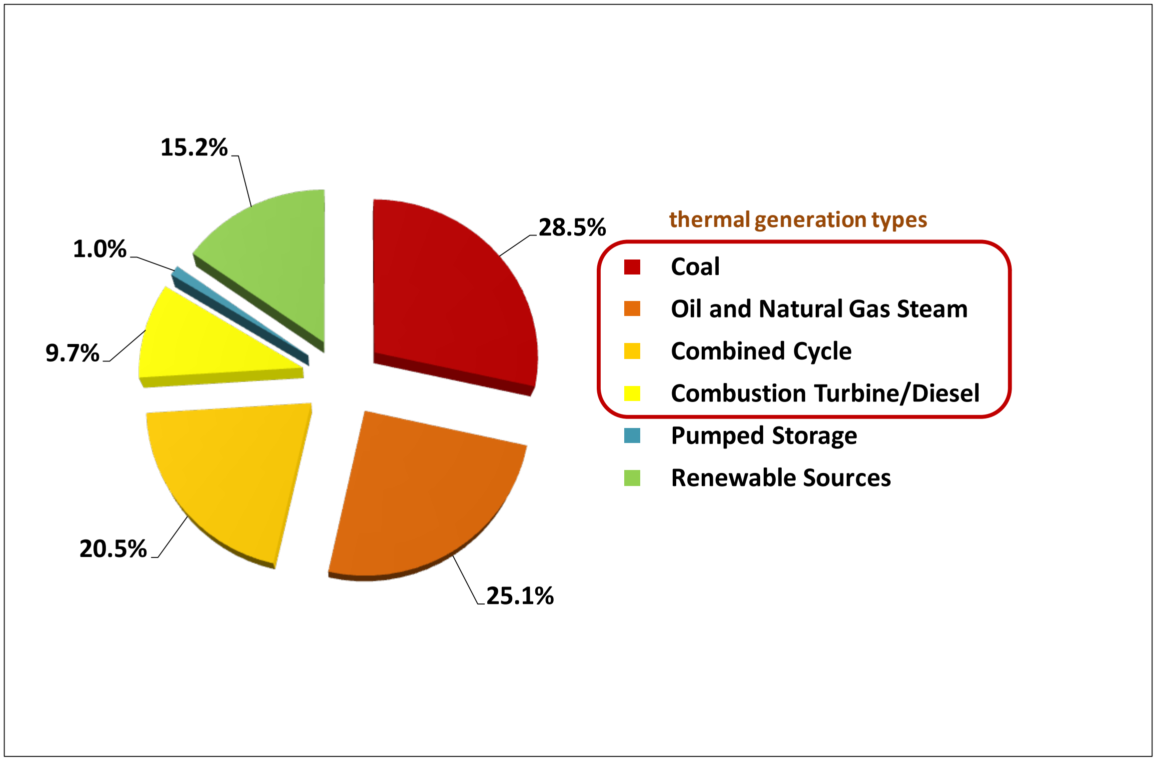
However, at storage projects, normal reservoir drawdown can result in a loss of capability due to a loss in head. At other times, stream flows in low flow periods may result in insufficient generation to support the available capability in the load. Capability accounts for these factors by giving a measure of the amount of capability that can be provided with some degree of reliability during peak demand periods.

5.2. Capability Evaluation Method

The most appropriate method for evaluating a hydropower plant's capability in a predominantly thermal-based power system is the average availability method, as described in Section 6-7g of EM 1110-2-1701, *Hydropower,* dated 31 December 1985. The occasional unavailability of a portion of hydro project's generating capability due to hydrologic variations is treated in the same manner as the occasional unavailability of all or part of a thermal plant's generating capacity due to forced outages. The average availability method attempts to measure the average capability available during the peak demand periods of the year.

The SPP (southern sub-region) is primarily a thermal-based power system with only a small amount of hydropower, as illustrated in Figure 5-1. Consequently, the average availability method is the most appropriate method for measuring capability for this analysis.

Figure 5-1. Thermal Generation Type for SPP Southern Sub-region



Source: Annual Energy Outlook 2013, Energy Information Agency, U.S Department of Energy

5.3. Hydrologic Period of Analysis

In order to evaluate the average capability of a project during its peak demand season, a long-term record of project operation must be used. Actual project operating records can be used, but the period of operation may not be long enough to give a statistically reliable value. Furthermore, operating changes may have occurred over the life of the project, which would make actual data somewhat inconsistent.

An alternative method is the use of a period-of-record computer simulation of system operation. As described in Section 2.5, the Little Rock District provided a daily simulation of the Ouachita River projects over the period of record of 52 years, from 1961 through 2012. This simulation, which was performed using the RESSIM streamflow routing model, served as the basis of this study's dependable capacity computations. Because reallocation of water at Lake Ouachita changes the amount of water available for power, capability calculations were performed for each project and then summed to estimate changes in capability for Lake Ouachita.

The initial step is to calculate the project's contribution (average weekly generating hours) to the system's capacity for the regional critical year. That contribution estimate was determined by first calculating the project's average weekly energy produced (MWh) for the peak demand months of June through September in 1964, which appears to be a critical year for water availability and power generation. That number was then divided by the marketable capacity (MW), giving an estimate of average weekly generating hours during the peak demand months. These values, as well as the marketable capacity and machine capability (i.e., the overload capacity) for Lake Ouachita, are presented in Table 5-1.

Table 5-1. Machine Capability, Weekly Energy, Marketable Capacity, and Average Weekly Generation Hours for Lake Ouachita, Blakely Mountain Hydropower Plant

Machine Capability (MW)	88.59
Average Weekly Energy (MW) (critical period)	2,548.14
Marketable Capacity (MW)	75
Average Weekly Generation Hours (critical period of 1964)	33.98

Next, the project's average weekly energy (MWh) produced during the peak demand months was calculated for each simulated year. Dividing those values by the project's average weekly generating hours from the critical period, as determined in the previous step, yields an array of yearly potential supportable capacity values. However, energy produced is limited by the machine capability of the project. The actual supportable capacity for any given year is consequently the lesser of the potential supportable capacity or the machine capability. With the average availability method, capability is the average actual supportable capacity over the period of record.

These values are defined in the following equations:

(1) Average Weekly Energy (MWh)$_{(year\,=\,i)}$ =

$$\text{(Total Energy (MWh) 6/1/1954 – 9/27/1954)}_{(year\,=\,i)} \text{ / 17 weeks}$$

(2) Marketable Capacity (MW) = Marketable Capacity of 86 MW

(3) Average Weekly Generating Hours $_{(baseline\ critical\ period)}$ =

Average Weekly Energy (MWH) $_{\text{(baseline critical period)}}$ / Marketable Capacity (MW)

(4) Potential Supportable Capacity (MW) $_{\text{(year=i)}}$ =

Average Weekly Energy $_{\text{(year=i)}}$ / Average Weekly Generating Hours $_{\text{(baseline critical period)}}$

(5) Machine Capability (MW) = Overload Capacity of Project (MW)

(6) Actual Supportable Capacity (MW) $_{\text{(year=i)}}$ =

MIN (Potential Supportable Capacity (MW) $_{\text{(year=i),}}$ Machine Capability (MW))

(7) Dependable Capacity = Average Actual Supportable Capacity over the Period of Record

As an example of how dependable capacity is calculated, Table 5-2 shows the values described in the previous paragraphs for the baseline or no-action alternative for Lake Ouachita for the years 1961-2012 (the years 1974-1999 are not shown for brevity). The average actual supportable capacity for the years 1961-2012 for Lake Ouachita is 83.96 MW. For most years, the actual supportable capacity is equal to the machine capability (overload capacity) of the project. This is not surprising because the capability is calculated based on the average number of generating hours per week in a critical year in which water was scarce.

Table 5-2. Capability Calculations for Existing Conditions, Lake Ouachita, 1961-2012 Period of Record

Year	Average Weekly Energy (MWh)	Potential Supportable Capacity (MW)	Machine Capability (MW)	Actual Supportable Capacity (MW)
1961	3,414.93	100.5	88.55	88.55
1962	2,654.21	78.1	89.29	78.12
1963	2,873.58	84.6	88.58	84.58
1964	2,548.14	75.0	88.65	75.00
1965	3,404.78	100.2	88.57	88.57
1966	3,125.40	92.0	88.57	88.57
1967	4,024.04	118.4	88.47	88.47
1968	7,484.12	220.3	88.46	88.46
1969	3,928.07	115.6	88.39	88.39
1970	3,022.04	88.9	88.63	88.63
1971	2,686.62	79.1	88.65	79.08
1972	2,295.11	67.6	88.69	67.55
1973	6,126.21	180.3	88.27	88.27
…	…	…	…	…
2000	5,207.35	153.3	88.48	88.48
2001	2,713.50	79.9	88.58	79.87
2002	3,100.56	91.3	88.65	88.65
2003	4,469.53	131.6	88.52	88.52
2004	3,777.85	111.2	88.54	88.54
2005	2,167.63	63.8	88.79	63.80
2006	2,470.76	72.7	88.69	72.72
2007	3,398.84	100.0	88.52	88.52
2008	5,600.89	164.9	88.27	88.27
2009	7,703.01	226.7	88.30	88.30
2010	4,502.63	132.5	88.60	88.60
2011	6,019.26	177.2	88.60	88.60
2012	1,969.92	58.0	88.79	57.98
			Capability	83.96

Table 5-3 summarizes the capability for Lake Ouachita under the no-action, reallocation from the conservation pool alternatives. The loss or gain in capability for the conservation pool is also presented.

Table 5-3. Average Capability Summary (MW)

	Lake Ouachita
No Action	83.96
Conservation Pool or Inactive Pool	82.74
Change in Capability	-1.22

There is a loss of 1.22 MW of average capability.

5.4. Computation of Capacity Values

Capacity benefits are an estimate of the investment cost of thermal generating plant capacity that would be needed to replace the lost capacity due to the water withdrawals from the reservoir. Capacity benefits are computed as the product of the capability loss and a capacity unit value, which is based on the unit cost of constructing the most likely thermal generating alternative.

5.5. Most Likely Thermal Generating Alternative

A screening curve analysis was conducted to determine the mix of thermal resources that would be the most likely (least-cost) generation plant alternatives for each of the White River hydropower plants. The type of alternative plants considered were coal-fired steam (base loads displacement), gas-fired combined cycle (intermediate loads displacement), and gas-fired combustion turbine (peak loads displacement).

5.6. Values Used in Screening Curve Analysis

Capacity unit values for coal-fired steam, gas-fired combined cycle and combustion turbine plants were computed using procedures developed by the Federal Energy Regulatory Commission (FERC). Capacity values were computed based on a 3.125% percent discount rate and FY2016 price level. The adjusted capacity values incorporate adjustments to account for differences in reliability and operating flexibility between hydropower and thermal generating power plants. See EM 1110-2-1701, *Hydropower*, Section 9-5c for further discussion on the capacity value FERC adjustments.

Operating costs for coal-fired steam, gas-fired combined cycle and gas-fired combustion turbine plants were developed using information obtained from the *EIA Electric Power Monthly* (DOE/EIA-0226) and other sources. The information obtained included fuel costs, heat rates and variable O&M costs. Since current Corps of Engineers policy does not allow the use of real fuel cost escalation, these values were assumed to apply over the entire period of analysis.

Adjusted capacity values and operating costs for the Arkansas are presented in Table 5-4.

Table 5-4. Plant Capacity and Operating Costs

Metric	Coal-Fired Steam	Combined Cycle	Combustion Turbine
Adjusted Capacity Value ($/kW-yr)	$319.99	$178.39	$94.52
Operating Costs ($/MWh)	$27.75	$32.86	$52.56

5.7. Screening Curve Analysis

The values shown in Table 5-4 were used to develop a screening curve for each of the thermal generating plant types. A screening curve is a plot of total plant cost [fixed (capacity) cost plus variable (operating) cost] versus annual plant factor.

A screening curve analysis consists of the following steps:

- Construct total plant cost (in $/kW-year) versus annual plant factor (in percent) diagram which includes a curve for each thermal generating plant type; this screening curve will show which type of plant is least cost in each plant factor range.

- Construct a generation-duration curve for the ‘typical”/existing condition for the plant from 2004 hourly generation records. This curve represents the typical operation of the plant over the period of analysis.

- From the screening curve, determine the "breakpoints" (the plant factors at which the least cost plant type changes).

- Find the points on the generation-duration curve where the percent of time generation is numerically identical to the plant factor breakpoints defined in the preceding step. These intersection points and the maximum and minimum generation define how much generation would be carried by each thermal generation plant type.

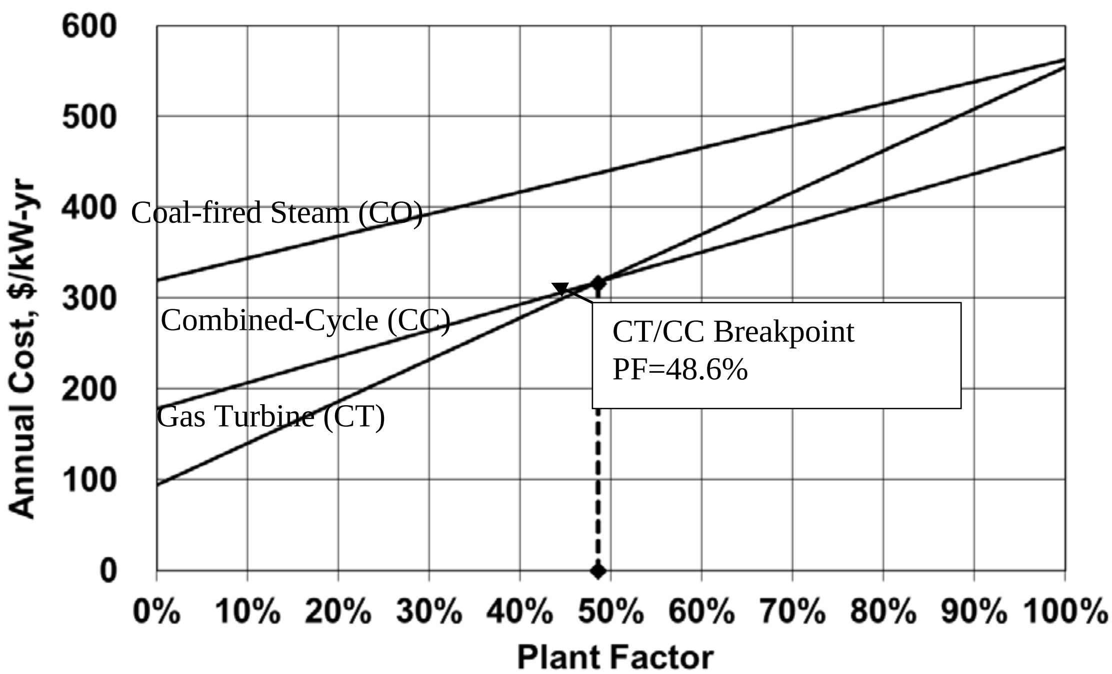
The plot for each thermal generation type was developed by computing the annual plant cost for various plant factors ranging from zero to 100 percent. The annual costs were computed using the following equation:

$$AC = CV + (EV * 0.0876 * PF)$$

where: AC = annual thermal generating plant total cost ($/kW-year)
CV = thermal generating plant capacity cost ($/kW-year)
EV = thermal generating plant operating cost ($/MWh)
PF = annual plant factor (percent)

The screening curve for the Lake Ouachita project is shown in Figure 5-2. The breakpoint between Combustion Turbine and Combined Cycle is at a plant factor of 9.3%.

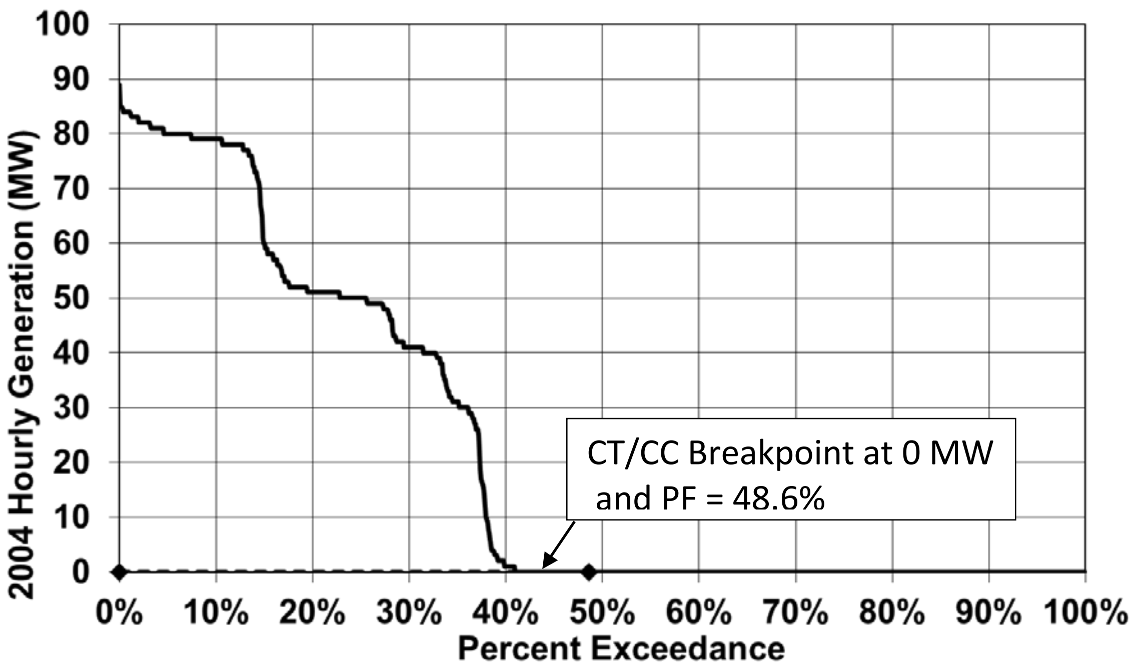
Figure 5-2. Thermal Screening Curve



5.8. Least-Cost Thermal Mix and Composite Capacity Value

As an example of how the generation-duration curve and screening curves are used to develop a composite capacity value, Figure 5-3 presents the generation-duration curve for Lake Ouachita. The breakpoint plant factor (48.6% percent) obtained from the screening curve in Figure 5-1 are matched to the same percent exceedence values on the generation-duration curves in order to determine the level of generation at which the least cost thermal alternative changes from combined cycle to combustion turbine (0 MW).

Figure 5-3. Generation Duration Curve for Lake Ouachita



Using this value, the mix of lowest cost thermal generating plants needed to replace the full capacity of Lake Ouachita's 89 MW of generating capacity would consist of 89.0 MW of Gas-fired combustion turbine plant capacity. From Table 5.4 the adjusted capacity value of gas-fired combustion turbine plant is;

$94.52 /kW-year

The capacity value is then converted to dollars per MW-year and multiplied by the respective changes in capability from Table 5-3 to give capacity benefits foregone. The effect of the conservation pool alternative on project capability is a small loss. Capacity value and capacity benefits foregone are summarized in Table 5-5.

Table 5-5. Capability, Composite Capacity Values, and Capacity Benefits Foregone for the Conservation Pool Alternative

	Lake Ouachita
Change in Capability (MW)	-1.22
Capacity Values ($/kW-year)	$94.52
Average Annual Capacity Benefits Foregone	**$115,314**

6. SUMMARY OF POWER BENEFITS FOREGONE

Table 6-1 summarizes power benefits foregone for Lake Ouachita hydropower project due to water reallocation from conservation pool storage. The data in Table 6-1 is derived from information developed in prior sections of this report. Table 4-3 provides the Contract Peak, Peak and Off-Peak lost energy, Table 4-5 provides the annualized price by calendar month of the energy lost, and energy benefits foregone are listed in Table 4-6. Project capability lost is described in Table 5-3, and the composite unit value for capability and the calculated capacity benefits foregone are found in Table 5-5.

Table 6-1. Summary of Average Annual Power Benefits Foregone

Energy Benefits Foregone	**$336,867**
Capacity Benefits Foregone	**$115,314**
Total Hydropower Benefits Foregone	**$452,181**

7. REPLACEMENT COSTS OF POWER

Because energy benefits foregone are based on the costs of the equivalent costs of thermal generating energy, the replacement costs of power are identical to energy benefits foregone and do not require separate calculation.

8. REVENUE FOREGONE

Revenue foregone is based on the current SWPA contract rates applicable to power generation by Lake Ouachita hydropower plant. The current rates are;

Firm Energy,	$9.40/MWh
Power Purchase Adder:	+<u>$5.90/MWh</u>
ANNUAL Contract ENERGY RATE:	$15.30 /mwh
Supplemental Energy, and Excess Energy Rate:	$9.40/MWh
Monthly Capacity Charge:	$4,500.00/MW
Ancillary Services:	
Monthly Regulation and Frequency Response:	$70.00/MW
Monthly Spinning Operating Reserve:	$14.60/MW
Monthly Supplemental Operation Reserve:	<u>$14.60/MW</u>
ANNUAL CAPACITY RATE:	$55.190.40/MW

To compute energy revenues foregone, the contract peaking energy rate is applied to the average annual on-peak contract energy losses, and the supplemental peaking energy rate is applied to on-peak non-contract energy losses and off-peak energy losses.

It is important to realize that the terms “energy” and “capacity” both mean very different things in the context of revenues foregone as opposed to their meaning when calculating benefits foregone. In the benefits foregone context, energy benefits foregone are the variable costs of generating the energy lost due to reallocation with an appropriate mix of thermal generating plants. These variable costs are mostly fuel and, to a lesser extent, operating and maintenance costs that vary with the amount of power generated. When calculating energy revenues foregone, the rates charged by the PMA are used and because the fuel (water) is essentially cost-free, these rates are much lower per unit of energy than the equivalent thermal costs.

Conversely, the capital costs of hydropower plants is typically much higher than the capital costs of equivalent thermal generation, particularly for gas-fired peaking plants that would be the most likely alternative for much of the power generated at Lake Ouachita. The capacity rates that SWPA charges its customers are calculated to repay the government for its investments.

Previous HAC studies have used changes of dependable capacity as the basis for calculating capacity revenue foregone. However, dependable capacity is based only on ability of projects to supply firm energy during the summer peak demand months of June through September. As presented in Table 4.3, most of the energy losses resulting from the conservation pool alternative occurs in the non-peak season months of October – May. The Lake Ouachita plant generates about a third of the average annual energy during the June – September peak season (66,246 MWh) and during the October – May off-peak season

(134,406 MWh). However, nearly 55% of the losses of contract on-peak power would occur during the off-peak season for the conservation pool alternative. More than 75% of all energy generation losses combined (contract on-peak, non-contract peak, and off-peak power) occur during the off-peak season. Using dependable capacity as a measure of capacity revenue would therefore miss more than half of the revenue losses resulting from the proposed reallocation.

As presented in Table 4.6, the average annual loss of contract on-peak energy resulting from the conservation pool alternative is about 1,978 MWh. It is reasonable to project that if SWPA loses the ability to generate an average of about 1,978 MWh each year during on-peak contract hours, they will necessarily need to reduce the capacity they market for contract on-peak hours by about 1.65 MW (1,978 MWh loss divided by 1,200 hours firm energy per MW of marketed capacity) once the current contract expires in 2027. This will cause a reduction in annual capacity revenue of 1.65 MW times $55,190 per MW, or about $91,064 per year at current rates.

Power revenues foregone are summarized in Table 8.1. Power revenue foregone of $173,910 means a loss of this amount, not an increase in revenue.

Table 8.1. Power Revenue Foregone Summary for Conservation Pool Alternative

	Energy Loss (MWh) or Capacity Loss (MW)	**SWPA Current Rates**	**Power Revenue Foregone**
On-Peak Energy (contract)	1,978 MWh	$15.30/MWh	$30,263
On-Peak Energy (non-contract)	3,388 MWh	$9.40/MWh	$31,847
Off-Peak Energy	2,206 MWh	$9.40/MWh	$20,736
Capability/ Capacity	1.65 MW	$55,190.40/MW	$91,064
Total			**$173,910**

9. CREDIT TO POWER MARKETING AGENCY

Project costs originally allocated to hydropower are repaid through power revenues based on rates designed by the federal power marketing agency (PMA) to recover allocated costs, plus interest within 50 years of the date of commercial power operation. If a portion of a project's storage is reallocated from hydropower to water supply, the PMA's repayment obligation may be reduced in proportion to the lost energy and capacity through a system of financial credits.

Planning Guidance Notebook, Appendix E-57.d.(3)(a) of ER 1105-2-100 (22 April 2002) states;

> "When hydropower is adversely impacted by reallocation of the flood pool to satisfy additional water supply needs, hydropower losses can be mitigated through the provision of financial credit. In this case, credits will be provided to the hydropower account from a portion of the water supply storage proceeds. This credit is based on revenues foregone to the United States Treasury for repayment of the hydropower costs assigned to the project. Revenues foregone reflect the allocated costs to power upon which the rates are based. When reallocation is accomplished through this credit approach, in essence, the allocation of costs is adjusted without performing a laborious new cost allocation. …" *(credit #1)*
>
> *(credit #2)* "Additionally, where existing Federal power delivery contracts require market purchases of power as a result of storage reallocations and withdrawals, the power marketing agency may obtain an additional credit for the funds expended for those purchases upon demonstration that they were made as a direct result of the reallocation."

Planning Guidance Notebook, ER 1105-2-100 (22 April 2002), Appendix E, SECTION VIII - Water Supply, Para. E-57.d.(3). states;

> "If hydropower revenues are being reduced as a result of the reallocation, the power marketing agency will be credited for the amount of revenues to the Treasury foregone as a result of the reallocation assuming uniform annual repayment. In instances where existing contracts between the power marketing agency and its customer would result in a cost to the Federal Government to acquire replacement power to fulfill the obligations of contracts, an additional credit to the power marketing agency can be made for such costs incurred during the remaining period of the contracts. Such credits should not actually be made for replacement costs until the costs are incurred and documented by the power marketing agency."

Thus, there may be an annual credit due to the PMA resulting from the proposed water supply reallocation that reduces revenues.

For the purposes of providing an estimate, the annual credit will be based on the revenue foregone as calculated in Section 9 because the power sales contracts are "evergreen" with the rate adjusted periodically to cover the cost of O&M for providing hydropower from the Federal projects and to repay the Treasury for the hydropower portion of the Federal investment in the project. In either case, the annual credit is based on revenue lost or costs actually incurred (and documented by the PMA).

10. SUMMARY OF RESULTS

Power benefits foregone are described in Sections 3, 4, 5, and 6. Total average annual power benefits foregone under the conservation pool alternative is $ per year, annualized over the 50-year period of analysis at the prescribed discount rate of 3.5 percent.

Table 10-1. Average Annual Power Benefits Foregone

Alternative	On-Peak Energy (contract)	On-Peak Energy (non-contract)	Off-Peak Energy	Capacity/ Capability	Total
Conservation Pool	$118,666	$147,650	$70,551	**$115,314**	**$452,181**

Revenues foregone are described in Section 8. Total average annual revenues foregone under the conservation pool alternative at current power sales contract rates is $173,910 per year.

Table 10-2. Average Annual Revenue Foregone

Alternative	On-Peak (contract)	On-Peak (non-contract)	Off-Peak	Capacity/ Capability	Total
Conservation Pool	$30,263	$31,847	$20,736	$91,064	**$173,910**

The average annual credit due the PMA under the water supply reallocation from conservation pool is $173,910, described in Section 9.

Table 10-3. Annual PMA Credit

	Annual PMA Credit
Water Supply Reallocation	**$173,910**

,

APPENDIX B

HYDROLOGY AND HYDRAULICS ANALYSIS

Lake Ouachita
Water Supply Yield Study

Aaron Short,
Little Rock District USACE

3/19/14

1. Purpose of Study: The purpose of this study was to consider the change in population and demand based on new members to the system, which has increased since the last completed study. Furthermore, this study took into consideration the existing raw water sources that were available to Central Arkansas Water, which were not considered in the initial study. Based on these findings and after meetings with the U.S. Army Corps of Engineers Little Rock District (SWL), Mid-Arkansas Water Alliance (MAWA) decided their goals could be met through the year 2025 A letter requesting the purchase of storage to provide 30 MGD from Lake Ouachita was submitted to the Little Rock District on 9 May 2005 by MAWA. A U.S. Army Corps of Engineers Study, "Mid-Arkansas Water Resource Study Update", was completed in December 2004 to update the needs of the eight counties in central Arkansas that comprise MAWA because the member utilities doubled since the initial report was completed.

Authority for the Corps to reallocate existing storage space to M&I water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended. The Secretary of the Army is authorized to cooperate with local interests in providing storage space for M&I water supply in Corps of Engineers projects as long as the local interests agree to pay the costs associated with the storage space. The Corps has the discretionary authority to reallocate 50,000 acre feet of the total storage capacity in Lake Ouachita provided the reallocation has no severe effect on other authorized purposes and will not involve major structural or operational changes.

2. Pertinent Lake Data: Lake Ouachita was constructed and is operated by the Vicksburg District of the Corps of Engineers. Lake Ouachita is located at the head of Lake Hamilton on the Ouachita River at mile 430.4, approximately 10 miles northwest of Hot Springs in Garland County, Arkansas, and 487 miles above the mouth of Black River. Lake Ouachita was designed for flood control and the production of hydroelectric power. Construction of the spillway began 15 August 1947 and was completed 31 August 1948. Construction of the diversion tunnels began in July 1948 and was completed in June 1950. The river was diverted through these tunnels in May 1950. Work on the earth dam and concrete intake structure was begun in March 1950 and completed in September 1953. Construction of the power plant was begun in December 1952 and completed in October 1955. The first generation of electric power was in August 1955, and the plant was placed in commercial operation 1 October 1955. The current Lake Ouachita storage allocations are provided in Table 1.

Table 1
Lake Ouachita Storage Allocations

Purpose	Elevation Range	Storage (AF)
Surcharge	**610.2 – 592.0**	**993,000**
Flood Control	**592.0 – 578.1**	**617,400**
Power	**578.1 – 535.0**	**1,286,200**
Minimum	**535.0**	**864,900**

3. Dam Safety Action Classification: Blakely Mountain Dam currently has a Corps of Engineers Dam Safety Action Classification (DSAC) III rating. The DSAC III rating is for dams with confirmed and unconfirmed dam safety issues where the combination of life or economic consequences with probability of failure relative to other dams is moderate to high. The Corps of Engineers policy prohibits reallocation of flood pool storage to other purposes if a dam has a DSAC rating of I, II, or III. Reallocation of conservation pool storage (below normal pool) is acceptable for DSAC III under the policy.

4. Study Methodology: The expected yield is evaluated through the iterative simulation method. A daily model (Model) of lake operation has been prepared using the Hydrologic Engineering Center's Reservoir Simulation Program, Revision 3.1(HEC-ResSim). The HEC-ResSim software performs hydrologic routing and determines reservoir releases based on a guide curve approach plus user-specified operation rules. The rules provide for lake operation according to the current lake Water Control Manuals. The period of the study is 1961 through 2012 (51-year, Period of Record). The Model is run multiple times for a specific water supply yield value with varying account storage amounts. Using this method, the minimum storage required for a specific yield value (firm yield) is determined.

5. Hydrology: Input data for the Model has been taken from the historic record. The available record and simulation methods are described below.

5.1 Evaporation: Evaporation is a critical factor in water supply studies. During drought conditions, the evaporation loss from a large reservoir represents a substantial percentage of the total water loss. Evaporation was calculated by picking an average day that was representative of the month. From the average day, the flow in cubic feet per second (cfs) of the evaporation was found. The average lake elevation for the month was calculated. Using average lake elevation and the flow from evaporation, the total evaporation for the average day is found then multiplied by the number of days in the month. The monthly totals are in Table 2.

Table 2
Monthly Total Evaporation

January	**0.96**
February	**0.98**
March	**1.82**
April	**2.03**
May	**2.50**
June	**2.65**
July	**3.21**
August	**3.10**
September	**2.41**
October	**1.77**
November	**1.26**
December	**0.98**

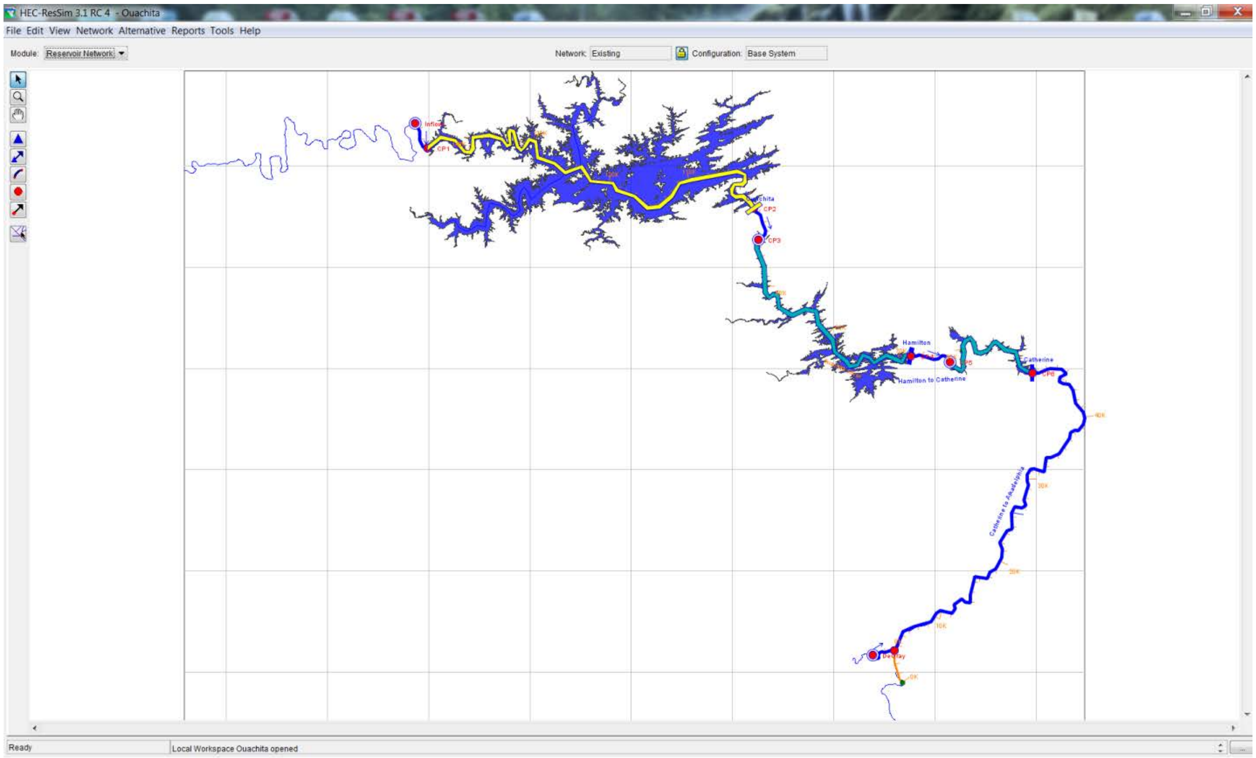
5.2 Lake Inflow: The Vicksburg District inflow record for Lake Ouachita begins on June 1, 1960. The record provides mean daily flow, but included negative inflows for some values even after adjusting for evaporation. The negative values were set to zero. The total monthly inflow was preserved by adjusting the positive ordinates downward, while maintaining peaks from larger rainfall events. Blakely Mountain Dam has a drainage area of 1,105 square miles.

Simulation of intervening flows at Arkadelphia was completed using historical data, in DSS format, obtained from the U. S. Army Corps of Engineers Vicksburg District (MVK). The data provided a 0600 instantaneous flow from January 1, 1961 through March 12, 2013. The flows used in the model were created by subtracting the known releases from Remmel Dam routed to Arkadelphia from the given flows supplied by MVK.

5.3 Lake Storage: The area-capacity table for Blakely Mountain Dam was compiled from the graph of the Stage-Storage Curve, Plate 3-7, in the draft version of the water control manual. The table was used in the study without adjustment for future sedimentation.

6. Model Structure: The Model for Lake Ouachita operates on a 6-hour time step and represents the period 1961 through 2012 (51-year, Period of Record). The Model incorporates the current operation criteria defined within the lake's Water Control Manual (WCM). A screen capture of the Model is provided as Figure 1.

Figure 1
HEC ResSim Model



Lake Ouachita is primarily operated for flood control and hydroelectric power generation. The multiple-purpose project provides collateral benefits of water supply, recreation, industry, and navigation downstream. The method of incorporating each of these primary purposes into the Model is discussed below.

<u>6.1 Flood Control</u>: Lake Ouachita is operated for the downstream control point in tandem with DeGray Lake. However DeGray Lake has not been included in the Model. Balancing the releases from Lake Ouachita with DeGray at Arkadelphia is common during flood water evacuation operation. However, the operational manual did not detail the balancing rules; therefore, the observed releases DeGray made were used in place of including the lake in the Model. For intervening flows into Arkadelphia historical data was used. The flow from DeGray was lagged and added with the intervening flow at Arkadelphia. Arkadelphia is one of only two control points for this lake system. The other control point is at Malvern, AR. The control point at Malvern does not and has not had a gauge for some time now, so the WCM states that "Remmel releases are used in lieu of Malvern flows." It goes on to state that "a peak flow of 13,000 cfs at Remmel is comparable to a peak flow of 15,000 cfs at Malvern." There is also a rule for rainfall exceeding two inches to keep the maximum flow of 3,000 cfs in order to prevent unnecessary downstream flooding.

6.2 Hydropower: Lake Ouachita is operated to provide hydropower for distribution by the Southwestern Power Administration (SWPA), a sub-agency of the Department of Energy. Entergy Arkansas, Inc currently operates the power generation for Lake Ouachita and provides SWPA their power upon request. The amount of power generated from Lake Ouachita is influenced by the current lake elevation, because of this it was not possible to estimate power releases solely from a power demand rule. Entergy Arkansas, Inc provided information that in turn, allowed SWL to develop an appropriate guide curve. The guide curve is able to let the model know how much water to release, and from that the power generated can be calculated. The guide curve is provided in Chart 1. The guide curve was implemented with a brute force method. Normally rules used in a model will conform to many different situations. This method was not precise enough for this rule so the brute force method used was to make a table for every pool elevation and every day of the year to give a release. Entergy Arkansas, Inc does not try to keep the pool on the guide curve, but rather tries to hit the inflection points while not straying too far from the curve. The inflection points are shown in Table 3. To accomplish this, a table was made so that given a day and a pool elevation a release can be determined by the rule.

Chart 1

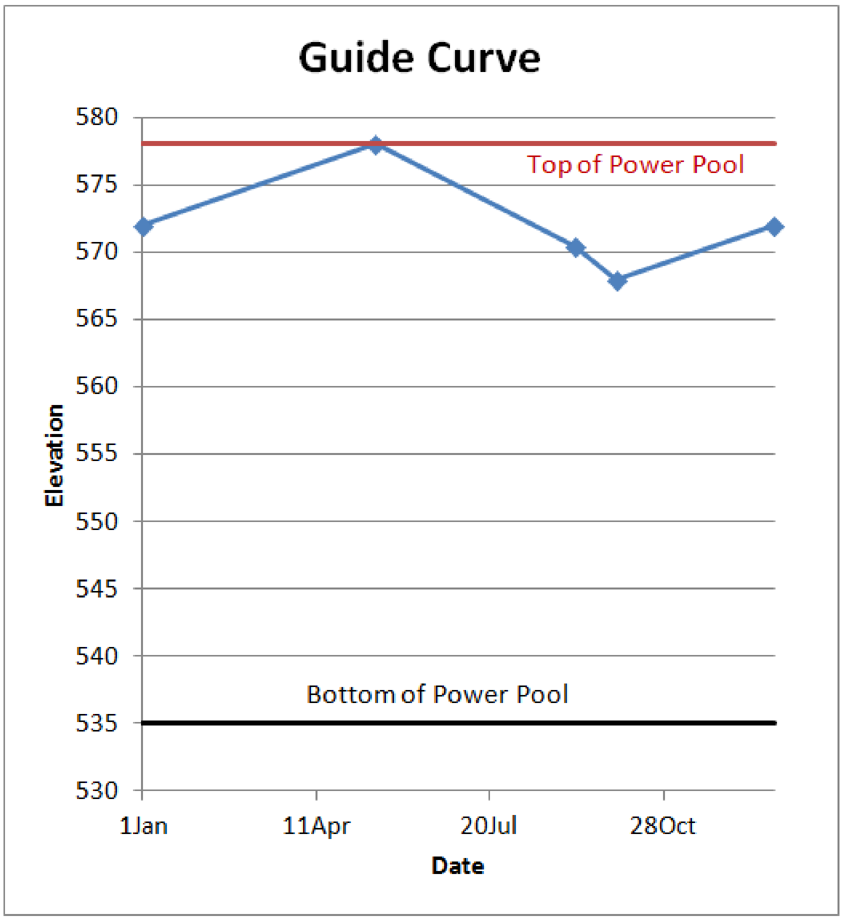


Table 3
Guide Curve Inflection Points

Date	1 Jan	15 May	7 Sep	1 Oct
Elevation	572.0	578.1	570.5	568.0

A list of the Flood Control Rules from the water control manual is:

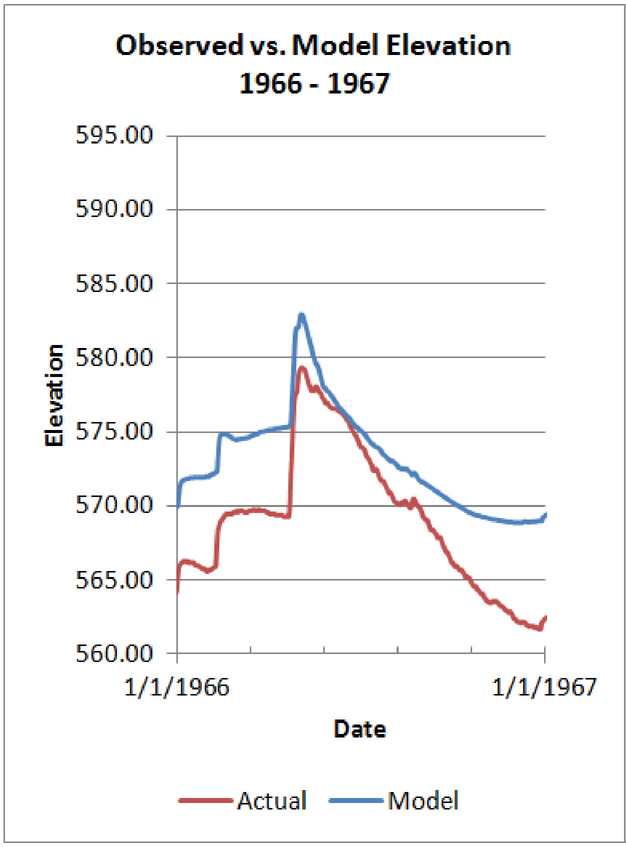
- The power release form Blakely Mountain Dam will be limited to 3,000 cfs average per day when discharge at Remmel Dam exceeds 13,00 cfs
- When the stage at Arkadelphia, AR is predicted to exceed 25 feet, where major damage begins, the power release will be restricted to the amount required to generate the primary energy of the project (about 1,100 cfs daily discharge).
- Reservoir releases for both flood control and power will be regulated so as not to exceed 15,000 cfs at Malvern, AR. No releases will be made through the flood control conduit when the flow at Arkadelphia, AR exceeds 20,000 cfs (approximately 16.0 feet stage).
- Any time 2 or more inches of rain are recorded at the power plant within a 24-hour period, the total reservoir release will be restricted to a maximum of 3,000 cfs. If generation of electricity is not required, the release should be reduced to no outflow. This restriction will remain in effect until the outflow from Remmel Dam peaks and begins to fall.
- Any time the elevation in the lake rises into the flood control pool which is above elevation 578.1 feet NGVD, the Water Control Management Section will determine regulation requirements for release of excess flood water in consideration of downstream conditions. These decisions could include requiring the power company to generate at full capacity and/or opening the flood control gates in order to draw the lake back down below elevation 578.1 feet NGVD subject to the above restrictions.

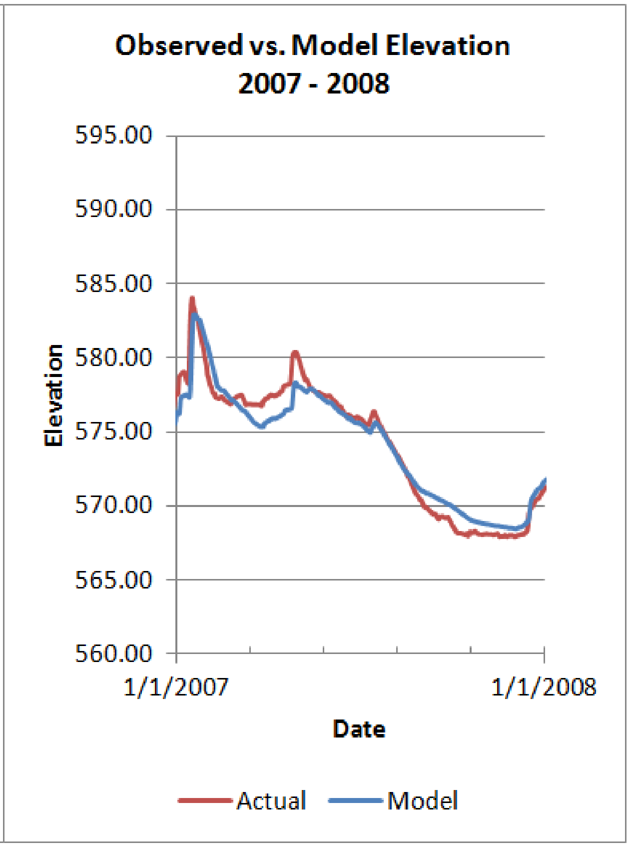
7. Model Calibration: To calibrate the Model, a few rules were incorporated to account for how the lake is operated in practice. A rate of change limit for releases has been limited to 500 cubic feet per second (cfs) per hour. After talking with the staff at MVK, the conduit gates are not opened until the lake elevation is more than two feet into the Flood Control Pool and if the lake is not projected to crest within the day.

Entergy Arkansas, Inc did not provide power demand to be used for the Model due to how the lake is operated. In regards to target lake elevation in the Power Pool, Entergy Arkansas, Inc creates a guide curve based from where the lake elevation was at the end of the previous year. To account for this a basic curve was used as a target. There were some small adjustments needed to the guide curve rule to get the lake elevations match. After running the Model it was noted that the initial settings were following the guide curve too closely and had to be adjusted. One trend with how the power was generated that was observed is there tends to be a slight difference in operation around rainfall events. There was a new rule that changes how closely the guide curve is followed for these situations. Integrative numerical methods were used to fine tune the rules following the guide curve till the Model was operating at an optimal performance.

Due to the freedom Entergy Arkansas, Inc has in controlling the lake elevation within the power pool and because of new lake managers over the years, the way in which the lake releases and there for pool elevation has been decided has changed throughout the lakes history. There was a large change in how the lake was operated in 1971 to a method that is closer to how the lake is currently operated. There have only been smaller changes to how the lake is operated past this date. The last change seems to have happened around 2001. With this in mind, the goal was to match the Model more to the current operation rather than some of the other periods of time. This is the reason the first ten years of the Model does not match well with the observed data, especially when compared to the last twelve years. See Chart 2 for an example year from both sections of time.

Chart 2

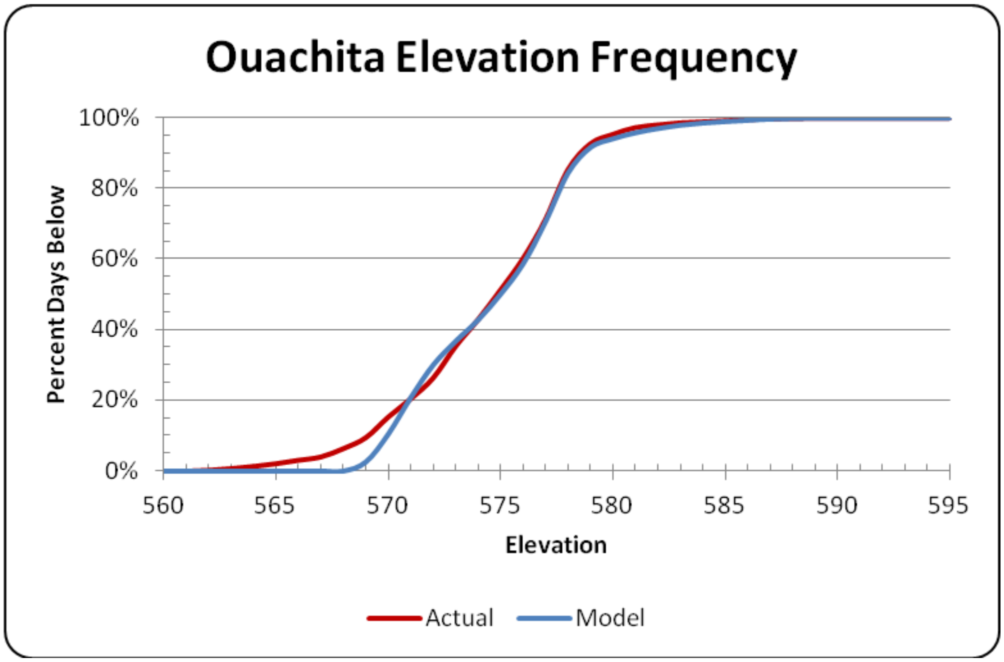




It was noticed when calculating the critical date for the yield that the current rule set did not properly function when the pool elevation got too low. To resolve this issue a new zone was added to the Model called “Stressed Power.” This zone starts at the highest elevation of the warning line from the WCM, elevation 535.0. In this zone the power demand rule had its values divide by two. In doing this we can keep the normal operating curve shape while maintaining a good balance between producing power and conserving the pool.

A comparison of the daily elevation frequency for the period 1961 through 2012 is provided in Chart 3.

Chart 3



As expected, the Model output reflects a higher average elevation when looking at the lower elevations. This is due to the change in the management and guide curves used to regulate the lake's elevation.

After sending the data for the cost analyst, the data was not in a format and condition that could be easily used. A new approach was developed for how the Model looks at the power generation. The new approach looked more to a power demand table. This table was created by working with SWPA and some statistics on the data SWPA provided. After have some difficulty getting an accurate Model, the new version of the Model was taken to a meeting with SWPA to receive input on ways to optimize the Model and the best way to process the power generation data. After the meeting with SWPA it was agreed that the best way to process the power generation data was with a post processing of the data from the Model. Once this method was chosen as the best option, none of the changes to the Model were needed so the originally submitted data was used for analysis.

8. Water Supply Yield: The water supply demand was set to an amount without seasonal variation. Then the Model was run multiple times with varying storage values allocated to that water supply, until the storage was just depleted while still supplying the demand through the most severe drought. The iterative process was repeated for each of the different yield values. The critical date for the yield was November 10, 1967. There were no additional runs made to evaluate the effect of using Lake Ouachita flood zone storage for water supply, because of the Dam's DSAC III rating.

9. Conclusion: The Model adequately simulates the operational rules found in the WCM and modifications were made to reflect the current use patterns. The Model produced a firm yield of 1194 cfs. From this, MAWA would need 49,982.98 acre-ft to supply their demand of 30 mgd.

APPENDIX C

ECONOMIC ANALYSIS

Lake Ouachita **Annual Repayment Cost for Reallocated Storage**	
Item	Amount
Storage Required, ac.-ft.	49,983
Water Supply Yield, mgd	30
Interest Rate, percent	3.500%
Repayment Period, years	30
Useable Project Storage	
Flood Control - ac-ft	617,000
Hydropower Storage - ac-ft	1,286,000
Total - ac-ft	1,903,000
Percent of Usable Project Storage	2.6257%
Joint-Use Project Cost	
Initial Construction (2016 Price Level)	$224,768,000
O&M (Estimated Average Annual)	1,201,000
Allocated Water Supply	
Storage Cost	5,904,000
Annual Cost of Storage	
Investment*	310,000
O&M**	32,000
Total	342,000

* Based on 3.50% interest rate and 30-year repayment period.
** Based on 2.63% of the estimated average annual joint-use O&M cost.

UPDATED PROJECT COST ESTIMATE

Categories	Initial Project Cost 1957 Prices	1957 ENR Index[2]	Jul 67 ENR Index	Jul 67 CWCCIS Index	FY 16 CWCCIS Index [1]	FY 16 Project Cost	
Land and Damages	2,361,600	477	1,078	100		41,881,000	J
Relocation	1,083,700	477	1,078	100	832.09	20,379,000	J
Reservoir	2,009,900	477	1,078	100	876.67	39,821,000	J
Dam and Spillway							
Main Dam	6,306,500	477	1,078	100	794.69	113,263,000	J
Power Intake Works	6,724,900	477	1,078	100	794.69	120,777,000	P
Flood Control Outlet Works	3,275,300	477	1,078	100	794.69	58,823,000	F
Powerplant	7,479,800	477	1,078	100	739.84	125,063,000	P
Roads	347,200	477	1,078	100	810.02	6,356,000	J
Buildings	169,200	477	1,078	100	790.52	3,023,000	J
Equipment	1,091,900	477	1,078	100	739.84	18,257,000	P
TOTAL	30,850,000					547,688,000	
SUMMARY							
Specific Costs							
Flood Control	3,275,300					58,823,000	FC
Power	15,296,600					264,097,000	P
SUBTOTAL	18,571,900					322,920,000	
Joint-Use Cost	12,278,100					224,768,000	
TOTAL PROJECT COST	30,850,000					547,688,000	

[1] CWCCIS factors are taken from EM1110-2-1304, dated 19 September 2016.

[2] ENR factors are taken from Engineering News Record, http://enr.construction.com/, 19 September 2016.

Allocation of Updated Construction Cost for Blakely Mountain dam - Lake Ouachita

Feature	Cost - FY96 a/	Cost - FY16 b/	% of Joint Use Construction Cost
Flood Control			
Specific	33,910,000	61,053,000	
Joint Use	47,409,000	85,357,000	35.53%
Hydropower			
Specific	158,329,000	285,062,000	
Joint Use	86,026,000	154,885,000	64.47%
Total Aloc. Joint Use	133,435,000	240,242,000	

a/ based on FY96 price levels.
b/ updated using CWCCIS factors for FY96 price levels to FY16.

96 costs above from the 1996 reallocation report to Garland Co. Water District
CWCCIS factors for updating the costs from 96 to current dollars

FY96	462.16
FY16	832.0925
factor	1.800442487

http://publications.usace.army.mil/publications/eng-manuals/EM_1110-2-1304.pdf
Updated 19-Sept-16

APPENDIX D

PERTINENT CORRESPONDENCE

APPENDIX E

NEPA DOCUMENTATION
ENVIRONMENTAL ASSESSMENT

FINDING OF NO SIGNIFICANT IMPACT

BLAKELY MOUNTAIN DAM WATER REALLOCATION STUDY
LAKE OUACHITA, GARLAND COUNTY, ARKANSAS

As required by the Procedures for Implementing the National Environmental Policy Act (33 CPR, Part 230), the attached Environmental Assessment (EA) for the proposed action of increasing water available for water supply for distribution by the Mid-Arkansas Water Alliance (MAWA) by reallocating 50,000 acre feet of storage capacity of Lake Ouachita to water supply has been completed by the U.S. Army Corps of Engineers, Regional Planning and Environment Division South, Vicksburg District. The EA addresses the potential environmental effects of the proposed action.

Based on the information provided in the EA, the proposed action is not reasonably likely to cause significant adverse impacts to the human environment. In addition, no historic properties listed in or determined eligible for inclusion in the National Register of Historic Places will be affected by the project. Therefore, this Finding of No Significant Impact is issued. An Environmental Impact Statement will not be prepared.

26 March 2015
(Date)

John W. Cross
John W. Cross
Colonel, Corps of Engineers
District Commander

Attachment

ENVIRONMENTAL ASSESSMENT

ENVIRONMENTAL ASSESSMENT
BLAKELY MOUNTAIN DAM WATER REALLOCATION STUDY
LAKE OUACHITA, GARLAND COUNTY, ARKANSAS

MARCH2015

U.S. Army Corps of Engineers
Regional Planning and Environment Division South
Vicksburg District

ENVIRONMENTAL ASSESSMENT
BLAKELY MOUNTAIN DAM WATER REALLOCATION STUDY
LAKE OUACHITA, GARLAND COUNTY, ARKANSAS

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ENVIRONMENTAL ASSESSMENT
BLAKELY MOUNTAIN DAM WATER REALLOCATION STUDY
LAKE OUACHITA, GARLAND COUNTY, ARKANSAS

1.0 INTRODUCTION

This Environmental Assessment (EA) has been prepared in accordance with the Procedures for Implementing the National Environmental Policy Act (33 CFR, Part 230). The EA identifies existing conditions and determines potential environmental impacts of the reallocation of up to 50,000 acre feet in Lake Ouachita. Sufficient information is provided in this EA on the potential environmental effects of the proposed action to allow the U.S. Army Corps of Engineers, Vicksburg District Commander, to make an informed decision on the appropriateness of an Environmental Impact Statement or Finding of No Significant Impact (FONSI).

1.1 PROPOSED ACTION

The proposed action consists of increasing water available for water supply for distribution by the Mid-Arkansas Water Alliance (MAWA) by reallocating 50,000 acre feet of storage capacity of Lake Ouachita to water supply.

1.2 PROJECT AUTHORITY AND NEED

Authority for the Corps to reallocate existing storage space to municipal and industrial water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended. The Secretary of the Army is authorized to cooperate with local interests in providing storage space for municipal and industrial water supply in Corps of Engineers projects as long as the local interests agree to pay the costs associated with the storage space. The Corps has the discretionary authority to reallocate the lesser of 15 percent or 50,000 acre feet of the total storage capacity in Lake Ouachita provided the reallocation has no severe effect on other authorized purposes and will not involve major structural or operational changes.

MAWA is group of 27 water utilities in the eight counties in central Arkansas. They are requesting this storage reallocation from Lake Ouachita to meet their future water needs through the year 2050.

1.3 PROJECT DESCRIPTION

Lake Ouachita was constructed and is operated by the Vicksburg District Corps of Engineers. Blakely Mountain Dam which contains Lake Ouachita is located at the head of Lake Hamilton on the Ouachita River at mile 430.4, approximately 10 miles northwest of Hot Springs in Garland County, Arkansas. Construction of the spillway began August 15, 1947, and was completed August 31, 1948. Construction of the diversion tunnels began in July 1948 and was completed in June 1950. The river was diverted through these tunnels in May 1950. Work on the earth dam and concrete intake structure was begun in March 1950 and completed in September 1953. Construction of the power plant was begun in December 1952 and completed in October 1955. The first generation of electric power was in August 1955, and the plant was placed in commercial operation October 1, 1955.

2.0 ALTERNATIVES

2.1 NO-ACTION ALTERNATIVE (ALTERNATIVE 1)

The no-action alternative does not allow for the future water supply needs for members of MAW A. This would be inconsistent with existing and future water supply needs for the association and could severely impact the safety and health of their customers. Existing users in MAWA would be forced to find alternate water supplies for municipal and industrial needs.

2.2 ALTERNATIVE 2 (RECOMMENDED ALTERNATIVE)

The recommended plan is to reallocate 50,000 acre feet of the total storage of Lake Ouachita to meet the growing water needs of the citizens of central Arkansas.

2.3 ALTERNATIVE 3

These alternative supplies would mostly be groundwater withdrawals. Declining aquifer water levels create a multitude of problems. Because of these excessive withdrawals of groundwater, the safe yield has been approached or exceeded in the alluvial and Sparta aquifers. The Arkansas Soil and Water Conservation Commission has declared these aquifers as "critical groundwater levels" due to the safe yield concerns relating to poor water quality and to saline intrusions consistent with declining groundwater levels. Several of the existing entities currently use groundwater and are already experiencing difficulty in obtaining adequate water from their sources. Therefore, additional groundwater withdrawal is not considered a viable alternative.

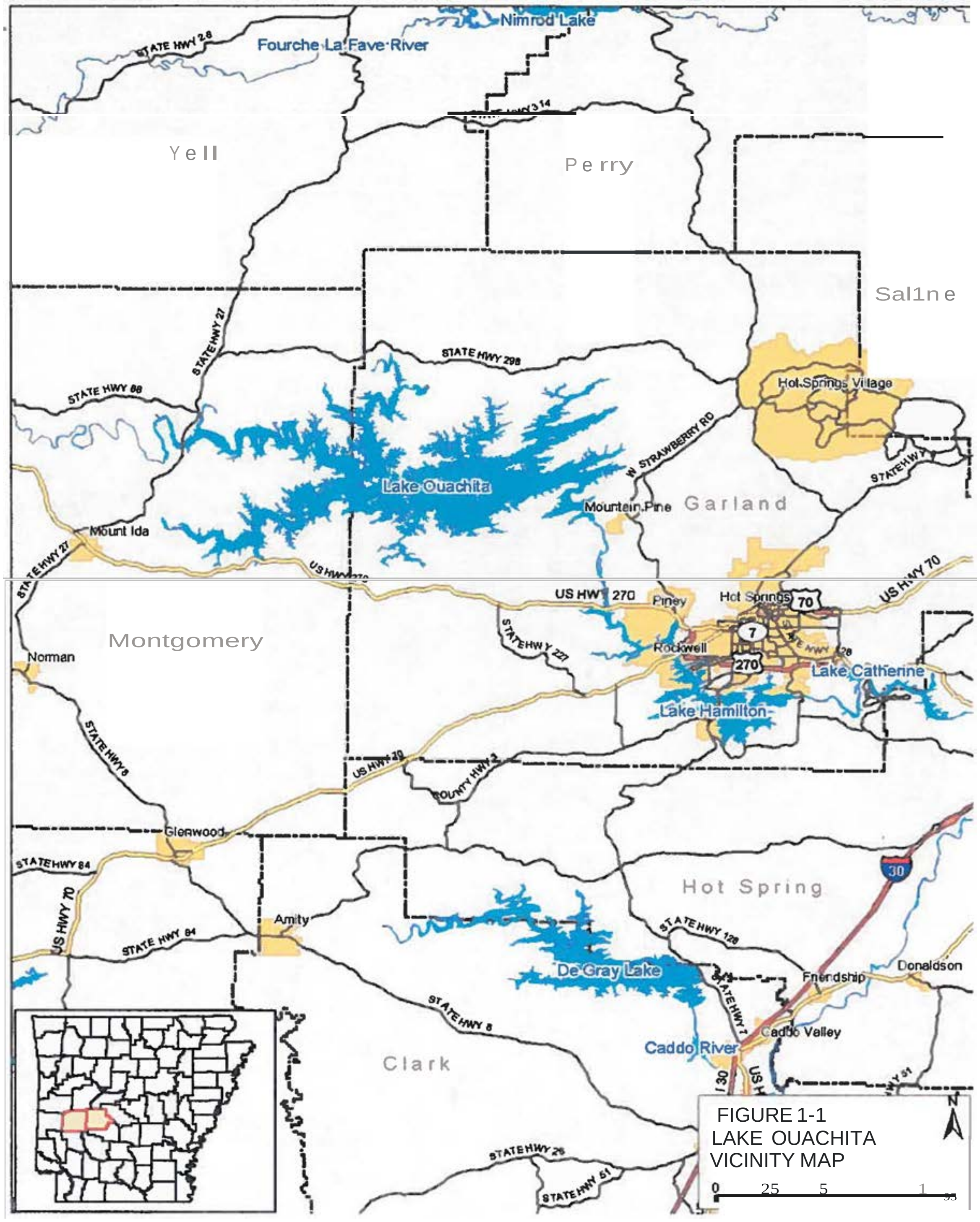

Figure 1. Lake Ouachita and Surrounding Communities

EA#36
Lake Ouachita
Blakely Mountain Dam
March2015
U.S. Army Corps of Engineers
Regional Planning and Environment Division South
Vicksburg District

3.0 AFFECTED ENVIRONMENT

Lake Ouachita contains an average of 1,000,000 acre feet of water storage. The surface acreage averages from approximately 40,000 to 48,000 acres throughout the year and surface elevations fluctuate approximately 9 feet each year. These fluctuations result from lake operations for flood control and hydropower generation. The project is a feature of the comprehensive plan for water resources development in the Ouachita River Basin. Entergy Power Company owns and operates two hydroelectric dams (Carpenter and Remmel Dams) immediately downstream from Blakely Mountain Dam.

In addition to the authorized purposes of Lake Ouachita for flood control and hydroelectric power generation, the multiple-purpose project provides collateral benefits of water supply and to recreation and to industry and navigation downstream from the dam through regulation of low flows in the Ouachita River.

3.1 AIR QUALITY

The air quality of the proposed project location is considered very good. Currently, the entire State of Arkansas meets all air quality standards for criteria pollutants.

3.2 WATERQUALITY

The drinking water quality of the area is good. Lake Ouachita and the Ouachita River provide the major water supply for Hot Springs and seven counties in central Arkansas while various aquifers located deep beneath the ground provide drinking water for areas away from those water bodies. Section 303(d) of the Clean Water Act requires states to identify water bodies that are considered impaired due to not meeting one or more applicable water quality standards.
Section 303(d) water bodies include Indian Springs Creek in Garland County and the Caddo and South Fork Caddo River in Montgomery County.

3.3 CLIMATE

Garland County Arkansas has a humid subtropical climate with hot, humid summers and generally mild to cool winters. July and August are the hottest months of the year, with an average high of 93°F (34°C) and an average low of 70.5 op (21.4°C). The highest recorded temperature in Hot Springs was 115 degrees Fahrenheit in 1986 while the lowest temperature recorded was -5 degrees Fahrenheit in 1989. Precipitation is weakly seasonal, with a bimodal pattern: wet seasons in the spring and fall, and relatively drier summers and winters, but some rain in all months. The spring wet season is more pronounced than fall, with the highest rainfall in May. Hot Springs precipitation is impacted by the geographic effect of the Ouachita Mountains.

3.4 SOILS

The soils in Garland County are predominantly made up of Bismarch-Complex, Carnasas-Pirum-Clebit complex, and Yanush-Avant complex soils. The soils tend to be moderately sloped in the project area.

3.5 TERRESTRIAL RESOURCES

Wooded terrestrial habitat exist as many species of hardwood and softwood trees. Some wildlife resources that may occur within the project area are, but are not limited to, the white-tailed deer, eastern wild turkey, gray squirrel, and the northern bob white quail. No individual species of significant commercial value occur within the project area.

3.6 AQUATIC RESOURCES

The project area is Lake Ouachita. Lake Ouachita contains many species of sport and game fish including: largemouth bass, spotted bass, smallmouth bass, white bass, striped bass, crappie, and walleye. Rough fish include several species of catfish, gar, and carp. Additionally, Lake Ouachita is home to many forage fish such as sunfishes, minnows, gizzard, and threadfin shad.

3.7 WATERFOWLRESOURCES

Lake Ouachita is on the western side of the Mississippi Flyway. The open waters of the lake and flood plain forests in the general area are used year-round by wood ducks and to a lesser extent by migratory waterfowl.

3.8 WETLAND RESOURCES

In addition to their wildly recognized wildlife values, wetlands provide short- and long-term storage, water velocity reduction and sediment detention, nutrient removal, and export of organic carbon to downstream ecosystems.

3.9 HAZARDOUS, TOXIC, AND RADIOLOGICAL WASTES (HTRW)

A preliminary assessment screening for HTRW will be conducted prior to construction of the structure in the future.

3.10 RECREATION AND ESTHETICS

A great variety of recreational activities are available in or close to the proposed project area. These activities include, but are not limited to, consumptive activities such as large and small game hunting and fishing in and around Lake Ouachita. Hiking, sightseeing, boating, picnicking, bird watching, scuba diving, and nature photography are some of the major non-consumptive recreational opportunities available.

3.11 THREATENED AND ENDANGERED SPECIES

The results of the species review by Vicksburg District biologists find that the Bald Eagle *(Haliaeetus leucocephalus),* the Northern Long-eared Bat *(Myotis septentrionalis),* Missouri Bladderpod *(Physariafiliformis),* Harperella *(Ptilimnium nodosum),* as well as several species mussel are known to inhabit Garland and Montgomery County.

4.0 ENVIRONMENTAL IMPACTS

4.1 AIR QUALITY

Since the reallocation of storage requires no actual construction to take place, no impacts to air quality are expected to take place. Further, the climatic conditions of the region favor rapid dispersal of pollutants and thus, would not allow concentrations to accumulate.

4.2 WATERQUALITY

Since the reallocation of storage requires no actual construction to take place, no construction impacts to water quality are expected to take place. Furthermore, the reallocation of storage in Lake Ouachita will not affect the normal pool or minimum flows from the reservoir.

4.3 TERRESTRIAL RESOURCES

Since the reallocation of storage requires no actual construction to take place, no construction impacts to terrestrial resources are expected to take place. Furthermore, the reallocation of storage in Lake Ouachita will not affect the normal pool or minimum flows from the reservoir.

4.4 AQUATIC RESOURCES

The proposed reallocation of water to water supply will have no effect on the normal pool or the low flows of the lake. Therefore, no impacts to aquatics are expected.

4.5 WATERFOWL RESOURCES

The project would have no effect on the normal pool or the low flows from the lake so it would not adversely impact migratory or resident waterfowl.

4.6 RECREATION AND ESTHETICS

Since the reallocation of water will not affect the normal pool elevation of the lake, there will be no impact on recreation or esthetic resources.

4.7 HTRW

Since this reallocation will not change the normal pool of the lake or low water flows, it is expected that the potential to expose or affect any HTRW is very low.

4.8 SECTION 404 CONSIDERATIONS

Since there is no affect to wetlands, no Section 404(b)(l) evaluations will be required for this action.

4.9 FLOOD PLAIN MANAGEMENT AND WETLAND PROTECTION

The EA has considered the objectives of Executive Orders 11988 and 11990 "Flood Plain Management" and "Protection of Wetlands," respectively. The proposed project would not result in impacts to the flood plain or wetlands.

4.10 THREATENED AND ENDANGERED SPECIES

On October 22, 2014, an email was sent to the U.S. Fish and Wildlife Service (FWS) for their comments about the proposed project and its potential effects, if any, to threatened and endangered species. The FWS responded by email on October 27, 2014, stating they have determined the proposed project is unlikely to have any adverse affects on any Federally listed species or their habitats (Attachment 1). Therefore, it is our recommendation that no Federally listed species or their habits will be impacted by the proposed action.

4.11 CULTURAL RESOURCES

The proposed project will involve no ground disturbing activities nor affect water levels within the existing lake. Therefore; it is the determination of Vicksburg District that the proposed undertaking is a type of activity that does not have the potential to cause effects on historic properties. No further archeological work is necessary or recommended.

4.12 ENVIRONMENTALJUSTICE

Because the proposed project involves only the reallocation of existing water storage, no Environmental Justice concerns will be encountered during the project.

4.13 CUMULATIVE IMPACTS

The Council on Environmental Quality regulations (40 CPR §1500-1508) for implementing the procedural provisions on the National Environmental Policy Act define cumulative effects as the impact on the environment which results from the incremental impact of the action when added to other past, present, and foreseeable future actions regardless. This reallocation of water in Lake Ouachita is needed in order to provide for the future water supply needs to the residents in the MAWA area. The incremental impacts of this reallocation of water, when added to former, past, and foreseeable future action, within geographical boundaries for the project would result in minimal adverse impacts to the environment.

5.0 COORDINATION

Preparation of this EA and FONSI were coordinated with appropriate congressional and Federal, state, and local interests, as well as environmental groups, Native American Indian tribes, and other interested parties.

FWS
EPA, Region VI
Natural Resources Conservation Service
Advisory Council on Historic Preservation
Arkansas Department of Wildlife, Fisheries and Parks
ADEQ

6.0 COMPLIANCE WITH ENVIRONMENTAL LAWS AND REGULATIONS

Environmental compliance for the proposed action would be achieved upon coordination of this EA and draft FONSI with appropriate agencies, organizations, and individuals for their review and comments; FWS confirmation that the proposed action would not be likely to adversely affect any endangered or threatened species; and receipt and acceptance or resolution of all Arkansas Department of Environmental Quality comments on the EA. The FONSI will not be signed until the proposed action achieves environmental compliance with applicable laws and regulations, as described above. The relationship of this work to requirements of environmental laws, executive orders, memorandums, land use plans, and permits was evaluated (Table 1).

7.0 CONCLUSION

This project involves the reallocation of existing water. It will have no effect on the normal pool of the lake or the outflows from it. It has been determined that the proposed action would have no adverse or beneficial impact upon cultural resources, air quality, terrestrial, aquatic, waterfowl, and wetland resources; recreation and esthetics; HTRW concerns; water quality; threatened and endangered species; cultural concerns; flood plains; and Environmental Justice concerns. There are also no cumulative impacts, adverse or beneficial, associated with the proposed action.

TABLE 1
RELATIONSHIP OF THE PROPOSED ACTION TO ENVIRONMENTAL PROTECTION STATUTES AND REQUIREMENTS

Item	Compliance
Federal Statutes Archeological and Historic Preservation Act, as amended, 16 U.S.C. 469, et se g.	Full Compliance
Clean Air Act, as amended, 42 U.S.C. 7401, et se_g.	Full Compliance
Clean Water Act, as amended (Federal Water Pollution Control Act), 33 U.S.C. 1251, et .	Full Compliance
Coastal Zone Management Act, as amended, 16 U.S.C. 1451, et se_g.	Not Applicable
Endangered Species Act, as amended, 16 U.S.C. 1531, et s .	Full Compliance
Estuary Protection Act, 16 U.S.C. 1221, et se_g.	Not Applicable
Federal Water Project Recreation Act, as amended, 16 U.S.C. 460-1(2), et se_g.	Full Compliance
Fish and Wildlife Coordination Act, as amended, U.S.C. 661, et se_g.	Full Compliance
Land and Water Conservation Act, as amended, 16 U.S.C. 4601, ets .	Not Applicable
Marine Protection, Research and Sanctuaries Act, 22 U.S.C. 1401, et SC¢1.	Not Applicable
National Historic Preservation Act, as amended, 16 U.S.C. 470a, ets .	Full Compliance
National Environmental Policy Act, as amended, 42 U.S.C. 4321, ets .	Full Compliance
Rivers and Harbors Act, 33 U.S.C. 401, et s .	Not Applicable
Watershed Protection and Flood Prevention Act, 16 U.S.C. 1001, ets .	Full Compliance
Wild and Scenic Rivers Act, as amended, 16 U.S.C. 1271, et s .	Not Applicable
Farmland Protection Policy Act	Not Applicable

Table 1 (Cont.)

Item	Compliance
Executive Orders. Memorandums, etc. Flood Plain Management (Executive Order 11988)	 Full Compliance
Protection of Wetlands (Executive Order 11990)	Full Compliance
Environmental Effects Abroad of Major Federal Actions (Executive Order 12114)	Not Applicable
Analysis of Impacts of Prime and Unique Farmlands (CEQ Memorandum, 30 August 1976)	Not Applicable
State and Local Policies Arkansas Water Quality Standards	 Full Compliance

NOTES: The compliance categories used in this table were assigned based on the following definitions:

a. Full Compliance. All requirements of the statute, executive order, or other policy and related regulations have been met for this stage of planning.
b. Partial Compliance. Some requirements of the statute, executive order, or other policy and related regulations remain to be met for this stage of planning.
c. Noncompliance. None of the requirements have been met for this stage of planning.
c. Not Applicable. Statute, executive order, or other policy not applicable.

8.0 COMMENTS AND RESPONSES

Comment: A Public Notice was distributed on 3 December 2014, informing the public of the proposed reallocation. Copies of the draft report were distributed to the Environmental Protection Agency, U.S. Fish and Wildlife Service (FWS), SWPA, the State of Arkansas and other interested parties for review. Comments received are included in Appendix D, "Pertinent Correspondence."

Response: Concur

Comment: By letter, 30 December 2015, The City of Hot Springs Deputy City Manager indicated they were in agreement with the conclusion in this EA.

Response: Concur

Comment: By letter, 31 December 2015, The Department of Arkansas Heritage indicated by letter that they concurred that the proposed undertaking has no potential to impact cultural resources and that have no objection to it.

Response: Concur

Comment: By e-mail, 27 January 2015, the district EPA office indicated that they had reviewed the EA and concurs with the Finding of no Significant Impact.

Response: Concur

Comment: On 23 December 2014 and 5 January 2015, letters were received from Department of Energy and the Southwestern Power Resources Association, respectively. Both of the entities expressed concern about reallocation of water storage from the hydropower pool to water supply.

Response: These concerns will be looked at further in the main report for this project and no reallocation will take place until then.

Comment: By e-mail, 5 January 2015, the Historic Preservation Department of the Choctaw Nation of Oklahoma notified that they thought the area was outside the Choctaw Nation of Oklahoma area of historic interest.

Response: Concur

Comment: On 22 January 2015, a letter was received from the Osage Nation Tribal Historic Preservation Office. The Osage Nation does not anticipate that this project will adversely impact any cultural resources or human remains protected under any currents laws. They did ask that if any artifacts or human remains are discovered during project construction that work cease immediately and they be contacted.

Response: Concur