BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.	)))))	**<u>Case No. ER-2008-0093</u>** Tariff File No. YE-2008-0205

NOTICE REGARDING EXTERNAL COMMUNICATIONS

Issue Date: January 31, 2008

On January 31, 2008, I received the attached electronic mail message and attachments from George Robbins, Director, Division of Resources and Rates Southwestern Power Administration.

Dated at Jefferson City, Missouri,
on this 31st day of January, 2008.
Davis, Chairman

Gregory, Sheryl

From: Davis, Jeff
Sent: Thursday, January 31, 2008 1:53 PM
To: Gregory, Sheryl
Cc: Henderson, Wess
Subject: FW: White River Minimum Flows

Attachments: SWPA Letter.pdf; SWPA to LRD ltr 1-31-2008.pdf; MinFlowFedRegNotice.pdf; MinFlowDraftReport.pdf

SWPA Letter.pdf (60 KB) SWPA to LRD ltr 1-31-2008.pdf ... MinFlowFedRegNotice.pdf (321 K... MinFlowDraftReport .pdf (2 MB)

Dear Sheryl,

Please file this and the attachments as a notice of external communications in the EDE rate case.

Thanks,

JND

-----Original Message-----
From: George Robbins [mailto:george.robbins@swpa.gov]
Sent: Thursday, January 31, 2008 1:38 PM
To: Biggs, Mike L SWL
Cc: Jackson, Donald E COL SWL; Anslow, Patricia M SWL; Colette.Honorable@arkansas.gov; T.Wright@kcc.state.ks.us; Davis, Jeff; J.Cloud@occemail.com; Ted Coombes; Tom Snyder
Subject: RE: White River Minimum Flows

Mike -
We have not yet received a copy of the Colonel's letter (attachment 1) in the mail. However, because of the time constraints and our commitment to provide the information, I am attaching Southwestern's response letter (attachment 2). The two enclosures to our letter are included. The enclosures are our Federal Register notice (attachment 3) and our draft determination report (attachment 4).

The Federal Register notice provides for a 30-day review and comment period that will begin on the date the notice is published, which should be by February 5, 2008.

Since we are providing the Corps this copy prior to the Federal Register notice being published, we are also furnishing Empire District Electric Company and the relevant state public utility commissions this copy as well. Southwestern's customers' organization is also being copied with the message.

Please provide distribution within the Corps as needed. If you have any questions, please contact me.

Thanks,

George Robbins
Director, Division of Resources and Rates Southwestern Power Administration
(918) 595-6680

-----Original Message-----
From: Biggs, Mike L SWL [mailto:Mike.L.Biggs@usace.army.mil]
Sent: Wednesday, January 30, 2008 4:06 PM
To: George Robbins
Cc: Jackson, Donald E COL SWL; Anslow, Patricia M SWL
Subject: White River Minimum Flows

Good afternoon George,
I am attaching a copy of a letter from Little Rock District to your Administrator. Hope everything is moving forward on Minimum Flows, please don't hesitate to contact me.

Regards

Michael L. Biggs, P.E.
Programs and Project Management Div.
Little Rock District Corps of Engineers
phone: (501) 324-5842 x 1071
mobile: (501) 749-5248

<<SWPA Letter.pdf>>

DEPARTMENT OF THE ARMY
LITTLE ROCK DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 867
LITTLE ROCK, ARKANSAS 72203-0867

REPLY TO
ATTENTION OF

January 28, 2008

Planning and Environmental Office

Mr. Jon Worthington
Administrator, Southwestern Power Administration
One West Third Street
Tulsa, OK 74103-3502

Dear Mr. Worthington:

On behalf of The U.S Army Corps of Engineers, Little Rock District, I want to thank you for Southwestern Power Administration's efforts as team members on the White River Minimum Flows Project. Section 132(a) of the Energy and Water Development Appropriations Act, 2006 (P.L. 109-103) authorized the implementation of plans BS-3 at Bull Shoals and NF-7 at Norfork Lakes at full Federal expense. The Act also establishes the Administrator of the Southwestern Power Administration as the responsible agent for determining the costs for compensating Empire Electric (non-Federal FERC operator no. 2221) for loss of electrical generation as well as the impacts to the Federal hydropower purposes at Bull Shoals and Norfork Dams. The calculations provided by SWPA are integral pieces of the EIS and Project Report and are on the project schedule critical path. The Environmental Impact Statement (EIS) and Project Report for the White River Minimum Flows Project are scheduled to be available for public review in August 2008. The schedule is aggressive, with no lag-time; therefore we appreciate the diligence your employees have shown under challenging circumstances. Based on a conversation between the Corps of Engineers Southwest Division's Program Director and SWPA's technical lead, it is our understanding that the hydropower impacts are currently being reviewed by your staff with a delivery date for Corps review of 31 January 2008.

If you have any questions, my staff is available to coordinate with your office concerning project status, roles and responsibilities of the PDT members, and schedule. We look forward to receiving the hydropower impact calculations no later than 31 January 2008. The district's point of contact is the Project Manager, Mr. Michael Biggs. He can be reached by phone at 501-324-5842 x1071, or by email at mike.l.biggs@usace.army.mil.

Sincerely,

Donald E. Jackson, Jr.
Colonel, US Army
District Commander

Copy Furnished:

Honorable John Boozman
House of Representatives
Region's Plaza
303 North Main Street
Suite 102
Harrison, AR 72601

Honorable Marion Berry
House of Representatives
108 East Huntington Avenue
Jonesboro, AR 72401

Mr. Scott Henderson
Arkansas Game & Fish Commission
2 Natural Resources Drive
Little Rock, AR 72205

Mr. Mike Fallon
1100 Commerce Street
CESWD-PD
Dallas, TX 75242

Department of Energy
Southwestern Power Administration
One West Third Street
Tulsa, Oklahoma 74103-3519

JAN 3 1 2008

Colonel Donald E. Jackson, Jr.
District Commander
U.S. Army Corps of Engineers, Little Rock District
P.O. Box 867
Little Rock, AR 72203-0867

Dear Colonel Jackson:

This is in response to your letter dated January 28, 2008, concerning the White River Minimum Flows Project. As your letter states, the authorizing legislation for the minimum flows project established the Southwestern Power Administration (Southwestern) as the responsible agent for determining the costs for compensating Empire District Electric Company (non-Federal FERC Project No. 2221) for loss of electrical generation at the non-Federal hydroelectric project and the costs of compensating the Federal hydropower purpose for the impacts to the Bull Shoals and Norfork projects.

Southwestern has developed a draft determination of the cost impacts to the non-Federal hydropower project and the Federal hydropower projects and has produced a draft report detailing that determination. A "Notice of Public Review and Comment" concerning the draft determination is in the process of being published in the Federal Register and should be available by February 5, 2008. There will be a thirty day public review and comment period, which will begin on the date the notice is published in the Federal Register.

Copies of both the Federal Register notice and Southwestern's draft determination report are attached. As indicated in the Federal Register notice, all inquiries on Southwestern's determination should be addressed to George Robbins, Director of Southwestern's Division of Resources and Rates. If I can be of further assistance, please do not hesitate to call me at 918-595-6601. As the new Administrator of Southwestern, I look forward to working with you on this and other issues.

Sincerely,

Jon C. Worthington
Administrator

Enclosures

cc:

Honorable John Boozman
House of Representatives
Region's Plaza
303 North Main Street
Suite 102
Harrison, AR 72601

Honorable Marion Berry
House of Representatives
108 East Huntington Avenue
Jonesboro, AR 72401

Mr. Scott Henderson
Arkansas Game and Fish Commission
2 Natural Resources Drive
Little Rock, AR 72205

Mr. Mike Fallon
1100 Commerce Street
CESWD-PD
Dallas, TX 75242

6450-01-P

DEPARTMENT OF ENERGY

SOUTHWESTERN POWER ADMINISTRATION

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

AGENCY: Southwestern Power Administration, DOE

ACTION: Notice of Public Review and Comment

SUMMARY: Section 132 of Public Law 109-103 (2005) authorized and directed the Secretary of the Army to implement alternatives BS–3 and NF–7, as described in the White River Minimum Flows Reallocation Study Report, Arkansas and Missouri, dated July 2004.

The law states that the Administrator, Southwestern Power Administration (Southwestern), shall determine any impacts on electric energy and capacity generated at Federal Energy Regulatory Commission (FERC) Project No. 2221 caused by the storage reallocation at Bull Shoals Lake. Further, the licensee of Project No. 2221 shall be fully compensated by the Corps of Engineers for those impacts on the basis of the present value of the estimated future lifetime replacement costs of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project.

The law also states that losses to the Federal hydropower purpose of the Bull Shoals and Norfork Projects shall be offset by a reduction in the costs allocated to the Federal hydropower purpose. Further, such reduction shall be determined by the Administrator of Southwestern on the basis of the present value of the estimated future lifetime replacement cost of the electrical energy and capacity at the time of implementation of the White River Minimum Flows project.

Assuming a January 1, 2011, date of implementation, Southwestern has made a draft determination that the present value of the estimated future lifetime replacement costs of the electrical energy and capacity at FERC Project No. 2221 is $21,363,700. Southwestern has

made a draft determination that the present value of the estimated future lifetime replacement costs of the electrical energy and capacity for Federal hydropower is $41,584,800.

DATES: The consultation and comment period will begin on the date of publication of this Federal Register notice and will end ***[Insert 30 days after date of publication of this FEDERAL REGISTER notice***].

FOR FURTHER INFORMATION CONTACT: Mr. George Robbins, Director, Division of Resources and Rates, Southwestern Power Administration, U.S. Department of Energy, One West Third Street, Tulsa, Oklahoma 74103, (918) 595-6680, george.robbins@swpa.gov.

SUPPLEMENTARY INFORMATION:

I. Discussion

Originally established by Secretarial Order No. 1865 dated August 31, 1943, Southwestern is an agency within the U.S. Department of Energy which was created by an Act of the U.S. Congress, entitled the Department of Energy Organization Act, Pub. L. No. 95-91 (1977). Southwestern markets power from 24 multi-purpose reservoir projects with hydroelectric power facilities constructed and operated by the U.S. Army Corps of Engineers. These projects are located in the states of Arkansas, Missouri, Oklahoma, and Texas. Southwestern's marketing area includes these states plus Kansas and Louisiana.

Southwestern developed projected energy and capacity losses for the Bull Shoals and Norfork projects and FERC Project No. 2221, including additional losses related to the reallocation for minimum flows as appropriate. Currently, the calculated credit due to Federal hydropower is $41,584,800, and the calculated compensation due to the licensee of FERC Project No. 2221 is $21,363,700. The values were calculated on the basis of the present value of the estimated future lifetime replacement cost of the electrical energy and capacity assuming an implementation date of January 1, 2011, for the White River Minimum Flows project. The final calculation will depend on the official date of implementation as specified by the Corps of Engineers and the value of the specified parameters in effect at that time.

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

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

MWh of off-peak energy and 6,762 MWh of on-peak energy, for a total annual energy loss of 13,524 MWh. The marketable capacity loss is 3.93 megawatts (MW).

FERC Project No. 2221, the non-Federal hydroelectric project at Powersite Dam, will be directly affected by the minimum flow plan. The normal top of conservation pool will be raised five feet at Bull Shoals, the project immediately downstream of Powersite Dam. The pool level increase at Bull Shoals will reduce the amount of gross head (headwater elevation minus the tailwater elevation) available for generation at the non-Federal project at Powersite Dam. The reduction in gross head will result in an annual energy loss of 5,792 MWh of on-peak energy and 2,853 MWh of off-peak energy, or an annual total energy loss of 8,645 MWh. Also associated with the loss of gross head, there will be a capacity loss of 3.00 MW at the project.

II. Procedural and Regulatory Review Requirements

A. Review Under Executive Order 12866

Southwestern has an exemption from centralized regulatory review under Executive Order 12866, "Regulatory Planning and Review," 58 FR 51735, October 4, 1993. Accordingly, this notice of draft determination was not reviewed by OMB under the Executive Order.

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601 et seq.) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. This draft determination is not a rulemaking.

C. Review Under the Paperwork Reduction Act

No new information or record keeping requirements are imposed by this draft determination. Accordingly, no OMB clearance is required under the Paperwork Reduction Act (44 U.S.C. 3501 et seq.).

D. Review Under the National Environmental Policy Act of 1969

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321 et seq.); the Council on Environmental Quality Regulations for implementing NEPA (40 CFR parts 1500-1508); and DOE NEPA Implementing Procedures and Guidelines (10 CFR part 1021), Southwestern has determined that this draft determination is not addressed under DOE NEPA Implementing Procedures and Guidelines for Power Marketing Administrations, and no further action is required.

E. Review Under Executive Order 13132

Executive Order 13132, "Federalism" (64 FR 43255, August 10, 1999), imposes certain requirements on agencies formulating and implementing policies or regulations that preempt State law or that have federalism implications. Southwestern is not formulating or implementing policies or regulations that preempt State law or that have federalism implications. Executive Order 13132 does not apply.

F. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3, (a) of Executive Order 12988, "Civil Justice Reform" (61 FR 4729, February 7, 1996), imposes on Federal agencies the general duty to adhere to the following requirements: (1) Eliminate drafting errors and ambiguity; (2) write regulations to minimize litigation; and (3) provide a clear legal standard for affected conduct rather than a general standard and promote simplification and burden reduction. Section 3(b) of Executive Order 12988 specifically requires that Federal agencies make every reasonable effort to ensure that the regulation: (1) Clearly specifies the preemptive effect, if any; (2) clearly specifies any effect on existing Federal law or regulation; (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction; (4) specifies the retroactive effect, if any; (5) adequately defines key terms; and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Federal agencies to determine whether the regulations meet the applicable standard in section 3(a) and section 3(b), or it is unreasonable to meet one or more of them. Southwestern is not reviewing existing regulations or promulgating new regulations. Executive Order 12988 does not apply.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (Pub. L. No. 104-4 (1995)) requires each Federal agency to assess the effects of a Federal regulatory action on State, local, and tribal governments, and the private sector. Southwestern has determined that the Unfunded Mandates Reform Act of 1995 does not apply to the draft determination.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 (112 Stat 2681-528) of the Treasury and General Government Appropriations Act, 1999 (Pub. L. No. 105-277, (1998)) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This draft determination is not a rule. Therefore, Section 654 (112 Stat 2681-528) of the Treasury and General Government Appropriations Act, 1999 (Pub. L. No. 105-277, (1998)) does not apply.

I. Review Under the Treasury and General Government Appropriations Act, 2001.

The Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3316 note) provides for agencies to review most disseminations of information to the public under guidelines established by each agency pursuant to general guidelines issued by the Office of Management and Budget (OMB). OMB's guidelines were published at 67 FR 8452 (February 22, 2002), and DOE's guidelines were published at 67 FR 62446 (October 7, 2002). Southwestern has reviewed this notice under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

J. Review Under Executive Order 13211

Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001), requires Federal agencies to prepare and submit to the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget, a Statement of Energy Effects for any proposed significant energy action. A "significant energy action" is defined as: (1) Any action by an agency that promulgated or is expected to lead to promulgation of a final rule; (2) is significant regulatory action under Executive Order 12866, or any successor order; and (3) is likely to have significant adverse effect on the supply, distribution, or use of energy, or is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use. This draft determination is not an energy action. Executive Order 13211 does not apply.

III. Public Review and Comment Procedures

Opportunity is presented for interested parties to receive copies of the Draft Report detailing Southwestern's determination of the Federal and non-Federal hydropower impacts. If you desire a copy of the report, submit your request to Mr. George Robbins, Director, Division of Resources and Rates, Southwestern Power Administration, One West Third, Tulsa, OK 74103, (918) 595-6680.

Written comments on Southwestern's determination are due on or before [***Insert 30 days after date of publication of this FEDERAL REGISTER notice***]. Comments should be submitted to George Robbins, Director, Division of Resources and Rates, Southwestern, at the above-mentioned address for Southwestern's offices.

Southwestern will review and address the written comments, making any necessary changes to the draft determination. The Administrator will then submit the final determination to the Corps of Engineers.

Dated: January 30, 2008

Jon Worthington
Administrator

DRAFT REPORT

White River Minimum Flows Study

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

Southwestern Power Administration

January 2008

Executive Summary

This report details the procedures used by Southwestern Power Administration (Southwestern) to determine the losses to the Federal hydropower purpose at Bull Shoals and Norfork hydroelectric projects and to the non-Federal Ozark Beach hydroelectric project at Powersite Dam in Missouri due to the implementation of White River Minimum Flows as authorized in Section 132 of Public Law 109-103 (2005). Energy and capacity losses were developed for the Federal and non-Federal projects, and additional losses related to the reallocations for minimum flows were included as appropriate.

Currently, the calculated loss to Federal hydropower is $41,584,800, and the calculated loss to the non-Federal project is $21,363,700. The loss values were calculated on the basis of the present value of the estimated future lifetime replacement cost of the electrical energy and capacity assuming an implementation date of January 1, 2011, for the White River Minimum Flows project. The final calculation will depend on the official date of implementation as specified by the Corps of Engineers and the value of the specified parameters in effect at that time.

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

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

Federal Energy Regulatory Commission (FERC) Project No. 2221, the non-Federal Ozark Beach hydroelectric project at Powersite Dam, will be directly affected by the minimum flow plan. The normal top of conservation and seasonal pool will be raised five feet at Bull Shoals, the project immediately downstream of Powersite Dam. The pool level increase at Bull Shoals will reduce the amount of gross head (headwater elevation minus the tailwater elevation) available for generation at the non-Federal project at Powersite Dam. The reduction in gross head will result in an annual energy loss of 5,792 MWh of on-peak energy and 2,853 MWh of off-peak energy, or an annual total energy loss of 8,645 MWh. Also associated with the loss of gross head, there will be a capacity loss of 3.00 MW at the project.

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

1.0 Introduction

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

2.0 Background

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

2.1 Section 374 of WRDA 1999.

SEC. 374. WHITE RIVER BASIN, ARKANSAS AND MISSOURI 1999.
(a) IN GENERAL. - Subject to subsection (b), the project for flood control, power generation, and other purposes at the White River Basin, Arkansas and Missouri, authorized by section 4 of the Act of June 28,1938 (52 Stat. 1218, chapter 795), and modified by House Document 917, 76th Congress, 3rd Session, and House Document 290, 77th Congress, 1st Session, approved August 18, 1941, and House Document 499, 83rd Congress, 2d Session, approved September 3, 1954, and by section 304 of the Water Resource Development Act of 1996 (110 Stat. 3711) is further modified to authorize the Secretary to provide minimum flows necessary to sustain tail water trout fisheries by reallocating the following amounts of project storage: Beaver Lake,

1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.
(b) REPORT. -

(1) IN GENERAL. - No funds may be obligated to carry out work on the modification under subsection (a) until completion of a final report by the Chief of Engineers finding that the work is technically sound, environmentally acceptable, and economically justified.
(2) TIMING. - The Secretary shall submit the report to Congress not later than July 30, 2000.
(3) CONTENTS. - The report shall include determinations concerning whether-

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

2.2 Section 304 of WRDA 2000.

SEC. 304. WHITE RIVER BASIN, ARKANSAS AND MISSOURI 2000.
(a) IN GENERAL. - Subject to subsection (b), the project for flood control, power generation, and other purposes at the White River Basin, Arkansas and Missouri, authorized by section 4 of the Rivers and Harbors Act of June 28,1938 (52 Stat. 1218), and modified by House Document 917, 76th Congress, 3rd Session, and House Document 290, 77th Congress, 1st Session, approved August 18, 1941, and House Document 499, 83rd Congress, 2d Session, approved September 3, 1954, and by section 304 of the Water Resource Development Act of 1996 (110 Stat. 3711) is further modified to authorize the Secretary to provide minimum flows necessary to sustain tail water trout fisheries by reallocating the following recommended amounts of project storage: Beaver Lake, 1.5 feet; Table Rock Lake, 2 feet; Bull Shoals Lake, 5 feet; Norfork Lake, 3.5 feet; and Greers Ferry Lake, 3 feet.
(b) REPORT. -

(1) IN GENERAL. - No funds may be obligated to carry out work on the modification under subsection (a) until the Chief of Engineers, through completion of a final report, determines that the work is technically sound, environmentally acceptable, and economically justified.
(2) TIMING. - Not later than January 1, 2002, the Secretary shall transmit to Congress the final report.
(3) CONTENTS. - The report shall include determinations concerning whether-

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

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

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

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

SEC. 132. WHITE RIVER BASIN, ARKANSAS.—
(a) MINIMUM FLOWS.—

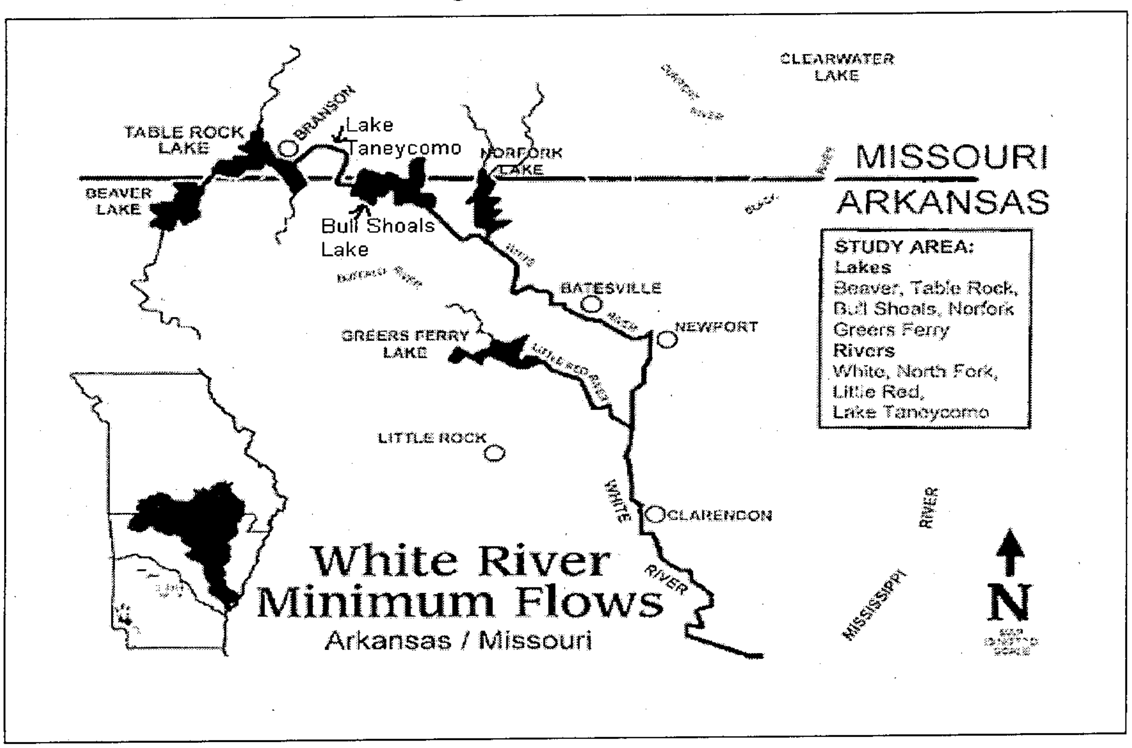
(1) IN GENERAL.—The Secretary is authorized and directed to implement alternatives BS–3 and NF–7, as described in the White River Minimum Flows Reallocation Study Report, Arkansas and Missouri, dated July 2004.
(2) COST SHARING AND ALLOCATION.—Reallocation of storage and planning, design and construction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

(b) FISH HATCHERY.—In constructing, operating, and maintaining the fish hatchery at Beaver Lake, Arkansas, authorized by section 105 of the Water Resources Development Act of 1976 (90 Stat. 2921), losses to the Federal hydropower purpose of the Beaver Lake Project shall be offset by a reduction in the costs allocated to the Federal hydropower purpose. Such reduction shall be determined by the Administrator of the Southwestern Power Administration based on the present value of the estimated future lifetime replacement cost of the electrical energy and capacity at the time operation of the hatchery begins.
(c) REPEAL.—Section 374 of the Water Resources Development Act of 1999 (113 Stat. 321) and section 304 of the Water Resources Development Act of 2000 (Public Law 106–541) are repealed.

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

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

Figure 1 – Study Area



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

3.0 Determination of Hydropower Impacts Due to Minimum Flows

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

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

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

4.0 SUPER Program Analysis

4.1 SUPER Reservoir Simulation Program

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

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

4.2 SUPER Minimum Flows Storage and Storage Accounting

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

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

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

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

4.3 SUPER Runs for Minimum Flows Analysis

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

<u>4.3.1 Base Run</u>

- Existing Conditions Run = W08X01 (Southwestern run designation).

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

4.3.2 Minimum Flows Run

General

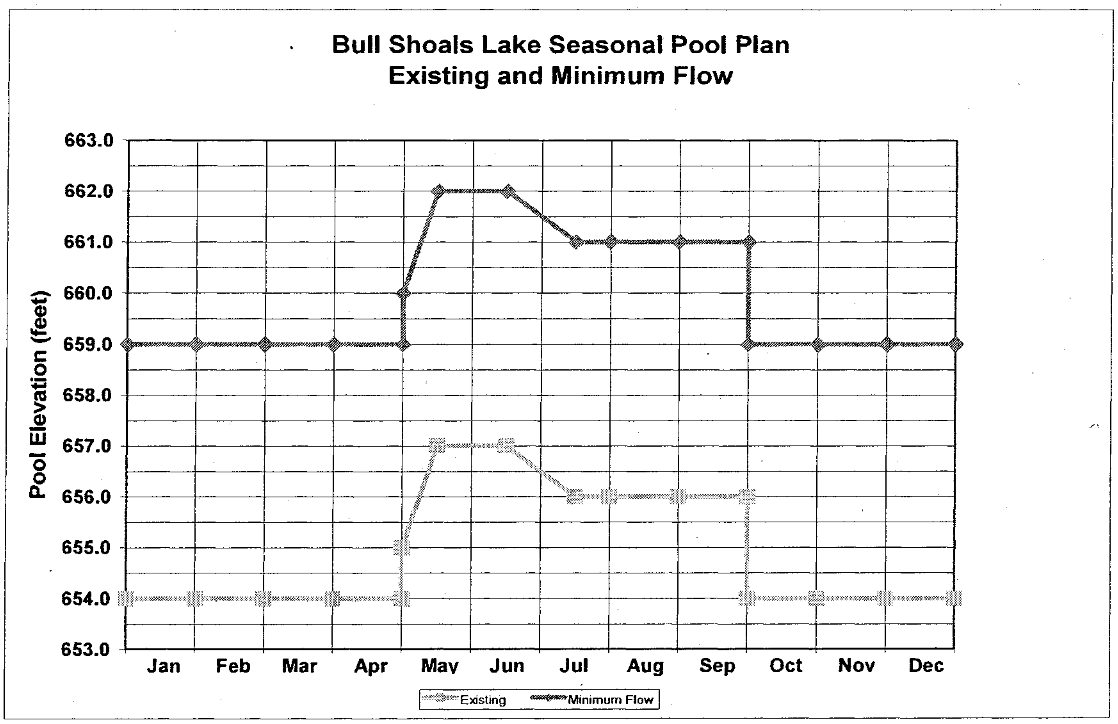
- Minimum Flows Run = W08X02 (Southwestern run designation).
- Minimum flows implemented as in the Corps run (W06X03) with modifications as made to the base run (balancing levels, regulation criteria, water supply, etc.) for consistency.
- Water storage accounting performed to ensure that minimum flows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

Bull Shoals

- Plan BS-3, reallocation of five feet of flood storage at Bull Shoals.
- Both the normal (non-seasonal) and seasonal pool elevations increased by five feet (Figure 2).
- Minimum flow at Bull Shoals made with a main unit whenever the project is not otherwise generating. The required minimum flow release (including 210 cfs for leakage and station service) is 800 cfs.

- HYPO storage included to maintain the yield of the hydropower storage at Bull Shoals. The total amount of flood storage reallocated is 233,000 acre-feet which includes 111,271 acre-feet for DYMS and HYPO and 121,729 acre-feet for minimum flows storage as computed by the Corps.

Figure 2 – Bull Shoals Pool Elevations

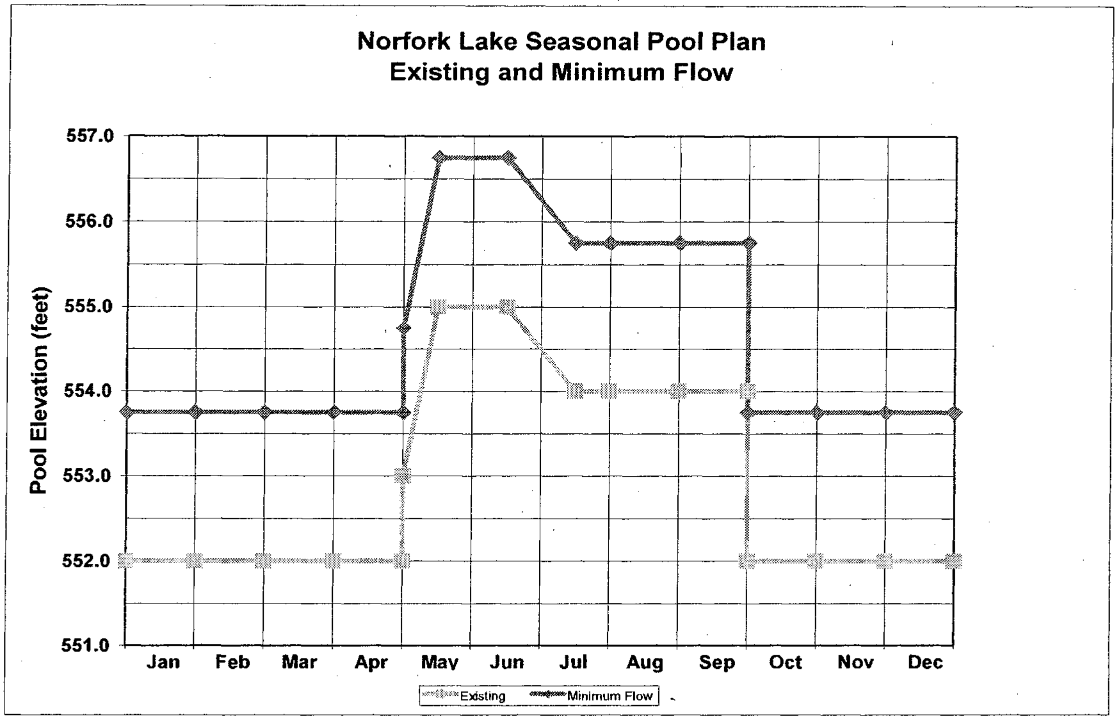


<u>Norfork</u>

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

- The total amount of storage available for minimum flows is 46,219 acre-feet as computed by the Corps.

Figure 3 – Norfork Pool Elevations



5.0 Energy and Capacity Losses

5.1 The Power Equation

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

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

Where

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

- 550 = conversion factor (550 foot-pounds per second = 1 horsepower)
- 1000 = conversion factor (1000 kW = 1 MW)

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

5.2 Federal Hydropower

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

5.3 Bull Shoals

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

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

Because plan BS-3 includes storage to maintain the yield of the hydropower storage, Southwestern's ability to produce current quantities of on-peak energy is not diminished. The energy lost from the flood pool is not considered as dependable and is not typically available to meet Southwestern's contractual peaking obligations. Therefore, the lost energy is considered off-peak energy. In addition, because the minimum flow releases will be made through one of the main units, there will be energy produced with those releases. However, the minimum flow releases through a main unit will be made at a much lower rate of generation and therefore a much lower efficiency.

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

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

<u>5.3.2 Capacity Losses.</u> Southwestern bases its marketable capacity on the worst drought in the period of record. The critical drought occurred in Southwestern's system during the period from June 1953 through August 1954, with August 1954 being the critical month. Thus, the computed capacity loss was also determined based on that drought period. Any reduction in the yield of the hydropower storage will result in a reduction of the capacity that can be supported by the storage. A reduction in the supportable capacity results in a capacity loss. Because plan BS-3 reallocates flood storage and includes HYPO storage for hydropower, there will be no reduction in yield of the storage allocated to the Federal hydropower purpose and no reduction in the Bull Shoals energy production during the critical drought. Therefore, there will be no loss of capacity at Bull Shoals.

5.4 Norfork

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

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

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

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

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

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

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

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

5.5 Summary of Federal Hydropower Energy and Capacity Losses

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

Table 1 – Federal Hydropower Annual Energy and Capacity Losses

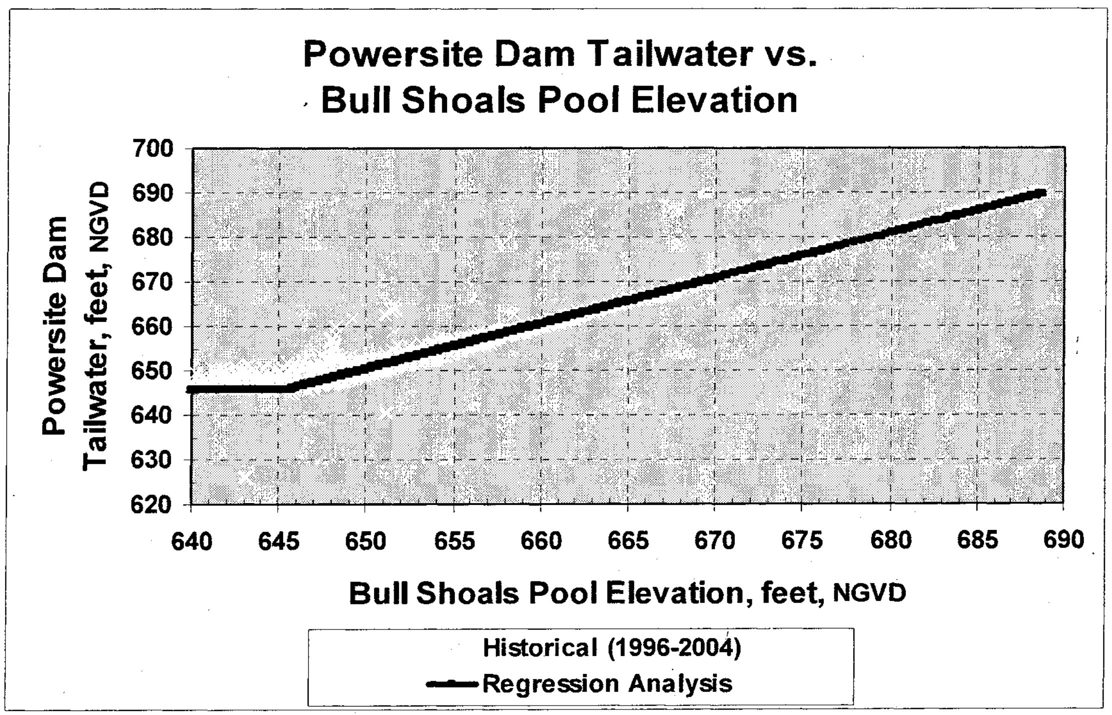
Project	Total Energy Loss, MWh	On-Peak Energy Loss, MWh	Off-Peak Energy Loss, MWh	Capacity Loss, MW
Bull Shoals	23,855	0	23,855	0.00
Norfork	13,524	6,762	6,762	3.93
Total Losses	37,379	6,762	30,617	3.93

5.6 Non-Federal Project

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

5.6.1 Spreadsheet Model Description. Powersite Dam is located on the White River between Table Rock Dam and Bull Shoals Dam. Because the project is operated as a run of river project with little storage, Southwestern's model assumed that the water that is released from Table Rock Dam in a day will flow through the turbines at Powersite Dam or be spilled during that same day. Due to the close proximity, the tailwater elevation below Powersite Dam can be directly related to the pool elevation above Bull Shoals Dam. A separate analysis by Southwestern of historical Bull Shoals pool elevations and tailwater elevations immediately below Powersite Dam showed that the tailwater elevation can be reliably estimated based on the Bull Shoals pool elevation (see Figure 4). Because Powersite Dam is a run of river project with limited water storage, the pool elevation above Powersite Dam was estimated at 701.0 for all days. Based on the plant data provided by Empire, Southwestern estimated that a plant efficiency of 85 percent and a friction loss of 0.5 feet would be reasonable values for use in all power equation calculations.

Figure 4 – Powersite Dam Tailwater versus Bull Shoals Pool Elevation



The daily spreadsheet calculation proceeded as follows:

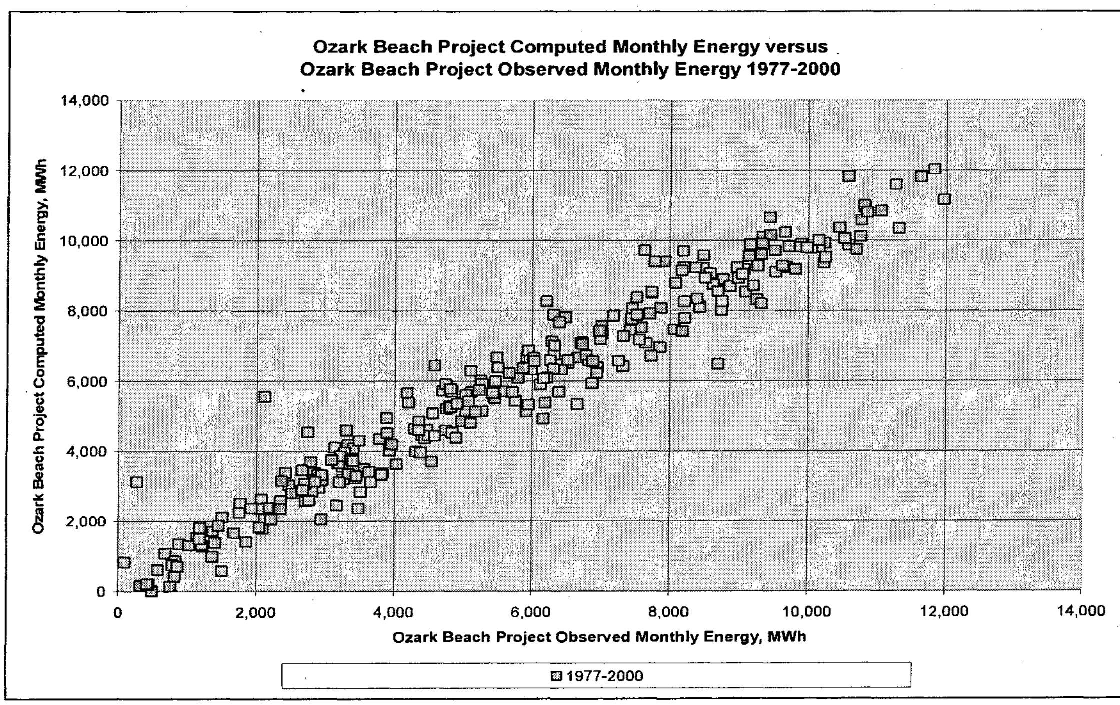
1. Compute the tailwater elevation based on the Bull Shoals midnight pool elevation.
2. Compute the gross head (= 701.0 minus the computed tailwater elevation).
3. Determine the maximum plant capacity for the day by looking up the gross head in the Empire-provided head vs. generating capability table and interpolating. Data

for the old turbines was used in verifying the model. Data for the new turbines was used in determining the losses (Appendix C).

4. Using the power equation, calculate the discharge associated with the maximum plant capacity determined in step 3.
5. If the Table Rock discharge for the day is greater than the discharge computed in step 4, the daily generation is the maximum plant capacity times 24 hours and the additional discharge is assumed to be spilled.
6. If the Table Rock discharge for the day is less than the discharge computed in step 4, the power equation is used to calculate the daily energy generated based on the available discharge. There is no spill.
7. Go to the next day.

<u>5.6.2 Spreadsheet Model Verification.</u> The verification of the spreadsheet model for Powersite Dam was performed using historical data. Empire provided monthly generation data from the project for the thirty year period 1977-2006. They also provided gross head versus generating capability tables for both the old turbines and new turbines. Generation during the period 1977-2000 was with the old turbines. Empire performed an upgrade of the turbines during the period 2001-2005. Southwestern used the 1977-2000 period for verifying the spreadsheet model. Daily discharges from Table Rock Dam and midnight pool elevations at Bull Shoals Lake from historical data were used as input to the spreadsheet model. Using the 1977-2000 historical data, the results showed a strong correlation between the computed monthly generation and the actual monthly generation at Powersite Dam (see Figure 5). From those results, it was determined that the spreadsheet model would be an appropriate method for determining the energy losses due to White River Minimum Flows.

Figure 5 – Computed versus Observed Generation at Powersite Dam

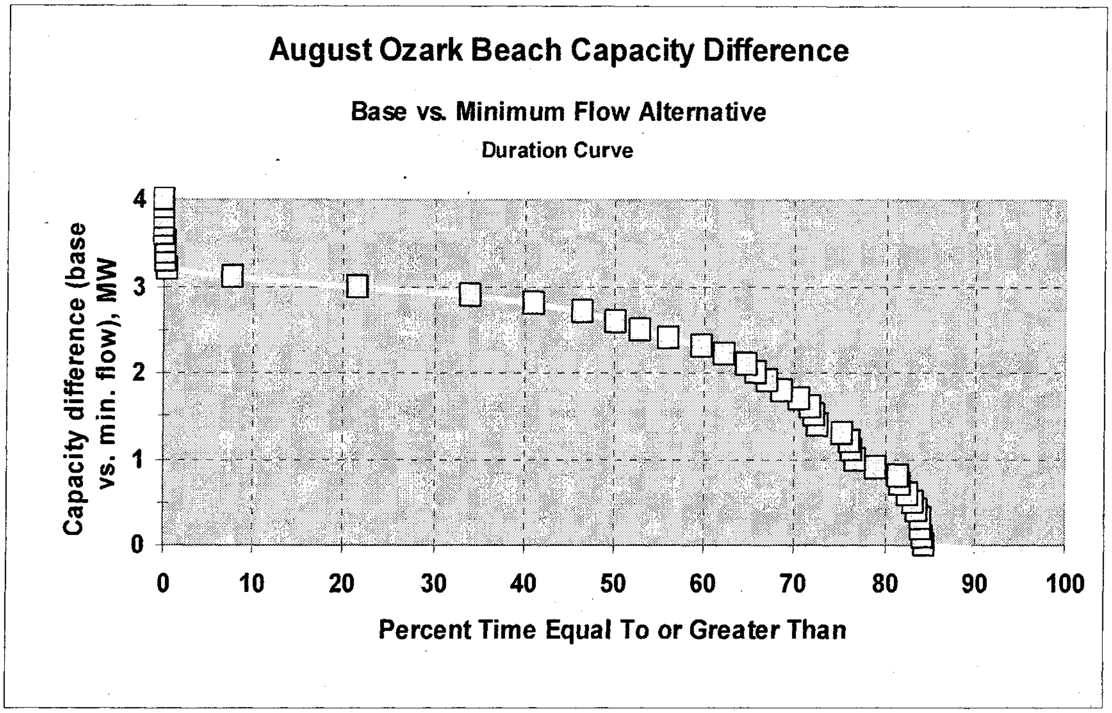


5.6.3 Spreadsheet Model Application - Energy Losses. As stated previously, any losses at Powersite Dam will be due to a loss of head from the raised pool at Bull Shoals. Southwestern used a spreadsheet analysis of the SUPER daily output data from the base run and minimum flow run. The SUPER data used were the daily discharges from Table Rock and the midnight pool elevations at Bull Shoals. As described in the previous section, Southwestern assumed the pool elevation at Powersite Dam to be a constant 701.0, the plant efficiency was 85 percent, and the friction loss through the plant was 0.5 feet. The gross head versus generating capability table for the new turbines, provided by Empire, was used (Appendix C). From the spreadsheet analysis, the annual energy loss at Powersite Dam was computed to be 8,645 MWh. The Corps had previously estimated the annual energy loss to be 6,150 MWh, and Empire had estimated the annual energy loss to be 12,436 MWh. A portion of the non-Federal energy loss calculations is included in Appendix D.

In previous discussions, the Corps, Empire, and Southwestern agreed that reasonable percentages of on-peak and off-peak generation for the project are 67 percent on-peak and 33 percent off-peak. Using these percentages, the annual energy loss is 5,792 MWh of on-peak energy and 2,853 MWh of off-peak energy at Powersite Dam.

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

Figure 6 – Duration Curve of August Capacity Loss at Powersite Dam



5.7 Summary of Non-Federal Hydropower Energy and Capacity Losses

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

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

Project	Total Energy Loss, MWh	On-Peak Energy Loss, MWh	Off-Peak Energy Loss, MWh	Capacity Loss, MW
Powersite Dam	8,645	5,792	2,853	3.00

6.0 Replacement Costs

6.1 Energy and Capacity

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

6.2 Federal Hydropower

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

Southwestern markets power from its interconnected system at a rate of 1,200 kWh per kW of marketed capacity each year. The 1,200 hours of firm generation results in an annual plant factor of 13.7 percent. Generation from a combustion turbine plant would be the most likely replacement for lost on-peak energy and capacity. Because the off-peak energy is more of a base load, high plant factor product, generation from a coal-fired steam plant would be the most likely replacement for off-peak energy.

For the Federal hydropower purpose, Southwestern used capacity and energy replacement cost values requested and received from the Corps' Hydropower Analysis Center (HAC) entitled "Thermal Plant Power Values for the Southwest Region" dated November 2007. The data is included in Appendix E. The costs were developed using the same FERC methodology mentioned previously. For on-peak energy, Southwestern used the Combustion Turbine Plant value for the state of Arkansas, currently \$91.44 per MWh. For off-peak energy, Southwestern used the Coal-Fired Steam Plant value for the state of Arkansas, currently \$17.50 per MWh. For capacity, Southwestern used the Combustion Turbine Plant value for the state of Arkansas, currently \$61.30 per kW-yr. The methodology is consistent with Southwestern's Draft White River Minimum Flow Study – Power Impacts Evaluation dated November 13, 2003.

6.3 Non-Federal Project

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

The HAC report for Greers Ferry stated that the least cost replacement thermal power plant type for operation at plant factors greater than 39.5 percent would be coal-fired steam generating plant, and for plant factors between 22.9 percent and 39.5 percent it would be a gas-fired combined cycle generating plant. Based on historical data from Empire and assuming 67 percent on-peak and 33 percent of-peak, on-peak generation has occurred at Powersite Dam at about a 30 percent plant factor. Therefore, generation from a combined cycle plant would be the most likely replacement for lost on-peak energy and capacity. Generation from a coal-fired steam plant would be the most likely replacement for off-peak energy.

For the non-Federal project, Southwestern used the HAC provided "Thermal Plant Power Values for the Southwest Region" dated November 2007 (Appendix E). For on-peak energy, Southwestern used the Combined Cycle Plant value for the state of Missouri, currently $56.45 per MWh. For off-peak energy, Southwestern used the Coal-Fired Steam Plant value for the state of Missouri, currently $13.75 per MWh. For capacity, Southwestern used the Combined Cycle Plant value for the state of Missouri, currently $128.47 per kW-yr.

In the Corps' previous analysis, the Corps had proposed and Empire agreed that the use of Platts Power Outlook Service projections of market prices for the High Fuel Value case were an appropriate set of values to use for the lost energy costs. Platts projects the energy costs for 20 years. The Corps then used the twentieth year values through the remainder of the 50-year time period. Empire proposed using a capacity cost value from the *Annual Energy Outlook* produced by the Energy Information Administration (EIA). Use of the Platts energy cost numbers produces a higher present value than the use of the cost numbers developed from FERC methodology, while the use of the capacity values from the FERC methodology produces a higher present value than the EIA capacity value. Using the Platts energy values and the EIA capacity values produced present value amounts similar to the values produced using the FERC values for energy and capacity.

Throughout the entire process, Southwestern attempted to use consistent methodologies as much as possible. Southwestern used the HAC-calculated numbers using FERC methodology in order to be consistent with the calculation for the Federal hydropower losses. That methodology has been used by Southwestern for many years in computing the impacts to Federal hydropower of storage reallocations for water supply and for the White River Minimum Flow Study. It is the methodology Southwestern would use for a Federal run of river project or a storage project.

7.0 Additional Losses

7.1 Increased Maintenance at Bull Shoals Powerhouse

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

2007 that additional maintenance at Bull Shoals will cost $68,000 annually. That cost is used in the analysis.

7.2 Low Dissolved Oxygen Impacts

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

7.3 Carbon Dioxide Tax

Empire proposed that a premium should be included in the energy costs for a carbon dioxide tax because they believe the Congress will pass legislation implementing such a tax in the near future. Because there is no way to reliably estimate if, when, or how a carbon dioxide tax would be implemented, Southwestern did not include losses based on a carbon dioxide tax. The issue must be revisited if carbon dioxide tax legislation is implemented before the time of final calculation.

7.4 Empire Roadway and Access Issues

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

8.0 Operational Considerations

8.1 Firm Energy

The 1986 Draft Operating Arrangement (Exhibit B to the 1980 Memorandum of Understanding between the United States Department of Energy, Southwestern Power Administration and the United States Department of the Army, Corps of Engineers) specifies daily firm energy amounts at each Southwestern Division project to be made available to Southwestern when hydropower operations are curtailed due to downstream flooding. Those values are also listed and discussed in the current White River Basin Water Control Master Manual dated March 1993. In general, hydropower generation is not to be limited to less than those firm energy amounts unless significant flood damage reductions can be achieved. The daily firm energy for Bull Shoals and Norfork is 1,352 MWh and 410 MWh, respectively, and would typically be scheduled by Southwestern to meet the most critical "peak" electrical demands of the day. The availability of firm energy from each of the projects is essential to preserving Southwestern's ability to meet its power delivery obligations. Releases made as a part of the White River Minimum Flow project which are not scheduled by Southwestern to meet its contractual peaking obligations must not reduce the daily firm energy amounts currently available. This analysis of the impacts of minimum flows to the hydropower purpose assumes that to be the case. If not, while not specifically quantified in this study, additional compensation would be required to offset the resulting increased energy purchases.

8.2 Water Temperature Control

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

8.3 Reservoir Drawdown Limits

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

8.4 Storage Accounting

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

9.0 Annual Losses

Based on the energy, capacity, and additional losses developed by Southwestern, the annual losses (in 2007 dollars) for Federal hydropower are shown in Table 3.

Table 3 – Federal Hydropower Annual Losses (2007 Dollars)

Project	Item	Annual Loss	Unit Cost	Annual Cost
Bull Shoals	On-Peak Energy	0 MWh	$91.44/MWh	$0
Bull Shoals	Off-Peak Energy	23,855 MWh	$17.50/MWh	$417,500
Bull Shoals	Capacity	0 MW	$61.30/kW-yr	$0
Bull Shoals	Increased Maintenance			$68,000
Norfork	On-Peak Energy	6,762 MWh	$91.44/MWh	$618,300
Norfork	Off-Peak Energy	6,762 MWh	$17.50/MWh	$118,300
Norfork	Capacity	3.93 MW	$61.30/kW-yr	$240,900
Total Losses				$1,463,000

Based on the energy and capacity losses developed by Southwestern, the annual losses (in 2007 dollars) for the non-Federal hydropower project are shown in Table 4.

Table 4 – Non-Federal Hydropower Annual Losses (2007 Dollars)

Project	Item	Annual Loss	Unit Cost	Annual Cost
Powersite Dam	On-Peak Energy	5,792 MWh	$56.45/MWh	$327,000
Powersite Dam	Off-Peak Energy	2,853 MWh	$13.75/MWh	$39,200
Powersite Dam	Capacity	3.00 MW	$128.47/kW-yr	$385,400
Total Losses				$751,600

10.0 Inflation

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

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

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

11.0 Present Value Determination

11.1 Assumptions

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

1. Implementation Date – The assumed date of implementation is January 1, 2011.
2. Project life – Southwestern used a 50-year project life in its analysis. The Corps and Empire had used 50 years as the project life in their preliminary analyses.
3. Discount Rate – The discount rate used in the present value calculations will be the current rate on 30-year U.S. Treasury notes. The current rate is available at http://www.treasurydirect.gov/RT/RTGateway?page=institHome and is currently 5.0 percent. The Corps used a rate of 5.125 percent in its analysis in 2005. Empire used the 30-year U.S. Treasury note rate in their analysis. That rate was 4.8 percent at the time of their analysis.

11.2 Federal Hydropower

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

Table 5 – Present Value of Losses to Federal Hydropower

Item	Present Value (2011)
Energy	$32,804,200
Capacity	$6,847,700
Increased Maintenance at Bull Shoals	$1,932,900
Total	$41,584,800

Using the High Fuel Value energy values from Platts and Empire-proposed capacity value from EIA would produce a present value of $54,638,300 for lost energy and $5,921,200 for lost capacity or a total present value of $62,492,400 for losses to Federal hydropower.

11.3 Non-Federal Project

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

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

Item	Present Value (2011)
Energy	$10,408,700
Capacity	$10,955,000
Total	$21,363,700

It should be noted here how the numbers would differ had Southwestern used the High Fuel Value energy values from Platts and the capacity value from the EIA in determining the non-Federal hydropower impacts. Those numbers would produce present values of $14,960,700 for lost energy and $4,054,100 for lost capacity for a total of $19,014,800.

11.4 Actual Calculation

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

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

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

12.0 Consultation Concerning Impacts to Non-Federal Project

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

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

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

Appendix A – Bull Shoals Energy Loss Calculations

Tailwater:	459.5						Tailwater:	450.54				
Efficiency:	0.85						Efficiency:	0.45				
Head Loss	0.5						Head Loss	0.5				
Norm. Leal	210											
Minimum Flow Requirement, cfs:			800									
Average Annual Energy Loss thru Minimum Flow Spill, MWh:							53,379			29,525		
Date	Bull Shoals 12-M SPP Elev., Ft.	Bull Shoals 12-M Pool Elev., Ft.	Bull Shoals Total Leakage, cfs	Bull Shoals Min Flow Release, cfs	BS Daily Energy Loss, MWH	BS Monthly Energy Loss, MWH	BS Annual Energy Loss, MWH	BS Daily Min Flow Energy, MWh	BS Monthly Min Flow Energy, MWH	BS Annual Min Flow Energy, MWH	BS Daily Net Energy Loss, MWh	BS Monthly Net Energy Loss, MWH
01/01/40	659.00	658.90	727.6	517.6	177.7			98.3			79.4	
01/02/40	659.00	658.82	727.6	517.6	177.6			98.3			79.3	
01/03/40	659.00	658.74	727.6	517.6	177.5			98.2			79.3	
01/04/40	659.00	658.68	727.6	517.6	177.5			98.2			79.3	
01/05/40	659.00	658.62	727.6	517.6	177.4			98.2			79.3	
01/06/40	659.00	658.64	800.0	590.0	202.3			111.9			90.4	
01/07/40	659.00	658.63	800.0	590.0	202.3			111.9			90.4	
01/08/40	659.00	658.55	727.6	517.6	177.4			98.1			79.2	
01/09/40	659.00	658.49	727.6	517.6	177.3			98.1			79.2	
01/10/40	659.00	658.44	727.6	517.6	177.3			98.1			79.2	
01/11/40	659.00	658.40	727.6	517.6	177.2			98.1			79.2	
01/12/40	659.00	658.35	727.6	517.6	177.2			98.0			79.1	
01/13/40	659.00	658.39	800.0	590.0	202.0			111.8			90.2	
01/14/40	659.00	658.40	800.0	590.0	202.0			111.8			90.2	
01/15/40	659.00	658.35	727.6	517.6	177.2			98.0			79.1	
01/16/40	659.00	658.32	727.6	517.6	177.2			98.0			79.1	
01/17/40	659.00	658.29	727.6	517.6	177.1			98.0			79.1	
01/18/40	659.00	658.25	727.6	517.6	177.1			98.0			79.1	
01/19/40	659.00	658.21	727.6	517.6	177.1			98.0			79.1	
01/20/40	659.00	658.22	800.0	590.0	201.8			111.7			90.2	
01/21/40	659.00	658.21	800.0	590.0	201.8			111.7			90.2	
01/22/40	659.00	658.12	727.6	517.6	177.0			97.9			79.0	
01/23/40	659.00	658.06	727.6	517.6	176.9			97.9			79.0	
01/24/40	659.00	657.99	727.6	517.6	176.9			97.9			79.0	
01/25/40	659.00	657.93	727.6	517.6	176.8			97.8			79.0	
01/26/40	659.00	657.86	727.6	517.6	176.8			97.8			78.9	
01/27/40	659.00	657.88	800.0	590.0	201.5			111.5			90.0	
01/28/40	659.00	657.87	800.0	590.0	201.5			111.5			90.0	
01/29/40	659.00	657.79	727.6	517.6	176.7			97.8			78.9	
01/30/40	659.00	657.73	727.6	517.6	176.6			97.8			78.9	
01/31/40	659.00	657.67	727.6	517.6	176.6	5689.3		97.7	3148.1		78.9	2541.

Appendix B – Norfork Energy Loss Calculations

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

Appendix C – Powersite Dam – Head vs. Capability (Old and New Turbines)

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

Appendix D – Powersite Dam Energy Loss Calculations

Base Run Calculations

							FL =	0.5	Efficiency=	0.85
Table Rock - Ozark Beach (New Wheels)										
SUPER output - W08X01 (base run)							Average Annual Energy, MWh			68,655
Date	**Table Rock Total Discharge, cfs**	**Bull Shoals 12-M Pool Elev., Ft.**	**Gross Head, feet**	**Adjusted BS Pool Elev., Ft. (1)**	**Adjusted Gross Head, feet**	**Maximum Capacity (from Table), MW**	**OB Full Discharge Capacity, cfs**	**OB Daily Energy, MWh**	**OB Monthly Energy, MWH**	**OB Annual Energy, MWH**
01/01/40	2,221	653.91	47.09	654.28	46.72	18.993	5,715	177.1		
01/02/40	2,221	653.85	47.15	654.22	46.78	19.032	5,719	177.4		
01/03/40	2,222	653.78	47.22	654.15	46.85	19.076	5,723	177.7		
01/04/40	2,222	653.74	47.26	654.11	46.89	19.102	5,726	177.9		
01/05/40	2,223	653.69	47.31	654.06	46.94	19.133	5,729	178.1		
01/06/40	120	653.73	47.27	654.10	46.90	19.108	5,727	9.6		
01/07/40	120	653.76	47.24	654.13	46.87	19.089	5,725	9.6		
01/08/40	2,223	653.68	47.32	654.05	46.95	19.140	5,730	178.2		
01/09/40	2,223	653.64	47.36	654.01	46.99	19.165	5,732	178.4		
01/10/40	2,224	653.61	47.39	653.98	47.02	19.184	5,734	178.6		
01/11/40	2,224	653.58	47.42	653.95	47.05	19.204	5,736	178.7		
01/12/40	2,225	653.55	47.45	653.92	47.08	19.223	5,738	178.9		
01/13/40	120	653.61	47.39	653.98	47.02	19.184	5,734	9.6		
01/14/40	120	653.66	47.34	654.03	46.97	19.153	5,731	9.6		
01/15/40	2,225	653.62	47.38	653.99	47.01	19.178	5,734	178.6		
01/16/40	2,225	653.61	47.39	653.98	47.02	19.184	5,734	178.6		
01/17/40	2,225	653.59	47.41	653.96	47.04	19.197	5,736	178.7		
01/18/40	2,226	653.57	47.43	653.94	47.06	19.210	5,737	178.8		
01/19/40	2,226	653.55	47.45	653.92	47.08	19.223	5,738	179.0		
01/20/40	120	653.59	47.41	653.96	47.04	19.197	5,736	9.6		
01/21/40	120	653.60	47.40	653.97	47.03	19.191	5,735	9.6		
01/22/40	2,226	653.52	47.48	653.89	47.11	19.242	5,740	179.1		
01/23/40	2,227	653.48	47.52	653.85	47.15	19.267	5,743	179.3		
01/24/40	2,227	653.43	47.57	653.80	47.20	19.299	5,746	179.5		
01/25/40	2,228	653.38	47.62	653.75	47.25	19.331	5,749	179.8		
01/26/40	2,228	653.33	47.67	653.69	47.31	19.363	5,753	180.0		
01/27/40	120	653.37	47.63	653.74	47.26	19.337	5,750	9.7		
01/28/40	120	653.39	47.61	653.76	47.24	19.325	5,749	9.7		
01/29/40	2,228	653.32	47.68	653.68	47.32	19.369	5,753	180.1		
01/30/40	2,229	653.28	47.72	653.64	47.36	19.395	5,756	180.3		
01/31/40	2,230	653.24	47.76	653.60	47.40	19.420	5,759	180.5	4190.3	

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

Minimum Flows Run Calculations

							FL =	0.5	Efficiency=	0.85
Table Rock - Ozark Beach (New Wheels)										
SUPER output - W08X02 (minimum flow run)							Average Annual Energy, MWh			60,011
Date	**Table Rock Total Discharge, cfs**	**Bull Shoals 12-M Pool Elev., Ft.**	**Gross Head, feet**	**Adjusted BS Pool Elev., Ft. (1)**	**Adjusted Gross Head, feet**	**Maximum Capacity (from Table), MW**	**OB Full Discharge Capacity, cfs**	**OB Daily Energy, MWh**	**OB Monthly Energy, MWH**	**OB Annual Energy, MWH**
01/01/40	2,221	658.90	42.10	659.34	41.66	15.813	5,343	157.7		
01/02/40	2,221	658.82	42.18	659.26	41.74	15.864	5,350	158.1		
01/03/40	2,222	658.74	42.26	659.18	41.82	15.915	5,356	158.4		
01/04/40	2,222	658.68	42.32	659.12	41.88	15.954	5,361	158.7		
01/05/40	2,223	658.62	42.38	659.06	41.94	15.992	5,366	159.0		
01/06/40	120	658.64	42.36	659.08	41.92	15.979	5,365	8.6		
01/07/40	120	658.63	42.37	659.07	41.93	15.986	5,365	8.6		
01/08/40	2,223	658.55	42.45	658.99	42.01	16.037	5,372	159.2		
01/09/40	2,223	658.49	42.51	658.93	42.07	16.075	5,377	159.5		
01/10/40	2,224	658.44	42.56	658.88	42.12	16.107	5,381	159.8		
01/11/40	2,224	658.40	42.60	658.84	42.16	16.132	5,384	160.0		
01/12/40	2,225	658.35	42.65	658.79	42.21	16.164	5,388	160.2		
01/13/40	120	658.39	42.61	658.83	42.17	16.138	5,385	8.6		
01/14/40	120	658.40	42.60	658.84	42.16	16.132	5,384	8.6		
01/15/40	2,225	658.35	42.65	658.79	42.21	16.164	5,388	160.2		
01/16/40	2,225	658.32	42.68	658.75	42.25	16.183	5,391	160.3		
01/17/40	2,225	658.29	42.71	658.72	42.28	16.202	5,393	160.4		
01/18/40	2,226	658.25	42.75	658.68	42.32	16.228	5,396	160.6		
01/19/40	2,226	658.21	42.79	658.64	42.36	16.253	5,400	160.8		
01/20/40	120	658.22	42.78	658.65	42.35	16.247	5,399	8.7		
01/21/40	120	658.21	42.79	658.64	42.36	16.253	5,400	8.7		
01/22/40	2,226	658.12	42.88	658.55	42.45	16.310	5,407	161.2		
01/23/40	2,227	658.06	42.94	658.49	42.51	16.349	5,412	161.4		
01/24/40	2,227	657.99	43.01	658.42	42.58	16.393	5,417	161.8		
01/25/40	2,228	657.93	43.07	658.36	42.64	16.431	5,422	162.0		
01/26/40	2,228	657.86	43.14	658.29	42.71	16.476	5,428	162.3		
01/27/40	120	657.88	43.12	658.31	42.69	16.463	5,426	8.7		
01/28/40	120	657.87	43.13	658.30	42.70	16.470	5,427	8.7		
01/29/40	2,228	657.79	43.21	658.22	42.78	16.521	5,433	162.6		
01/30/40	2,229	657.73	43.27	658.16	42.84	16.559	5,438	162.9		
01/31/40	2,230	657.67	43.33	658.10	42.90	16.597	5,443	163.2	3759.5	

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

Appendix E – Thermal Plant Power Values for the Southwest Region

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

Appendix F – Present Value Calculation for Federal Hydropower

Federal Hydropower Energy Losses								
Inflation rate =		2.00%		On-peak energy value =		$91.44	/MWh	
Discount rate =		5.00%		Combustion Turbine Plant for Arkansas (Nov 2007)				
BS energy loss =		23,855	MWh					
NF energy loss =		13,524	MWh	Off-peak energy value =		$17.50	/MWh	
On-peak energy loss =		6,762	MWh	Coal-Fired Steam Plant for Arkansas (Nov 2007)				
Off-peak energy loss =		30,617	MWh					
Total energy loss =		37,379	MWh	Energy values inflated annually by inflation rate.				
	Year	On-peak	Value	On-pk loss	Off-peak	Value	Off-pk loss	Total Loss
	2008	6,762	$91.44	$618,300	30,617	$17.50	$535,789	$1,154,089
	2009	6,762	$93.27	$630,666	30,617	$17.85	$546,505	$1,177,170
	2010	6,762	$95.13	$643,279	30,617	$18.21	$557,435	$1,200,714
				present value of 2011-2060 stream in 2011				**$32,804,243**
1	2011	6,762	$97.04	$656,145	30,617	$18.57	$568,583	$1,224,728
2	2012	6,762	$98.98	$669,268	30,617	$18.94	$579,955	$1,249,223
3	2013	6,762	$100.96	$682,653	30,617	$19.32	$591,554	$1,274,207
4	2014	6,762	$102.98	$696,306	30,617	$19.71	$603,385	$1,299,691
5	2015	6,762	$105.04	$710,232	30,617	$20.10	$615,453	$1,325,685
6	2016	6,762	$107.14	$724,437	30,617	$20.50	$627,762	$1,352,199
7	2017	6,762	$109.28	$738,925	30,617	$20.91	$640,317	$1,379,243
8	2018	6,762	$111.46	$753,704	30,617	$21.33	$653,124	$1,406,827
9	2019	6,762	$113.69	$768,778	30,617	$21.76	$666,186	$1,434,964
10	2020	6,762	$115.97	$784,154	30,617	$22.19	$679,510	$1,463,663
11	2021	6,762	$118.29	$799,837	30,617	$22.64	$693,100	$1,492,937
12	2022	6,762	$120.65	$815,833	30,617	$23.09	$706,962	$1,522,795
13	2023	6,762	$123.07	$832,150	30,617	$23.55	$721,101	$1,553,251
14	2024	6,762	$125.53	$848,793	30,617	$24.02	$735,523	$1,584,316
15	2025	6,762	$128.04	$865,769	30,617	$24.50	$750,234	$1,616,003
16	2026	6,762	$130.60	$883,084	30,617	$24.99	$765,238	$1,648,323
17	2027	6,762	$133.21	$900,746	30,617	$25.49	$780,543	$1,681,289
18	2028	6,762	$135.88	$918,761	30,617	$26.00	$796,154	$1,714,915
19	2029	6,762	$138.59	$937,136	30,617	$26.52	$812,077	$1,749,213
20	2030	6,762	$141.36	$955,879	30,617	$27.05	$828,319	$1,784,197
21	2031	6,762	$144.19	$974,996	30,617	$27.60	$844,885	$1,819,881
22	2032	6,762	$147.08	$994,496	30,617	$28.15	$861,783	$1,856,279
23	2033	6,762	$150.02	$1,014,386	30,617	$28.71	$879,018	$1,893,405
24	2034	6,762	$153.02	$1,034,674	30,617	$29.28	$896,599	$1,931,273
25	2035	6,762	$156.08	$1,055,367	30,617	$29.87	$914,531	$1,969,898
26	2036	6,762	$159.20	$1,076,475	30,617	$30.47	$932,821	$2,009,296
27	2037	6,762	$162.38	$1,098,004	30,617	$31.08	$951,478	$2,049,482
28	2038	6,762	$165.63	$1,119,964	30,617	$31.70	$970,507	$2,090,472
29	2039	6,762	$168.94	$1,142,364	30,617	$32.33	$989,917	$2,132,281
30	2040	6,762	$172.32	$1,165,211	30,617	$32.98	$1,009,716	$2,174,927
31	2041	6,762	$175.77	$1,188,515	30,617	$33.64	$1,029,910	$2,218,425
32	2042	6,762	$179.28	$1,212,285	30,617	$34.31	$1,050,508	$2,262,794
33	2043	6,762	$182.87	$1,236,531	30,617	$35.00	$1,071,518	$2,308,050
34	2044	6,762	$186.53	$1,261,262	30,617	$35.70	$1,092,949	$2,354,211
35	2045	6,762	$190.26	$1,286,487	30,617	$36.41	$1,114,808	$2,401,295
36	2046	6,762	$194.06	$1,312,217	30,617	$37.14	$1,137,104	$2,449,321
37	2047	6,762	$197.94	$1,338,461	30,617	$37.88	$1,159,846	$2,498,307
38	2048	6,762	$201.90	$1,365,230	30,617	$38.64	$1,183,043	$2,548,273
39	2049	6,762	$205.94	$1,392,535	30,617	$39.41	$1,206,704	$2,599,239
40	2050	6,762	$210.06	$1,420,386	30,617	$40.20	$1,230,838	$2,651,223
41	2051	6,762	$214.26	$1,448,793	30,617	$41.01	$1,255,455	$2,704,248
42	2052	6,762	$218.55	$1,477,769	30,617	$41.83	$1,280,564	$2,758,333
43	2053	6,762	$222.92	$1,507,325	30,617	$42.66	$1,306,175	$2,813,500
44	2054	6,762	$227.38	$1,537,471	30,617	$43.52	$1,332,298	$2,869,770
45	2055	6,762	$231.92	$1,568,221	30,617	$44.39	$1,358,944	$2,927,165
46	2056	6,762	$236.56	$1,599,585	30,617	$45.27	$1,386,123	$2,985,708
47	2057	6,762	$241.29	$1,631,577	30,617	$46.18	$1,413,846	$3,045,422
48	2058	6,762	$246.12	$1,664,208	30,617	$47.10	$1,442,123	$3,106,331
49	2059	6,762	$251.04	$1,697,492	30,617	$48.04	$1,470,965	$3,168,457
50	2060	6,762	$256.06	$1,731,442	30,617	$49.01	$1,500,384	$3,231,827

Federal Hydropower Capacity Losses					**Bull Shoals Increased Maintenance**		
Total Capacity Loss=		3.93	MW		Estimated annual costs =		$68,000
Capacity Value =		$61.30	/kW-yr				
Combustion Turbine Plant for Arkansas (Nov 2007)							
Year	Cap loss	Value	Total Loss		Year	Annual Maint	
2008	3.9	$61.30	$240,909		2008	$68,000	
2009	3.9	$62.53	$245,727		2009	$69,360	
2010	3.9	$63.78	$250,642		2010	$70,747	
			$6,847,687			**$1,932,857**	
2011	3.9	$65.05	$255,655		2011	$72,162	
2012	3.9	$66.35	$260,768		2012	$73,605	
2013	3.9	$67.68	$265,983		2013	$75,077	
2014	3.9	$69.03	$271,303		2014	$76,579	
2015	3.9	$70.41	$276,729		2015	$78,111	
2016	3.9	$71.82	$282,263		2016	$79,673	
2017	3.9	$73.26	$287,909		2017	$81,266	
2018	3.9	$74.72	$293,667		2018	$82,892	
2019	3.9	$76.22	$299,540		2019	$84,549	
2020	3.9	$77.74	$305,531		2020	$86,240	
2021	3.9	$79.30	$311,641		2021	$87,965	
2022	3.9	$80.88	$317,874		2022	$89,725	
2023	3.9	$82.50	$324,232		2023	$91,519	
2024	3.9	$84.15	$330,716		2024	$93,349	
2025	3.9	$85.83	$337,331		2025	$95,216	
2026	3.9	$87.55	$344,077		2026	$97,121	
2027	3.9	$89.30	$350,959		2027	$99,063	
2028	3.9	$91.09	$357,978		2028	$101,044	
2029	3.9	$92.91	$365,138		2029	$103,065	
2030	3.9	$94.77	$372,440		2030	$105,127	
2031	3.9	$96.66	$379,889		2031	$107,229	
2032	3.9	$98.60	$387,487		2032	$109,374	
2033	3.9	$100.57	$395,237		2033	$111,561	
2034	3.9	$102.58	$403,141		2034	$113,792	
2035	3.9	$104.63	$411,204		2035	$116,068	
2036	3.9	$106.72	$419,428		2036	$118,390	
2037	3.9	$108.86	$427,817		2037	$120,757	
2038	3.9	$111.04	$436,373		2038	$123,173	
2039	3.9	$113.26	$445,101		2039	$125,636	
2040	3.9	$115.52	$454,003		2040	$128,149	
2041	3.9	$117.83	$463,083		2041	$130,712	
2042	3.9	$120.19	$472,345		2042	$133,326	
2043	3.9	$122.59	$481,791		2043	$135,992	
2044	3.9	$125.05	$491,427		2044	$138,712	
2045	3.9	$127.55	$501,256		2045	$141,487	
2046	3.9	$130.10	$511,281		2046	$144,316	
2047	3.9	$132.70	$521,506		2047	$147,203	
2048	3.9	$135.35	$531,937		2048	$150,147	
2049	3.9	$138.06	$542,575		2049	$153,150	
2050	3.9	$140.82	$553,427		2050	$156,213	
2051	3.9	$143.64	$564,495		2051	$159,337	
2052	3.9	$146.51	$575,785		2052	$162,524	
2053	3.9	$149.44	$587,301		2053	$165,774	
2054	3.9	$152.43	$599,047		2054	$169,090	
2055	3.9	$155.48	$611,028		2055	$172,471	
2056	3.9	$158.59	$623,249		2056	$175,921	
2057	3.9	$161.76	$635,714		2057	$179,439	
2058	3.9	$164.99	$648,428		2058	$183,028	
2059	3.9	$168.29	$661,396		2059	$186,689	
2060	3.9	$171.66	$674,624		2060	$190,422	

Appendix G – Present Value Calculation for Non-Federal Hydropower

Empire Energy Losses										**Empire Capacity Losses**			
Inflation rate =		2.00%		On-peak energy value =		$56.45	/MWh			Total Capacity Loss=		3	MW
Discount rate =		5.00%		Combined Cycle Plant for Missouri (Nov 2007)									
On-peak % =		67%								Capacity Value =		$128.47	/kW-yr
Off-peak % =		33%		Off-peak energy value =		$13.75	/MWh			Combined Cycle Plant for Missouri (Nov 2007)			
Total energy loss =		8,645	MWh	Coal-Fired Steam Plant for Missouri (Nov 2007)									
On-peak loss =		5,792	MWh										
Off-peak loss =		2,853	MWh	Energy values inflated annually by inflation rate.									
Carbon Tax =		$0	per ton	Annual carbon tax computed in 2010-EDEC-Platts									
CT Risk Premium=		0%											
	Year	On-peak	Value	On-pk loss	Off-peak	Value	Off-pk loss	Total Loss		Year	Cap loss	Value	Total Loss
	2008	5,792	$56.45	$326,962	2,853	$13.75	$39,226	$366,189		2008	3.00	$128.47	$385,410
	2009	5,792	$57.58	$333,502	2,853	$14.03	$40,011	$373,512		2009	3.00	$131.04	$393,118
	2010	5,792	$58.73	$340,172	2,853	$14.31	$40,811	$380,983		2010	3.00	$133.66	$400,981
				present value of 2011-2060 stream in 2011				**$10,408,683**					**$10,955,038**
1	2011	5,792	$59.91	$346,975	2,853	$14.59	$41,627	$388,602		2011	3.00	$136.33	$409,000
2	2012	5,792	$61.10	$353,915	2,853	$14.88	$42,460	$396,374		2012	3.00	$139.06	$417,180
3	2013	5,792	$62.33	$360,993	2,853	$15.18	$43,309	$404,302		2013	3.00	$141.84	$425,524
4	2014	5,792	$63.57	$368,213	2,853	$15.48	$44,175	$412,388		2014	3.00	$144.68	$434,034
5	2015	5,792	$64.84	$375,577	2,853	$15.79	$45,059	$420,636		2015	3.00	$147.57	$442,715
6	2016	5,792	$66.14	$383,089	2,853	$16.11	$45,960	$429,048		2016	3.00	$150.52	$451,569
7	2017	5,792	$67.46	$390,750	2,853	$16.43	$46,879	$437,629		2017	3.00	$153.53	$460,601
8	2018	5,792	$68.81	$398,565	2,853	$16.76	$47,816	$446,382		2018	3.00	$156.60	$469,813
9	2019	5,792	$70.19	$406,537	2,853	$17.10	$48,773	$455,310		2019	3.00	$159.74	$479,209
10	2020	5,792	$71.59	$414,667	2,853	$17.44	$49,748	$464,416		2020	3.00	$162.93	$488,793
11	2021	5,792	$73.02	$422,961	2,853	$17.79	$50,743	$473,704		2021	3.00	$166.19	$498,569
12	2022	5,792	$74.48	$431,420	2,853	$18.14	$51,758	$483,178		2022	3.00	$169.51	$508,540
13	2023	5,792	$75.97	$440,048	2,853	$18.51	$52,793	$492,842		2023	3.00	$172.90	$518,711
14	2024	5,792	$77.49	$448,849	2,853	$18.88	$53,849	$502,699		2024	3.00	$176.36	$529,085
15	2025	5,792	$79.04	$457,826	2,853	$19.25	$54,926	$512,752		2025	3.00	$179.89	$539,667
16	2026	5,792	$80.62	$466,983	2,853	$19.64	$56,025	$523,008		2026	3.00	$183.49	$550,460
17	2027	5,792	$82.24	$476,323	2,853	$20.03	$57,145	$533,468		2027	3.00	$187.16	$561,470
18	2028	5,792	$83.88	$485,849	2,853	$20.43	$58,288	$544,137		2028	3.00	$190.90	$572,699
19	2029	5,792	$85.56	$495,566	2,853	$20.84	$59,454	$555,020		2029	3.00	$194.72	$584,153
20	2030	5,792	$87.27	$505,477	2,853	$21.26	$60,643	$566,120		2030	3.00	$198.61	$595,836
21	2031	5,792	$89.02	$515,587	2,853	$21.68	$61,856	$577,443		2031	3.00	$202.58	$607,753
22	2032	5,792	$90.80	$525,899	2,853	$22.12	$63,093	$588,991		2032	3.00	$206.64	$619,908
23	2033	5,792	$92.61	$536,417	2,853	$22.56	$64,355	$600,771		2033	3.00	$210.77	$632,306
24	2034	5,792	$94.46	$547,145	2,853	$23.01	$65,642	$612,787		2034	3.00	$214.98	$644,952
25	2035	5,792	$96.35	$558,088	2,853	$23.47	$66,955	$625,042		2035	3.00	$219.28	$657,851
26	2036	5,792	$98.28	$569,250	2,853	$23.94	$68,294	$637,543		2036	3.00	$223.67	$671,008
27	2037	5,792	$100.25	$580,635	2,853	$24.42	$69,660	$650,294		2037	3.00	$228.14	$684,428
28	2038	5,792	$102.25	$592,247	2,853	$24.91	$71,053	$663,300		2038	3.00	$232.71	$698,117
29	2039	5,792	$104.30	$604,092	2,853	$25.40	$72,474	$676,566		2039	3.00	$237.36	$712,079
30	2040	5,792	$106.38	$616,174	2,853	$25.91	$73,923	$690,097		2040	3.00	$242.11	$726,321
31	2041	5,792	$108.51	$628,498	2,853	$26.43	$75,402	$703,899		2041	3.00	$246.95	$740,847
32	2042	5,792	$110.68	$641,067	2,853	$26.96	$76,910	$717,977		2042	3.00	$251.89	$755,664
33	2043	5,792	$112.89	$653,889	2,853	$27.50	$78,448	$732,337		2043	3.00	$256.93	$770,777
34	2044	5,792	$115.15	$666,967	2,853	$28.05	$80,017	$746,984		2044	3.00	$262.06	$786,193
35	2045	5,792	$117.45	$680,306	2,853	$28.61	$81,617	$761,923		2045	3.00	$267.31	$801,917
36	2046	5,792	$119.80	$693,912	2,853	$29.18	$83,250	$777,162		2046	3.00	$272.65	$817,955
37	2047	5,792	$122.20	$707,790	2,853	$29.77	$84,915	$792,705		2047	3.00	$278.10	$834,314
38	2048	5,792	$124.64	$721,946	2,853	$30.36	$86,613	$808,559		2048	3.00	$283.67	$851,001
39	2049	5,792	$127.14	$736,385	2,853	$30.97	$88,345	$824,730		2049	3.00	$289.34	$868,021
40	2050	5,792	$129.68	$751,113	2,853	$31.59	$90,112	$841,225		2050	3.00	$295.13	$885,381
41	2051	5,792	$132.27	$766,135	2,853	$32.22	$91,914	$858,049		2051	3.00	$301.03	$903,089
42	2052	5,792	$134.92	$781,458	2,853	$32.86	$93,753	$875,210		2052	3.00	$307.05	$921,150
43	2053	5,792	$137.62	$797,087	2,853	$33.52	$95,628	$892,714		2053	3.00	$313.19	$939,573
44	2054	5,792	$140.37	$813,029	2,853	$34.19	$97,540	$910,569		2054	3.00	$319.45	$958,365
45	2055	5,792	$143.18	$829,289	2,853	$34.87	$99,491	$928,780		2055	3.00	$325.84	$977,532
46	2056	5,792	$146.04	$845,875	2,853	$35.57	$101,481	$947,356		2056	3.00	$332.36	$997,083
47	2057	5,792	$148.96	$862,792	2,853	$36.28	$103,510	$966,303		2057	3.00	$339.01	$1,017,024
48	2058	5,792	$151.94	$880,048	2,853	$37.01	$105,581	$985,629		2058	3.00	$345.79	$1,037,365
49	2059	5,792	$154.98	$897,649	2,853	$37.75	$107,692	$1,005,342		2059	3.00	$352.70	$1,058,112
50	2060	5,792	$158.08	$915,602	2,853	$38.50	$109,846	$1,025,448		2060	3.00	$359.76	$1,079,274

Appendix H – Southwestern's Draft White Paper

Southwestern Power Administration
Water Storage Reallocations
Hydropower Impacts

Dated 07/18/2005

07/18/2005

DRAFT

Southwestern Power Administration
Water Storage Reallocation
Hydropower Impacts
Executive Summary

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

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

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

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

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

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

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

DRAFT

Southwestern Power Administration
Water Storage Reallocations
Hydropower Impacts

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix I – Empire Report

Empire District Electric Company

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

Dated August 2007

SERVICES YOU COUNT ON

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

August 2007

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Key Findings

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

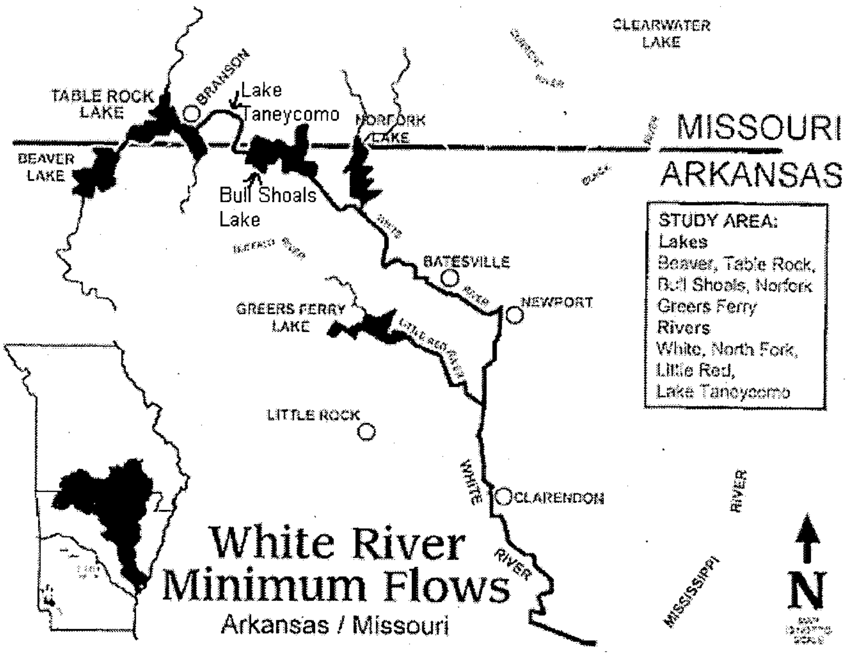
- Empire will lose five feet of net head with which to generate electricity at its Ozark Beach hydroelectric dam as a result of the Reallocation of storage in the White River by the U.S. Army Corps of Engineers (Corps).
- The Administrator of the Southwestern Power Administration (SWPA), in consultation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

Background

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

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

Figure 1



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

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

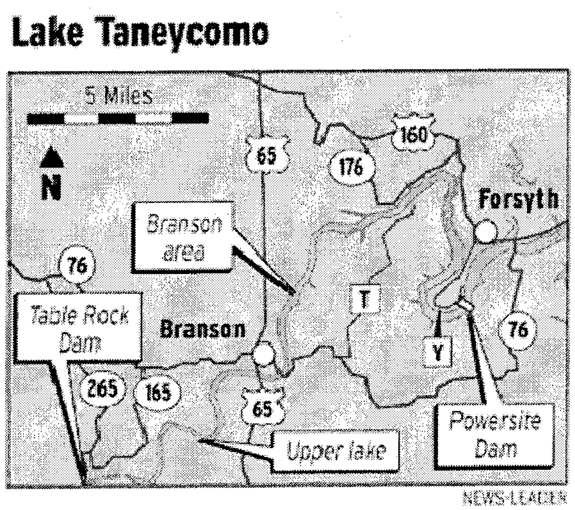
Bull Shoals Dam was completed in July of 1951 and is located approximately 7 miles north of Cotter, Arkansas at White River Mile 418.6. It has a maximum height above the river bed of 256 feet, is 2,256 feet in length, has 17 spillway crest gates, and is the fifth largest concrete dam in the United States.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

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

Empire's Ozark Beach Facility

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

Figure 2



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

Figure 3
Ozark Beach Dam

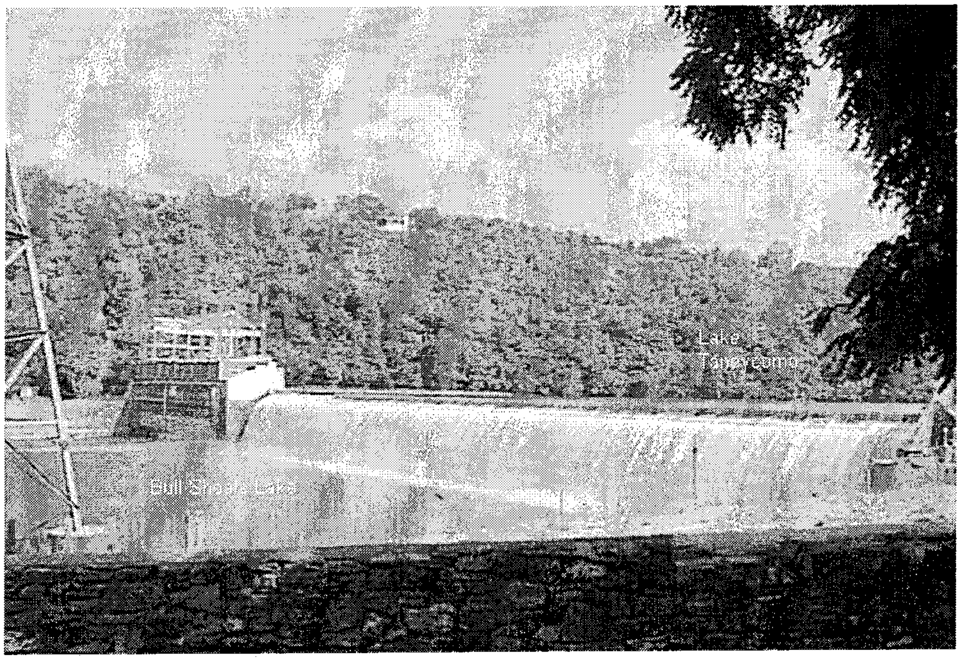


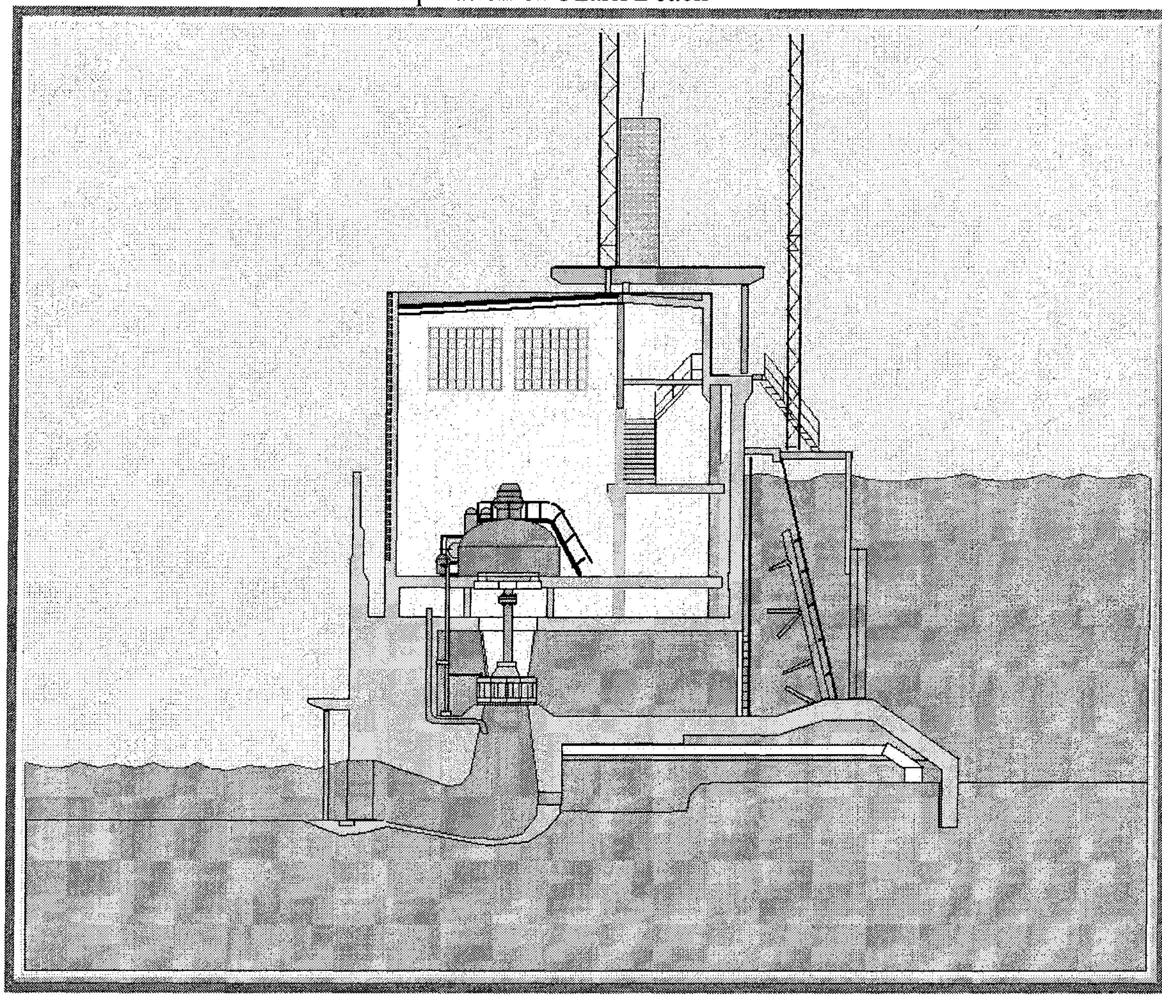
Table Rock Lake and Bull Shoals Lake are operated by the Corps' Little Rock District. With the installation of upgraded water wheels during 2002-2005, Ozark Beach has the capacity of 20 MW at full head. It is designated as license number 2221 by the Federal Energy Regulatory Commission.

Key Hydraulic Parameters

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

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

Figure 4
Operation of Ozark Beach



Explanation of Capacity and Energy Losses

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

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

Calculation for Lost Energy

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

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

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

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

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

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

Financial Parameter Assumptions

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

Calculation of Capacity Cost

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

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

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

Calculation of Energy Cost

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

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

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

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

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

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

Other Costs to Empire

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

Total Costs

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

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

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

Sensitivity Analysis

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

Table 3
Results of Sensitivity Analysis

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

Discussions with the Southwestern Power Administration

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

Conclusions

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

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

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

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

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

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

Appendix B

Formula for Calculation of Hydropower as a Function of Head

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

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

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

Appendix C

Ozark Beach Energy Lost Due to Reallocation
Table 1

Month	Lake Taneycomo Elevation	Capacity Factor (%)	Current Allocation: Bull Shoals Elevation	Current Allocation: Net Head (ft)	Current Allocation: Expected Generation (MWh) New Wheels	Reallocation: Bull Shoals Elevation	Reallocation: Net Head (ft)	Reallocation: Expecte Generati (MWh New Wheels
January	701.18	49.11	653.63	47.55	6,906	658.63	42.55	6,1
February	701.54	59.16	653.30	48.24	7,872	658.30	43.24	6,7
March	701.77	66.51	654.42	47.35	9,352	659.42	42.35	8,3
April	701.91	67.31	657.35	44.56	8,510	662.35	39.56	7,0
May	701.50	55.67	661.15	40.35	6,296	666.15	35.35	5,0
June	701.18	45.52	661.52	39.66	4,785	666.52	34.66	3,4
July	701.05	52.03	658.63	42.42	6.496	663.63	37.42	5,0
August	700.83	54.00	655.08	45.74	7,192	660.08	40.74	6,1
September	700.56	37.23	651.76	48.80	5,308	656.76	43.80	4,5
October	700.41	30.96	650.54	49.87	4,653	655.54	44.87	4,0
November	700.76	40.52	650.73	50.04	5,893	655.73	45.04	5,2
December	701.33	49.74	653.25	48.07	7,327	658.25	43.07	6,3

Average Annual Generation Los

Appendix D

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

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

Appendix E

Data Requirements and Sources

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

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

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

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

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

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

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