US Army Corps of Engineers®
Tulsa District

# STORAGE REALLOCATION REPORT
# LAKE TEXOMA
# OKLAHOMA AND TEXAS

**MARCH 2010**
**FINAL**

**Addendum – 1 October 2009**
**Storage Reallocation Report Lake Texoma, Oklahoma and Texas (April 2009)**

**Reference.** Memorandum for the Deputy Commanding General for Civil and Emergency Operations from the Acting Assistant Secretary of the Army (Civil Works), July 30, 2009, Subject: Lake Texoma, Texas, Water Storage Reallocation

**Introduction**.

The purpose of this addendum is to document the hydropower credit scenario in accordance with the referenced memorandum. The hydropower credit described in this addendum supersedes the credit scenario presented in Section 7.0 of the Storage Reallocation Report. The credit prescribed in this addendum only applies to the Denison Dam (Lake Texoma) project as related to Section 838 of the Water Resources Development Act of 1986, P.L. 99-662.

**Background**.

Section 838(d)(3) of the Water Resource Development Act of 1986, P.L. 99-662 directs the Secretary of the Army to provide credit to the Southwestern Power Administration (SWPA) equal to the replacement costs of the hydropower lost due to the reallocation of 300,000 acre-feet of storage in Lake Texoma from hydropower to water supply. The Corps of Engineers prepared the Storage Reallocation Report, Lake Texoma, Oklahoma and Texas (April 2009) in accordance with applicable laws and Corps of Engineers regulations and policy.

The Secretary of the Army subsequently determined that to implement the statute as intended by Congress, such credit should be extended for as long as the reallocated water storage is used for water supply purposes. Because Public Law 88-140 (October 16, 1963) grants storage rights for indefinite periods to non-Federal entities who enter into water supply storage contracts with the Department of the Army, the credit required by Section 838(d)(3) must equal the replacement costs of lost hydropower for an indefinite period of time.

Section 838(d)(4) of the Water Resources Development Act of 1986 prohibits increasing the payments of water supply users on account of the credit required Section 838(d)(3). Therefore, the maximum allowable credit is limited to the total payments for storage by water supply users.

**Hydropower Credit Determination.**

The hydropower credit determination assumes a continuing contractual relationship for an indefinite period between the SWPA and its customers for the sale of hydropower from Denison Dam, although such a relationship is not required by law or by the terms of current power contracts. To implement the determination of the Secretary of the Army, the Corps of Engineers will provide credit to the SWPA's hydropower account in the U.S. Treasury equal to the annual payments from water supply users during the 30-year repayment period under water storage agreements authorized by Section 838. This is the maximum credit allowable under Section 838(d)(4).

The credit is limited to annual payments for the cost of storage, but does not include payments by water supply users for the operation, maintenance, repair, rehabilitation or replacement costs of the project, or payments for any modification or mitigation costs associated with a reallocation.

Details of the hydropower credit will be documented in a memorandum of agreement between the Assistant Secretary of the Army (Civil Works) and the SWPA.

## TABLE OF CONTENTS


| Section | Title | Page No. |
|---|---|---|
| | Abbreviations and Acronyms | iv |
| | EXECUTIVE SUMMARY | 1 |
| 1.0 | PURPOSE | 1 |
| 1.1 | Reallocation Amount | 1 |
| 1.2 | Authority | 2 |
| 2.0 | PROJECT BACKGROUND | 5 |
| 2.1 | Authorization and Construction | 5 |
| 2.2 | Project Location, Purposes, and Outputs | 7 |
| 2.3 | Previous Storage Reallocations and Repayment Agreements | 10 |
| 2.4 | Reservoir Storage | 12 |
| 2.5 | Future Reallocation Policy | 14 |
| 2.6 | Additional Project Information | 15 |
| 3.0 | PROBLEMS AND NEEDS | 17 |
| 3.1 | Water Supply and Demand Analysis | 17 |
| 3.2 | North Texas Municipal Water District | 21 |
| 3.3 | Greater Texoma Utility Authority (GTUA) | 27 |
| 4.0 | PLAN FORMULATION | 30 |
| 4.1 | Preliminary Alternatives | 30 |
| 4.2 | No Action Measures | 31 |
| 4.3 | Action Alternatives | 32 |
| 4.4 | Evaluation of Conservation Pool and Flood Pool Alternatives | 35 |
| 4.5 | Reallocation from Conservation Flood Control Storage | 35 |
| 4.6 | Alternative Evaluation | 37 |
| 4.7 | Total Average Annual Losses using SUPER | 44 |
| 4.8 | Other Costs Associated with Pool Rise | 46 |
| 4.9 | Water Supply Benefits | 54 |
| 4.10 | Summary of Alternative Screening Evaluations | 55 |
| 4.11 | Economic Assessment | 56 |
| 4.12 | Environmental Assessment | 58 |
| 4.13 | Selected Alternative | 60 |
| 5.0 | DERIVATION OF USER COST | 61 |
| 5.1 | Methodology | 61 |
| 5.2 | Derivation of User Cost – The Value of Storage | 62 |
| 5.3 | Initial Value of Storage Summary | 64 |
| 5.4 | Validation of Value of Storage Selection - 2009 | 65 |
| 5.5 | User Cost | 65 |

## TABLE OF CONTENTS (cont.)


| Section | Title | Page No. |
|---|---|---|
| 6.0 | TEST OF FINANCIAL FEASIBILITY | 70 |
| 6.1 | Least Costly Water Supply Alternatives to Meet Future Regional Demands | 70 |
| 6.2 | Most Likely Water Supply Alternatives to Meet Future Regional Demands | 71 |
| 7.0 | PROJECT COST ACCOUNTS - HYDROPOWER AND WATER SUPPLY | 72 |
| 7.1 | Traditional Policy | 73 |
| 7.2 | Non-Traditional Policy – Project Specific Provisions of Section 838 | 76 |
| 7.3 | The Hydropower Project Account Credit Process | 82 |
| 7.4 | Corps and SWPA Methodology Differences | 83 |
| 8.0 | ADMINISTRATION GOALS | 84 |
| 8.1 | Environmental Operating Principles | 84 |
| 8.2 | The 12 Actions for Change | 86 |
| 9.0 | DAM SAFETY | 87 |
| 10.0 | CONCLUSIONS | 87 |
| 11.0 | RECOMMENDATION | 89 |


## TABLES


| Table | Title | Page No. |
|---|---|---|
| 1 | Lake Texoma (Denison Dam), Texas and Oklahoma Pertinent Data | 7 |
| 2 | Conservation Pool Storage Year 2044 | 12 |
| 3 | Lake Texoma Usable Storage Year 2044 | 13 |
| 4 | Historical and Projected Water Demand by Selected Counties (acre-feet) | 20 |
| 5 | Sources of Water Supply and Water Demand by Decade, Recommended Water Management Strategies North Texas Municipal Water District | 26 |
| 6 | Costs of Recommended Water Management Strategies North Texas Municipal Water District | 27 |
| 7 | Recommended Water Management Strategies for GTUA | 29 |
| 8 | Summary of Costs for GTUA Recommended Water Measurement Strategies | 30 |
| 9 | Evaluation Matrix of Preliminary Measures | 35 |
| 10 | Storage Reallocation Alternatives | 37 |
| 11 | Average Annual Downstream Flood Damages by Alternative | 41 |
| 12 | Average Annual In-Pool Losses by Alternative | 42 |
| 13 | Average Annual Recreation Benefits by Alternatives | 43 |
| 14 | Average Annual Total Hydropower Production by Alternative | 44 |
| 15 | Hydropower Benefits Forgone HAC Valuation | 44 |
| 16 | SUPER Evaluation of Alternatives by Category | 45 |
| 17 | Cultural Mitigation, Recreation Facility Relocation, and Oil Well Mitigation | 53 |
| 18 | Average Annual Cultural, Facilities, and Oil Well Costs by Alternative | 54 |

## TABLE OF CONTENTS (cont.)

### TABLES (cont.)


| Table | Title | Page No. |
|---|---|---|
| 19 | Summary of Annual Impacts and Benefits by Alternative | 57 |
| 20 | Hydropower Revenues Foregone | 63 |
| 21 | Annual Hydropower Benefits Foregone | 64 |
| 22 | Updated Storage Costs for FY 2009 | 69 |
| 23 | 2006 Region C Water Plan | 71 |
| 24 | Lower Bois D'Arc Creek Reservoir Project Cost And Annual Costs | 72 |
| 25 | Estimated Replacement Power Purchases Immediate Need Water Supply Reallocation | 82 |


### FIGURES


| Figure | Title | Page No. |
|---|---|---|
| 1 | Vicinity Map, Lake Texoma Storage Reallocation Project | 7 |
| 2 | Texas Water Development Board Regional Water Planning Areas | 18 |
| 3 | Region C and Major Outside Water Supplies Currently Used in Region C | 19 |


### APPENDICES


| Appendix | Title |
|---|---|
| A | Red River Compact |
| B | Letter Requests from NTMWD and GTUA for Water Storage Agreements |
| C | Letter from Oklahoma Water Resources Board to U.S. Army Corps of Engineers Regarding Proposed Reallocation Apportionment |
| D | Red River SUPER Model, Texoma Yield Analysis, and Water Supply Reallocation at Texoma |
| E | Hydropower Analysis Center Reports |
| F | Southwestern Power Administration Documents |
| G | Contract No. DE-PM75-00SW00435 |

## Abbreviations and Acronyms

| | |
|---|---|
| ASA (CW) | Assistant Secretary of the Army (Civil Works) |
| CWCCIS | Civil Works Construction Cost Index System |
| CFS | cubic feet per second |
| DEA | Draft Environmental Assessment |
| DSAC | Dam Safety Action Classification |
| DWU | Dallas Water Utilities |
| EA | Environmental Assessment |
| ENR | Engineering News Record |
| FEA | Final Environmental Assessment |
| FONSI | Finding of No Significant Impact |
| FY | Fiscal year |
| GTUA | Greater Texoma Utility Authority |
| HAC | Hydropower Analysis Center |
| kW | Kilowatt |
| mgd | million gallons per day |
| MW | Megawatt |
| NED | National Economic Development |
| NEPA | National Environmental Policy Act |
| NGVD | National Geodetic Vertical Datum |
| NTMWD | North Texas Municipal Water District |
| O&M | Operation and Maintenance |
| OTRD | Oklahoma Tourism and Recreation Department |
| PMA | Power Marketing Agency |
| RRAT | Red River Authority of Texas |
| SRWD | Sulphur River Water District |
| SWPA | Southwestern Power Administration |
| TP&L | Texas Power & Light |
| TRA | Trinity River Authority |
| TRWD | Tarrant Regional Water District |
| TXU | Texas Utilities(also known as Texas Power & Light) |
| UOF | Use of Facilities |
| USGS | U.S. Geological Survey |
| UTRWD | Upper Trinity River Water District |
| WRDA | Water Resources Development Act |

# STORAGE REALLOCATION REPORT

## LAKE TEXOMA
## OKLAHOMA AND TEXAS

## APRIL 2009

## EXECUTIVE SUMMARY

This reallocation report was prepared in response to requests for water supply storage in Lake Texoma, Oklahoma and Texas, by the North Texas Municipal Water District (NTMWD) and the Greater Texoma Utility Authority (GTUA). The Water Resources Development Act (WRDA) of 1986, Section 838 (Sec 838), authorized the Assistant Secretary of the Army for Civil Works (ASA (CW)) to reallocate storage to water supply in increments as needed, up to an additional 150,000 acre-feet each for Oklahoma and Texas.

The request for 100,000 acre-feet of storage by the NTMWD and 50,000 acre-feet of storage by the GTUA would reallocate all of the storage authorized for reallocation to Texas. The intent of the water supply utilities to immediately begin payment for the storage is the definition of an immediate water supply need. This study evaluated the near term reallocation of 150,000 acre-feet of storage to Texas, for potential impacts to social, economic, and environmental conditions.

No Oklahoma water supply needs were identified, but the Red River Compact apportions water storage equally between the states of Oklahoma and Texas, for Lake Texoma. Therefore, this study also evaluated a potential future reallocation of 150,000 acre-feet to Oklahoma, for potential impacts to social, economic, and environmental conditions.

Lake Texoma was constructed in 1944 by the Corps of Engineers and has authorized purposes of flood control, water supply, hydroelectric power, regulation of Red River flows, improvement of navigation, and recreation. Water supply storage has been reallocated at Lake Texoma prior to this study; the project currently provides 150,000 acre-feet, of which 148,485 is under contract.

The study also addresses the current and future water supply needs for municipal and industrial uses in Oklahoma and Texas. It evaluates various measures to provide the water needed for Texas, including reallocation from the conservation storage, as authorized, and reallocation from flood control storage, which was not within the authorization of Sec 838. Reallocation from the conservation storage was found to be economically viable and would have no significant environmental impacts. Reallocation from the flood control storage was found to be economically infeasible and was screened from detailed economic or environmental assessment. The potential reallocation of 150,000 acre-feet of conservation storage to Texas, and 150,000 acre-feet of conservation storage to Oklahoma were evaluated in detail.

A reallocation of water supply storage from conservation storage does not occur until water storage agreements are signed by all parties and the water supply user starts to pay for the storage. Therefore, the actual reallocation is often incremental and is implemented upon

execution of water storage agreements. The storage authorized for reallocation, but not under agreement, is considered by the Corps to be hydropower storage and is considered to be available when estimating a projects dependable power production.

The study complies with the National Environmental Policy Act (NEPA). An Environmental Assessment (EA) was conducted and a Finding of No Significant Impact (FONSI) was signed in May 2006. A draft supplemental environmental assessment (SEA), dated April 2009, was prepared to provide additional supporting information and details for analyses previously presented in the Final EA. The SEA presents findings that the storage reallocation authorized by Sec 838 for 150,000 acre-feet or 300,000 acre-feet of storage would have no significant adverse effects on the natural or human environment. Based on the 2006 EA and the 2009 SEA a determination was made that no significant environmental impacts are anticipated to occur as a result of the reallocation. However, future reallocations in increments up to 150,000 acre-feet for Oklahoma may or may not require supplemental NEPA documentation. The current NEPA documents are time sensitive.

Assuming that the water storage agreements evaluated for immediate need reallocation (150,000 acre-feet) are approved for final negotiations, the remaining balance of storage identified for reallocation under Sec 838 would be for Oklahoma (also 150,000 acre-feet). The total storage that would be available for Oklahoma communities would represent an additional 15.202% of the conservation storage. Hydropower generation would have use of 69.6% of the conservation storage plus all of the supplemental power generation until Oklahoma executed a water storage agreement. Supplemental energy may be generated from conservation pool storage releases if in excess of generation under contract or more commonly from flood control storage releases. Supplemental power generation is estimated to be 60% of total average annual energy production at Lake Texoma.

When conservation storage is reallocated from hydropower production to water supply, the change in storage use reduces the storage available for the production of power because water from the water supply storage would no longer continue to be available for release through the hydropower plant. The power production decrease tends to affect only the firm energy contracts (typically associated with a guaranteed capacity of kilowatts for a specified duration of hours). The production of supplemental energy is generally not impacted because supplemental energy is predominantly produced from flood control storage releases.

For the reallocation of 150,000 acre-feet of storage, hydropower impacts would consist of reduced energy and capacity that the SWPA could market. The average annual impact measured as the cost of replacement power from alternative sources, evaluated over a 50-year economic evaluation period and a discount rate of 4.625%, would be $1,416,784. (This is an economic value and does not represent the estimated value of U. S. Treasury credits to the Lake Texoma hydropower account.)

Average annual water supply benefits for the reallocation of 150,000 acre-feet of storage (about 150 mgd), evaluated over a 50-year economic evaluation period and a discount rate of 4.625%, would be $3,021,654 (including O&M). (This is an economic evaluation value suitable for comparison to the estimated economic value of hydropower impacts, but does not represent the annual water storage agreement payments amortized over 30 years.) The revenue provided to

the Treasury from the sale of water supply storage would be slightly more than twice the value of the hydropower impact as defined by Sec 838.

During the course of the evaluation, the Corps and the Southwestern Power Administration (SWPA) had numerous discussions concerning the appropriate methodologies to be used for evaluating impacts to energy and capacity benefits when hydropower storage is reallocated to other uses. Initially, the issues included the following: computation of dependable capacity; energy value used to compute power benefits foregone; SWPA's contract rates used to compute revenue forgone; calculation of energy loss; value applied to the capacity; and time period used when calculating the SWPA credit.

Two primary subjects capture the specific issues above: the appropriate value to place on the hydropower replacement costs as a result of the water supply reallocation; and the term of U.S. Treasury credits to the Lake Texoma hydropower account. Evaluations of the hydropower replacement costs were performed by the Corps' Hydropower Analysis Center according to Corps policy redefined by Sec 838. Estimates presented by the SWPA are based on their power marketing strategy and reflect their interpretation of the intent of the language of Sec 838. With regard to the term of compensation, the Corps opinion is that Section 838 does not address the term of credits to the U.S. Treasury project account for hydropower. Therefore, the term of hydropower credit should be based on traditional policy, which for replacement costs would be the term of current contracts between SWPA and their power customers. Those contracts expire at the end of 2018. The SWPA has expressed that, because of both the Federal and non-Federal investment in hydropower, that the term of credit should be indefinite; that is, never ending. The District has presented, in an appendix of this report, the information provided by the SWPA to represent their position on these issues.

To test the financial feasibility of Lake Texoma storage reallocation, the annual cost of the reallocated storage was compared to the annual cost of the most likely, least costly, water supply source that would provide an equivalent quality and quantity of water if storage reallocation at Lake Texoma was not an option for the water supply customer. The planned project, Lower Bois D'Arc, was found to be the most likely and least costly water supply alternative to Lake Texoma storage reallocation. The Lower Bois D'Arc project is estimated to supply about 110 mgd for the NTMWD and would have an estimated average annual cost of about $35,000,000. The Lake Texoma storage reallocation, with an average annual cost of $3,021,654, passes the test of financial feasibility by a factor of more than ten to one.

The water supply storage cost allocated to the NTMWD and GTUA is the "updated cost of storage". The updated cost of reallocated storage is estimated by updating the cost of the joint use features from the midpoint of construction to the fiscal year in which the reallocation of storage is approved. The updated cost of the joint use features is then multiplied by the proportion of useable storage that is to be reallocated to estimate the value of the reallocated storage.

The value of the 100,000 acre-feet of storage requested by NTMWD for reallocation is calculated to be $38,134,060 based on updated cost of storage for fiscal year 2009. The annual value would be $2,270,639 based on a 30-year repayment period with an interest rate of 4.625%. Using actual O&M expenses for FY 2008, the estimated annual operation and maintenance cost

would be about $45,073. The total annual payment during the 30 year repayment period would be $2,315,712. An annual payment for O&M would continue to be made by the NTMWD following the 30-year storage repayment period.

The value of the 50,000 acre-feet of storage requested by GTUA for reallocation is calculated to be $19,073,891 based on updated cost of storage for fiscal year 2009. The annual value would be $1,135,728 based on a 30-year repayment period with an interest rate of 4.625%. Using actual O&M expenses for FY 2008, the estimated annual operation and maintenance cost would be about $22,545. The total annual payment during the 30 year repayment period would be $1,158,273. An annual payment for O&M would continue to be made by the GTUA following the 30-year storage repayment period.

Recommendations are to execute water storage agreements for conservation storage reallocation to meet the immediate needs of 100,000 acre-feet of storage for NTMWD and 50,000 acre-feet of storage for GTUA. Draft agreements have been prepared and accompany the storage reallocation report.

# STORAGE REALLOCATION REPORT
# LAKE TEXOMA
# OKLAHOMA AND TEXAS

**APRIL 2009**

## 1.0 PURPOSE

In response to requests by north Texas municipalities and water users near Lake Texoma, Congress authorized the Assistant Secretary of the Army for Civil Works (ASA (CW)) to reallocate conservation storage to water supply up to 150,000 acre-feet each for Oklahoma and Texas. This authorization was in Section 838 of the 1986 Water Resources Development Act (1986 WRDA) (Public Law 99-662). The authorization is referred to as Sec 838 throughout this report. Many of the communities and water users in north Texas are served by the North Texas Municipal Water District (NTMWD) and the Greater Texoma Utility Authority (GTUA). This report documents the reallocation study findings and recommendations.

Reallocations are classified as discretionary (referring to the discretionary authority of the Chief of Engineers) or required by Congressional authorization. A change in the use of storage in an existing reservoir project from its present use to water supply is authorized by the Water Supply Act of 1958. Reallocations or addition of storage that would seriously affect the purposes for which the project was authorized, surveyed, planned, or constructed, or which would involve major structural or operational changes, will be made only upon the approval of Congress. Providing the above criteria are not violated, 15 percent of total storage capacity allocated to all authorized project purposes or 50,000 acre-feet, whichever is less, may be allocated from storage authorized for other purposes or may be added to the project to serve as storage for M&I water supply at the discretion of the Commander, USACE.

The requested reallocation of 150,000 acre-feet exceeds the discretionary authority of the Chief of Engineers and was included in the authorization by Congress in the 1986 WRDA.

### 1.1 Reallocation Amount

Currently, 148,485 acre-feet of storage is under agreement for water supply at Lake Texoma. The remaining 1,515 acre-feet of the original 150,000 acre-feet reallocation (1983 and 1985 reallocations) is being placed under agreement to the GTUA to provide the city of Pottsboro, Texas with water supply. This agreement will be sent for approval under separate cover. The amount of storage under prior agreement is generally referred to as 150,000 acre-feet in this 2009 reallocation report.

Section 838 of the Water Resources Development Act of 1986 authorized the Assistant Secretary of the Army for Civil Works (ASA (CW)) to reallocate storage from hydropower to water supply in Lake Texoma in increments as needed, up to an additional 150,000 acre-feet each for Oklahoma and Texas. Of the 300,000 acre-feet authorized by Sec 838, 150,000 acre-feet is identified for immediate reallocation to water supply for Texas.

The North Texas Municipal Water District (NTMWD) has requested a water storage agreement for 100,000 acre-feet. The GTUA has requested a water storage agreement for 50,000 acre-feet. Copies of the NTMWD and the GTUA letters requesting water supply storage agreements for Lake Texoma are in Appendix B.

No Oklahoma water supply needs were identified, but the Red River Compact apportions water storage equally between the states of Oklahoma and Texas. This reallocation report evaluated both the immediate need for reallocation of 150,000 acre-feet to Texas and a potential future reallocation of 150,000 acre-feet of storage to Oklahoma.

Projected municipal and industrial water needs in the Texas region are described in the State of Texas Senate Bill 1 *Initially Prepared 2006 Region C Water Plan* and are reviewed in this report. The authorization of 150,000 acre-feet for reallocation to Oklahoma is consistent with the apportionment provisions of the Red River Compact (see Appendix A). Of the total storage (986,730 acre-feet) about 490,000 acre-feet could be allocated to each Texas and Oklahoma under the apportionment provisions of the Red River Compact. The previous 150,000 acre-feet allocation to Texas and the proposed 150,000 acre-feet allocation to Texas would total 300,000 acre-feet – well below the Texas allocation limit of 490,000 acre-feet established by the Red River Compact (based on current storage estimates, forecast to 2044).

**1.2 Authority.** The national policy of the United States regarding water supply, as defined by Congress, has been developed over a number of years and is still being clarified and extended by legislation. This policy recognizes a significant but declining Federal interest in the long range management of water supplies and assigns the financial burden of supply to users.

**1.2.1 Water Supply Act of 1958**. Reallocation is the reassignment of the use of existing storage space in a reservoir project to a higher and better use. Authority for the Corps to reallocate existing storage space to municipal and industrial (M&I) water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended (72 Stat. 319) […]. Section 301(b), of this Act states ". . . it is hereby provided that storage may be included in any reservoir project surveyed, planned, constructed or to be surveyed, planned, and/or constructed . . . to impound water for present or anticipated future demand or need for municipal and industrial water supply." Section 301(d) of the Act states "[M]odifications of a reservoir project heretofore authorized, surveyed, planned, or constructed to include storage as provided in subsection (b), which would seriously affect the purposes for which the project was authorized, surveyed, planned, or constructed, or which would involve major structural or operational changes, will be made only upon the approval of Congress as now provided by law." (Water Supply Handbook, Dec 1998, Revised IWR Report 96-PS-4)

**1.2.2 Water Resources Development Act of 1986.** The Water Resources Development Act (WRDA) of 1986 (Public Law 99-662), sharply modified the Federal role that had been largely defined in the Water Supply Act of 1958. This act included the following: elimination of the 10-year interest free period, reduction of the payback period from 50 to 30 years, annual reimbursement of the operation and maintenance cost (although it had been established policy that these costs be repaid on an annual basis), non-Federal share of municipal and industrial water supply was assigned 100 percent of the costs and the non-Federal share of agricultural water supply was assigned 35 percent of the costs, the interest rate formula was modified, a rate

of 0.125 percent was added for transaction costs, and the interest rate is to be recomputed every five years. These amendments are applicable only to Corps projects and not the Bureau of Reclamation projects. The 1986 WRDA also included specific project authorization language for Lake Texoma storage reallocation.

**1.2.3 Lake Texoma Authorization in 1986 WRDA**. Authorization for this study was provided by Congress in Section 838 (Sec 838) of the 1986 WRDA. The ASA (CW) was authorized to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 150,000 acre-feet each for Oklahoma and Texas for municipal, industrial, and agricultural water uses (a total reallocation of 300,000 acre-feet). The authorization is shown below.

Sec 838, DENISON DAM (LAKE TEXOMA), RED RIVER, TEXAS AND OKLAHOMA

(a) The project for Denison Dam (Lake Texoma), Red River, Texas and Oklahoma, authorized by the Flood Control Act approved June 28, 1938 (52 Stat. 1219), is modified to provide that the Secretary is authorized to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 150,000 acre-feet for municipal, industrial, and agricultural water users in the State of Texas and up to 150,000 acre-feet for municipal, industrial and agricultural water users in the State of Oklahoma.

(b) For that portion of the water storage reserved for users in the State of Oklahoma, the Secretary may contract, in increments as needed, with qualified individuals, entities, or water utility systems for use within the Red River Basin; except that for any portion of that water to be utilized outside the Red River Basin, the Secretary shall contract with the Red Ark Development Authority.

(c) For that portion of the water storage reserved for users in the State of Texas, the Secretary shall contract, in increments as needed, for 50,000 acre-feet with the Greater Texoma Utility Authority and 100,000 acre-feet with other qualified individuals, entities, or water utility systems. Nothing in the preceding sentence shall supersede any requirement of State law with respect to the use of any water subject to a contract.

(d) (1) All contracts entered into by the Secretary under this section shall be under terms in accordance with section 301(b) of the Water Supply Act of 1958 (Public Law 85-500), as amended by section 932 of this Act.

(2) No payment shall be required from and no interest shall be charged to users in the States of Oklahoma or Texas for the reallocation authorized by this section until such time as the water supply storage reserved under such reallocation is actually first used. Any contract entered into for the use of the water received under this section shall require the contracting entity to begin principal and interest payments on that portion of the water allocated under the contract at the time the entity begins the use of such water. Until such time; storage for which reallocation is authorized in this section may be used for hydropower production.

(3) With respect to any water supply contract entered into by the Secretary under this section after June 1, 1985, the Secretary shall determine (A) the amount of hydropower lost, if any, as a result of the implementation of such contract, and (B) the replacement cost of the hydropower lost (where replacement cost is defined as the cost to purchase power from existing alternative sources). If hydropower is lost as a result of the implementation of such contract, the

Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement costs. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower. In each such case the Southwestern Power Administration shall reimburse each preference customer for an amount equal to the customer's actual replacement cost for hydropower lost as a result of the implementation of such contract, less the cost such customer would have had to pay the Southwestern Power Administration for such hydropower.

(4) The Secretary may not increase payments of water users under a water supply contract under this section on account of the credits and reimbursement required to be provided under this section.

(e) Nothing in this section shall be construed as amending or altering in any way the Red River Compact. In consideration of benefits in connection with such reallocation and usage of municipal, industrial, and agricultural water, all benefits that can be assigned to the Red River chloride control project, Texas and Oklahoma, or the Red River and tributaries multipurpose study, Oklahoma, Texas, Arkansas, and Louisiana, and any individual projects arising from such study, shall be reserved for such projects. Nothing in this section shall affect water rights under the laws of the States of Texas and Oklahoma.

(f) Such project is further modified to include recreation as a project purpose.

**1.2.4 Section 932, Public Law 99-662.** Section 932 (Sec 932) of Public Law 99-662 (WRDA '86), further amended the Water Supply Act of 1958. This amendment applies to Corps projects but not to Bureau of Reclamation projects. The amendment eliminated the 10-year interest free period for future water supply, modified the interest rate formula, limited repayment to 30 years, and required annual operation, maintenance and replacement costs to be reimbursed annually. This latter requirement had always been a part of Corps policy and repayment procedures. Sec 932 legislation did not have a bearing on this 2009 reallocation study or the pricing of storage, but is presented because it was referenced in Sec 838 that authorized the 2009 reallocation study.

SEC. 932. WATER SUPPLY ACT AMENDMENTS.

(a) Section 301(b) of the Water Supply Act of 1958 (72 Stat. 319; 43 U.S.C. 390b(b)), is amended as follows:

(1) in the third proviso, after "That" insert the following: "(1) for Corps of Engineers projects, not to exceed 30 percent of the total estimated cost of any project may be allocated to anticipated future demands, and, (2) for Bureau of Reclamation projects,",

(2) in the fourth proviso, after "That" insert the following: "for Corps of Engineers projects, the Secretary of the Army may permit the full non-Federal contribution to be made, without interest, during construction of the project, or, with interest, over a period of not more than thirty years from the date of completion, with repayment contracts providing for recalculation of the interest rate at, five-year intervals, and for Bureau of Reclamation projects,",

(3) after the first sentence insert the following: "For Corps of Engineers projects, all annual operation, maintenance, and replacement costs for municipal and industrial water supply storage under the provisions of this section shall be

reimbursed from State or local interests on an annual basis. For Corps of Engineers projects, any repayment by a State or local interest shall be made with interest at a rate to be determined by the Secretary of the Treasury, taking into consideration the average market yields on outstanding marketable obligations of the United States with remaining periods to maturity comparable to the reimbursement period, during the month preceding the fiscal year in which costs for the construction of the project are first incurred (or, when a recalculation is made), plus a premium of one-eighth of one percentage point for transaction costs.", and

(4) strike out "The interest rate used" and insert in lieu thereof: "For Bureau of Reclamation projects, the interest rate used".

(b) Nothing in this section shall be deemed to amend or require amendment of any valid contract entered into pursuant to the Water Supply Act of 1958, or Federal reclamation law and approved by the Secretary of the Army or the Secretary of the Interior prior to the date of enactment of this Act.

## 2.0 PROJECT BACKGROUND

**2.1 Authorization and Construction**. Lake Texoma (Denison Dam), Oklahoma and Texas, was authorized for flood control and power by the Flood Control Act approved June 28, 1938, Project Document HD 541, 75th Congress, 3d Session. Subsequent laws in 1940, 1944, 1953, 1957, and 1986 made further changes to the original authorization.

- Public Law 868, 76th Congress, 3d Session, was approved October 17, 1940, to improve navigation, regulate flow of the Red River, control floods, and add other beneficial purposes.

- Public Law 454, 78th Congress, 2d Session, approved September 30, 1944, designated the name of the impoundment as Lake Texoma.

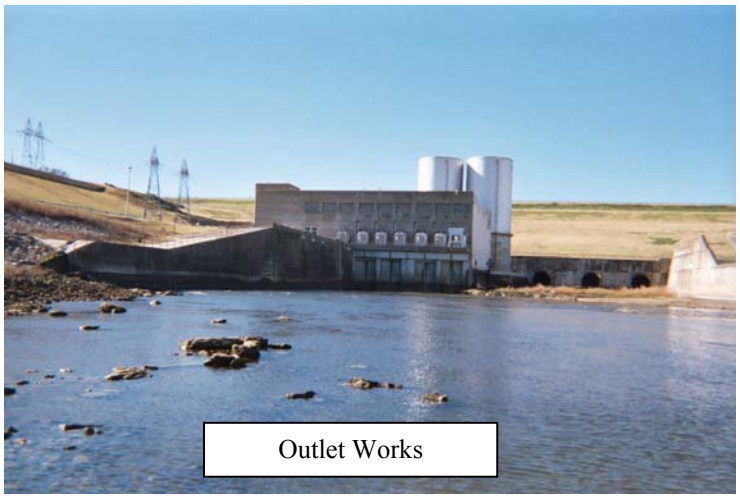
- Public Law 273, 83rd Congress, 1st Session, approved August 14, 1953, added water supply storage for the city of Denison, Texas.

- Public Law 146, 85th Congress, 1st Session, approved August 14, 1957, Project Document HD 541 75th Congress, 3d Session, set aside 22,600 acre-feet of storage for municipal and industrial water supply for the city of Sherman, Texas.

- Public Law 662, 99th Congress, 2d Session, approved November 17, 1986, added recreation as a project purpose and authorized the potential future reallocation of an additional 300,000 acre-feet of storage for water supply.

Construction of the dam, spillway, and outlet works was started in August 1939 and completed in February 1944. The project was first available to operate for full flood control without any restrictions in January 1944. The first hydroelectric turbine was placed on line in March 1945 and the second in September 1949. Construction of a highway bridge across Lake Texoma at the Willis Ferry site began on April 24, 1958, and was completed on October 30, 1960. The 5,426- foot long bridge replaces a former crossing south of Woodville, Oklahoma, on Oklahoma State Highway 99 and Texas State Highway 91.

The structure is a rolled earth-filled embankment with a rock-protected upstream slope. Total length along the crest, including the spillway, is 17,200 feet. The main embankment is 15,200 feet long. The maximum height of the structures is 165 feet above the streambed. A rolled earth-filled dike 5,870 feet long and 15 feet high is located in the vicinity of Platter, Oklahoma. The Cumberland levee is 23,480 feet long with a crest elevation of 647.0 feet. The Cumberland Levee System is part of the project.




The uncontrolled spillway is a concrete, gravity, chute-type structure, 2,000 feet long, located in a saddle on the right bank. Spillway capacity at maximum pool (elevation 666.4) is 1,050,000 cubic feet per second (cfs). The outlet works consist of three 20-foot diameter concrete conduits through the embankment and six 9- by 19-foot vertical lift gates and one emergency gate. Capacity of the outlet works is 67,500 cfs at the top of the flood control pool and 60,120 cfs at the top of the power pool. Limiting channel capacity below Denison Dam is about 45,000 cfs. The power intake structure will permit future installation of three additional power units.

Pertinent data for Lake Texoma, representing elevations, area, capacity, and equivalent runoff, are shown in Table 1. A reduced storage, 986,730 acre-feet, was used in this reallocation study and is based on a 2002 sediment survey with remaining storage forecast to 2044. The pertinent data was shown because it is published data.

| TABLE 1<br>LAKE TEXOMA (DENISON DAM), TEXAS AND OKLAHOMA<br>PERTINENT DATA | | | | |
|---|---|---|---|---|
| **Feature** | **Elevation (feet)** | **Area (acres)** | **Capacity (acre-feet)** | **Equivalent Runoff (1) (inches)** |
| Top of dam | 670.0 | -- | -- | -- |
| Top of flood control pool | 640.0 | 141,418 | 5,061,062 (2) | 2.81 |
| Top of conservation pool | 617.0 | 74,686 | 2,516,232 (3) | 1.40 |
| Bottom of active conservation pool | 590.0 | 40,434 | 1,048,949(3) | 0.58 |
| Conservation storage | 590.0-617.0 | -- | 1,467,283(3) | 0.81 |
| Flood control storage | 617.0-640.0 | -- | 2,544,830(2) | 1.41 |

NOTE: Data are based on 2002 sedimentation survey.
(1) From 39,719 square miles of drainage area upstream from dam.
(2) Includes storage in Cumberland pool.
(3) Excludes storage in Cumberland pool because the Cumberland storage is not accessible for conservation storage purposes. The value reflects published pertinent data.

**2.2 Project Location, Purposes, and Outputs**. Denison Dam is located on the Red River at river mile 725.9, 5 miles northwest of Denison in Grayson County, Texas (see Figure 1). The dam, which impounds the Red River to form Lake Texoma, is located on the borders of Texas and Oklahoma. The topography surrounding the lake varies from gently sloping flats to rocky and precipitous cliffs and steep, wooded hillsides.

Figure 1. Vicinity Map, Lake Texoma Storage Reallocation Project.

**2.2.1 Purposes.** Authorized project purposes are flood control, hydroelectric power, navigation, Red River flow regulation, water supply, and recreation. The project also provides habitat for native and introduced sport fish and wildlife species. The flood control, hydropower, and recreation purposes are discussed below.

- **Flood Control.** The Denison Dam was opened for full flood control operations in January 1944. Since that time, Denison Dam has prevented cumulative flood damages of $852,786,510 in average 2008 dollars and average annual damages prevented of $853,000 per year. The five flood events causing the greatest damage are shown below. The Tulsa District Pertinent Data Book lists floods of record based on peak discharge measures in cubic-feet per second (cfs) and/or volume in acre-feet. Floods of record or note include: May-June 1908 with 470,000 cfs and 8,517,000 acre-feet, May 1990 with 300,000 cfs and 5,087,000 acre-feet, May-June 1987 with 315,000 cfs and 2,879,000 acre-feet, and 1957 with a volume of 8,364,000 acre-feet.

| Top Five Flood Events | | |
|---|---|---|
| **Year** | **Damages Value at Time of Flood ($1 ,000's)** | **Damages In Current Value (2008 $1,000s)** |
| 1990 | $33,292.00 | $58,465.03 |
| 1995 | $50,116.70 | $76,123.15 |
| 1945 | $3,013.00 | $81,292.31 |
| 2007 | $111,160.26 | $115,946.00 |
| 1957 | $10,050.00 | $116,968.49 |

- **Hydropower.** Power produced at Denison Dam (Lake Texoma) is marketed by the Southwestern Power Administration (SWPA). As one of four Power Marketing Administrations in the United States, SWPA markets hydroelectric power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas, from 24 U.S. Army Corps of Engineers multipurpose dams with a generating capacity of approximately 2,174 MW. Lake Texoma facilities have a generating capacity of 70MW.

  By law, the SWPA markets and delivers power primarily to public bodies and rural electric cooperatives. The SWPA has over one hundred such "preference" customers, and these entities ultimately serve 7.5 million end-use customers. The SWPA operates and maintains 1,380 miles (2,220 km) of high voltage transmission lines, 24 substations, and a communications system that includes microwave, VHF radio, and state-of-the-art fiber optics. Staff members (179 full-time equivalents) work from offices located in Gore, Oklahoma; Jonesboro, Arkansas; Springfield, Missouri; and Tulsa, Oklahoma. Around-the-clock power scheduling and dispatching are conducted by staff in the Springfield Operations Center. Annual revenue for the SWPA has averaged about $126 million over the last five years. This revenue is used to pay the cost of operating and

maintaining the generation and transmission facilities and to repay the principal and interest on the Federal investment associated with hydropower at Corps projects.

Power produced at Lake Texoma represents just less than 4% of the estimated average annual energy that could be generated at Corps projects. In the 2004-2006 period, power produced at Lake Texoma averaged just less than 3% of the actual net energy production at Corps projects in the SWPA power system. Power is marketed by the SWPA through contracts for firm or supplemental power. Firm power can be represented as a block of energy with units of kilowatt-hours (kWh). The block of firm energy has an associated capacity in units of kilowatts (kW) that is guaranteed for a duration of time, in this case 1,200 hours. The block of firm energy is usually produced from water released through the power generation turbines from the conservation pool storage. Supplemental energy is also marketed through contracts for 1,200 hours, but without a guarantee for capacity. Supplemental energy may be generated from conservation pool storage releases if in excess of generation under contract or more commonly from flood control storage releases. Based on information from the SWPA, the total estimated average annual energy from Lake Texoma is 232 Million kWh. Of that amount, the firm energy plus a 10% reserve (77,000 kW over 1,200 hours) would be about 92.4 Million kWh. Supplemental energy would be about 139.6 Million kWh. Turbine upgrades since the Annual Report may slightly increase the capacity of the Lake Texoma power plant. Based on these estimates, firm energy would be about 40% and supplemental energy would be about 60% of total average annual energy production at Lake Texoma.

When conservation storage is reallocated from hydropower production to water supply, the change in storage use reduces the storage available for the production of power because water from the water supply storage would no longer continue to be available for release through the hydropower plant. The power production decrease tends to affect only the firm energy contracts. The production of supplemental energy is generally not impacted because supplemental energy is predominantly produced from flood control storage releases.

- **Water Supply.** The GTUA, acting for the city of Sherman, is the only full-time user of Lake Texoma for water supply. All other customers use Lake Texoma water when other water resources are impacted due to low flow periods or as mixing water in other lakes. Because of this, water supply withdrawals from the lake are relatively small compared to the amount of storage under agreement. However, population growth has forced the States of Oklahoma and Texas to secure future water supplies. This significant interest in developing and identifying sufficient water sources for the north-central region of Texas resulted in passage of Texas Senate Bill 1 and a determination that another large reallocation of conservation storage to water supply was necessary at Lake Texoma. Texas Senate Bill 1 enabled the development of regional water plans in the State of Texas. The *Initially Prepared Region C Water Plan* was first developed in year 2000 and updated in years 2005 and 2006. This plan is the basis for the preparation of water management strategies for future utilization of water resources in the region and the State. The impacts of this reallocation on hydropower and other authorized uses were first analyzed using the Corps SUPER modeling tool as part of the hydropower benefits forgone evaluation in 2003. Further SUPER evaluations were completed on 2008. The SUPER

modeling tool is a suite of computer programs written for use in the Southwestern Division of the U.S. Army Corps of Engineers to model hydraulic operations of multi-purpose reservoir systems for flood control, hydropower, navigation, and other project purposes.

- **Recreation.** Lake Texoma is the twelfth largest lake in capacity in the United States and one of the most popular Federal recreation facilities in the country, with more than 6 million visitors annually. In 2006, Texoma ranked first among Corps of Engineers lake projects nationwide, with visitors spending over 90 million hours at the lake. Texoma offers a multitude of amenities. It provides two state parks and two national wildlife refuges. It has 10 different campgrounds, over 600 individual campsites, 40 miles of equestrian trails, and several scenic Cross Timbers hiking trails that wind for many miles above the lake on rocky ledges and through scenic woodland areas. Lake Texoma also has 22 commercial concession areas, many of which provide overnight accommodations and boat and slip rental availability. With 89,000 acres of water, Texoma is also known as the "Striper Capital of the World". It is one of the few reservoirs in the nation where striped bass reproduce naturally and is a popular southwest fishing destination with plentiful and popular species including largemouth and smallmouth bass, white bass, hybrid striped bass, white and black crappie, channel catfish, and blue catfish. Wildlife visitors can enjoy two national wildlife refuges. Each year thousands of Canadian geese and snow geese, ducks, and bald eagles migrate through the two national wildlife refuges. Deer, turkey, and other native animals reside year round on the 30,000 acres set aside in the national parks.

**2.3 Previous Storage Reallocations and Repayment Agreements**. The Water Supply Act of 1958 authorizes the reassignment of existing storage space in a reservoir project to a higher and better use. Authority for the Corps to reallocate to municipal and industrial water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended. Guidance for reallocations is found in ER 1105-2-100. Previous water storage reallocation documents were prepared in 1983, 1985, 1992, 1997, and 2004.

**2.3.1 1983 Reallocation.** In August 1983, 72,600 acre-feet was reserved for water supply in an integrated hydropower and water supply conservation pool between elevations 590.0 and 617.0 feet National Geodetic Vertical Datum (NGVD). Of this amount, 41,094 acre-feet was set aside for the existing current users (City of Denison, Texas Power and Light, and Red River Authority of Texas). The reallocation study was initiated when the Red River Authority of Texas requested and additional 1,806 acre-feet of water supply storage. This would have left 7,100 acre-feet for potential future users. Since the Chief of Engineers had discretionary authority to reallocate up to 50,000 acre-feet or 15 percent of the conservation pool, whichever was less, the full amount of storage that could be reallocated was identified in the report. The study also included 22,600 acre-feet of storage reserved specifically for the city of Sherman, Texas, by Public Law 85-146, approved in August 1957. It should be noted that the storage in this report was based on the most current sedimentation survey at that time which indicated that remaining usable storage after 100 years of sediment would have been 3,338,000 acre-feet. The conservation pool was estimated to have 880,000 acre-feet of water storage remaining after 100 years of sedimentation (forecast to 2044).

**2.3.2 1985 Reallocation.** A reallocation of 77,400 acre-feet of hydropower storage to water supply storage was approved by the Assistant Secretary of the Army (Civil Works) in December 1985. This reallocation report addressed the impacts of reallocating up to a total of 150,000 acre-feet, inclusive of the 72,600 acre-feet reallocated and identified for reallocation in 1983, and served as the basis for a 75,000 acre-foot storage agreement with the NTMWD. It also identified and evaluated 2,400 acre-feet of storage for future use. The 1985 report addressed the impacts of the total reallocation (150,000 acre-feet) on the project to ascertain if the last added increment of water supply storage would seriously affect the purpose for which the project was constructed or if major structural or operational changes would have been necessary. It was determined that the reallocation would neither seriously affect other project purposes nor would it seriously affect any structural or operational changes needed.

**2.3.3 1992 Supplemental Reallocation Report to the 1983 Letter Report.** The 1992 supplemental reallocation report addressed the impacts of reallocating 5,500 acre-feet of Sherman's authorized 22,600 acre-feet of storage from conservation storage to water supply storage. National Environmental Policy Act (NEPA) documentation and public comment were accomplished under the 1985 Environmental Assessment (EA) and Finding of No Significant Impact (FONSI) for Regulatory Permit Application No. TXR3001311. A sedimentation study in 1992 conducted using a range-line survey methodology showed that there would be 3,589,620 acre-feet of usable storage remaining after 100 years of sediment. The conservation pool was estimated to have 1,114,909 acre-feet of storage remaining after 100 years of sediment. Based upon the new storage amounts, HQUSACE directed Tulsa District to redistribute the increased storage amounts in the water storage agreements that stated the user had the right to utilize a percentage of the usable storage space. When the storages were redistributed it was discovered that the 150,000 acre-feet that had been reallocated or identified for reallocation had been exceeded by over 8,000 acre-feet.

**2.3.4 1997 Supplemental Reallocation Report to the 1983 Letter Report.** In 1997, a supplemental reallocation report was accomplished to address not only the impacts of reallocating an additional 5,500 acre-feet of Sherman's authorized storage but to also address the impacts of reallocating the remaining 11,600 acre-feet. NEPA documentation in the form of an EA that included public comments and a hydrologic analysis for the entire 22,600 acre-feet was accomplished for that report and concluded in a FONSI. Coordination with the U.S. Fish and Wildlife Service, the Oklahoma Department of Wildlife Conservation, the Oklahoma and Texas Historical Societies, and the Oklahoma Archeological Survey concluded that there would be no impacts due to reallocation of the entire 22,600 acre-feet of storage. This reallocation did not require operational changes or construction modifications to the project.

**2.3.5 2004 Supplemental Reallocation Report to the 1983 Letter Report.** In 2002, the GTUA requested that the last of Sherman's 11,600 acre-feet of storage be placed under agreement. A supplemental reallocation report was accomplished and a determination made there were no significant changes in the project since the 1997 reallocation. The agreement was finalized in 2005 which placed all of Sherman's congressionally set aside storage under agreement. A volumetric sediment survey was done at Denison Lake in 2002 which showed there would be 3,598,169 acre-feet of usable storage remaining after 100 years of sediment. The conservation pool would have 986,730 acre-feet remaining at the end of the 100 year period. Tulsa District again redistributed storage based on percentages in each user's water storage

agreement. When the redistribution was done it showed that there would be 1,515 acre-feet of storage available from the previous 150,000 acre-foot reallocation. GTUA has requested to place this storage under agreement for use by the city of Pottsboro, Texas.

**2.4 Reservoir Storage.** The volume of storage in the reservoir is reduced by sedimentation. Sedimentation surveys have been completed at Lake Texoma in 1969, 1992, and 2002. From those surveys, estimates of storage remaining in the conservation pool for 100 years of sedimentation (2044) were estimated. Table 2 displays the year the sediment survey was conducted and the projected storage in the conservation pool between elevation 590.0 and 617.0 NGVD in year 2044.

**TABLE 2**

**CONSERVATION POOL STORAGE (Forecast to 2044)**

| Sediment Survey (year) | Conservation Pool Storage (Acre-feet) |
|---|---|
| 1969 | 880,000 |
| 1992 | 1,114,909 |
| 2002 | 986,730 |

As a result of the 2002 sediment survey, storages for each water supply user and project purpose have been adjusted in accordance with applicable storage agreement provisions or legislation. This information and data is summarized in Table 3. The U.S. Army Corps of Engineers, Tulsa District currently has three draft water storage agreements in the approval process. Two of these are the draft agreements for 100,000 acre-feet of storage with the NTMWD and 50,000 acre-feet of storage under the GTUA. The other draft agreement is for the 1,515 acre-feet requested by GTUA for the city of Pottsboro, Texas.

Assuming that the agreements evaluated for immediate need reallocation (150,000 acre-feet) are approved for final negotiations, the remaining balance of storage identified for reallocation under Sec 838 would be for Oklahoma (also 150,000 acre-feet). The total storage that would be available for Oklahoma communities would represent 15.202% of the conservation storage. Hydropower generation would have use of 69.6% of the conservation storage plus all of the supplemental power generation until Oklahoma executes a water storage agreement.

If all storage authorized for reallocation by Sec 838 is reallocated, the total water supply storage would be 450,000 acre-feet. At that time, 54.4% of the conservation storage would be available for hydropower generation. Supplemental power generation from flood control storage releases would continue to be produced.

**TABLE 3**

**LAKE TEXOMA USABLE STORAGE**
**(Forecast to 2044)**

| Purpose | Elevation (feet, NGVD) | Usable Storage (acre-feet) (1) | Usable Storage (percent) | Conservation Storage (percent) |
|---|---|---|---|---|
| Flood Control | 617-640 | 2,611,439 | 72.577 | |
| Conservation | 590-617 | 986,730 | 27.423 | 100.000 |
| Water Supply | | 300,000 | 8.338 | 30.403 |
| Denison | | 21,300 | 0.592 | 2.159 |
| TP&L | | 16,400 | 0.456 | 1.662 |
| RRAT | | 450 | 0.013 | 0.046 |
| RRAT | | 2,054 | 0.057 | 0.208 |
| NTMWD | | 85,406 | 2.374 | 8.655 |
| GTUA (2) | | 5,500 | 0.153 | 0.557 |
| GTUA (2) | | 5,500 | 0.153 | 0.557 |
| Buncombe Creek View | | 0.3 | 0.000008 | 0.00003 |
| GTUA(2) | | 11,600 | 0.322 | 1.176 |
| OTRD | | 275 | 0.008 | 0.028 |
| GTUA(4) | | 1,514.7 | 0.042 | 0.154 |
| NTMWD (Pending(3)) | | 100,000 | 2.779 | 10.134 |
| GTUA (Pending) (3) | | 50,000 | 1.39 | 5.067 |
| Hydropower(5) | | 686,730 | 19.086 | 69.597 |
| Total Usable Storage | | 3,598,169 | 100.000 | |

Notes:
(1) Storage remaining after 100 years sedimentation from the date the project became operational based on the 2002 sediment survey.
(2) Public Law 85-146 states rights to storage for Sherman, Texas. Actual law states 41,000 acre-feet, but withdrawal is limited. Amount shown reflects the conservation storage required for the withdrawal limitation during critical hydrologic period.
(3) Section 838 of Public Law 99-662 authorizes the Secretary of the Army to reallocate up to 300,000 acre-feet of storage for water supply from hydropower. Total allocated available water supply is 450,000.
(4) GTUA has requested the remaining 1,515 acre-feet of storage identified for reallocation from the 1985 reallocation; storage will be used for water supply for the town of Pottsboro
(5) Storage authorized for reallocation for the State of Oklahoma by Sec 838 would be reallocated from the hydropower purpose in conservation pool storage.

**2.5 Future Reallocation Policy.** A reallocation report is separate from a reallocation action. A report may include future needs, but a reallocation action can only be in the context of satisfying immediate needs. An immediate need can be defined as the amount of storage the sponsor will make payment for immediately. A reallocation action is not complete until a water storage agreement for those immediate needs is approved. When the need for reallocation or addition of storage at a project first arises, districts are encouraged to survey not only the immediate water needs but should include the water needs for the next 15-20 year planning horizon, although such need may be met through several reallocation actions over a period of several years. This entire need is to be put into one reallocation report. Agreements submitted after approval of the original reallocation report will be accompanied by the original approved report with information showing the changes in impacts (if any) since the time of the report. The new information will also determine the price of storage in the new agreement. (Water Supply Handbook, IWR Report 96-PS-4)

Need for Lake Texoma Reallocation. Subsequent to the initial requests for storage reallocation by the GTUA and the NTMWD, the Corps initiated a reallocation study. In compliance with the general policy above, the Corps sought to determine if other water needs from Texas or Oklahoma could be identified for inclusion in a 15-20 year planning horizon for the purpose of presenting the entire need in one reallocation report. The following discussion summarizes the findings in regard to immediate needs and the planning horizon for Oklahoma and Texas.

- Texas. The GTUA intends to make immediate payment for 50,000 acre-feet of storage and the NTMWD intends to make immediate payment for 100,000 acre-feet of storage. The willingness of the sponsors to make immediate payments defines the reallocation of 150,000 acre-feet to Texas as an immediate need. No additional needs were identified in the planning horizon.

- Oklahoma. No immediate need has been identified for a reallocation action for Oklahoma and no need has been identified within the planning horizon. However, the provisions of Section 838 of the 1986 WRDA and of the Red River Compact were critical in defining the scope of the reallocation study for potential reallocation for Oklahoma. The scope of study would inherently include the evaluation of potential impacts that would result from the immediate reallocation of 150,000 acre-feet to Texas, but because of the provisions of the law and compact, the evaluation was expanded to include an assessment of potential impacts of reallocation of the 150,000 acre-feet to Oklahoma. That additional assessment was considered important for recognizing potential (although not immediate) impacts of an eventual reallocation of 150,000 acre-feet to Oklahoma and the cumulative impacts that would potentially be associated with a total reallocation of 300,000 acre-feet under the provisions of the 1986 WRDA.

Because Section 838 specifically allocates equal total amounts of storage to Oklahoma and Texas, and because of the provisions of the Red River Compact that also equally distribute storage between Oklahoma and Texas for Lake Texoma, this reallocation report evaluates both the immediate need for reallocation of 150,000 acre-feet to Texas and the potential impacts to all reservoir purposes and potential economic, environmental, and social impacts for an ultimate

reallocation under the provisions of Sec 838 of 300,000 acre-feet. No future reallocations were identified or evaluated beyond the planning horizon or the storage reallocation provisions of Sec 838.

**2.6 Additional Project Information**. The NTMWD has requested a 100,000 acre-foot water storage agreement from the Texas allocation under Section 838. The other storage available under the Texas allocation is 50,000 acre-feet specifically set aside for the GTUA. The GTUA has requested a 50,000 acre-feet water storage agreement. Letters from GTUA and NTMWD indicate their need for additional water supply storage and their intent to sign agreements for storage at Lake Texoma. In anticipation of increased demand and approval by the ASA (CW) of this reallocation report and water storage agreements, the North Texas Municipal Water District is analyzing plans for a future desalinization plant and has received permits from the state of Texas for disposal of the plant products. Normal business practices require that future storage agreements are in place in order to obtain funding necessary to build the plant. The city of Dallas, Texas, has also contacted the U.S. Army Corps of Engineers, Tulsa District, on numerous occasions concerning available storage from Lake Texoma, but has been informed that there is no additional storage available from the Texas allocation. Oklahoma has shown no interest in contracting for storage authorized by Sec 838.

**2.6.1 Oklahoma and Texas Apportionment.** A related issue being addressed in the reallocation study is the apportionment of water supply between Oklahoma and Texas. The State of Oklahoma has raised an issue regarding previous allocations and whether additional contracts with entities in the State of Texas would be contrary to the terms of the Red River Compact. The Corps has determined that the reallocation authorized by the Sec 838 does not provide a basis for altering existing allocations or contracts with any Oklahoma or Texas entity, nor do the existing contracts with Texas provide a basis to diminish the amount of the reallocation made available to entities in the State of Texas for future water supply storage contracts to less than that specified in Sec 838. The Oklahoma Water Resources Board's letter to the Corps of Engineers dated May 25, 2004, addressed the issue of apportionment and is enclosed in Appendix C.

Section 838(a) of the 1986 WRDA specifically authorizes the reallocation from hydropower storage to water supply storage, in increments as needed, up to 150,000 additional acre-feet for users in the State of Texas and 150,000 additional acre-feet for users in the State of Oklahoma. With regards to the Texas portion of that reallocation, the statute further specifies at 838(c) that the Secretary "shall contract, in increments as needed, for 50,000 acre-feet with the Greater Texoma Utility Authority and 100,000 acre-feet with other qualified individuals, entities, or water utility systems." The statute contains no language that could be construed as limiting the amounts specified for reallocation. The language of Section 838 provides one course of action through which each State has up to the 150,000 acre-foot reallocation specified therein.

Previous allocations or actual agreements entered into for water supply storage do not affect the amount to be made available to each State under the reallocations specified in Section 838. Conversely, the reallocations specified in Section 838 do not affect or alter the allocations previously made and/or agreements previously entered into with any entity. Because there is a greater volume of remaining conservation storage than the total volume of storage that is under consideration for reallocation to Texas for water supply storage, the provisions of the Red River

Compact are satisfied and an equal distribution of storage has been maintained. All remaining conservation storage would be available for hydropower generation.

Section 838(e) of the 1986 WRDA states that "[n]othing in this section shall be construed as amending or altering in any way the Red River Compact." Section 4.04 of the Red River Compact provides that, with regard to the main stem of the Red River and Lake Texoma, water storage therein is apportioned among the signatory states with 200,000 acre-feet for Oklahoma and 200,000 acre-feet for Texas, and any additional quantities at a ratio of 50% for Oklahoma and 50% for Texas. In a letter dated May 5, 2004, the state of Oklahoma contends that the Red River Compact apportions the storage of Lake Texoma and flow of the mainstem of the Red River into Lake Texoma on a 50-50 basis between the states of Oklahoma and Texas. The letter states, "Any reallocation of storage of Lake Texoma must be consistent with the apportionment provisions of the compact."

The Corps is not "amending or altering" the terms of the Red River Compact or any other contract by complying with Sec 838. The Red River Compact is an agreement between the signatory states. Accordingly, the U.S. is not responsible for the administration or the enforcement thereof. If either Oklahoma or Texas takes action that is contrary to the Red River Compact, it will be the responsibility of the States to address those actions.

The approach to evaluate the reallocation of 150,000 acre-feet of storage for immediate needs and to further evaluate an additional 150,000 acre-feet of storage for Oklahoma is consistent with NEPA with regard to cumulative impact analysis. It is also Corps policy to evaluate the authorized storage when larger than an initial request because the resources required to evaluate and document necessary reallocation studies and to prepare NEPA documentation would be essentially the same for one or both storage evaluations.

**2.6.2 Hydrologic Data Information**. The determination of dependable water supply yield was calculated using the Corps SUPER Model. The SUPER modeling tool can simulate flood control operations and conservation pool operations, including hydropower, water supply, water quality, diversions, and returns. In addition to modeling dependable yield, it also was used for baseline data in calculating hydropower energy changes. This hydrologic information was used by the U.S. Army Corps of Engineers Northwestern Division Hydropower Analysis Center (HAC) in its Power Benefits Foregone Water Supply Storage Reallocation Report, April 2005. Findings of the SUPER model simulation indicated that a critical dependable yield of 295 million gallons per day (mgd) would be available from the proposed 300,000 acre-foot reallocation. The Hydrologic SUPER model Hydrology and Hydraulics (H&H) Storage Yield Analysis report is attached as Appendix D.

**2.6.3 Hydropower Credit Guidance.** The Corps has determined that Sec. 838(d)(3) does not bar the application of current policy on hydropower credit, and will therefore follow the policy in Appendix E, Section VIII, of ER 1105-2-100. Under that policy, the SWPA would be credited for replacement costs through the remaining period of its current power contracts and thereafter credited for revenues forgone for the remainder of a 50-year credit period. Because the amortization period for water storage agreement (the Treasury source of credits in this instance) is 30 years, the present value of the revenues forgone for the 50-year period would be annualized over 30 years. However, because there are power contracts between the Federal power

administration and its customers that require credit based on the cost of acquisition of replacement power through 2018 (9 years), then the credit for revenue foregone would be based on the remaining period within a 50-year total credit period. To summarize, credits for the first nine years would be replacement costs and credits for the remaining 21 years of the water supply payments would be based on 41 years of hydropower revenue foregone that would be amortized over the 21 years of remaining Treasury revenue from the water storage agreement payments. Because the balance of the Lake Texoma hydropower Treasure account will be repaid within only a few years of hydropower revenues (from the sale of power) and hydropower credits (from water storage agreement payments), the Corps has determined that the hydropower credits may be distributed by the SWPA to other projects at their discretion. In this way the water storage agreement payments from Lake Texoma will assist in repaying the cost of hydropower facilities and hydropower operations at projects where the SWPA has generation facilities and has not yet repaid the Treasury debt.

## 3.0 PROBLEMS AND NEEDS

### 3.1 Water Supply and Demand Analysis.

**3.1.1. Introduction.** The demand for water in the region and the current and potential water supply to meet future needs is based on the Oklahoma Comprehensive Water Plan and the Texas State Water Plan.

No immediate water demand has been identified for the Oklahoma portion of the study area, either in adjacent counties or major metropolitan areas; however, desires to preserve Oklahoma water resources at Lake Texoma are specified in the Red River Compact. The Oklahoma Southern Region sub-state regional water planning districts (not shown) represent the region around Lake Texoma. This region consists of Atoka, Bryan, Carter, Coal, Garvin, Johnston, Love, Marshall, Murray, and Pontotoc counties in Oklahoma.

The Texas portion of the study area includes the counties and water systems or districts in the north Texas region that are currently using Lake Texoma water or may use Lake Texoma water in the future. The North Texas region is defined as Regional Water Planning Group, Region C, which includes Grayson County adjacent to Lake Texoma mainly in the Red River Basin, and the Dallas-Fort Worth metropolitan area, lying mostly in the Trinity River Basin.

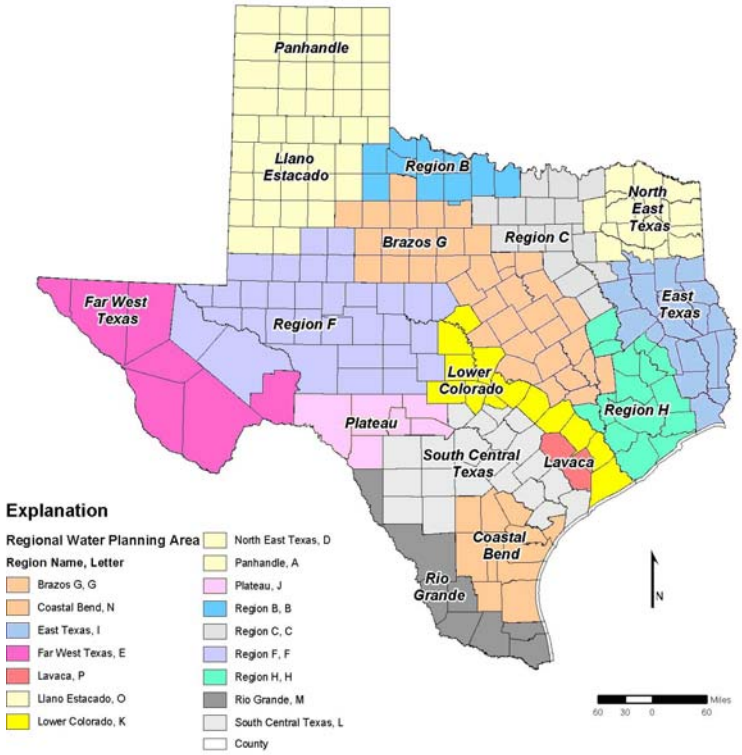
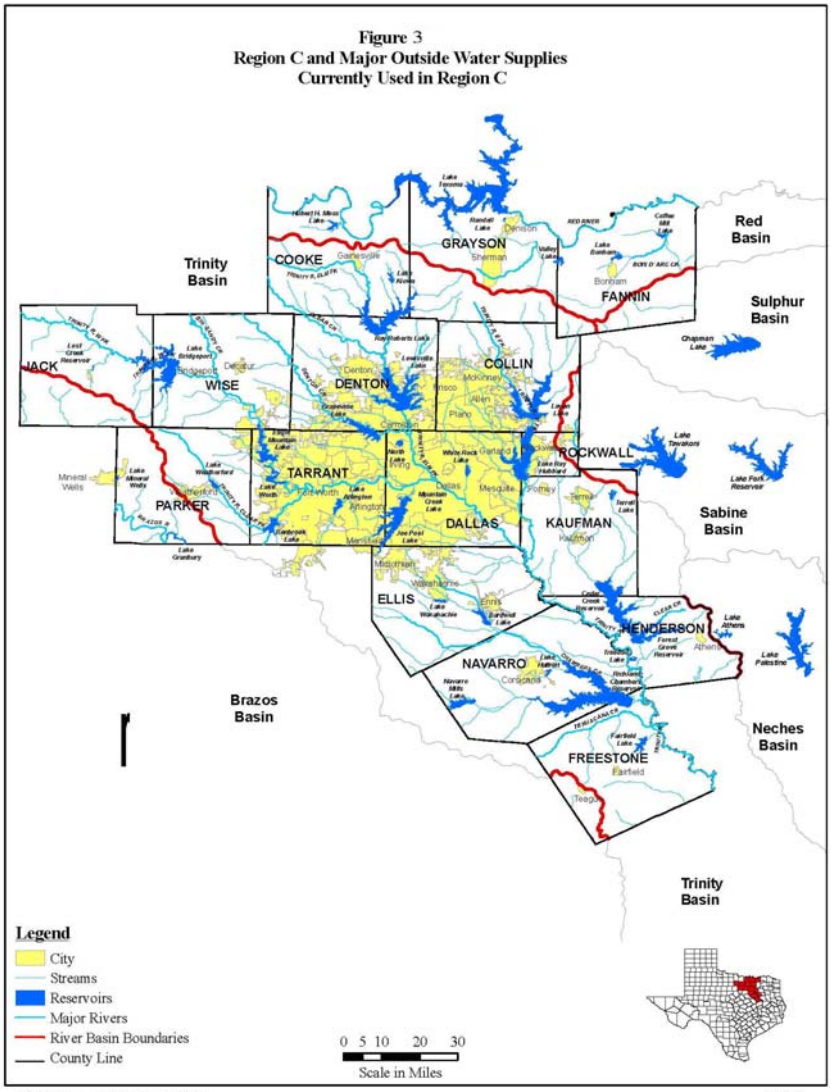



Figure 2
Texas Water Development Board Regional Water Planning Areas

The evaluation of water supply and demands for water in the Texas region utilized the "*Initially Prepared Texas State Water Plan for Region C 2006*," June 2005 draft. The data and information in that report are consistent with both the 2006 Region C Water Plan and the draft 2007 State Water Plan, which was adopted by the Texas Water Development Board (TWDB) on 14 November 2006. The 15 regional plans for Texas that were adopted by the Regional Water Planning Groups (RWPG) were delivered to the TWDB in January 2006. This plan was posted in May 2006 to the website, http://www.twdb.state.tx.us/RWPG.




*2006 Region C Water Plan* ES.2

There are over 34 reservoirs in Texas Region C with conservation storage pools exceeding 5,000 acre-feet. Additional reservoirs outside the region also provide water supply to the region. Sources include groundwater, surface sources, and water reuse. Although use of groundwater has been decreasing, the Trinity Aquifer supplies most of the groundwater used in this region, mainly in rural areas. Ninety percent of the total water supplied in the region is from surface sources. Municipal supply accounts for about 85% of current water use. Little wastewater is treated and returned for use, although municipalities are considering reuse as a source of future supply. In addition to the Greater Texoma Utilities Authority (GTUA) serving the Sherman-Denison communities in Grayson County, there are five major water providers in the region. They are: a) North Texas Municipal Water District (NTMWD), b) Dallas Water Utilities (DWU), c) Tarrant Regional Water District (TRWD), d) the city of Fort Worth, and e) the Trinity River Authority (TRA). Since the NTMWD and the GTUA have requested additional water supply storage at Lake Texoma, existing and potential sources of water supply for the NTMWD and the GTUA are discussed below.

Future Oklahoma demand for quality water is dependent on geographical locations within Oklahoma, with ample sources of water being abundant in the eastern portions of the region and relatively scarce in the western portions. The Oklahoma Water Resources Board (OWRB) and the U.S. Army Corps of Engineers, Tulsa District, are in the process of determining future demands for water and sources of water supply for inclusion in the Oklahoma State Water Plan, which is expected to be completed by 2011.

**3.1.2 Water Demand**. Although all 16 counties in Region C are evaluated in the Texas State Water Plan, five counties (Collin, Dallas, Denton, Grayson, and Tarrant) stand out for comparative purposes relative to probable future use of Lake Texoma water. There are 35 wholesale water providers and 351 water user groups in Region C. Major water providers serve all or portions of other counties as well. These counties have as their major providers of water the NTMWD (Collin County), the DWU (Dallas County), and the GTUA (Grayson County). Two other counties, Denton (DWU) and Tarrant (TRWD), also account for expected large future municipal water demands. Water conservation is also built into the demand projections. Currently implemented water conservation strategies and water conservation assumption are implicit in the water demand projections for the region.

Table 4 shows historical and forecasts future water demand for selected counties in Region C. These counties represent the majority of the demand for water in the region. By 2010, it is expected that about 1,768,464 acre-feet of water will be demanded in Region C, of which 1,534,703 acre-feet is municipal, according to the 2006 Water Plan.

**TABLE 4**

**HISTORICAL AND PROJECTED WATER DEMAND BY SELECTED COUNTIES (acre-feet)**

| County | Year | | | | |
|---|---|---|---|---|---|
| | **2000** | **2010** | **2020** | **2040** | **2060** |
| Collin | 138,316 | 211,501 | 287,247 | 402,383 | 526,315 |
| Dallas | 623,535 | 714,952 | 785,788 | 879,106 | 1,055,030 |
| Denton | 93,982 | 162,003 | 212,211 | 307,951 | 406,700 |
| Grayson | 32,478 | 38,656 | 45,954 | 55,613 | 66,715 |
| Tarrant | 311,066 | 399,714 | 451,536 | 559,650 | 718,098 |
| | | | | | |
| Total | 1,199,377 | 1,526,826 | 1,782,736 | 2,204,703 | 2,772,858 |
| Region C Total | 1,380,556 | 1,768,464 | 2,100,519 | 2,622,513 | 3,311,217 |
| Municipal | 1,196,452 | 1,534,703 | 1,828,831 | 2,294,491 | 2,915,773 |

Source: Region C Water Plan 2006.

An analysis of the 2006 Regional Water Plan Region C, which was incorporated into the 2007 Texas Water Plan, includes a detailed analysis of the future water supply needs of the region served by Lake Texoma. That plan identifies Lake Texoma as a primary water supply source for Texas State Planning Region C. Between 2010 and 2060 the population of the region is projected to grow 98%, from 6,625,000 to 13,087,849. The water plan projected an 87% increase in Region C long term water demand, a 1,540,700 acre-feet increase, between years

2010 and 2060. In addition, recent analysis by the Texas State Demographer indicates that population projections used in the State Water Plan for the Region C area are already outdated and underestimate population trends for the Region. The total population of Region C on January 1, 2008 was 6,539,000. Water demand in Region C is expected to increase proportional to population increases.

Information from the Texas Water Plan clearly demonstrates both short and long term needs for Lake Texoma water supply storage. The Water Plan projects an increase in needs of 611,000 acre-feet of water, based on existing water supply and future demands from 2010 to 2030 for Region C.

The State of Texas Water Plan projected the water demand for region C to be 1,768,464 acre-feet in 2010. Short term water supply needs through year 2010 indicates that there is a deficit of 254,451 acre-feet in region C based on connected supply. This deficit will rise to 1,931,933 acre-feet by year 2060. Municipal water demand accounts for about 89 percent of the deficit. Current deficits are being met through conservation and temporary interim water management strategies.

Long range projections identify that the needs will continue to increase through the year 2060. The plan identifies Lake Texoma as an existing and primary source to provide an additional 100,000 acre-feet of water supply storage by 2010. Based on immediate short term demand, the NTMWD has requested 100,000 acre-feet of storage in Lake Texoma. Fifty thousand acre-feet of storage has been requested by the GTUA. Appendix B of the Reallocation Report contains letters from GTUA and NTMWD indicating their need for additional water supply storage and their intent to sign approved agreements for storage at Lake Texoma. In anticipation of increased demand and approval by the Assistant Secretary of the Army (Civil Works), ASA (CW), of the reallocation report and water storage agreements, the North Texas Municipal Water District is analyzing plans for a future desalinization plant and has received permits from the state of Texas for disposal of the plant's products. Normal business practices require that future storage agreements are in place in order to obtain funding necessary to build the plant.

While the population and water demand in Region C are expected to continue to increase, as discussed above, the total water supply of Region C is projected to decline by approximately 10%, between 2010 and 2060, from 1,979,727 acre-feet to 1,906,007 acre-feet. Existing reservoirs provide nearly 60% of total water supply in the region. About 28 percent of the water used in Region C is imported from other regions. The State Water Plan identifies four new major reservoirs at a capital cost of $13.2 billion in 2002 dollars, and also acknowledges that this water management strategy could prove difficult to implement due to cost and regulatory requirements. Being an existing current source of water for both NTMWD and GTUA, Lake Texoma water supply storage is the most realistic and economically viable water supply alternative for these entities that serve the region.

**3.2 North Texas Municipal Water District.** The NTMWD supplies wholesale water and wastewater service to member cities and customers in Collin, Denton, Fannin, Dallas, Rockwall, Hunt, and Kaufman counties in north-central Texas. The cities of Plano, Richardson, Garland, Mesquite, and McKinney are a few of the larger municipalities receiving all or part of their

service from the NTMWD. Water demand is expected to double between 2010 and 2060, with a shortage of about 100,000 acre-feet by 2010, based on current available supplies, increasing to 534,000 acre-feet by 2060. The main water treatment plant for the NTMWD is located near Lake Lavon. The NTMWD receives its surface water supply from three primary sources, Lake Lavon, Cooper Lake, and Lake Texoma.

### 3.2.1 Existing Sources of Water Supply: NTMWD

**Lake Lavon.** Lake Lavon is located on the East Fork of the Trinity River approximately 1 mile northwest of Lavon, Texas, in Collin County. The Corps of Engineers built Lake Lavon in 1953 for flood control and water supply. The lake has conservation storage of 380,000 acre-feet with a dependable yield of about 92.0 mgd. The entire yield is allocated and contracted to the NTMWD which has a water right to 104,000 acre-feet of storage. The lake also receives up to 24.0 mgd of effluent from the Wilson Creek Wastewater Treatment Plant and is the receiving point for inter-basin transfers of water from Lake Texoma and Lake Cooper. Facilities are in place to utilize the entire available yield of Lake Lavon.

**Jim Chapman Lake/Cooper Dam.** Jim Chapman Lake/Cooper Dam is a Corps of Engineers reservoir on the South Sulphur River, 4 miles southeast of Cooper, Texas, in Hopkins and Delta counties. Jim Chapman Lake was completed in 1992. The reservoir has conservation storage of 273,120 acre-feet with a dependable yield of ±107.1 mgd. The NTMWD, the city of Irving, and the Sulphur River Water District (SRWD) hold water rights in Lake Chapman totaling 146,250 acre-feet per year, of which 127,320 acre-feet per year can be exported for use in Region C. The NTMWD receives 57,214 acre-feet per year; the city of Irving, 54,000 acre-feet per year; and the Upper Trinity Regional Water District (UTRWD) (purchased from the SRWD), 16,106 acre-feet per year. The SRWD has contracted a portion of its yield to the UTRWD for use in the Denton County, Texas, area. Currently available water from Lake Jim Chapman for the NTMWD is 50,802 acre-feet per year in 2000 decreasing to 45,843 acre-feet per year by 2060. The city of Irving receives 47,948 acre-feet per year in 2000 decreasing to 43,268 acre-feet in 2060. Finally, the UTRWD receives 14,301 acre-feet per year in 2000 decreasing to 12,905 acre-feet per year by 2060. Each entity is permitted to divert at a maximum rate of 122% of allocated yield. The NTMWD has facilities in place to transfer up to 110 mgd of water from Cooper Lake to Lake Lavon.

**Lake Texoma.** Lake Texoma, on the Red River near Denison, Texas, is the third surface water source utilized by the NTMWD. The reservoir has 1,467,000 acre-feet of conservation storage. Lake Texoma is expected to have 986,730 acre-feet of conservation storage by year 2044. The RRAT, the GTUA, the city of Denison, the NTMWD, and Texas Utilities (TXU) have water rights in Lake Texoma. Lake Texoma water is pumped and then gravity flowed to Lake Lavon and blended for subsequent use. The NTMWD has contractual rights to divert up to 77,300 acre-feet or about 75.0 mgd of water from Lake Texoma. Other entities that have storage at Lake Texoma are the GTUA, acting for the city of Sherman, Texas, 22,600 acre-feet; the city of Denison, 21,300 acre-feet; the TXU, 16,400 acre-feet; and the RRAT, 2,473 acre-feet.

Groundwater sources for the NTMWD area are of poor quality or limited quantity and, therefore, are not considered adequate potential sources of water supply.

The total current available supplies identified by the Texas Water Plan for the NTMWD in year 2010 are 257,854. These supplies come from the following existing water supply sources:

| Source | Acre-Feet |
|---|---|
| Lake Lavon | 104,000 |
| Lake Texoma | 77,300 |
| Lake Chapman | 49,976 |
| Wilson Creek Reuse | 35,941 |
| Lake Bonham | 3,800 |
| Treatment and Distribution losses | (13,163) |
| Total Existing Water Sources: | 272,557 |

**3.2.2 Potential Sources of Water Supply: NTMWD.** Major regional wholesale water providers, such as the NTMWD, the DWU, the TRWD, and the UTRWD, have similar strategies. These strategies include water conservation, reuse water, installation of connections to existing sources already under contract, connection to other existing sources, and development of new reservoirs. In the Region C Water Plan, three new reservoirs are proposed: Muenster Reservoir (Cooke County), Lake Ralph Hall (Fannin County), and Lower Bois d'Arc Reservoir (Fannin County). Lower Bois d'Arc, formerly known as New Bonham Reservoir, will provide supplies for the NTMWD. The water plan also includes two lakes outside the region that will provide supplies to the region, Marvin Nichols Reservoir and Fastrill Reservoir. Even with these and other recommended projects, the 2006 Region C Water Plan shows that supplies are needed from Lake Texoma. Toledo Bend Reservoir and Oklahoma water are possible sources of new supply for the NTMWD, as well as for the other major providers. Oklahoma water remains a promising source of supply for the North Texas region although the Oklahoma legislature has a current moratorium on export of water from the state. Although the long term (year 2060) recommended strategy in the Water Plan is to consider Oklahoma water as an additional source of water supply for the TRWD and the NTMWD, discussions with the State of Oklahoma have precluded this water being available to meet immediate needs. Oklahoma water is also considered an alternate strategy for the DWU and the city of Irving if the water becomes available in the future.

**3.2.3 Water Supply Alternatives: NTMWD.** Water supply alternatives other than those joint efforts discussed above are:

- **NTMWD Conservation.** Conservation is the projected conservation savings for the NTMWD's existing and potential customers based on the Region C recommended water conservation program.

- **Interim Treated Water Purchase from Dallas Water Utilities.** The NTMWD is negotiating with the DWU to purchase an annual average of up to 10 mgd (11,210 acre-feet per year) of treated water.

- **Additional Wilson Creek Reuse Project.** The NTMWD currently has a water right allowing the reuse of up to 35,941 acre-feet per year (32 mgd) of actual discharges from the Wilson Creek Wastewater Treatment Plant.

- **East Fork Reuse Project.** The NTMWD has applied for a water right to divert treated wastewater from the East Fork of the Trinity River near Crandall. The estimated supply available from this project will increase with increasing wastewater flows to 102,000 acre-feet per year.

- **Additional Lake Lavon Yield.** The NTMWD currently has a water right allowing the diversion of up to 104,000 acre-feet per year from Lake Lavon (in addition to water delivered to the lake from return flows, Lake Texoma, and Lake Chapman).

- **Interim Purchase of Lake Texoma Water from GTUA/Sherman.** The NTMWD has reached an agreement with the city of Sherman and the GTUA to purchase surplus Lake Texoma water.

- **Upper Sabine Basin Supply.** The NTMWD is negotiating with the Sabine River Authority to divert water from Lake Tawakoni or Lake Fork on an interim basis.

- **New Supply from Lake Texoma.** The NTMWD has requested a contract for additional storage in Lake Texoma from the U.S. Army Corps of Engineers, Tulsa District and has applied for a Texas water right to impound up to 100,000 acre-feet in Lake Texoma and divert up to 113,000 acre-feet per year from the lake. The U.S. Congress has authorized the reallocation of 150,000 acre-feet of storage in Lake Texoma from hydroelectric power generation to municipal use in Texas, with 50,000 acre-feet per year reserved for the GTUA. The NTMWD has expressed interest in an agreement for 100,000 acre-foot reallocation for municipal use not reserved for the GTUA and would blend the water with higher quality supplies from other sources or develop a desalination plant. At this time, blending appears to be the more economical approach. It is assumed that the NTMWD will use one part of Lake Texoma supply for four parts of other imported water. The NTMWD would deliver the water directly from Lake Texoma and/or from the Red River downstream of the lake. (Downstream diversions would require a longer pipeline but offer the advantage of reduced levels of dissolved solids.)

- **Lower Bois d'Arc Creek Reservoir.** The Lower Bois d'Arc Creek Reservoir is a proposed reservoir on Bois d'Arc Creek in the Red River Basin. It was included in the 2001 Region C Water Plan as a supply for the NTMWD, and the NTMWD has continued to study the project. The Lower Bois d'Arc Creek Reservoir would provide up to 123,000 acre-feet per year for the NTMWD and Fannin County. The Lower Bois d'Arc Creek Reservoir would be developed by 2020.

- **Fannin County Water Supply System.** The NTMWD would cooperate with Fannin County entities to develop a treated water supply system for Fannin County water users after the Lower Bois d'Arc Creek Reservoir is developed in 2020.

- **Marvin Nichols Reservoir** is another potential two-stage impoundment on the Sulphur River and White Oak Creek in southwestern Bowie and Morris counties. The total yield of water supply is about 612,300 acre-feet per year, assuming that Ralph Hall Lake is senior to Marvin Nichols Reservoir and that Marvin Nichols

Reservoir is operated as a system with Lake Wright Patman. With about 489,430 acre-feet available for Region C, the NTMWD share would be about 174,840 acre-feet, while the TRWD would receive the largest amount at 280,000 acre-feet per year. Phase 1 would be developed by 2030 and Phase 2 by 2050. Most of the cost is in the pipelines and pump stations.

- **Toledo Bend Reservoir** in East Texas is recommended for the TRWD and the NTMWD as a primary strategy and for the DWU and the UTRWD as an alternate strategy. NTMWD's share would be 200,000 acre-feet per year of the total 500,000 acre-feet available by 2050.

- **Oklahoma water** remains a promising source of supply for the North Texas region although the Oklahoma legislature has a current moratorium on export of water from the state.

**3.2.4 Summary of Water Supply Alternatives: NTMWD.** Nearly 790,000 acre-feet per year of new supplies are recommended in the Region C water plan for the NTMWD, leading to a total supply of 1.01 million acre-feet per year in 2060. A summary of current water supplies and potential water management alternatives or strategies and projected demand is presented in Table 5. Interpolation of data in Table 5 for year 2015 would indicate that about 169,551 acre-feet of water would be required from new sources of supply. Some existing sources of water supply would diminish over time due to sedimentation. Projected demands exceed current available supplies as shown in Table 5 requiring the consideration of alternative water management strategies over time. Table 5 shows potential sources of water as identified and prioritized by the Region C Water Plan.

Costs for the water supply alternatives identified are shown in Table 6. The water management strategy for Region C, prepared for the Region C Water Planning Group by Freese and Nichols, Consulting Engineers, and others, anticipates additional Lake Texoma storage would be required by year 2015. Capital costs for the alternatives would typically be financed by 30-year bonds. Pre-amortization costs refer to the 30-year period during which debt service payments on the bonds are being made. Post-amortization costs refer to the period after the bonds are paid off and there are no debt service costs (but operational costs would continue). Three new major reservoirs are presented that might be built in the future at a cost of $3.3 billion. However, the plan acknowledges that implementation of the construction part of the strategy could be difficult due to cost and regulatory requirements. Table 6 illustrates the cost per thousand gallons for each of the water supply alternatives in the strategy. As shown in the table, an additional reallocation at Lake Texoma would occur before the construction of the new reservoirs. The low cost and availability of Lake Texoma storage makes this strategy the preferred choice over the yet to be constructed reservoirs.

**TABLE 5**

**SOURCES OF WATER SUPPLY AND WATER DEMAND BY DECADE**
**RECOMMENDED WATER MANAGEMENT STRATEGIES**
**NORTH TEXAS MUNICIPAL WATER DISTRICT**
**(acre-feet)**

| | Year | | | | | |
|---|---|---|---|---|---|---|
| **Source** | **2010** | **2020** | **2030** | **2040** | **2050** | **2060** |
| **Existing Sources** | | | | | | |
| Lake Lavon | 104,000 | 104,000 | 104,000 | 104,000 | 104,000 | 104,000 |
| Lake Texoma | 77,300 | 77,300 | 77,300 | 77,300 | 77,300 | 77,300 |
| Lake Chapman | 49,976 | 49,150 | 48,324 | 47,498 | 46,672 | 45,843 |
| Wilson Creek Reuse (permitted) | 35,941 | 35,941 | 35,941 | 35,941 | 35,941 | 35,941 |
| Lake Bonham | 3,800 | 3,800 | 3,800 | 3,800 | 3,800 | 3,800 |
| Treatment & Distribution Losses | (13,163) | (13,122) | (13,120) | (13,770) | (12,553) | (12,714) |
| Total | 257,854 | 257,069 | 256,245 | 254,769 | 255,160 | 254,020 |
| Projected Demands | 371,170 | 482,856 | 567,856 | 650,027 | 722,158 | 799,386 |
| Surplus or (Shortage) From Existing Sources | (113,316) | (225,787) | (311,611) | (395,258) | (466,998) | (545,366) |
| **Potential Sources/Strategies** | | | | | | |
| Conservation | 12,638 | 33,936 | 47,866 | 60,800 | 72,991 | 86,114 |
| Interim DWU Supply | 11,210 | 11,210 | 0 | 0 | 0 | 0 |
| Wilson Creek Reuse (new) | 26,956 | 35,941 | 35,941 | 35,941 | 35,941 | 35,941 |
| East Fork Reuse | 81,400 | 96,400 | 102,000 | 102,000 | 102,000 | 102,000 |
| Additional Lake Lavon Yield | 11,000 | 10,000 | 9,000 | 8,000 | 7,000 | 6,000 |
| Interim GTUA Supply | 20,000 | 0 | 0 | 0 | 0 | 0 |
| Upper Sabine Basin | 50,000 | 30,000 | 20,000 | 10,000 | 10,000 | 10,000 |
| Additional Lake Texoma Reallocation | 0 | 38,250 | 57,105 | 54,105 | 100,460 | 112,460 |
| Lower Bois d'Arc Creek Reservoir | 0 | 123,000 | 121,000 | 119,000 | 117,000 | 115,000 |
| Marvin Nichols Reservoir | 0 | 0 | 87,420 | 87,420 | 174,840 | 174,840 |
| Toledo Bend Phase 1 | 0 | 0 | 0 | 0 | 100,000 | 100,000 |
| Oklahoma Water | 0 | 0 | 0 | 0 | 0 | 50,000 |
| Treatment and Distribution Losses | (10,028) | (17,240) | (21,623) | (20,823) | (32,362) | (35,312) |
| Total Potential Supplies | 213,204 | 378,737 | 480,332 | 477,266 | 720,232 | 792,355 |
| | | | | | | |
| Total Supplies (including losses) | 461,030 | 618,566 | 714,954 | 711,212 | 943,030 | 1,011,063 |
| | | | | | | |
| Total from Conservation & Reuse | 156,935 | 202,218 | 221,748 | 234,682 | 246,873 | 259,996 |
| Percent from Reuse and Conservation | 34.0% | 32.7% | 31.0% | 33.0% | 26.2% | 25.7% |
| | | | | | | |
| Projected Demands | 371,170 | 482,856 | 567,856 | 650,027 | 722,158 | 799,386 |
| Surplus or (Shortage) From Existing and Potential Sources | 89,860 | 135,710 | 147,098 | 61,185 | 220,872 | 211,677 |

Source: Region C Water Plan 2006.

| TABLE 6<br><br>COSTS OF RECOMMENDED WATER MANAGEMENT STRATEGIES<br>NORTH TEXAS MUNICIPAL WATER DISTRICT | | | | | | |
|---|---|---|---|---|---|---|
| Potential Sources/Strategies | Develop Dates | Quantity for NTMWD (acre-feet/year) (mgd) | | NTMWD Share of Capital Cost($) | Unit Cost ($/kGal) | |
| | | | | | Pre-Amort | Post-Amort |
| Interim DWU Supply | 2006 | 11,210 | 10 | 1,350,000 | $0.75 | $0.72 |
| Wilson Creek Reuse (new) | 2005 | 35,491 | 32 | 1,150,000 | $0.01 | $0.00 |
| East Fork Reuse | 2010 | 102,000 | 91 | 288,879,000 | $0.92 | $0.21 |
| Additional Lake Lavon Yield | 2006 | 11,000 | 10 | 270,000 | $0.01 | $0.00 |
| Interim GTUA Supply | 2006 | 20,000 | 18 | 104,000 | $0.09 | $0.09 |
| Upper Sabine Basin | 2010 | 50,000 | 45 | 60,232,000 | $0.52 | $0.25 |
| Additional Lake Texoma Reallocation | 2015 | 113,000 | 101 | 201,829,000 | $0.58 | $0.18 |
| Lower Bois D'Arc Creek Reservoir | 2020 | 123,000 | 110 | 399,190,000 | $0.87 | $0.14 |
| Fannin County Water Supply System | 2020 | 0 | 0 | 55,458,000 | $1.96 | $0.52 |
| Marvin Nichols Reservoir | 2030 | 174,840 | 156 | 534,125,000 | $0.94 | $0.26 |
| Toledo Bend Phase 1 | 2050 | 200,000 | 179 | 886,002,000 | $1.56 | $0.57 |
| Oklahoma Water | 2060 | 50,000 | 45 | 128,898,000 | $0.95 | $0.37 |
| Treatment and Distribution Improvements | 2005-2060 | | N/A | 1,290,523,000 | N/A | N/A |
| Total Capital Costs | | | | 3,848,010,000 | | |

Source: Region C Water Plan 2006 (2002 prices levels).

### 3.3 Greater Texoma Utility Authority (GTUA)

The Greater Texoma Utility Authority, also known as "the Authority" or "GTUA," is a local political subdivision of the State and is governed by a Board of Directors. The Authority is a special-law district organized under Article XVI, Section 59, of the Texas constitution. The Authority operates under the provisions of Chapter 49 of the Texas Water Code. The Authority has no taxing power, but may incur debt by the issuance of bonds supported by revenues from the operations it finances. The Authority may enter into contracts to provide services for member cities and others when requested. The GTUA is located in Denison, Texas.

While the State Legislature may have enacted a law to authorize the Authority, the cities of Denison and Sherman actually created the district by a confirmation election held on August 19, 1979. Since that time, the cities of Bailey, Collinsville, Gainesville, Gunter, Howe, Leonard, Muenster, Pottsboro, Tioga, Tom Bean, Valley View, Van Alstyne, Whitesboro, and Whitewright have also joined as member cities of the Authority.

The Authority provides its member cities with assistance in financing and construction of water and wastewater facilities. The Authority may also be requested to provide operations services for water and wastewater facilities by member cities and others. The Authority has been designated as a cooperating local sponsor to negotiate with the U.S. Army Corps of Engineers for purchase of water from Lake Texoma on behalf of the cities in this area, which enables the

Authority, controlled by local municipalities, to have greater influence in obtaining future water supplies.

**3.3.1 Existing Sources of Water Supply: GTUA** Lake Texoma, on the Red River near Denison, Texas, is the primary surface water source utilized by the GTUA. The reservoir has 1,467,000 acre-feet of conservation storage. Lake Texoma is expected to have 986,730 acre-feet of conservation storage by year 2044. The RRAT, the GTUA, the city of Denison, the NTMWD, and Texas Utilities (TXU) have water rights in Lake Texoma. The GTUA, acting as an agent for Sherman, Texas, has contractual rights to divert up to 22,600 acre-feet of water from Lake Texoma. The 1986 WRDA reserves another 50,000 acre-feet for the GTUA. Lake Texoma water is pumped to a desalinization facility near the Grayson County Airport for treatment prior to distribution. Other entities that have storage at Lake Texoma are the city of Denison, 21,300 acre-feet; the TXU (TP&L), 16,400 acre-feet; NTMWD; 84,406 acre-feet; and the RRAT, 2,473 acre-feet.

**3.3.2 Potential Sources of Water Supply: GTUA** Lake Texoma, on the Red River near Denison, Texas, is the only potential surface water source that can be utilized by the GTUA at this time. Therefore, as discussed above, the GTUA relies on Lake Texoma for future supplies of water to serve its member cities.

Groundwater resources in Grayson County are of poor quality or limited quantity and, therefore, are not considered adequate potential sources of water supply. Groundwater resources are generally over-drafted as noted in the regional water plan. Table 7 shows the recommended water management strategies for GTUA as found in the regional water plan in 2006.

| TABLE 7<br>RECOMMENDED WATER MANAGEMENT STRATEGIES FOR GTUA<br>(acre-feet per year) | | | | | | |
|---|---|---|---|---|---|---|
| **Source** | **2010** | **2020** | **2030** | **2040** | **2050** | **2060** |
| **Existing Sources** | | | | | | |
| Lake Texoma (Potable) | 11,210 | 11,210 | 11,210 | 11,210 | 11,210 | 11,210 |
| Total | 11,210 | 11,210 | 11,210 | 11,210 | 11,210 | 11,210 |
| Projected Demands | 31,544 | 23,780 | 31,977 | 42,957 | 55,757 | 72,956 |
| Surplus or (Shortage) From Existing Sources | (20,334) | (12,570) | (20,767) | (31,747) | (44,547) | (61,764) |
| **Potential Sources/Strategies** | | | | | | |
| Customer Water conservation | 629 | 1,724 | 2,670 | 3,567 | 4,558 | 5,843 |
| Change Permitted Lake Texoma to Municipal or Industrial | 0 | 0 | 0 | 0 | 0 | 0 |
| Additional Lake Texoma (interim NTMWD Supply) | 20,000 | 0 | 0 | 0 | 0 | 0 |
| Collin-Grayson Municipal Alliance Pipeline Project | 3,481 | 9,672 | 14,544 | 17,886 | 29,453 | 40,979 |
| Additional Lake Texoma-Grayson county Water Supply Project (Phase 1) | 0 | 14,572 | 14,572 | 14,572 | 14,572 | 14,572 |
| Additional Lake Texoma-Grayson county Water Supply Project (Phase 2) | 0 | 0 | 0 | 11,557 | 11,557 | 11,557 |
| Total Supplies from Strategies | 24,110 | 25,968 | 31,786 | 47,582 | 60,140 | 72,951 |
| Total Supplies | 35,320 | 37,178 | 42,996 | 58,792 | 71,350 | 84,161 |
| Total from Conservation & Reuse | 3,567 | 6,084 | 7,642 | 9,760 | 11,159 | 14,801 |
| Percent from Conservation & Reuse | 10.1% | 16.4% | 17.8% | 16.6% | 15.6% | 17.6% |
| Projected Demands | 31,544 | 23,780 | 31,977 | 42,957 | 55,757 | 72,956 |
| Surplus or (Shortage) From Existing and Potential Sources | 3,776 | 13,398 | 11,019 | 15,835 | 15,593 | 11,205 |

Source: Region C Water Plan 2006

The costs for the GTUA recommended water management strategies as shown in the regional water plans are in Table 8, below.

**Table 8**

**Summary of Costs for GTUA Recommended Water Management Strategies**

| Strategy | Develop Dates | 2060 Quantity (acre-feet Per year) | Capital Cost ($) | Unit Cost ($/kGal.) | |
|---|---|---|---|---|---|
| | | | | Pre-Amort. | Post-Amort. |
| Change Permitted Lake Texoma Use to Municipal or Industrial | 2005 | 0 | $20,000 | N/A | N/A |
| Additional Lake Texoma (Interim NTMWD Raw Water Supply) | 2006 | 20,000 (in 2010) | $15,729,000 | $0.18 | $0.00 |
| Collin-Grayson Municipal Alliance Pipeline Project – Phase 1 | 2006 | 16,813 | $15,342,000 | $1.48 | $1.28 |
| Collin-Grayson Municipal Alliance Pipeline Project – Phase 2 | 2038 | 24,200 | $36,112,400 | $1.46 | $1.13 |
| Grayson County Water Supply Project – Phase 1 | 2020 | 14,572 | $168,787,000 | $4.55 | $1.96 |
| Grayson County Water Supply Project – Phase 2 | 2040 | 11,557 | $46,578,000 | $2.40 | $1.50 |
| **TOTAL CAPITAL COSTS** | | | **$282,568,400** | | |

Source: Region C Water Plan 2006 (2002 prices levels).

## 4.0 PLAN FORMULATION

This section documents a preliminary screening of measures for: (a) an identification of the most likely source for water supply, and (b) an identification of which storage reallocation, with options of flood control or conservation pool storage, would be most appropriate when considering economic, social, and environmental impacts of the potential reallocation. The identification of measures and the evaluation of measures and alternatives were guided by the Corps' Environmental Operating Principles (EOP) and the 12 Actions for Change. An assessment of how those Administration goals were applied is presented later in this report.

**4.1 Preliminary Alternatives**. During plan formulation the goal is to identify and perform an initial evaluation of preliminary measures and alternatives for water supply. Consideration of all reasonable alternatives is required under the Economic and Environmental Principles for Water and Related Land Resources Implementation Studies. The National Environmental Policy Act (NEPA) requires Federal agencies to incorporate environmental considerations in their planning and decision-making process and requires the use of a systematic and interdisciplinary approach. The Planning Guidance Notebook, Engineering Regulation (ER 1105-2-100), dated April 2000, requires the formulation and evaluation of a full range of reasonable

alternative plans. Alternatives are formulated to take into account the overall problems, needs, and opportunities afforded by the proposed action. Those alternatives are assessed in a manner consistent with the national objective of contributing to National Economic Development (NED) and protecting the Nation's Environment, and consistent with Federal laws and regulations. The NED objective for water supply is to provide the most cost-effective water supply source to meet the region's future municipal and industrial requirements.

Problems and needs in the Lake Texoma region include insufficient sources of municipal and industrial water supply at affordable costs to meet future municipal and industrial needs. Water marketers in Texas have identified a need for additional storage in Lake Texoma as a high priority and economical source of water in their water management strategy. Due to the increasing time required for the Corps to evaluate the issues of storage reallocation and near term need, water marketers in Texas have requested storage for immediate need. The reallocation opportunity would provide an incremental source of water supply of sufficient quantity and reasonable cost to meet demands. The storage available at Lake Texoma for water supply will not meet all of the expected future demand for water in the region.

For Oklahoma, water supply and demand information is taken from studies completed by the Tulsa District for the Oklahoma Water Resources Board (OWRB) in support of the Oklahoma State Water Plan. This study indicates that at this time, existing and potential sources of water supply are available to meet future municipal and industrial needs in the Oklahoma region surrounding Lake Texoma.

The identified need examined in this reallocation report is at the request of the North Texas Municipal Water District (NTMWD) for additional water supply storage of 100,000 acre-feet and GTUA's request for 50,000 acre-feet from Lake Texoma. The Region C Water Plan recommends, as a water management strategy, the reallocation of 100,000 acre-feet of storage in Lake Texoma to the NTMWD and 50,000 acre-feet of storage to the GTUA, as directed in the 1986 WRDA.

The "Denison Dam-Lake Texoma Restudy, Oklahoma and Texas, Feasibility Report," completed by the Corps of Engineers in September 1990, evaluated whether Lake Texoma should be modified to deal with present and projected water supply resource problems, particularly the needs in the North Texas region in conjunction with increased hydropower production at Lake Texoma. Although the restudy focused on increasing hydropower production at Denison Dam, subject to growing North Texas water supply demand constraints, the restudy is useful to the preliminary plan formulation of this reallocation. Evaluation of the 1990 alternative plans regarding changes in the size of the conservation pool and the flood pool at Lake Texoma are useful in selection of alternatives for this reallocation.

## 4.2 No Action

The Council on Environmental Quality (CEQ) regulations implementing the provisions of NEPA requires Federal agencies to consider a No Action alternative. These regulations define the No Action alternative as the continuation of existing conditions and their effects on the environment, without implementation of, or in lieu of, a proposed action. The No Action alternative represents the existing condition, would not result in any new project-related environmental impacts, and serves as the baseline against which to compare the effects of the

other alternatives. The Corps considers the option of "No Action" the condition reasonably expected to prevail over the period of analysis, given current conditions and trends and assuming that no project would be implemented by the Federal government to achieve the planning objectives. No Action is synonymous with the without-project condition and is the basis from which other alternatives are measured.

**4.3 Action Measures.** The measures are proposed to provide an equivalent quality and quantity of water that the non-Federal interest would undertake in the absence of using storage from Lake Texoma.

**4.3.1 Groundwater Wells**. Current use of groundwater exceeds or is near the estimate of long-term reliable groundwater supply in some counties in Region C. The Region C Water Plan indicates that water suppliers will need to develop alternate sources of water supply since groundwater resources are overused by temporary over drafting. Some entities in the region rely on groundwater to meet existing and future water needs. These users tend to need smaller quantities of water. However, with large users, the quantity of water available from groundwater wells would not be sufficient to meet long-term future needs for reliable water supply in the region. Temporary over drafting of groundwater can be used only as an interim measure until other supplies are developed. Groundwater wells would not be a reasonable alternative to Lake Texoma storage reallocation.

**4.3.2 Existing Surface Water Sources**. The Region C Water Plan is a guide to utilization of existing sources of water supply. The plan discusses existing sources of surface water supply currently used and expected to be used in the region to year 2060. The water management strategy in Region C is to use those sources of supply that are the most cost effective and viable to meet demands. Existing surface water sources are already considered Region C water strategies and would not meet water needs.

**4.3.3 New Surface Water Sources**. The Region C Water Plan discusses all new sources of surface water supply currently used and expected to be used in the region to year 2060 to meet future water demands. In addition, the water management strategy and institutional problems are presented by decade and source of supply for the major water users along with their estimated costs of development. In some cases, several water using entities combine their resources to develop a new source of water supply for a shared use. The reallocation report discusses the water management strategy for the NTMWD and the GTUA regarding existing and new surface sources of water supply. New sources are recognized to be less cost effective than existing sources of storage. A subcategory of this measure, surface reservoirs upstream of Lake Texoma, is listed in the May 2006 Environmental Assessment as a measure. That subcategory was not considered a discrete measure in this reallocation investigation. The measure considered in this reallocation includes potential new surface water sources regardless of regional location.

**4.3.4 Downstream Red River Diversion**. The 1990 Restudy addressed pumped storage hydropower facilities at Lake Texoma with an afterbay dam constructed about 7 miles downstream of the existing dam. That study concluded that the afterbay pool would increase the tailwater elevation at the existing units and reduce their efficiency. This option was not economically feasible. Downstream re-regulation dams and offsite storage would be required with the Red River Diversion. Construction of a downstream dam was considered at the Kiamichi River but was removed from further study because evaporation and seepage would

result in losses of up to approximately 25% between there and the Denison Dam. Water quality releases from Hugo Dam into the Kiamichi River could not be withdrawn for water supply without increased releases from Hugo to replace water quality flows. This would result in a faster drawdown of Hugo Lake. Releases of water from Lake Texoma would have to be increased by the amount lost to evaporation and seepage which would result in a faster drawdown of Lake Texoma. Withdrawal of water from the Red River below Denison would require communities located in the upper reaches of Lake Texoma to construct extensive pipeline facilities to transport water greater distances rather than withdrawing water from intake structures located much closer within the lake. The need for a dependable supply using downstream water withdrawals would tend to require storage reallocation versus a run-of-river operation. Downstream Red River diversions would not be a reasonable alternative to Lake Texoma reallocation.

**4.3.5 Non-Structural Solutions - Conservation**. Potential non-structural solutions include those that would alter the demand for increased water supply in the future. These alternatives would at least partially address some of the problems and needs in the region. The non-structural alternative is to conserve water to reduce the need for additional sources of water supply. Water conservation can include altering the demand for water by water rationing and pricing methods. Communities and major water user groups, such as the NTMWD and the GTUA, already have plans to reduce water consumption as discussed in the "*Initially Prepared Region C Texas Water Plan 2006.*" Water reuse is also a viable non-structural alternative that has been implemented in many areas where permitted. Reuse water in Region C is expected to be about 771,000 acre-feet per year by 2060. Those communities and major water utilities, such as the NTMWD, that have undertaken steps to reuse water where feasible are shown in the Region C water plan. Where available, reuse water is utilized prior to development of other sources of water supply. Further conservation efforts would not be a reasonable alternative to Lake Texoma storage reallocation.

**4.3.6 Structural and/or Reallocations**. Reservoirs whose originally authorized project purposes may no longer be required to meet present needs or may be available for some new equal or higher purpose may offer an opportunity for reallocation. The opportunity to modify or update the authorized project purposes through reallocation of conservation storage or flood control storage may exist to respond to changing needs. For example, changes in a reservoir's upstream conditions, such as reduction in sediment entering a stream, may provide an opportunity to consider whether to extend the period that sediment could be collected without encroachment on other storage or to allow part of the storage initially reserved for sediment to be reallocated to water supply. Or, where water quality storage originally provided to dilute pollutants may no longer be needed if pollutants are now being removed before being discharged into a stream or river. The reallocation of storage is the most common example of reallocation of conservation storage. This has been accomplished nationwide several times when the benefits of the reallocation are positive.

Reallocation of flood control space, however, may require an evaluation that identifies the costs and benefits of such an action. The Corps of Engineers Water Supply Manual has identified three conditions that may create an opportunity to reallocate flood control storage to water supply storage. These conditions are:

- Where reallocated flood control storage volumes are small and do not affect flood protection. The increase in flood damages downstream, within the reservoir pool, and other costs and/or damages to project purposes must be quantified. If the effect is large, Congressional action is required.
- Where the downstream floodplain has changed or supplemental protection has been provided. Mitigation of flood losses and/or damages and costs may require modification of existing structures, construction of new flood protection structures, or other measures, such as non-structural alternatives.; and
- Where reservoirs have been designed to a maximum site capacity that is larger than required by hydrologic analysis. Upstream or downstream hydrologic changes may have occurred that would mitigate any loss in current flood protection.

The cost allocated to the non-Federal sponsor for the capital investment for reallocated storage space will normally be established as the highest of the benefits or revenues foregone, the replacement cost, or the updated cost of storage in the Federal project. The non-Federal sponsor is also responsible for any specific construction and/or operational costs associate with the reallocation action including costs associated with the revision of the water control plan and environmental mitigation costs.

Benefits foregone are usually estimated using standard Corps National Economic Development (NED) evaluation criteria for the remaining economic life of the project or 50 years, whichever is greater. Revenues foregone to hydropower are the reduction in revenues accruing the U.S. Treasury as a result of the reduction in hydropower outputs based on the existing rates that are charged by the power marketing agency.

If the reallocated storage is being taken from the flood control pool and adverse impacts warrant replacement measures, it is appropriate to use the replacement cost of equivalent flood damage reduction measures. Examples of when replacement of flood control storage would be appropriate are when there is a real estate taking or when the value of the lost flood control storage is greater than the value of the added municipal and industrial storage. This would not be appropriate for reallocations within the discretionary authority of Commander, USACE, which by definition do not have severe impacts. In any event, the 1958 Water Supply Act as amended requires that any modification of a reservoir project that has been authorized, surveyed, planned, or constructed to include storage as provided in the Act, which would seriously affect the proposes for which the project was authorized, surveyed, planned, or constructed, or which would involve major structural or operation changes, shall be made only upon the approval of Congress.

**4.3.7 Evaluation Matrix of Preliminary Measures**. The following evaluation matrix, Table 9, displays the screening of preliminary alternatives. The matrix displays potential study alternatives. Two preliminary alternatives, reallocating storage from the existing conservation pool to water supply and from the flood pool to water supply are evaluated further.

**Table 9**
**Evaluation Matrix of Preliminary Measures**
**Screening Criteria and Results**

| | Measure | Meet Future Water Demands | Hydropower Impacts | Environmental Impacts | Flood Control Impacts | Recreation Impacts | Economic Costs | Evaluated in Previous Studies | Comment | Further Evaluation |
|---|---|---|---|---|---|---|---|---|---|---|
| | No Action | No | No | No | No | No | NA | Yes | This is the basis for evaluation of action alternatives. | Yes |
| 1 | New Groundwater Wells | No | No | Low | No | No | High | Yes | Production not sufficient to meet high municipal and industrial demands. | No |
| 2 | Existing Surface Water Sources (Other than Lake Texoma) | No | No | Low | No | No | NA | Yes | All existing sources are already scheduled and prioritized in Texas State Water Plan, Region C | No |
| 3 | New Surface Water Sources | Yes | No | Yes | Yes | Yes | High | Yes | Accounted for in Region C in Texas State Water Plan | No |
| 4 | Downstream Red River Diversion | Yes | No | Yes-Medium | No | Yes | High | Yes | Economically unfeasible, excessive water loss, extensive pipeline construction. | No |
| 5 | Conservation | No | No | No | No | No | Low | No | Conservation incorporated into Region C water management strategy prior to use of Lake Texoma | No |
| 6 | Change in Pools – Reallocation from Flood Control Pool | Yes | Yes | Yes | Yes | Yes | High | Yes | Potentially high economic and environmental impacts; may impact dam safety certification rating. | Yes |
| 7 | Reallocation from Conservation Pool | Yes | Yes | Yes - Low | No | Yes Low | Low | Yes | Legislative authorization to reallocate storage to water supply storage. | Yes |

**4.4 Evaluation of Conservation Pool and Flood Pool Alternatives.** From the screening of the preliminary measures a more detailed evaluation of conservation and flood storage reallocations alternatives was conducted. The evaluation used data and information obtained from the economic output of the Tulsa District SUPER computer program and other data sources. SUPER was utilized to analyze the hydrologic and hydraulic impacts and the resulting economic impacts on reservoirs and streams within the Red River basin from reallocating water from hydropower and flood storage. In addition to economic outputs from SUPER, other economic data were used to evaluate the various water supply alternatives. The alternatives consisted of conservation pool storage and flood control pool storage reallocations of 150,000 acre-feet and 300,000 acre-feet, for a total of four alternatives.

## 4.5 Reallocation from Conservation or Flood Control Storage

Previous studies have evaluated the economic, environmental and social impacts of reducing the Lake Texoma flood pool. A Corps 1990 study of Lake Texoma, the Denison Dam-Lake Texoma Restudy Feasibility Report, addressed raising the conservation pool at Lake

Texoma and evaluated three alternatives: raising the pool by one, two, or three feet. Evaluations were conducted to determine the impacts of reallocating storage from the conservation pool or the flood control pool to provide additional storage for water supply. The 1990 evaluation indicated raising the flood control pool for the purposes of hydropower generation was not economically feasible. The dollar values of the reduction of flood risks, environmental and cultural resource degradation, and damage and losses to recreation facilities and concessionaires as a result of a pool rise would exceed potential additional hydropower generation benefits. The analysis was relevant to addressing alternatives that would involve reallocation from flood control pool to water supply conservation. In a screening level approach, the updated values identified in the 1990 report and were initially compared to water supply benefits that would be generated by reallocation of 150,000 to 300,000 acre-feet of storage. The preliminary screening indicated that the impacts (costs) of reallocation from flood control storage were greater than the impacts of the same storage reallocation from the conservation pool. To confirm these preliminary indications, a more thorough screening was also performed and is described below.

To accomplish a more specific evaluation of reallocating 150,000 acre-feet or 300,000 acre-feet of storage to the water supply purpose, alternatives were analyzed using the SUPER program for conservation storage and flood control storage reallocation. Table 10 displays comparative information for the No Action plan and alternatives for storage reallocation from the flood control storage and from conservation storage. The table shows whether there is a seasonal pool plan, the raised top of conservation pool elevation, and, whether Dependable Yield Mitigation Storage (DYMS) for current users of water supply was used in determining the total dependable yield of the project. The DYMS evaluation is conducted to ensure that current water supply users would not be adversely affected by reallocation of flood control storage to new water supply users.

Brief descriptions of the alternatives that were evaluated using SUPER economic output data for Lake Texoma follow.

**No Action.** The existing condition represents the current 150,000 acre-feet of water supply storage within the conservation pool. The top of conservation pool elevation is 617.0 feet. The seasonal pool plan is also part of this condition that raises the top of conservation pool to elevation 619 feet for the June to August period.

**Alternative 1.** This alternative would reallocate an additional 150,000 acre-feet of storage from the conservation pool. The total water supply storage would be 300,000 acre-feet. The top of pool elevation would be 617.0 feet. The seasonal pool plan is also part of this condition that raises the top of conservation pool to elevation 619 feet for the June to August period.

**Alternative 2.** This alternative would reallocate an additional 300,000 acre-feet from the conservation pool. The total water supply storage would be 450,000 acre-feet. The top of pool elevation would be 617.0 feet. The seasonal pool plan is also part of this condition that raises the top of conservation pool to elevation 619 feet for the June to August period.

**Alternative 3.** This alternative would reallocate 150,000 acre-feet from flood control storage. The top of conservation pool would be raised to elevation 618.51, with no seasonal pool raises. The total water supply storage would be 300,000 acre-feet (150,000 acre-feet previously reallocated from the conservation pool and an additional 150,000 acre-feet reallocated from the flood control pool).

**Alternative 4.** Alternative 4 would reallocate 300,000 acre-feet from the flood control pool. The top of conservation pool would be raised to 619.99 feet with no seasonal pool raises. The total water supply storage would be 450,000 acre-feet (150,000.acre-feet previously reallocated from the conservation pool and an additional 300,000 acre-feet reallocated from the flood control pool).

The following table summarizes the No Action plan, the conservation storage reallocation, and the flood control storage reallocation alternative conditions.

**Table 10**

**Storage Reallocation Alternatives**

| Alternative | Description (acre-feet) | Total Water Supply Storage (acre-feet) | Seasonal Pool Plan | Top of Pool Elevation (feet) |
|---|---|---|---|---|
| No Action | 150,000 from Conservation Pool (Prior Reallocation) | 150,000 | Yes | 617.00 |
| 1 | 150,000 from Conservation Pool | 300,000 | Yes | 617.00 |
| 2 | 300,000 from Conservation Pool | 450,000 | Yes | 617.00 |
| 3 | 150,000 from Flood Pool (DYMS) | 300,000 | No | 618.51 |
| 4 | 300,000 from Flood Pool (DYMS) | 450,000 | No | 619.99 |

**4.6 Alternative Evaluation.** Impacts of alternatives were evaluated and, where applicable, were quantified for purposes of comparison. The alternatives were evaluated for several potential changes to the existing condition of the No Action plan. One set of evaluations utilized the SUPER model (discussed below) and other, non-SUPER model evaluations were grouped under the heading of "Other Evaluations". The potential impacts evaluated using the SUPER model and the other evaluations are listed immediately below and are explained in detail in the discussions that follow.

- The SUPER model was used to evaluate impacts to the following:
    a. Flood Damages Downstream
    b. Flood Damages In-Pool
    c. Recreation Impacts
    d. Hydropower Impacts

- Other Evaluations
    a. Cultural Resources Impacts
    b. Recreation Facilities
    c. Oil Well Impact
    d. Lake Texoma Land Transfer
    e. Dam Safety

**4.6.1 SUPER Model.** The SUPER model was used to develop economic output information by reach, reservoir pool, reservoir, or gage for those downstream areas impacted by changes in conservation and/or flood pool storages for each of the alternatives. SUPER program evaluation is discussed in Appendix D. The data for the existing condition can be compared to impacts as described for each alternative. SUPER relies on economic input data developed at a particular point in time which is updated using an Engineering News Record (ENR) factor that represents changes in general price levels for structural impact evaluations and a Prices Received by Farmers Index for agricultural impacts. The ENR factor increase is 1.624 from December 1993 to October 2008. The Prices Received by Farmers Index is 1.422 from December 1993 to October 2008. Four major categories of economic output data are calculated by SUPER. These are:

- Flood Damages Downstream. Downstream average annual flood damages by reach and by major category, structures and crop or agricultural.

- Flood Damages In-Pool. Average annual flood damages within the Lake Texoma pool as a result of project operation. In addition to Lake Texoma in-pool damages, other reservoirs may be impacted depending on the alternative evaluated. Those lakes are Sardis, Hugo, Pine Creek, Broken Bow, Dequeen, Gillham, Dierks, and Millwood.

- Recreation. Average annual recreation benefits at Lake Texoma and, where applicable, the other lakes mentioned above. There may be losses or gains in recreation benefits related to changes in storages and pool heights.

- Hydropower. SUPER output displays changes in total energy in GWH, as well as load, dump energy, and thermal buy energy. Broken Bow power is not affected under any of the alternatives.

The SUPER model can perform period-of-record analysis to evaluate changes in operational scenarios and can simulate flood control operations and conservation pool operations including hydropower, water supply, water quality, diversions and returns. In addition to period-of record analysis, it has the capability to perform conservation pool yield analysis and firm energy analysis. The SUPER model can perform the following functions:

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

- Determination of critical data for evaluating hydropower.

Both SWD and the SWPA, a power marketing agency for the Department of Energy, use SUPER for period-of-record simulation modeling to determine impacts, including hydropower energy and capacity losses.

In accordance with EC 1105-2-407, Planning Models Improvement Program: Model Certification, it was necessary to consider whether the SUPER model required certification as a planning model for the purpose of its use in the reallocation study. The SWD Water Management and Reallocation Studies planning center of expertise lead reviewed the document Protocols for Certification of Planning Models, dated July 2007, and determined that the SUPER model meets the definition of an engineering model, "Models that represent engineering systems such as models used to perform hydrologic and hydraulic analyses are engineering models and not Planning Models." Therefore, model certification for the SUPER model was not required.

The guidance presented in the Engineering and Construction Bulletin No. 2007-6, "Model Certification Issues for Engineering Software in Planning Studies", dated 10 April 2007, requires the Engineering Community of Practice to ensure that the application and proper use of the software is documented in the independent technical review process. Accordingly, the planning center of expertise requested a review of the model by the Division's Water Management Team Lead to ensure its technical soundness.

In March of 2009, Mr. Ron Bell, P.E., SWD Water Management Team Leader, stated "The Southwestern Division Reservoir Regulation Computer Model (commonly referred to as "SUPER") is an excellent reservoir system simulation model which has been used in SWD for many years. It has proven to provide very accurate results when compared to actual system operations. It is a well tested model and should be considered acceptable for use. I have reviewed the Lake Texoma Storage Reallocation Report including the H&H [hydrology and hydraulic] Appendix D, as well as the ATR review comments by Little Rock District. My conclusion is that the SUPER model is an appropriate model to use for the Lake Texoma H&H analysis. I further conclude that the model was appropriately used and the analyses of the results from the model are based on technically sound engineering principles."

The flood damage values estimated using SUPER were updated using the ENR factor and the Prices Received by Farmers Index as described previously. The floodplain consists of property subject to flooding with a value of $195 million (in 2008 dollars, updated from the 1990 Denison Dam- Lake Texoma Restudy Oklahoma and Texas Feasibility Report and Environmental Impact Statement, Tulsa District). The land use in the area is predominantly agriculture and there are many low level local flood protection projects and levees in the floodplain. Lake Texoma provides an estimated 23-year level of flood protection immediately downstream of Denison Dam, but the reduction in damages can be forecast throughout the 260 mile reach to Louisiana. The floodplain in that 260 mile reach covers over 390,000 acres (roughly 10 times the area of the District of Columbia). The flood damage reduction occurs because Lake Texoma has over 2.5 million acre-feet of flood control storage and the lake is a main stem reservoir on the Red River. Lake Texoma provides storage for about 1.41 inches of runoff from the contributing drainage area above the lake. The total drainage area is about 39,719 square miles with 33,783 square miles of contributing drainage area.

The total flood damages prevented over the life of the project are nearly $866 million in 2008 dollars. The most recent significant flood operations at Lake Texoma occurred in 2007 and the estimated flood damages prevented totaled approximately $116 million that year. Average annual flood damages prevented for Denison Dam are simply the updated cumulative total divided by the number of years in operation, and total approximately $13 million. Reduction of flood control storage in Lake Texoma would have economic impacts in Texas, Oklahoma, Arkansas, and Louisiana.

**4.6.2 Flood Damages Downstream.** The main stem Red River has been divided by reaches that are associated with gages downstream of Lake Texoma. Downstream flood damages occur to both agriculture and structures within the floodplain. The SUPER model assists in the forecasting of economic outputs for downstream flood losses for each economic reach. The gages that define the reaches are Texoma outflow, Arthur City, DeKalb, Index, Fulton, and Shreveport. Total average annual flood loss under the existing condition is about $4,086,800 on the main stem Red River, as modeled in SUPER. Table 11 shows these flood damages updated to 2008 price levels.

The downstream flood damage values shown in Table 11 for each alternative represent the accumulation of flood damages by category (structural and agricultural) in the Red River reaches from Denison Dam to Shreveport, LA, as estimated using the SUPER model. The flood damages for Alternatives 1 and 2 (the conservation storage reallocation alternatives), are less than the flood damages experienced under the existing conditions. Alternatives 3 and 4 (the flood control storage reallocation alternatives), would increase downstream flood damages over that experienced under the existing conditions. The reduction in flood control storage would result in flooding that was more frequent than is currently experienced. The depth of downstream flooding would inherently be greater when compared to similar frequency events entering Lake Texoma because lake operations would require that releases be made with less lake retention time and releases would therefore tend to be larger than for existing conditions. The duration of downstream flooding could be extended when required lake releases coincided with downstream tributary flows. The reduction of flood control storage capacity would reduce the level of control available at the project and in the Red River system operations.

The two alternatives (3 and 4) that were evaluated for storage reallocation from flood control storage would be expected to have greater downstream flood damages than the existing conditions of the No Action plan. The values for flood damages in Table 11 show that is the case: Alternative 3 has an estimated increase of $101,700 per year and Alternative 4 has an estimated increase of $144,600 per year in downstream flood damages over the existing conditions.

Alternatives 1 and 2, the conservation storage reallocation alternatives, indicate slightly less downstream flood damages would occur annually than would occur for the existing conditions. Alternative 1 is estimated to have about $12,200 per year less damages, and Alternative 2 is estimated to have about $53,400 per year less damages than existing conditions. The reduction in damages would result because of a slight and more consistent conservation pool drawdown associated with water withdrawal for water supply than would occur for hydropower production.

**Table 11**

**Average Annual Downstream Flood Damages By Alternative**

**October 2008 Prices**

| Alternative | Description (acre-feet) | Total Water Supply (acre-feet) | Downstream Flood Damages | | | Difference from Exist ($1,000) | Percent Change (%) |
|---|---|---|---|---|---|---|---|
| | | | Structures ($1,000) | Agriculture ($1,000) | Total ($1,000) | | |
| No Action | 150,000 from Conservation Pool (Prior Reallocation) | 150,000 | $1,844.5 | $2,242.2 | $4,086.8 | | |
| 1 | 150,000 from Conservation Pool | 300,000 | $1,851.7 | $2,222.9 | $4,074.6 | -$12.2 | -0.3 |
| 2 | 300,000 from Conservation Pool | 450,000 | $1,832.5 | $2,200.9 | $4,033.4 | -$53.4 | -1.3 |
| 3 | 150,000 from Flood Pool | 300,000 | $1,905.8 | $2,282.8 | $4,188.5 | $101.7 | 2.5 |
| 4 | 300,000 from Flood Pool | 450,000 | $1,947.3 | $2,284.0 | $4,231.4 | $144.6 | 3.5 |

Note: Positive value for difference represents an increase in average annual flood damages.

There is a decrease in downstream flood damages for the conservation pool alternatives, and an increase in downstream average annual flood damages for the flood control pool alternatives ranging from about $101,700 to $144,600 over the existing condition.

**4.6.3 Flood Damages In-Pool**. In-pool losses are those damages within the Lake Texoma reservoir area that result from routine project operation. Damages may occur to infrastructure within the reservoir area that would include recreation facilities, such as boat ramps, and camping and picnic facilities. The SUPER model was used to perform a period-of-record analysis to evaluate changes in the operational conditions of the existing conditions (No Action) and the four alternatives for water storage reallocation. The model simulated flood control operations and conservation pool operations including hydropower, water supply, water quality, diversions and returns for these conditions. In-pool losses shown in Table 12 provide a comparison of Alternatives 1 and 2 to the existing condition (No Action). Alternatives 1 and 2 would slightly reduce in-pool losses estimated for the No Action plan by reducing pool fluctuations above the conservation pool. The in-pool losses for the existing conditions reflect the routine impacts to facilities included in the SUPER in-pool inventory rating curve. The existing conditions indicate an average annual impact of about $400,000 per year. This includes impacts of the seasonal pool plan on facilities. The impact and the value represent estimated impacts to all facilities in the flood control pool, not just those facilities impacted by the seasonal pool plan.

In-pool losses were not estimated using the SUPER model for Alternatives 3 and 4 because it was assumed that if either alternative (3 or 4) was implemented that the facilities to be impacted either permanently or severely by a pool raise would be relocated as needed to either mitigate an increase of routine average annual damages or to reduce the risk and value of average annual damages. The relocated facilities would still be subject to damages during less frequent flood control operations. An evaluation of facility relocations and a re-estimation of all facilities in the lake would have been required to establish a modified depth versus damage rating curve for use in the SUPER model to evaluate Alternatives 3 and 4. Establishing a modified fating

curve was beyond the scope of the screening level evaluation. The rating curve is used by SUPER for the period-of-record operational analyses and includes all existing facilities in relation to the existing pool conditions. If reallocation from the flood control pool was found to be a more viable alternative, a more detailed evaluation of in-pool flood damages would have been necessary. By not estimating in-pool losses the overall evaluation would tend to slightly favor selection of Alternatives 3 and 4 because any reduction in the flood control storage would tend to cause more frequent and higher pool fluctuations in the flood control pool. More frequent flood pool fluctuations would tend to result in more frequent inundation of all facilities within the inventory and therefore higher in-pool losses than the $400,000 annual estimate for existing conditions. Because it was assumed that some facilities would be relocated, the cost of facility relocations is addressed in the Other Evaluations section for Alternatives 3 and 4. It was also assumed that even with relocation of facilities that the average annual in-pool losses would be equal to or higher than the existing conditions in-pool losses of about $400,000.

Costs associated with relocating facilities are presented in Section 4.8.1.

**Table 12**

**Average Annual In-Pool Losses By Alternative**

**October 2008 Prices**

| Alternative | Description (acre-feet) | Total Water Supply (acre-feet) | In-Pool Losses ($1,000) | Difference from Exist ($1,000) | Percent Change (%) |
|---|---|---|---|---|---|
| No Action | 150,000 from Conservation Pool (Prior Reallocation) | 150,000 | $401.0 | | |
| 1 | 150,000 from Conservation Pool | 300,000 | $392.8 | -$8.1 | -2.0 |
| 2 | 300,000 from Conservation Pool | 450,000 | $379.5 | -$21.4 | -5.3 |
| 3 | 150,000 from Flood Pool | 300,000 | Est $400.0 | 0 | 0 |
| 4 | 300,000 from Flood Pool | 450,000 | Est $400.0 | 0 | 0 |

Est – In-pool losses for the flood control storage reallocation alternatives were estimated to be equal to the No Action condition in-pool losses..

**4.6.4 Recreation Benefits**. The SUPER model was considered for a period-of-record analysis to evaluate changes in the operational conditions of the existing conditions (No Action) and the four alternatives for water storage reallocation related to recreation benefits. The model can simulate flood control operations and conservation pool operations including hydropower, water supply, water quality, diversions and returns for these conditions. Recreation benefits are shown in Table 13 for the existing conditions (No Action). However, no change in recreation benefits was assumed for the four alternatives. Minor changes might be expected for Alternatives 1 and 2, but were not evaluated.

Alternatives 3 and 4 would tend to experience short term impacts while recreation facilities would be relocated to accommodate the permanent conservation pool increases for these alternatives. Changes in the annual recreation benefits were not assumed to be substantially different between conservation pool reallocation alternatives and flood control pool reallocations.

Recreation benefits are based on recreational use of the lake and related lakeside recreation facilities. It was assumed that Alternatives 3 and 4 would include relocation of recreation facilities to a higher elevation. As a result, the recreational use of relocated facilities would be similar to the existing conditions. However, because the flood control pool would have less total storage, the remaining flood control storage would tend to be utilized more frequent with the result of higher pool fluctuations. More frequent and higher flood pool fluctuations would tend to result in more frequent inundation of all facilities within the inventory and therefore recreation benefits would be expected to be less than the annual estimate for existing conditions of about $8.5 million dollars. Because it was assumed that some facilities would be relocated, the cost of facility relocations is addressed in the other evaluations, later in this section for Alternatives 3 and 4.

**Table 13**

**Average Annual Recreation Benefits by Alternative**

**October 2008 Prices**

| Alternative | Description (acre-feet) | Total Water Supply (acre-feet) | Recreation Benefits ($1,000) |
|---|---|---|---|
| No Action | 150,000 from Conservation Pool (Prior Reallocation) | 150,000 | $8,485.9 |
| 1 | 150,000 from Conservation Pool | 300,000 | No Change |
| 2 | 300,000 from Conservation Pool | 450,000 | No Change |
| 3 | 150,000 from Flood Pool | 300,000 | No Change |
| 4 | 300,000 from Flood Pool | 450,000 | No Change |

**4.6.5 Hydropower Production and Valuation.** The SUPER model does not provide a monetary value for hydropower but does estimate average annual total energy production. For screening purposes, Table 14 shows average annual hydropower energy production in GWH by alternative estimated using SUPER. The Hydropower Analysis Center in August 2008 provided preliminary hydropower benefits forgone for the four alternatives. Estimates of hydropower benefits foregone for the four alternatives are shown in Table 15.

The SUPER model was used for screening purposes to determine the relative impacts of reallocation from conservation storage and flood control storage to existing conditions (No Action). Reallocation from either conservation storage or from flood control storage would have an impact on total power generation because both conservation storage and flood control storage is used to produce power.

| Table 14<br>Average Annual Total Hydropower Production By Alternative | | | | | |
|---|---|---|---|---|---|
| **Alternative** | **Description (acre-feet)** | **Total Water Supply (acre-feet)** | **Total Hydropower (GWh)** | **Difference from Exist (GWh)** | **Percent Change (%)** |
| No Action | 150,000 from Conservation Pool (Prior Reallocation) | 150,000 | 232.1 | | |
| 1 | 150,000 from Conservation Pool | 300,000 | 220.1 | -12.0 | -5.2 |
| 2 | 300,000 from Conservation Pool | 450,000 | 208.3 | -23.8 | -10.3 |
| 3 | 150,000 from Flood Pool | 300,000 | 223.6 | -8.5 | -3.6 |
| 4 | 300,000 from Flood Pool | 450,000 | 215.7 | -16.4 | -7.1 |
| Negative value for difference represents a decrease in total hydropower generation. | | | | | |

**4.6.6 Reallocation Impact based on Hydropower Benefits Forgone using HAC Preliminary Values.** The Hydropower Analysis Center (HAC) derived preliminary hydropower values at November 2008 price levels for this alternative screening using the SUPER model power generation estimates. The summary is shown below. This is a preliminary evaluation of benefits foregone used to conduct the evaluation of the four preliminary alternatives for storage alternative screening. The benefits foregone were developed as an interim product for this screening and do not reflect the final estimate of hydropower impact. The estimates reflect a seasonal pool plan, the monthly peaking generation based on SUPER modeling of the existing condition, and hourly generation for the year of 1998 to represent a typical generating sequence.

| Table 15<br>Hydropower Benefits Forgone<br>HAC Valuation<br>2008 Prices | | | | | |
|---|---|---|---|---|---|
| **Alternative** | **Description (acre-feet)** | **Total Water Supply Storage (acre-feet)** | **Average Annual Energy Impact ($1,000)** | **Average Annual Capacity Impact ($1,000)** | **Average Annual Benefits Foregone ($1,000)** |
| No Action | 150,000 from Conservation Pool (Prior Reallocation) | 150,000 | | | |
| 1 | 150,000 from Conservation Pool | 300,000 | $1,192 | $225 | $1,417 |
| 2 | 300,000 from Conservation Pool | 450,000 | $2,407 | $368 | $2,775 |
| 3 | 150,000 from Flood Pool | 300,000 | $634 | $170 | $834 |
| 4 | 300,000 from Flood Pool | 450,000 | $1,399 | $235 | $1,634 |

## 4.7 Total Average Annual Losses using SUPER

Total average annual losses by alternative using SUPER by damage category as compared to the existing condition is shown in Table 16 below. This table shows only SUPER related economic output.

## Table 16

## SUPER Evaluation of Alternatives by Category
## Average Annual Damages By Alternative

## October 2008 Prices ($1,000

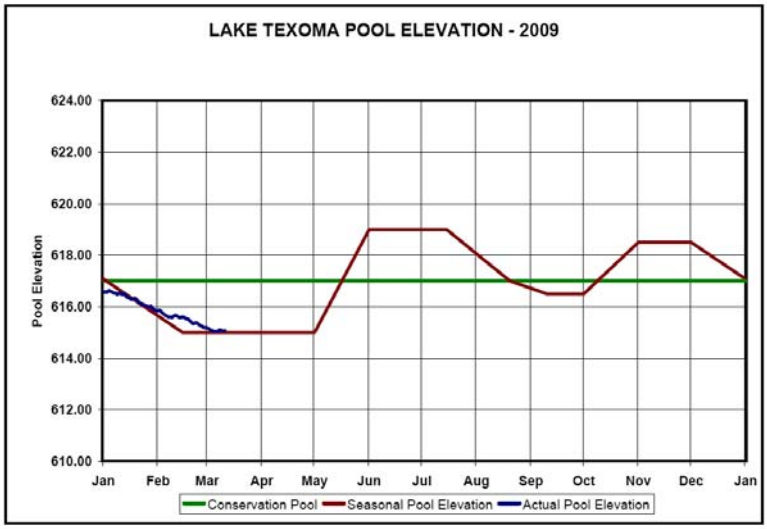
| Alternative | Description (acre-feet) | Total Water Supply (acre-feet) | Pool Elevation (feet) | Downstream Flood Damages Table 11 ($1,000) | In Pool Losses Table 12 ($1,000) | Recreation Benefits Table 13 ($1,000) | Hydropower Benefits (Foregone) Table 15 ($1,000) |
|---|---|---|---|---|---|---|---|
| 1 | 150,000 from Conservation Pool | 360,000 | 617.00 | $12.2 | $8.1 | No Change | -$1,417 |
| 2 | 300,000 from Conservation Pool | 255,000 | 617.00 | $53.4 | $21.4 | No Change | -$2,775 |
| 3 | 150,000 from Flood Pool | 300,000 | 618.51 | -$101.7 | Est $0 | No Change | -$834 |
| 4 | 300,000 from Flood Pool | 450,000 | 619.99 | -$144.6 | Est $0 | No Change | -$1,634 |

Notes:
Negative signs indicate a negative impact compared to the existing conditions.
Hydropower Benefits Foregone were not estimated using the SUPER model, but the power generation from which the benefits foregone estimates were developed by the HAC were developed using the SUPER model.

## 4.8 Other Costs Associated with Pool Rise

Other costs may be associated with any potential flood control storage reallocation and a resulting permanent conservation pool elevation increase. Those costs include, but are not limited to, natural resource impacts, cultural site mitigation for cultural resources located around the reservoir, recreation facility relocation costs, potential impacts to the Cumberland Levee system level of protection or safety assessment, and potential costs associated with an ongoing Lake Texoma land transfer and an ongoing dam safety study. There are also 108 leases within the flood control pool; 101 leases would be impacted by any conservation pool raise. The impacted leases have a total area of 40,387 acres. No evaluation was conducted to quantify potential lease impacts.

Although there is a seasonal pool plan in place at Lake Texoma, as shown in the figure below, the lake is only held at or near Elevation 618.5 for a one month period in the fall of the year and at or near Elevation 619.0 for approximately 6 weeks in early summer. Permanently raising the conservation pool elevation to either 618.51 (approximately 618.5) or 619.99 (approximately 620.0) (see Table 10), creates more frequent and longer duration flooding on existing recreation and marina facilities and cultural resource sites located within the flood pool. Recreation and marina facilities at the lake were designed and constructed to accommodate temporary fluctuations in the pool level. But as shown in the evaluation of In-Pool Losses (Table 12), costs associated with inundation of those facilities and other in-pool losses under existing conditions ("No Action") are estimated to be about $400,000 per year.




A permanent increase in the conservation pool would have a permanent and greater impact to In-Pool Losses, including all in-pool recreation facilities. Therefore, the potential pool increase for Alternatives 3 and 4 to elevations 618.5 and 620.0 respectively would have permanent and greater In-Pool Losses. The seasonal pool plan and impacts of its implementation are discussed in Section 4.8.1, below. Environmental mitigation costs for permanently raising the pool were not calculated for screening level cost estimates, but would be required for more detailed analysis of alternatives that would reduce the flood control storage capacity. Section 4.8.2, below, includes further discussion of environmental impacts of a permanent pool raise. Impacts to cultural resource sites within the pool area would also be increased by permanent pool raises. Costs for cultural resource mitigation and relocations of recreation and marina facilities were assessed by conducting a screening level inventory of resources located within two 2-foot zones above the current conservation pool, for resources that would be affected by permanent

pool elevation increases within these two zones. Section 4.8.3 includes further information regarding cultural resource mitigation costs and Section 4.8.4 includes information about the costs associated with relocation of recreation and marina facilities. Potential impacts to the land transfer, Cumberland Levee system, and the safety of Denison Dam are also discussed below, but no cost estimates were prepared. The conclusion was that for screening level analyses only, the cultural mitigation and recreation facility relocation costs would be quantified for Alternatives 3 and 4.

**4.8.1 Seasonal Pool Plan.** Lake Texoma is currently operated on a seasonal pool plan. A graphic showing the approved plan for fiscal year 2009 is shown, above. Although the plan has changed slightly from year to year, it is essentially as shown. Under the 2009 plan, the pool would be raised to elevation 618.5 for the month of November and to elevation 619.0 from the first of June through the middle of July. The plan is to modify lake levels for environmental benefits. The plan is to hold the pool above the top of conservation for approximately 2-1/2 months out of the year if sufficient flows are available and if doing so does not impact the project's flood control purpose.

A review of previous year pool elevations compared to the seasonal pool plan shows the plan is not attained much of the time. For recreation, natural, and cultural resources, operating the pool at elevation 618.5 for a one month period and Elevation 619.0 for a 1-1/2 month period is significantly different than operating the project for a permanent pool raise of 618.5 or greater. Impacts include but are not limited to damages to recreation and marina facilities and cultural resources due to permanent inundation and increased frequency of higher flood control pool levels, increased potential for wind and wave action causing erosion – a significant issue for both cultural and natural resources, and permanent loss of habitat due to inundation.

From an environmental compliance standpoint, seasonal pool plans are problematic. Tulsa District has not yet addressed the current Texoma seasonal pool plan as a Section 106 undertaking. The fact that Tulsa District currently operates a seasonal pool plan is a separate issue to be considered under Section 106. The impacts to cultural resources for a seasonal pool plan are not as likely to be classified as an adverse effect as they would for a permanent pool raise. Impacts include but are not limited to damages because of inundation and increased frequency of higher flood control pool levels, and increased potential for wind and wave action causing erosion. These factors are significant issues that ultimately cause destruction of cultural resources.

**4.8.2 Natural Resource Impacts.** Impacts to natural resources and habitat were considered during the screening level analyses, however, mitigation costs were not developed. Preliminary screening clearly indicated that reallocation from the flood control pool would not be recommended and development of impacts and mitigation measures for Alternatives 3 and 4 would have been costly to develop. However, approximate habitat losses for Alternative 3, based on information provided in the U.S. Fish and Wildlife Service's (USFWS) Coordination Act Report (CAR) for the 1990 Texoma restudy (September 1990), would be somewhere in the range of 5,000 total acres along the Lake Texoma shoreline, with about 1,800 acres permanently lost on wildlife management units under management by USFWS (estimates based on evaluation of a 2-foot permanent increase in conservation pool elevation). The USFWS stated that no

adverse effects to terrestrial vegetation would be anticipated with implementation of a seasonal pool plan similar to the one currently in existence at Lake Texoma, as inundation duration would not be sufficient to result in permanent loss of wildlife habitat. The USFWS also stated that operation of a seasonal pool plan would not result in the permanent displacement of wildlife species dependent upon the terrestrial environment – impacts that would be realized with a permanent increase in conservation pool elevation.

Permanent loss of terrestrial habitat associated with a permanent increase in conservation pool elevation would require mitigation for these losses. In the 1990 CAR, the USFWS estimated mitigation costs for a permanent 2-foot pool rise to be approximately $6,500,000 in initial costs and $2,500,000 annual maintenance costs (1990 dollars). In summarizing their conclusions in the 1990 CAR, the USFWS stated that several alternatives, including those involving a 2- or 3-foot permanent rise in the conservation pool of Lake Texoma, would " . . . constitute major environmental constraints to planning. It is our position that the substantial loss of important fish and wildlife resources anticipated with these projects represents an inappropriate tradeoff of resources, especially when less damaging alternatives may exist."

**4.8.3 Cultural Site Mitigation.** Under Section 106 of the National Historic Preservation Act (NHPA) of 1966 (as amended) and its implementing regulation (36 CFR Part 800), a permanent pool raise is considered an undertaking that has the potential to impact cultural resources. This determination was established through consultation with the Oklahoma State Historic Preservation Office (SHPO), the Oklahoma Archeological Survey (OAS), and the Texas Historical Commission (THC), and is in part based on similar conservation pool raise proposals at other operating projects.

For cultural resources, operating Lake Texoma with a seasonal pool plan (at elevation 618.5 for a one month period and elevation 619.0 for a 1-1/2 month period) is significantly different than operating the project for a permanent pool raise of 618.5 or greater. For the other three-quarters of the year, the new conservation pool level will cause shoreline erosion at elevations which previously were subject to a relatively short duration water levels and only during periods of high inflows into the reservoir. While evaluating the effects of erosion depends heavily on local topography, prevailing wind and current directions, and on soil and rock substrate types, the results of prolonged (and permanently) higher pool conditions would cause erosion of areas that previously were only rarely exposed to inundation conditions. From a sheer probability aspect, over time, a permanent pool raise will cause more adverse effects from erosion than from a seasonal pool plan operation. Similarly, inundation has been definitively shown to erode the soil substrate in which cultural resources are contained. Therefore, with the vertical loss of soil substrate, archaeological sites lose the very integrity that could otherwise be the key in determining their eligibility to the National Register of Historic Places (NRHP). New shoreline erosion and inundation by way of a higher elevation conservation pool thus constitute adverse actions for cultural resources. A permanent raise in the conservation pool therefore has the potential to adversely impact cultural resources in an accelerated fashion – perhaps exponential over time – in comparison to a seasonal pool plan.

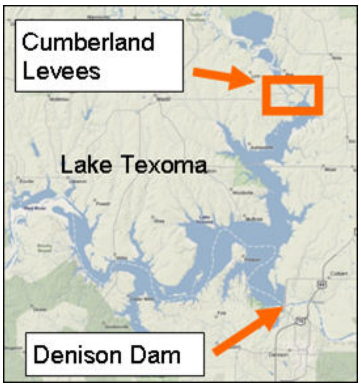
As a Section 106 undertaking with the potential to impact cultural resources, Tulsa District must conduct investigations to identify those cultural resources within the proposed pool raise that are

eligible for listing on the National Register of Historic Places (NRHP) and that may be adversely affected by the action. The investigation effort would be substantial. The Area of Potential Effect (APE) would first require a survey to identify cultural resources. While certain portions of the reservoir could be excluded because of previously conducted investigations, most of the reservoir shoreline was never adequately surveyed. The APE will be quite large, both in linear miles and in area. Once cultural resources are identified, they must be evaluated for NRHP eligibility. This can be extremely costly, as often test excavations are required to determine if archaeological sites have the potential to yield data and whether they have sufficient integrity to suggest historical significance. In general, the cost estimate provided for this report assumes that approximately 20% of the recorded archaeological sites will require NRHP evaluation. The cost estimate further assumes that only 5% of the total number of sites identified in the APE would be eligible for listing on the National Register, and would thus be adversely affected, requiring mitigation. It should be noted that cultural resources costs increase as additional, increasing raises in the conservation pool are considered. Furthermore, cost increases in these subsequent alternatives will likely be by factors greater than an arithmetic increase because of the land area involved.

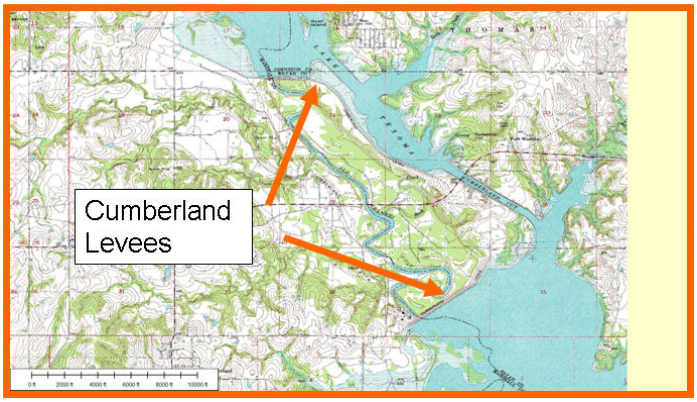
**4.8.4 Relocation of Recreation and Marina Facilities.** Permanent pool raise at Lake Texoma would result in impacts to facilities that support the recreation at the project. Marinas, campsites and picnic facilities, boat ramps, access roads, parking areas and other resources would all experience some degree of impact in a permanent pool raise. In addition to the 13 Corps recreation areas and 10 different campgrounds at Lake Texoma, there are 22 private marinas, 2 state parks, and 2 wildlife refuges that offer recreation opportunities and would be impacted by a permanent pool raise. There are 651 private docks on the lake and private docks may have from one to six slips. The marinas are frequently expanding, and the latest estimate in 2008 was 6,000 marina slips.

Lake Texoma is one of the most popular Federal recreation facilities in the country with more than 6 million visitors annually. In 2006, Texoma ranked first among Corps of Engineers lake projects nationwide, with visitors spending over 90 million hours at the lake. Because of the Lake's proximity to high population areas including the Dallas-Fort Worth metroplex and because of the popularity of recreation at Lake Texoma, it is likely that impacted features would be relocated. Relocations costs developed for screening level analyses were developed by staff at the Lake Texoma project office for pool raises of 2 feet (to Elevation 619) and 4 feet (to Elevation 621). Facilities were identified for relocation based on previously experienced flood control pool operation. The inventory and cost estimates were prepared by Lake Texoma project staff that are familiar with lake operations, especially those operations that cause facilities to be routinely posted and closed by the Corps for flood control operations.

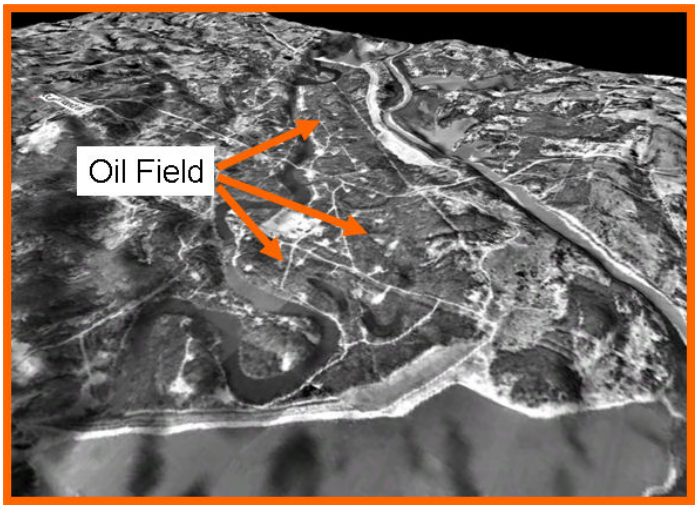
**4.8.5 Cumberland Levee System.** The Cumberland Levee system is located on the Washita Arm of Lake Texoma, about 16 miles northwest of Durant, Oklahoma. The levee system is part of the Lake Texoma project and consists of three main dikes, connecting levees, and two channels to divert the Washita River and to retain the Lake Texoma pool. The North Levee consists of an 87 foot high 3.5 mile dike across the Washita River channel, a 67 foot high dike across Rock Creek, and connecting levees that range from 5-30 feet high. The levee system was raised one foot in 1957 and portions of the levee were raised up to 3 feet after a section of the levee was nearly overtopped during the 1990 flood.




The levee was built as a part of the Lake Texoma project and is operated and maintained by the Corps. The segment of the Cumberland Levees that is closest to Denison Dam is 25 miles upstream of the dam on the Washita River. Water levels on the levee are controlled by Washita River stages or Lake levels or a combination of both conditions. The Cumberland Levees protect 113 oil wells, including 71 wells in the Hagerman area. A high producing Hagerman well can generate sales from crude oil and natural gas of $1 to $3 million per year, depending on pricing. While no costs were estimated for impacts to the Cumberland Levee system, the potential for reallocation of flood control storage (raising the conservation pool) raises several issues related to potential impacts to the levee system. The Pertinent Data book for Tulsa District projects lists the top of levee elevation as 647. The spillway crest elevation is 640 which is the elevation of the top of flood control storage, but the maximum pool considered for operation is elevation 666.4. The hydraulic conditions at the Cumberland Levee system are related to the lake level at the dam, but the water surface elevation at the levee system is often dependant on the adjacent Washita River inflows.




The amount of sedimentation that has occurred in the Washita River arm of the reservoir is of significant concern in regard to the level of protection the Cumberland Levee system may provide. The Cumberland Levee protects from both the normal (Conservation) pool and from flood pools. Periodic inspections have identified seepage problems which have resulted in the formation of sand boils during some large flood events. Seepage control systems including relief wells, toe



drain, and a seepage berm have been recently constructed to control the seepage. Water levels have not been high enough to test the seepage systems since to determine if the seepage issues have been fully resolved.

The 1997 periodic inspection report recommended an evaluation of the Cumberland Levee system be conducted due to sediment accumulation in the flood control storage. Reallocation of storage from the flood pool to conservation storage would increase the frequency of filling the remaining flood control storage. There is a high probability that a flood control storage reallocation would require additional design and construction modifications to the Cumberland Levees. Because the Cumberland Levees are as large as many reservoir embankments, any modification would have a risk of significant costs.

A reallocation of flood control storage, which would raise the permanent pool of the Lake, would increase the pool elevation on the levee and would increase the piezometric pressure in the levee which could result in increased seepage problems and a more persistent condition of foundation saturation. A pool raise would also cause more frequent use of the flood control storage and at higher levels than are currently experienced. These flood control pool filling conditions would further threaten the integrity of the levee and would increase the risk of levee failure due to overtopping or piping.

A reallocation within the conservation pool would result in no raise in the permanent pool elevation and would not adversely impact the performance of the Cumberland Levee.

Dam safety studies are proposed which would address both the impacts of the sedimentation and the seepage issues at the Cumberland Levees.

**4.8.6 Lake Texoma Land Transfer.** The Water Resources Development Act of 2007 (Pub. L. 110–114) Section 3182 directed the Secretary of the Army (Secretary) to offer to convey, at fair market value to the city of Denison, TX, all right, title and interest of the United States in and to approximately 900 acres of land located in Grayson County, TX.

The exact acreage and description of the real property will be determined by a survey that is satisfactory to the Secretary. The lands subject to this action are located along the eastern shore of the Little Mineral Arm of Lake Texoma in Grayson County, TX. Upon receipt of title to the property, the City of Denison intends to develop the area, in conjunction with development of adjacent private lands, to include such features as single and multi-family residential housing, hotel and conference facilities, golf course(s), retail and commercial space, office and light industry, public boat ramp(s), beach and yacht clubs, and related commercial development facilities. An Environmental Impact Statement (EIS) is being prepared to address impacts associated with the conveyance.

A 2 to 3 foot rise in the flood pool would inundate about 50 acres from the conveyance. With a loss of 50 acres there would be a loss to the U.S. Government of about $600,000. The impact to the regional economy is anticipated to be much greater in value but has not been quantified in this study.

The potential for an impact to the land transfer due to reallocation of flood control storage to the conservation pool would be a relative certainty. However, there was limited information available to quantify the impacts of the alternatives. The potential for impact is recognized but costs were not included in the summary of costs and benefits shown in Table 19.

**4.8.7 Dam Safety**. USACE policy requires certification of any potential impact to dam safety from any pool raise alternative. A pool raise would incur dam safety evaluation costs and would potentially require design and modification of project features. Potential design/dam modification resulting from reduced flood protection could impact and force a redesign of the eight 20-foot-diameter, concrete conduits through the embankment, the emergency gates, and the uncontrolled 2,000 foot concrete gravity spillway structure. A certification would be required as part of any conservation pool raise reallocation alternative to insure that dam safety has not been impacted. Because of the size of Texoma Lake, safety review costs for reallocation of the flood pool could be significant.

For any pool raise alternative, a levee safety certification would also be required for the Cumberland Levee, discussed above. The risk of high additional costs for safety certification studies and design and modification is recognized as an important issue when considering flood control storage reallocation. No costs were estimated due to the lack of specific information. No costs were included in the summary of costs and benefits shown in Table 19.

**Section 4.8.8 Summary.** The total costs and annual costs for a 2-foot and 4-foot in the flood control pool by category are shown in Table 17 below. Total cost estimates were developed by Lake Texoma project staff. Alternative pool elevations were interpolated to the nearest one foot.

| Table 17<br>Cultural Mitigation, Recreation Facility Relocation, and Oil Well Mitigation<br>Total and Annual Costs<br>October 2008 Prices ($1,000) | | | | |
|---|---|---|---|---|
| **Description** | **2 Ft Pool Rise (619)** | | **4 Ft Pool Rise (621)** | |
| Cultural Mitigation | Total | Annual | Total | Annual |
| Research/Assess Many Previous Investigations | $250 | $13 | $250 | $13 |
| Shoreline Survey | $1,250 | $67 | $1,250 | $67 |
| Survey of broad, flat expanses | $750 | $40 | $1,500 | $81 |
| National register Assessment | $2,500 | $134 | $3,750 | $201 |
| Mitigation | $3,000 | $161 | $5,000 | $269 |
| NAGPRA and Mitigation | $1,000 | $54 | $1,000 | $54 |
| Long-term Curation Archeological Collections | $750 | $40 | $750 | $40 |
| In-house contract & Project Management | $500 | $27 | $500 | $27 |
| Total Cultural Mitigation | $10,000 | $537 | $14,000 | $752 |
| Facilities Relocation Costs | | | | |
| Corps Facilities | $500 | $27 | $7,200 | $387 |
| Marinas | $33,000 | $1,773 | $33,000 | $1,773 |
| Boat Docks | $645 | $35 | $645 | $35 |
| Boat Ramps | $8,000 | $430 | $8,000 | $430 |
| Total Facilities Relocation | $42,145 | $2,264 | $48,845 | $2,624 |
| | | | | |
| Oil Wells (Hagerman Area Only) | $205,900 | $11,061 | $205,900 | $11,061 |

The cultural mitigation costs with a pool rise, as well as additional costs to facilities relocation and to oil well mitigation within the pool of Lake Texoma, are shown by alternative in Table 18. Alternative pool elevations were interpolated to the nearest one foot. Oil well mitigation costs were considered because of the mineral resource protected by the Cumberland Levee system, but could not be quantified because the ongoing dam and levee safety study, that includes the Cumberland Levee system, is not complete. Mitigation could include an incremental increase in the modification costs of the Cumberland Levees due to a pool elevation increase or mitigation of the mineral resource protected by the levee system.

| Table 18<br><br>Average Annual Cultural, Facilities, and Oil Well Costs By Alternative<br>October 2008 Prices | | | | | |
|---|---|---|---|---|---|
| **Alternative** | **Top of Pool Elevation (feet)** | **Cultural Mitigation ($1,000)** | **Facilities Relocation ($1,000)** | **Oil Well Mitigation ($1,000)** | **Total ($1,000)** |
| No Action | 617.00 | - | - | - | - |
| 1 | 617.00 | NA | NA | NA | NA |
| 2 | 617.00 | NA | NA | NA | NA |
| 3 | 618.51 | $537.0 | $2,264 | Not Est | $2,801 |
| 4 | 619.99 | $644.5 | $2,444 | Not Est | $3,089 |
| NA – Not Applicable to conservation storage reallocation alternatives. | | | | | |

## 4.9 Water Supply Benefits.

Water supply benefits were estimated for this preliminary evaluation assuming the updated cost of storage for a conservation pool reallocation would be the appropriate cost option. The validity of this approach was verified during a thorough evaluation of the water supply user cost options, presented later in this report. Water supply benefits were assumed to be the updated cost of storage plus annual O&M that would be paid by the NTMD and the GTUA to the U.S. Treasury. The updated costs, annualized costs, and estimated annual O&M were prepared for a 50-year economic evaluation period and an interest rate of 4.625% for fiscal year 2009. Using this period of evaluation and interest rate allows a comparison to the total estimated impacts of Alternatives 1 through 4 presented in Table 19 that are based on October 2008 prices, an interest rate of 4.625%, and a 50-year economic evaluation period. The October 2008 prices represent the start of fiscal year 2009 and are compatible. Because of the 50-year evaluation period, the water supply benefit values will not match the annual water storage agreement payments shown elsewhere in this report and in the draft storage agreements themselves. The reason for the apparent difference is that the updated cost of storage is annualized over a 30-year repayment period as required by law.

| Estimated Water Supply Benefits<br><br>(October 2008 Prices, 4.625% interest, 50-year economic evaluation period) | | | | |
|---|---|---|---|---|
| Storage Reallocation<br><br>(acre-feet) | Updated Cost of Storage ($) | Annual Value Of Storage ($) | Annual Estimated O&M ($) | Annual Water Supply Benefit ($) |
| 150,000 | $57,207,952. | $2,953,920. | $67,734. | $3,021,654. |
| 300,000 | $114,415,904. | $5907840. | $135,468. | $6,043,308. |

## 4.10 Summary of Alternative Screening Evaluations

Table 19 displays the categories of impacts that were assessed for the screening of alternatives. The impacts evaluated using the SUPER model include flood damages downstream of Lake Texoma, in-pool flood losses, loss of recreation benefits, and loss of hydropower generation. Downstream flood damages are reduced for Alternatives 1 and 2, whereas, Alternatives 3 and 4 show a slight increase in downstream flood damages due to storage reallocation from the flood pool. In-pool losses are slightly decreased for reallocation from the conservation pool, Alternatives 1 and 2. No in-pool losses are shown for Alternatives 3 and 4 because relocation of recreation facilities would most likely occur if the flood pool is raised and it was beyond the scope of this reallocation study to conduct an assessment of recreation facility relocation. Recreation benefits are assumed to not change from existing conditions. The benefits foregone for hydropower would be greater for Alternatives 1 and 2 than for Alternatives 3 and 4. Also shown are other costs including: cultural resource mitigation and costs associated with relocation of recreation facilities, such as marinas and boat docks, due to increased pool levels (a reduction of flood control storage) and more frequent use of the remaining flood control storage. The other costs only apply to Alternatives 3 and 4. Water supply benefits are based on expected revenues to be received for contracted water supply storage from the NTMWD and the GTUA. From the economic evaluation, summarized in Table 19, it was concluded that reallocation from conservation pool storage would be more cost effective than reallocation from flood control storage.

Changes in conservation storage and flood pool storage will also have impacts on other elements related to Lake Texoma, although these economic impacts are not quantified and are therefore not shown in Table 19. The Lake Texoma land transfer project, currently underway, would require substantive changes if a rise in the flood pool occurs on a permanent basis. If the evaluation of flood control storage reallocation alternatives (3 and 4) had indicated more favorable economic or environmental conditions, then further evaluation would have been required to assess the economic costs related to safety issues. The safety issue evaluation would include the Denison Dam and the Cumberland Levee System. Safety investigations are underway for both project features independent of this reallocation study as part of a nation wide assessment of dam and levee safety. Because those investigations have not been completed, final results are unavailable. However, the initial assessment suggests that physical modification of both the dam and levee system may be necessary for existing conditions. Any decrease in flood control storage related to flood control storage reallocation alternatives would increase the conservation pool elevation and would increase the frequency and elevation of water stored in the flood control pool during project operations. Increased depth of inundation and increased frequency of operation on the dam and levees would inherently impact the functionality of these flood control features.

Risk and uncertainty were considered in development of impacts and benefit estimates used in the screening of alternatives. The purpose of considering risk and uncertainty was to assess to what degree parameters would have to change to impact the overall screening decision. The screening level effort is based on estimated outcomes, specifically the economic value gained or forgone for each of the alternative scenarios. The potential impacts or benefits were compared to the existing conditions, the No Action condition, using the same analytical approaches that were

used for the evaluation of alternatives. Given that the economic parameters used in the evaluation have no specific probabilities associated with them, the approach is to use the operational definition of uncertainty. Uncertain analytical situations are those in which the probability of potential outcomes and their results cannot be described by objectively known probability distributions, or the outcomes themselves are indeterminate. The parameters used in the screening do not have known statistical distributions. In order to address the uncertainty, the sensitivity of each economic impact or benefit was considered by examining how parameters might vary and how that variation might change the selection of one alternative over another. That procedure indicates that the final results of the screening process would be the same even if key parameter varied by as much as 50% percent. Based on this assessment, the selected alternative clearly merits more detailed analysis while the remaining alternatives should be eliminated from further consideration.

### 4.11 Economic Assessment

Alternatives 1 and 2 would reallocate storage from the conservation pool for 150,000 and 300,000 acre-feet for water supply storage, respectively. Water supply benefits for Alternatives 1 and 2 would exceed the evaluated impacts by more than 200%.

Alternatives 3 and 4 would reallocate storage from flood control storage for 150,000 and 300,000 acre-feet for water supply storage, respectively. Alternative 3 is shown to have notably greater economic impacts (a net loss of $715,000 annually) and would therefore not qualify as a Federal storage reallocation option. Alternative 4 is shown to be justified and if there were no other storage reallocation options, this alternative could be considered for further, more detailed study for reallocation of 300,000 acre-feet of storage. However, Alternative 2 is shown to have a large margin of net benefits for the same storage reallocation of 300,000 acre-feet with more than twice the net benefits of Alternative 4. Further, there were important impact categories that applied only to the flood control reallocation alternatives (3 and 4) that were not quantified due to the time and cost that would be required for those additional studies. Because Alternative 2 is appreciably more cost effective for relocation of 300,000 acre-feet of storage, Alternative 4 was not considered further.

In Section 4, the preliminary screening of measures presented: (a) an identification of the most likely source for water supply, and (b) an identification of which storage reallocation, with options of flood control or conservation pool storage, would be most appropriate when considering economic, social, and environmental impacts of the potential reallocation. The conclusions were that storage reallocation from Lake Texoma was the most likely source and that reallocation from the conservation pool storage was the more cost effective option. Therefore, from an economic evaluation only Alternatives 1 and 2 (conservation pool storage reallocation) merited further consideration. The following environmental assessment discussion includes the preliminary identification and evaluation of measures to meet water supply needs and the further evaluation of Alternatives 1 and 2 that were considered to be economically feasible.

## TABLE 19

## SUMMARY OF ANNUAL IMPACTS AND BENEFITS BY ALTERNATIVE

## OCTOBER 2008 PRICES ($1,000)

| | | | SUPER | | | Hydropower | Other Costs | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Alternative** | **Alternative Reallocation Storage (acre-feet)** | **Total Water Supply Storage (acre-feet)** | **Downstream Flood Damages Table 11 ($1,000)** | **In-Pool Losses Table 12 ($1,000)** | **Recreation Benefit Table 13 ($1,000)** | **Benefits Foregone Table 15 ($1,000)** | **Cultural & Rec Facilities Costs Table 18 ($1,000)** | **Total Impacts ($1,000)** | **Water Supply Benefits ($1,000)** | **Water Supply Benefits Less Total Impacts ($1,000)** |
| 1 | 150,000 | 300,000 | $12.2 | $8.1 | No Change | -$1,417. | NA | -$1,397 | $3,022 | $1,625 |
| 2 | 300,000 | 450,000 | $53.4 | $21.4 | No Change | -$2,775 | NA | -$2,700 | $6,043 | $3,433 |
| 3 | 150,000 | 300,000 | -$101.7 | Est $0.0 | No Change | -$834 | -$2,801 | -$3,737 | $3,022 | -$715 |
| 4 | 300,000 | 450,000 | -$144.6 | Est $0.0 | No Change | -$1,634 | -$3,089 | -$4,868 | $6,043 | $1,175 |

Note:
Negative signs indicate a negative impact compared to the existing conditions.
No Change – No change assumed.
NA – Not Applicable.
Water supply benefits for this evaluation are annualized over 50-years to allow for an appropriate comparison with total annual impact values. Benefits are based on updated costs of storage and include estimated O&M. See Section 4.9.

## 4.12 Environmental Assessment

The National Environmental Policy Act (NEPA) requires all Federal agencies to address the environmental impacts of any major Federal action on the natural and human environment. The Tulsa District initiated the NEPA scoping process by issuing a news release on August 6, 2003, and having paid advertisements placed in the Denison Herald Democrat on September 2, 14, and 16, and the Durant Democrat on September 3, 14, and 17, 2003. The news release and advertisements announced public information workshops being conducted to gather input for preparation of a Draft Environmental Assessment (DEA). Announcements also were sent to state and Federal agencies.

The workshops were held on September 16, 2003 at the Denison Public Library and on September 17, 2003 at the Durant Chamber of Commerce. Twenty persons attended the workshops including: representatives from local, state, and Federal agencies; Native American tribes; congressional delegates; and private citizens.

In addition to the local workshops, letters requesting preliminary information for preparation of an Environmental Assessment for the project were sent to four Federal agencies, four Native American tribes, nine state agencies, and one local agency. Responses to the preliminary request for information were received from one Federal agency (U.S. Fish and Wildlife Service) and five state agencies (Texas Water Development Board, Oklahoma Water Resources Board, Oklahoma Historic Preservation Office, Oklahoma Archeological Survey, and Texas State Historic Preservation Office).

On January 21, 2005, the DEA, identifying the recommended action, was formally released for a 30-day public comment period. Copies of the DEA were mailed to congressional delegates, government agencies, libraries, and interested members of the public. The comment period was scheduled to end February 21, 2005. However, a request from hydropower interests to extend the public comment period was granted and the public comment period ended April 7, 2005.

Comments received during the January 21 through April 7, 2005 public review period were generally aligned along three areas of interest: 1) public water supply, 2) hydropower, and 3) fish and wildlife. Public water supply entities were in favor of the reallocation because of the need for additional water supply to meet growing municipal water needs in the north Texas region that includes Dallas and Fort Worth. Hydropower interests were opposed to the reallocation because of revenue losses since the water would be reallocated from hydropower storage. Fish and wildlife interests expressed concern that if public water supply needs increased and the total reallocation was used, the additional water requirement would cause negative impacts upon lake levels and downstream releases for fish and wildlife.

Based upon comments received during the public comment period the DEA was revised with substantive comments addressed and the Hydropower Reallocation Report included as an appendix to the DEA. It was prepared for a second public comment period and on October 14, 2005, the revised DEA was formally released for a second 30-day public comment period. Copies of the revised DEA were again mailed to congressional delegates, government agencies, libraries, and interested members of the public. The comment period was scheduled to end

November 14, 2005. Hydropower interests again requested an extension to the public comment period for the revised DEA and the public comment period was extended to December 20, 2005.

Seven written comments were received during the second public review and were aligned between two water user groups. Water supply interests, who are in need of municipal and industrial water to meet growing water supply needs in the region, support the reallocation. Hydropower interests, who are concerned that hydropower benefits would be lost, oppose the reallocation and want the water to remain allocated for hydropower.

Responses received during the public comment period were reviewed and the Final EA (FEA) was revised to address substantial comments. Comments ranged from expressions for the need for additional water supply, to hypothetical 'what-ifs', to specific technical changes. Of particular concern to hydropower interests are the lost hydropower benefits and the method of calculation used by the Corps to determine credits for power benefits foregone. The main contention from SWPA was the method in which compensation would be calculated. The Corps of Engineers Hydropower Analysis Center calculates benefits foregone by using National Economic Development standards as specified in Corps of Engineers policy and guidance. Southwestern Power Administration measures the benefits lost based on market-based benefits lost.

The Corps responded to the comments in a variety of ways, which included:

1) Modifying the EA to better explain the hydrological effects of reallocation.

2) Addressing additional alternatives that previously had been considered but not included in the first DEA.

3) Modifying the EA to better address fish and wildlife concerns as they relate to pool levels and downstream releases.

4) Including the Lake Texoma Storage Reallocation Report as an appendix to the EA.

5) Making factual corrections.

6) Modifying the EA to better explain the rationale, authorities, and sources used in the DEA and why the Corp's position is maintained in the FEA.

It was determined from the Environmental Assessment that the water reallocation would not have a significant impact on the natural or human environment. A Finding of No Significant Impact (FONSI) was signed on May 24, 2006, stating that an Environmental Impact Statement would not be prepared.

A supplemental environmental assessment (SEA) was prepared (April 2009) to provide additional supporting information and details for analyses previously presented in the Final Environmental Assessment, Lake Texoma Storage Reallocation Study, Lake Texoma, Oklahoma and Texas (Tulsa District 2006). The SEA was prepared in accordance with U.S. Army Corps of

Engineers Regulations, Part 230, Policy and Procedures for Implementing the National Environmental Policy Act. Following an initial screening of Measures 1 through 7 (Table 9) using methodology and rationale provided in this reallocation report, Measure 6 (reallocation of flood control storage to water supply – Alternatives 3 and 4) was evaluated as a potential measure but was screened from further evaluation based on economic criteria. It was determined from the SEA that the proposed action Measure 7 (reallocation from conservation storage to water supply – Alternatives 1 and 2) was economically feasible and would have no significant adverse effects on the natural or human environment. Therefore, an environmental impact statement was not prepared.

**4.13 Selected Alternative.** Reallocation from the conservation pool was selected as the only economically feasible measure to meet both the immediate need for storage reallocation of 150,000 acre-feet and the potential long term reallocation of 300,000 acre-feet; and reallocation from the conservation pool was the most economical measure to meet either immediate or long term reallocation needs. Alternatives 1 and 2 meet the short and long term needs of the water supply users and have the least negative impacts to other project purposes. The analysis of water supply needs indicates that water supply users in Texas have an immediate need for 150,000 acre-feet of storage in Lake Texoma. No immediate Oklahoma water supply needs were identified, but the Red River Compact apportions water storage equally between the states of Oklahoma and Texas. Therefore, the selected plan for near term reallocation is Alternative 1, but Alternative 2 was evaluated for potential future implementation. Alternative 1 and 2 result from the same measure (conservation storage reallocation). Therefore they are effectively different scales of the same measure. Both scales (reallocation of 150,000 and 300,000 acre-feet of storage) were assessed and found to be cost effective and to have no significant adverse effects on the natural or human environment.

The North Texas Municipal Water District (NTMWD) has requested a water storage agreement for 100,000 acre-feet. The GTUA has requested a water storage agreement for 50,000 acre-feet. The requested 150,000 acre-feet of storage from the conservation pool would reallocate about 15.202% of the conservation pool storage or about 3.818% of the total usable storage in Lake Texoma.

- If the agreements evaluated for immediate need reallocation are approved for final negotiations, the remaining balance of storage identified for reallocation under Sec 838 would be for Oklahoma. The total storage that would be available for Oklahoma communities would be 150,000 acre-feet, which also represents 15.202% of the conservation storage.

- If the agreements evaluated for immediate need reallocation are implemented, hydropower generation would have use of 69.6% of the conservation storage (686,730 acre-feet) plus all of the flood control storage of 2,611,439 acre-feet. Flood control storage is about 72.6 percent of total usable storage in Lake Texoma.

The potential reallocation of 300,000 acre-feet of storage would fulfill the authorization provided to the ASA (CW) under the provisions of Sec 838. The increment of storage available

for Oklahoma communities would be 150,000 acre-feet of storage, which represents 15.202% of the conservation storage. Hydropower generation would be further impacted by this reduction in conservation pool storage. Hydropower generation using flood control storage would generally not be impacted.

## 5.0 DERIVATION OF USER COST – THE VALUE OF STORAGE

The cost charged to the NTMWD and GTUA for storage would be based on the value of the storage. The determination of the value is guided by the Corps policy (ER 1105-2-100). The implications of that policy application are summarized in a paper by H. Al Pless, Economist, U.S. Army Corps of Engineers, Savannah, Georgia, titled "*Reallocation of Water Storage in Federal Water Projects, Proceedings of the 1991 Georgia Water Resources Conference*," held March 19 and 20, 1991, at the University of Georgia.

**5.1 Methodology.** Following are excerpts from the paper presented by H. Al Pless. While the document was developed to discuss the Corps policy of reallocation of water storage at a Georgia Water Resources Conference and it references water supply contracts for the Savannah River Basin; the discussion is germane to all Corps projects where water supply and hydropower are authorized purposes.

> "U.S. Army Corps of Engineers Regulation ER 1105-2-100 specifies the four pricing methods used to calculate the value of storage. The four methods include: updated cost of storage, benefits foregone, revenues foregone, and replacement cost. The value placed on the storage is the highest of the four methods.
>
> - Updated Cost of Storage. The updated cost of reallocated storage is estimated by updating the cost of the joint use features from the midpoint of construction to the fiscal year in which the reallocation of storage is approved. The updated cost of the joint use features is then multiplied by the proportion of useable storage that is to be reallocated to estimate the value of the reallocated storage.
>
> - Hydropower Revenues Foregone. Hydropower revenues foregone are defined as the reduction in revenues accruing to the Treasury as a result of reallocating storage from hydropower to water supply. The revenues are based on the existing repayment agreement between the power marketing agency and the US Army Corps of Engineers.
>
> - Benefits Foregone. Benefits foregone are defined in terms of National Economic Development (NED) benefits. Generally these are equal to the net loss of average generating capacity and energy. It is possible that benefits foregone could be measured in terms of lost flood control benefits.

- Replacement Cost. Notwithstanding unforeseen circumstances, replacement costs are equal to benefits foregone. In the event that reallocated storage is being taken from the flood control pool, the Corps will estimate the replacement cost of equivalent protection. […]

  If the cost of reallocated storage is less than the most likely alternative non-Federal source of water supply, the reallocation is considered to be feasible. The reallocation is feasible because, net marginal benefits associated with water supply are greater than benefits associated with the displaced project purpose. […]"

**5.2 <u>Derivation of User Cost – The Value of Storage</u>.** Section 838 authorized the Secretary to reallocate storage, but did not implement a storage reallocation. The reallocation of water supply storage would not occur until water storage agreements are executed. Because storage is not considered to be reallocated from its original purpose until a water storage agreement is executed, conservation storage that has not been reallocated to another purpose would continue to be available for the production of hydropower. The evaluation of storage value method options therefore considers the cost option for the immediate need reallocation of 150,000 acre-feet only. The purpose of this method evaluation is to determine the appropriate cost of storage for the immediate reallocation request for 150,000 acre-feet of storage.

There is no value added in presenting storage value for the 300,000 acre-foot storage authorized by Sec 838. The reallocation of storage to Oklahoma may not occur for years and a value of storage evaluation using current price levels and interest rate would be required at the time of any subsequent reallocation request by Oklahoma.

An evaluation of the value of storage was conducted in fiscal year 2006 using interim findings by the Hydropower Analysis Center and detailed updated costs of storage. The validation discussion follows the interim evaluation below.

**5.2.1 Updated Cost of Storage – Fiscal Year 2006**. The updated cost of storage for 150,000 acre-feet was estimated at $53,728,850.5 when updated to fiscal year 2006 (October 2005 to September 2006). The estimated annual cost for an interest rate of 4.625% and an economic evaluation period of 50 years was $2,774,278. The estimated annual operation and maintenance, based on actual O&M, was $97,987. The total estimate was $2,872,265 per year. This value represents an interim estimate of the updated cost of storage at price levels comparable to the other value of storage method estimates below. An updated storage cost table is not presented for this 2006 interim evaluation and the derivation of costs is not presented. Those components of documentation are presented for the updated cost of storage based on fiscal year 2009 later in this section.

**5.2.2 Hydropower Revenues Foregone – December 2005 (Fiscal Year 2006)**. The hydropower revenues foregone or lost because of the storage reallocation were evaluated based

on current Southwestern Power Administration (SWPA) contract rates. The rates that are in effect, obtained from SWPA comments dated 20 December 2005, are shown:

Energy Charge: 8.20 mills/kWh
Capacity Charge: $36.36/kW-year

To compute revenues foregone, the energy charge was applied to the average annual energy losses. The capacity charge was applied to the loss in dependable capacity. SWPA's most critical operating year was in 1964. Under SWPA's current marketing procedures, the amount of marketable capacity at Denison Dam (Lake Texoma) was based on the capacity that could be supported during the 1964 peak demand period. The loss in marketable capacity was shown to be 12,730 kW, and is shown in Table 20. The annual revenues foregone for the potential reallocation of 150,000 acre-feet is also shown.

**TABLE 20**

**HYDROPOWER REVENUES FOREGONE**

(December 2005 Prices)

| **Allocation Alternatives** | **150,000 (acre-feet)** |
|---|---|
| Annual Energy Losses (MWh) | 11,995 |
| Energy Charge ($/MWh) | $8.20 |
| Annual Energy Revenues Foregone ($) | $98,359 |
| Capacity Losses (kW) | 12,730 |
| Capacity Charge ($/kW) | $36.36 |
| Annual Capacity Revenues Foregone ($) | $462,863 |
| Total Annual Revenues Foregone ($) | $561,222 |

**5.2.3 Hydropower Benefits Foregone – December 2005 (Fiscal Year 2006)**. The loss of project benefits that would result from the reallocation of 150,000 acre-feet of storage were computed based on December 2005 prices, a 4.625% interest rate, and an economic evaluation period of 50 years. Benefits were calculated assuming a 70-megawatt (MW) power plant. The annual energy loss based on SWD-SUPER stream flow data for 1938-2000 was 11,995 MWh. The annual hydropower benefits foregone are the sum of annual energy benefits foregone and annual capacity benefits foregone. Annual hydropower benefits foregone for the potential 150,000 acre-feet reallocation are shown in Table 21.

| TABLE 21<br><br>ANNUAL HYDROPOWER BENEFITS FOREGONE<br>(December 2005 Prices) | |
|---|---|
| **Allocation Alternatives** | **150,000 Acre-Feet** |
| Annual Energy Losses (MWh) | 11,995 |
| Energy Value ($/MWh) | $41.62 |
| Annual Energy Benefit Foregone ($) | $499,232 |
| Capacity Losses (kW) | 2,310 |
| Capacity Value ($/kW) | $111.48 |
| Annual Capacity Benefit Foregone($) | $257,519 |
| Total Annual Benefits Foregone($) | $756,751 |

**5.2.4 Hydropower Replacement Costs**. The replacement cost of power as used for computing the cost of reallocated storage is an economic or National Economic Development cost. The NED cost of replacement power is, by definition, identical to the hydropower benefits foregone.

**5.3 Initial Value of Storage Summary.** The preceding evaluations of four methods for determining the water supply user cost considered the immediate need reallocation of 150,000 acre-feet. The cost options are summarized below. The value of storage would be the highest of the four cost methods and would be the option that sets the user cost. The highest value of storage is the updated cost of storage as shown below.

| **Cost Options**<br>**Reallocation of 150,000 acre-feet** | **Annual Cost**<br>**$** |
|---|---|
| Updated Cost of Storage<br>(Fiscal Year 2006 Prices)<br>(October 2005 to September 2006) | $2,872,265 |
| Hydropower Revenues Foregone<br>(December 2005 Prices) | $561,222 |
| Hydropower Benefits Foregone<br>(December 2005 Prices) | $756,751 |
| Hydropower Replacement Cost | (Same as Benefits Foregone) |

**5.4 Validation of Value of Storage Selection – 2009.** The evaluation above was conducted in 2006 using interim estimates of benefits foregone, revenues foregone, and replacement costs. The updated cost of storage was a detailed estimate with a comparable price base for fiscal year 2006. (Fiscal year 2006 begins in October 2005.) The interim evaluation concluded the updated cost of storage was the highest value of the four methods and would be the user cost for storage. That evaluation was included in a draft report reviewed by HQUSACE. Subsequent HQUSACE guidance directed further evaluation of replacement costs, and further coordination with the PMA (the SWPA) concerning impacts to hydropower generation. More detailed hydropower evaluations were conducted by the Hydropower Analysis Center. The subsequent HAC evaluation methodology evolved as a result of the PMA coordination and through assistance by the Platts Power Outlook Research Service analytical service. (Platts is a global provider of energy information.) The evolution of the methodology, reassessment of the value of capacity, and market price increases for power through 2008 resulted in a large increase in the estimate of replacement costs (which are equal to benefits foregone).

To verify that the updated cost of storage would still set the value of the storage, the hydropower replacement cost (the second highest cost in the initial evaluations) was compared to the fiscal year 2009 updated costs of storage (October 2008 to September 2009). The current estimate of replacement power for a 50-year economic evaluation, interest of 4.625%, and October 2008 prices is $1,416,784 per year Appendix E, 50-year economic evaluation. The current estimate of the updated cost of storage is $57,207,951. The annualized value for a 50-year economic period and interest of 4.625% would be $2,953,920. The updated cost of storage was found to be more than double the estimate of replacement cost. Therefore, the updated cost of storage was verified as the highest of the four pricing methods and was confirmed as the method appropriate for setting the user's cost specified in the water storage agreements

**5.5 User Cost – Updated to Fiscal Year 2009**. The cost allocated to the user under this procedure updates the cost of the reservoir to present day price levels and then assigns a percentage of the costs based on the "Use of Facilities" cost allocation procedure. Costs are updated from "as built" costs to 1967 prices by use of the Engineering News Record (ENR) Construction Cost Index, and then from 1967 to current prices by use of the Corps' Civil Works Construction Cost Index System (CWCCIS). Land values are updated by the weighted average update of all other project features. Costs are indexed from the midpoint of the physical construction period to the beginning of the fiscal year in which the contract for the reallocated storage is approved.

Construction is considered as having been initiated at the start of the month when lands for the project were first acquired or on the date when the first construction contract was awarded whichever was earlier. Construction is considered as having been completed at the end of the government fiscal year in which final deliberate impoundment of the reservoir pool was initiated.

The Corps of Engineers policy on pricing storage reallocated from one authorized project purpose to another is based on the "Use of Facilities" (UOF) methodology. The cost of reallocated storage changes each government fiscal year.

Section 932 of the 1986 WRDA requires recalculation of the interest rate at 5-year intervals if the storage is paid annually over a 30-year period.

The storage cost calculations for the NTMWD and GTUA are shown in Illustrations 1 and 2. The cost calculations are based on the updated cost of storage of $1,372,222,400, see Table 22, and the actual total project operation and maintenance costs from FY 2008 of $1,621,911. Other values and procedures used in the calculations are presented in the illustrations.

**Illustration 1.**

The value of the 100,000 acre-feet of storage requested by NTMWD for reallocation is calculated to be $38,134,060 based on updated cost of storage for fiscal year 2009. The annual value would be $2,270,639 based on a 30-year repayment period with an interest rate of 4.625%. Using actual O&M expenses for FY 2008, the estimated annual operation and maintenance cost would be about $45,073. The total annual payment during the 30 year repayment period would be $2,315,712. An annual payment for O&M would continue to be made by the NTMWD following the 30-year storage repayment period.

| NTMWD Reallocation Request<br>Storage Cost Calculations | | |
|---|---|---|
| Total Usable Storage for Lake Texoma ($\mathbf{S_{Tot}}$) | | 3,598,169 acre-feet<br>(Table 3) |
| NTMWD Storage Request ($\mathbf{S_{Req}}$) | | 100,000 acre-feet |
| Percent of Total Usable Storage for NTMWD Storage Request (**P**)<br>$\mathbf{P = S_{Req} / S_{Tot}}$ = 100,000 / 3,598,169 | | 2.779% |
| Total Updated Cost of Storage for Lake Texoma ($\mathbf{C_{Tot}}$) | | $1,372,222,400<br>(Table 22) |
| NTMWD Cost of Storage Request ($\mathbf{C_{Req}}$)<br>$\mathbf{C_{Req} = P \times C_{Tot}}$ = 0.02779 x $1,372,222,400 | | $38,134,060 |
| NTMWD Annual Cost of Storage Request ($\mathbf{A_{Req}}$) | | |
| $\mathbf{A_{Req} = C_{Req} \frac{i(1+i)^{n-1}}{(1+i)^{n} - 1}}$ | Where: $\mathbf{C_{Req}}$ = $38,134,060<br>**i** = 4.625% discount rate<br>**N** = 30 year | $2,270,639 |
| Operation and Maintenance for Lake Texoma ($\mathbf{O\&M_{Tot}}$) | | $1,621,911<br>FY 2008 Actual |
| NTMWD Annual Operation and Maintenance Estimate ($\mathbf{O\&M_{Req}}$)<br>$\mathbf{O\&M_{Req} = P \times O\&M_{Tot}}$ =(0.02779 x $1,621,911) | | $45,073 |
| Replacement and Rehabilitation for Lake Texoma ($\mathbf{R\&R_{Tot}}$) | | $0<br>FY 2008 Actual |
| NTMWD Annual Replacement and Rehabilitation Estimate ($\mathbf{R\&R_{Req}}$)<br>$\mathbf{R\&R_{Req} = P \times R\&R_{Tot}}$ = (0.02779 x $0) | | $0 |
| NTMWD Total Annual Cost =<br>$\mathbf{A_{Req} + O\&M_{Req} + R\&R_{Req}}$ = ($2,270,639 + $45,073 + $0) | | $2,315,712 |

**Illustration 2.**

The value of the 50,000 acre-feet of storage requested by GTUA for reallocation is calculated to be $19,073,891 based on updated cost of storage for fiscal year 2009. The annual value would be $1,135,728 based on a 30-year repayment period with an interest rate of 4.625%. Using actual O&M expenses for FY 2008, the estimated annual operation and maintenance cost would be about $22,545. The total annual payment during the 30 year repayment period would be $1,158,273. An annual payment for O&M would continue to be made by the GTUA following the 30-year storage repayment period.

| GTUA Reallocation Request<br>Storage Cost Calculations | | |
|---|---|---|
| Total Usable Storage for Lake Texoma ($\mathbf{S_{Tot}}$) | | 3,598,169 acre-feet<br>(Table 3) |
| GTUA Storage Request ($\mathbf{S_{Req}}$) | | 50,000 acre-feet |
| Percent of Total Usable Storage for GTUA Storage Request (**P**)<br>$\mathbf{P = S_{Req} / S_{Tot}}$ = 50,000 / 3,598,169 | | 1.390% |
| Total Updated Cost of Storage for Lake Texoma ($\mathbf{C_{Tot}}$) | | $1,372,222,400<br>(Table 22) |
| GTUA Cost of Storage Request ($\mathbf{C_{Req}}$)<br>$\mathbf{C_{Req} = P \times C_{Tot}}$ = 0.01390 x $1,372,222,400 | | $19,073,891 |
| GTUA Annual Cost of Storage Request ($\mathbf{A_{Req}}$) | | |
| $\mathbf{A_{Req} = C_{Req} \frac{i(1+i)^{n-1}}{(1+i)^{n} - 1}}$ | Where: $\mathbf{C_{Req}}$ = $19,073,891<br>**i** = 4.625% discount rate<br>**N** = 30 year | $1,135,728 |
| Operation and Maintenance for Lake Texoma ($\mathbf{O\&M_{Tot}}$) | | $1,621,911<br>FY 2008 Actual |
| GTUA Annual Operation and Maintenance Estimate ($\mathbf{O\&M_{Req}}$)<br>$\mathbf{O\&M_{Req} = P \times O\&M_{Tot}}$ =(0.01390 x $1,621,911) | | $22,545 |
| Replacement and Rehabilitation for Lake Texoma ($\mathbf{R\&R_{Tot}}$) | | $0<br>FY 2008 Actual |
| GTUA Annual Replacement and Rehabilitation Estimate ($\mathbf{R\&R_{Req}}$)<br>$\mathbf{R\&R_{Req} = P \times R\&R_{Tot}}$ = (0.01390 x $0) | | $0 |
| GTUA Total Annual Cost =<br>$\mathbf{A_{Req} + O\&M_{Req} + R\&R_{Req}}$ = ($1,135,728 + $22,545 + $0) | | $1,158,273 |

**TABLE 22**

**UPDATED STORAGE COSTS FOR FY 2009**

| Category | Actual Joint-Use As of Jan 1942 ($1,000) | Mid-point Jan 1942 ENR Index ($1,000) | Oct 1967 ENR Index | Update Factor | Oct 1967 Joint Use Costs ($1,000) | October (1) ENR or (2) CWCCIS 1967 Index | October (1) ENR or (2) CWCCIS 2008 Index | Update Factor | Oct 2008 Joint Use Costs ($1,000) |
|---|---|---|---|---|---|---|---|---|---|
| Lands and Damages | 6,442.0 | 268 | 1,096 | 4.0896 | 26,345.2 | 100 (2) | 714 (3) | 7.140 | 188,104.7 |
| Relocations | 13,670.1 | 268 | 1,096 | 4.0896 | 55,905.2 | 1,096 (1) | 8551 (1) | 7.802 | 436,172.4 |
| Reservoir | 3,703.9 | 268 | 1,096 | 4.0896 | 15,147.5 | 100 (2) | 743 (2) | 7.430 | 112,545.9 |
| Dam and Spillway | 15,622.7 | 268 | 1,096 | 4.0896 | 63,890.6 | 100 (2) | 700 (2) | 7.000 | 447,234.2 |
| Outlet Works | 0.0 | 268 | 1,096 | 4.0896 | 0.0 | 100 (2) | 703 (2) | 7.030 | 0.0 |
| Roads | 271.3 | 268 | 1,096 | 4.0896 | 1,109.5 | 100 (2) | 706 (2) | 7.060 | 7,833.1 |
| Levees | 5,633.5 | 268 | 1,096 | 4.0896 | 23,038.8 | 100 (2) | 718 (2) | 7.180 | 165,418.6 |
| Buildings, grounds, and utilities | 258.0 | 268 | 1,096 | 4.0896 | 1,055.1 | 1,096 (1) | 8551 (1) | 7.802 | 8,231.9 |
| Permanent operating equipment | 209.4 | 268 | 1,096 | 4.0896 | 856.4 | 1,096 (1) | 8551 (1) | 7.802 | 6,681.6 |
| TOTAL | 45,810.9 | | | | | | | | 1,372,222.4 |
| Specific Costs<br>Water Supply Conduit | 0.0 | 268 | 1,096 | 4.0896 | 0.0 | 100 (2) | 703 (2) | 7.030 | 0.0 |

Project, Denison Dam - Construction Initiated, August 1939; Construction Completed, June 1944; Construction Mid-point, January 1942
(1) ENR - Engineering News Record Index
(2) CWCCIS - Civil Works Construction Cost Index System
(3) Updated by the weighted average of other project features

## 6.0 TEST OF FINANCIAL FEASIBILITY

To test the financial feasibility of the reallocation, the annual cost of the reallocated storage is compared to the annual cost of the most likely, least costly, water supply source that would provide an equivalent quality and quantity of water if storage reallocation at Lake Texoma was not an option for the water supply customer. The following sections present the evaluation of two potential least costly alternatives sources for the NTMWD and the GTUA; and the identification of the most likely, least costly water supply source if storage reallocation at Lake Texoma was not an option.

6.1 **Least Costly Water Supply Alternatives To Meet Future Regional Demands.** The forecasts for regional water demands for NTMWD and the GTUA and an inventory of existing and potential sources of water supply have been shown in previous sections of the report. These demands and existing and potential sources of water supply were comprehensively discussed in the 2006 Region C Water Plan. The GTUA has identified Lake Texoma water as its main source of water supply to meet forecast needs because of an existing desalinization facility designed and constructed to treat Lake Texoma water. This facility can be expanded to meet future needs in its service region. The NTMWD also has the capability of providing Lake Texoma water to the GTUA on an interim basis as needed from its storage at Lake Texoma. The NTMWD has identified Lake Texoma water as the preferred source to meet a portion of future needs.

The NTMWD is a large water utility. The NTMWD will require large volumes of water from Lake Texoma by year 2015 and beyond based on the 2006 Region C Water Plan. NTMWD will also seek to develop other sources of water supply to meet water needs beyond the near term of 2010 to 2020. Other sources are not expected to be realized in the near term because of the large financial resources required (hundreds of millions of dollars) and the need to consider social and environmental impacts.

- Lower Bois d'Arc Creek Reservoir is the first most likely source after Lake Texoma storage reallocation. The cost of this alternative is about $400 million (in 2002 dollars)

- Marvin Nichols reservoir is the second most likely source at about $534 million (in 2002 dollars).

The costs per acre foot and per thousand gallons based on annual costs are shown below. Table 23 shows the unit cost in terms of dollars per thousand gallons. The table below shows the annual cost in the first quarter fiscal year 2009 (October 2008) values, using the composite Civil Works Construction Cost Index System to update the Region C Water Plan values from year 2002. Based on the updated costs for the Lower Bois d'Arc project, the cost per acre-foot is $285 and the cost per thousand gallons is $0.87. Updating only the NTMWD portion of the total cost for Marvin Nichols Reservoir (over $2.2 billion) and using different assumptions for calculating annual costs, the unit cost would be lower than Lower Bois d'Arc at $0.85 per thousand gallons.

| TABLE 23<br><br>2006 REGION C WATER PLAN | | | |
|---|---|---|---|
| **Alternative Supply**<br><br>**Total Cost**<br>**(2002 Prices)** | **Annual Cost/**<br>**Total Cost**<br><br>**(October 2008)** | **Water Supply**<br><br>**Storage (acre-feet)/**<br>**Yield (mgd)** | **Cost Per acre-foot/**<br>**Cost Per 1000 gal**<br><br>**(October 2008)** |
| Lower Bois d'Arc Creek<br>$400 million | $35,009,000<br>$482,500,000 | 123,000<br>110 | $285<br>$0.87 |
| Marvin Nichols<br>$534 million | $48,690,000<br>$718,000,000 | 174,840<br>156 | $278<br>$0.85 |

**6.2 Most Likely Water Supply Alternatives To Meet Future Regional Demands.** Marvin Nichols reservoir would require a consortium of three major water utilities, including the Tarrant Regional Water District and the Upper Trinity River Water District, to develop the reservoir. The total capital cost of Marvin Nichols reservoir in 2002 dollars is estimated to be $2.2 billion, of which the NTMWD share is $534 million.

The total water supply yield of Marvin Nichols is about 489,800 acre-feet, with the NTMWD share of about 174,840 acre-feet. Not all of the three major water utilities would require Marvin Nichols as a source of water until 2030. The high total cost for Marvin Nichols, the necessary partnerships with other water purveyors, and the other institutional and environmental reasons require that the Lower Bois d'Arc be considered first. The 2006 Region C Water Plan data should be relied upon in this case in identifying the most likely, least costly alternative. Based on water supply yield and on the necessity for a developmental partnership for the implementation of Marvin Nichols, the Lower Bois d'Arc project would be constructed first.

Updated costs for the proposed Lower Bois d'Arc project are shown in Table 24. These costs are based on the Federal discount rate of 4 5/8 percent for interest during construction, and a 100-year period of analysis (the Region C Water Plan calculations use a 30-year bond repayment period).

The total cost and the quantities of water required for new sources of water supply by year 2020 indicate that the Lower Bois d'Arc would be the most likely and least costly choice for a new source of water supply.

The planned project, Lower Bois D'Arc, would be the most likely and least costly water supply alternative to (the existing source) Lake Texoma storage reallocation. The Lower Bois D'Arc project is estimated to supply about 110 mgd for the NTMWD and would have an estimated average annual cost of about $35,000,000. The Lake Texoma storage reallocation for NTMWD and GTUA, with an average annual cost of $3,021,654 and an estimated yield of about 150 mgd, passes the test of financial feasibility without further analysis. (The economic value of "$3,021,654" represents the Fiscal Year 2009 updated cost of storage annualized over a 50-year period at a discount rate of 4.625% (Presented in Section 4.9), and does not represent the annual water storage agreement payments amortized over 30 years.)

| TABLE 24<br>LOWER BOIS D'ARC CREEK RESERVOIR<br>PROJECT COST AND ANNUAL COSTS<br>(October 2008 Prices) | |
|---|---|
| **Total Project Costs** | **Value ($1,000)** |
| Dam and Reservoir | 75,033 |
| Conflicts | 22,627 |
| Land Acquisition-conservation pool | 30,006 |
| Land Acquisition-flood pool | 12,939 |
| Land Acquisition-terminal storage | 165 |
| Conveyance Facilities | |
| Pipeline | 210,033 |
| Intake Pump Station | 45,756 |
| Terminal Storage Facilities | 23,594 |
| Permitting & Mitigation-reservoir & storage | 60,344 |
| Permitting & Mitigation-pipeline | 1,991 |
| **Total Project Cost** | **482,490** |
| **Annual Costs** | |
| Total Project Cost | 482,490 |
| Interest During Construction | 34,587 |
| Total Gross Invest | 517,077 |
| Annual Charges | |
| Interest & Amortization | 26,680 |
| Operation & Main | 8,329 |
| Major Replacement | 0 |
| **Total Annual Cost** | **35,009** |

**7.0 PROJECT COST ACCOUNTS – HYDROPOWER AND WATER SUPPLY.** The potential for reallocation of federal hydropower project benefits to water supply storage benefits was envisioned by the Federal government with the Water Supply Act of 1958. This act authorized the Secretary of the Army to modify an existing Corps of Engineers project like Lake Texoma to include storage for water supply for State and local interests. Such a reallocation would reduce some portion of hydropower production in favor of water supply storage if that reallocation is considered to be a more beneficial use of storage. In return for the water supply storage reallocation, a non-Federal sponsor will agree pay the Treasury as much or more for the storage as would be realized through the sale of hydropower over a specified period of valuation.

The 1958 Water Supply Act gave sufficient authority to adjust and credit the Federal project accounts as the Secretary determined to be reasonably necessary to reflect the economic

consequences of the reallocation. Account transfers from water supply accounts to power accounts historically have been made to preserve the repayment capability of the power marketing agency for assets and operating expenses. Use of the term "operating expenses" herein is a broad characterization that would include major replacements and continuing operation costs that are single purpose or joint use costs assigned to (in this case) the hydropower purpose. The credit transfers are based on the equity concept that reallocation of storage and diversion of water from power production would adversely effect the power marketing agency's ability to recoup costs it had agreed to cover. The vast majority of those costs were the initial construction costs (assets). The typical repayment period is 50 years. For Lake Texoma the 50-year period ended in 1994. Subsequent assets have been added to the hydropower account, and include major replacement costs such as rewinding turbines. These costs are relatively small in comparison to the $1.4 billion total project cost.

Traditional policy for Lake Texoma credits was modified by provisions of Section 838 of the 1986 Water Resources Development Act. Traditional policy and the specific project provision of Sec 838 are discussed below. The modified policy established by Section 838 is discussed in section 7.2.

**7.1 Traditional Policy.** The traditional Corps policy has been to transfer credits to hydropower accounts that are only sufficient to make up for amounts the power marketing agency could not collect because it would sell less hydropower. It has not been the Corps policy to reimburse the power marketing agency or their customers directly for their purchase of alternative power. To do so would have implied that power marketing agency customers have an absolute right to a power subsidy. While there is a reduction in the ability of the power marketing agency to repay costs allocated to hydropower, the transfer of storage to the water supply purpose also transfers the responsibility to repay an equal or greater value to the Treasury. Water supply repayment of costs is accomplished through the water supply user's purchase of storage and associated operational costs.

The credit adjustments to project accounts are not transfers of funds among Federal agencies, they are Treasury account adjustments wherein the project account balances for assets and/or operating expenses allocated to a project purpose (in this case hydropower) are credited from the account of another purpose (in this case water supply). Historically, the Corps has never considered it a legal obligation to authorize or provide any funds to any other government agency affected by the reallocation. The responsible power marketing agency could potentially receive an annual hydropower account credit equal to the revenue lost (revenue foregone) as a result of a storage reallocation to water supply. The credit would potentially be limited to the account balance.

When there is a loss of revenue from existing purposes, or additional operation and/or maintenance expenses are incurred from existing purposes because of a water supply storage reallocation, these charges will be shown as a direct charge against the water supply function. All revenues lost to the project and the downstream areas must be considered. Traditionally, if hydropower revenues were to be reduced because of a water supply storage reallocation, the power marketing agency could be credited for the amount of revenues foregone to the Treasury because of the reallocation. This credit is typically estimated as a uniform annual credit. This is the first traditional credit condition.

In instances where existing repayment agreements between the power marketing agency and their customers (conditions within a power contract) would result in a cost to the Federal Government to acquire replacement power to fulfill the obligations of the agreements, an additional credit to the power marketing agency can be made for such costs incurred during the remaining period of the agreements. This is the second traditional credit condition. Corps regulations indicate that such credits would not be made until replacement costs are incurred and documented by the power marketing agency.

To summarize, the traditional policy for determining hydropower credits is contained in two conditions: [1] If hydropower revenues are reduced because of the reallocation, the power marketing agency could be credited for the amount of revenues foregone to the Treasury because of the reallocation assuming uniform annual credit. [2] In instances where existing repayment agreements between the power marketing agency and their customer would result in a cost to the Federal Government to acquire replacement power to fulfill the obligations of the agreements, an additional credit to the power marketing agency could be made for such costs incurred during the remaining period of the agreements. Traditional Corps policy indicates that the credit will be based on actual annual documented costs incurred by the power marketing agency to purchase replacement power.

While the second condition above is described here and in Corps regulation as an "additional credit," only one credit condition may apply at any point in time. If there is an existing power contract in place (Contract A) at the time of a water storage reallocation and Contract A includes terms for the Federal government to purchase replacement power (a normal condition) and such replacement power purchases would result from a proposed water supply storage reallocation, then the Federal government will potentially have an expense for the purchase of replacement power from the time the storage reallocation is implemented through the end of the power contract. The Federal obligation under guidance is for the increment of replacement power that results from the implementation of a storage reallocation – not for otherwise routine replacement power purchases by the PMA. That expense relates to the second (or additional) credit condition. The expense is termed potential because of the Corps policy that indicates credit will be based on actual annual documented costs incurred by the power marketing agency to purchase replacement power. Following the expiration of Contract A, a subsequent contract would likely be negotiated and executed between the power marketing agency and a power customer (one or more customers). If that contract (Contract B) also includes terms for the Federal government to purchase replacement power, the credit condition for replacement costs would not apply. This is because Contract B would have been executed after the reallocation of storage and would be based on the hydropower storage that remains.

Traditional policy is disseminated through the Planning Guidance Notebook, ER 1105-2-100, 22 April 2000 and is further explained in the Water Supply Handbook, Revised IWR Report 96-PS-4.

The Contract No. DE-PM75-00SW00435 between the United States of America and the Tex-La Electric Cooperative of Texas, Inc., and Rayburn Country Electric Cooperative, Inc is shown in Appendix G. The contract covers all power marketed from the Lake Texoma (Denison Dam) project for all customers. The current contract will expire at midnight on 31 December 2018.

**7.1.1 Traditional Evaluation of Credit Term**. The purpose of managing accounts and Federal agency repayment to those accounts is to assign and assure repayment of the initial Federal investment in the project and in repayment of subsequent operating expenses for those specific or joint use purposes by the appropriate Federal agency. The term of repayment to the Treasury for the initial investment is typically envisioned to be 50 years. For Lake Texoma, the initial hydropower investment has been repaid through power sales. Subsequent hydropower purpose assets have been added to the account and include major replacements, such as rewinding turbines. The large assets assigned to the hydropower account were repaid within the first 50 years of power sales and the subsequent assets (the result of major replacement costs) and operating expenses are relatively minor by comparison at about $14 million. It is anticipated that these assets would be repaid within a few years just based on hydropower revenues.

**7.1.2 Applicable Credit Conditions Under Traditional Policy**. The two traditional credit conditions outlined above would be considered in the determination of traditional hydropower project account credits. The traditional credit conditions are briefly reviewed to provide a basis for comparison with the project specific credit provisions of Sec 838 discussed later.

The first traditional condition regarding a general revenue reduction would apply because the selected plan of reallocation would reduce the storage available to produce hydropower and would therefore have a negative impact on revenue generation. Even though the initial construction and operating costs have been repaid from hydropower revenues, there are continuing operational costs and periodic major replacement costs that are applied to the hydropower account. While these costs are relatively small in comparison to the initial project costs, the concept of account repayment remains valid. Therefore a reduction in hydropower revenue resulting from water supply reallocation would qualify for a credit transfer from the water supply account to the hydropower account. The period of time during which such substantive transfers may occur is the duration of the water storage agreement wherein the water supply customer is making annual payments. Following the 30-year repayment period, the only funds provided by the water supply users would be annual joint-use operational payments. If credits were to be applied beyond the 30-year repayment term, then the maximum credit would be limited by the water storage share of operational expenses. The value of credits beyond the 30-year water supply repayment period could be added to the credits during the 30-year water supply repayment period.

The second traditional condition regarding an existing hydropower contract and the purchase of replacement power by the power marketing agency to fulfill obligations of the agreement would not have been applied because a provision of the existing hydropower contract transfers the responsibility to purchase replacement power to the power customers in exchange for a reduced contract price. Provisions of Sec 838 may have been included to address the purchase of replacement power by the power customers. Because the SWPA is not responsible for the purchase of replacement power under the terms of the existing contract, the power marketing agency's ability to recoup Federal hydropower costs it had agreed to cover would not be impacted under the terms of the power contract. Therefore, the second credit condition would not be met under the terms of traditional policy and would not be applicable for determining credit to the hydropower account. The power customers would bear a greater risk of purchasing additional replacement, but that risk was considered when the reduced rate of the

contract was negotiated and could also be mitigated through contract negotiations with the SWPA. An apparent lack of data regarding historic replacement power purchases would tend to complicate the issue, but estimates of those values could be developed by the power customers and by the SWPA using computer models versus financial accounting records.

Following are excerpts from the paper presented by H. Al Pless, Economist, U.S. Army Corps of Engineers, Savannah, Georgia, titled "*Reallocation of Water Storage in Federal Water Projects, Proceedings of the 1991 Georgia Water Resources Conference*," held March 19 and 20, 1991, at the University of Georgia.

While the document was developed to discuss the Corps policy of reallocation of water storage at a Georgia Water Resources Conference and it references water supply contracts for the Savannah River Basin, the discussion is germane to all Corps projects where water supply and hydropower are authorized purposes.

> "Power marketing agencies (PMA's) feel that reallocation of storage from hydropower to water supply results in a pecuniary externality to the preference customers and that the Corps should mitigate that externality. The PMA's feel that the externality could be mitigated by paying their preference customers for the replacement cost of power. It is the Corps' position that our credit to the PMA for revenues foregone covers the repayment obligation to the PMA. In addition, the Water Supply Act of 1958 gives the Corps authority to reallocate storage. Preference customers were never guaranteed generating capacity in perpetuity. Water storage reallocation contracts are considered a higher and better use of the water. […]
>
> In some instances reallocation of storage is a controversial issue, particularly when power interests become involved. Even though the reallocation of storage is seen by some as decreasing power benefits, marginal benefits to Federal projects are increased when storage reallocations are financially feasible."

(Note: As discussed later in the conclusions, the revenue provided to the U.S. Treasury by the NTMWD and GTUA through the purchase of water supply storage would be slightly more than twice the value of the hydropower impact, as defined by Sec 838.)

**7.2 <u>Non-Traditional Policy – Project Specific Provisions of Section 838</u>.** Section 838 of the 1986 WRDA defines the methodology for determining hydropower project credits and creates a related method for reimbursement of power customer purchases of replacement power. The provisions reaffirm the Secretary's authority to determine the impact of the reallocation on hydropower production. The legislation defines one condition for establishing credit , although the Corps has determined that the credit provision of Sec 838 does not eliminate the first traditional credit condition (hydropower revenue reduction) described above but would modify the second (Federal acquisition of replacement power). A more detailed assessment of legislation follows.

Sec 838 (d)(3) is shown again to facilitate the following discussion of how the legislation provisions guide the determination of credits. The subsection contains the credit and reimbursement provisions:

> "With respect to any water supply contract entered into by the Secretary under this section after June 1, 1985, the Secretary shall determine (A) the amount of hydropower lost, if any, as a result of the implementation of such contract, and (B) the replacement cost of the hydropower lost (where replacement cost is defined as the cost to purchase power from existing alternative sources). If hydropower is lost as a result of the implementation of such contract, the Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement costs. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower. In each such case the Southwestern Power Administration shall reimburse each preference customer for an amount equal to the customer's actual replacement cost for hydropower lost as a result of the implementation of such contract, less the cost such customer would have had to pay the Southwestern Power Administration for such hydropower."

The following assumptions were established:

(a) The provisions of Sec 838 were not assumed to have been drafted to establish a Federal subsidy for the long term purchase of power from alternative sources by the Tex-La Electric Cooperative of Texas, Inc., and Rayburn Country Electric Cooperative, Inc.

(b) The provisions were not assumed to modify the existing contract between the cooperatives and the SWPA to provide any guarantees beyond the term of the existing hydropower contract.

(c) The provisions were assumed to establish a methodology to fairly compensate the electric cooperatives for the impacts of storage reallocation on their purchases of replacement power during the term of the existing hydropower contract. Traditional policy would have provided credit to the hydropower project account if the power marketing agency had the responsibility to purchase replacement power, but there are no provisions in traditional policy for compensation of power customers (reimbursement) who have that purchasing responsibility.

The provisions of Sec 838(d)(3)(B) reaffirm aspects of traditional policy, modify or limit other aspects, and redefine or create project specific guidance:

- The Secretary's authority and responsibility is reaffirmed for determination of the amount of hydropower lost and the replacement cost of the hydropower lost.

- The traditional Corps policy for estimation of credits is modified. The provisions define the hydropower credit for Lake Texoma as the replacement costs, defines replacement costs as: "the cost to purchase power from existing alternative sources". The condition established by Sec 838 is similar to the second traditional policy condition above, where credits are valued as the "cost to the Federal Government to acquire replacement power to fulfill the obligations of the agreements" between the power marketing agency and their customers under an existing hydropower contract.

The Sec 838 provision recognizes that the electric cooperatives purchase replacement power instead of the SWPA.

- A limit is established on the total amount of credit that may be applied annually. The limiting provision is: "Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower." The balance of the project hydropower account in any year is the total remaining cost allocated to hydropower, or the "sums required to be paid by the Southwestern Power Administration". Under this provision, annual credits could not exceed the remaining hydropower account balance in any year. However, the Corps policy allows the SWPA to distribute credits to any Corps project with SWPA hydropower facilities. Therefore, for this limiting provision to be applicable the combined total of all hydropower assets at Corps projects would have to be less than the annual credit estimate.

- The traditional policy for documentation of actual annual costs for replacement power prior to the application of a credit is reaffirmed.

- The final provision of Sec 838 creates a reimbursement obligation for the SWPA. Under this obligation, the SWPA would repay the electric cooperatives for a portion of the cost of replacement power purchased due to a storage reallocation authorized by Section 838 and subsequently implemented. The SWPA would incur a financial obligation under this provision. The obligation would be for a portion of the actual expense of purchasing replacement power, defined as the "customer's actual replacement costs for hydropower lost as a result of the implementation of such contract, less the cost such customer would have had to pay the Southwestern Power Administration for such hydropower." Providing credits to the SWPA for this reimbursement, although discounted by the value of an equal amount of hydropower revenue, would otherwise be contrary to the Corps' longstanding policy to (1) not provide credits to power marketing agencies for replacement power costs in the absence of a contractual obligation, existing at the time of the reallocation, that requires the power marketing agency to purchase replacement power, and (2) not provide credits to power marketing agencies for the purpose of reimbursing power customers for the additional costs of replacement power incurred by the customers (unless directed by law). This policy reflects the principal that customers of the power marketing agencies do not have an absolute right to a Federal power subsidy.

**7.2.1 Evaluation of Credit Term - Provisions of Section 838**. To better present the evaluation of the credit term under the provisions of Sec 838, a brief review of "replacement power" is first discussed.

Lake Texoma hydropower production is dependant on the availability of inflow and because future inflows cannot be predicted with certainty, there is always a risk that the hydropower capacity or energy estimated to be available in the future may not be produced as needed. When conditions in the future are less conducive to power production than were expected, the hydropower facility will not be able to produce as much power as is stipulated in a hydropower contract. Because this shortage in production is realized under normal conditions at Corps

projects, there are typical contract provisions for the purchase of replacement power by the SWPA from other power sources so that the total power obligation of the government to the cooperatives is met. However, Lake Texoma is an exception to that typical provision because the electric cooperatives are responsible for the purchase of replacement power.

The purchase of replacement power under an existing contract occurs when one of two conditions is met. The conditions described both relate to an existing hydropower contract between a power marketing agency and power customers. The conditions do not relate to mechanical failure of hydropower facilities. The purpose of purchasing replacement power due to either condition is to satisfy the terms of an existing hydropower contract.

- The purchase of replacement power may occur when unexpected hydrologic conditions limit the amount of power that can be produced. In this case the actual capability of a power plant would, at certain times, be less than forecast conditions under which the contract terms apply.
- Replacement power purchases may be necessary if a storage reallocation is implemented during the term of a hydropower contract. A storage reallocation would reduce the capability of the power plant to produce electricity and would therefore impact the provisions of a hydropower contract in place at the time the reallocation was implemented. In this case the actual capability of a power plant would be reduced throughout the remainder of the hydropower contract.

If a new hydropower contract is negotiated, then the new contract provisions will account for the storage available for hydropower production and the SWPA will forecast hydrologic conditions over the term of the new contact with the intent of reasonably minimizing the need to purchase replacement power. Replacement power purchases may still be necessary during the term of the new contract, but those purchases will only occur if unexpected hydrologic conditions are experienced. (There would still be an opportunity for impacts due to a future storage reallocation, but that prospect would be evaluated through a future reallocation study.)

Under the traditional evaluation of credit term, if hydropower revenues were being reduced because of the water supply reallocation, the power marketing agency would be credited for the amount of revenues foregone to the Treasury because of the reallocation. Under Sec 838, the hydropower credit is defined as "the cost to purchase power from existing alternative sources" and the SWPA is directed to "reimburse each preference customer for an amount equal to the customer's actual replacement cost for hydropower lost as a result of the implementation of such contract, less the cost such customer would have had to pay the Southwestern Power Administration for such hydropower."

Given the assumptions at the start of this discussion that the provisions of Sec 838 were not drafted to (a) establish a Federal subsidy for the long term purchase of power in support of the two electric cooperatives, or (b) to provide any guarantees beyond the term of the existing hydropower contract, but that (c) the provisions were drafted to establish a methodology to fairly compensate the electric cooperatives for the impacts of storage reallocation on their purchases of replacement power during the term of the existing hydropower contract (because they bore the

responsibility for those purchases instead of the SWPA); then the credit term for replacement power could be no longer than the duration of the existing hydropower contracts.

The Corps has determined that Sec. 838(d)(3) does not bar the application of current policy on hydropower credit, and will therefore follow the policy in Appendix E, Section VIII, of ER 1105-2-100. Under that policy the SWPA would be credited for replacement costs through the remaining period of its current power contracts and thereafter credited for revenues forgone for the remainder of a 50-year credit period. Because the amortization period for water storage agreement (the Treasury source of credits in this instance) is 30 years, the present value of the revenues forgone for the 50-year period would be annualized over 30 years. The distribution of 50 years of credits over the 30 year water supply storage payments is policy specific to Lake Texoma at this time.

Because there are power contracts between the PMA and its customers that require credit under Sec 838 based on the cost of acquisition of replacement power through 2018 (9 years), then the credit for revenue foregone would be based on the remaining period within a 50-year total credit period. To summarize, credits for the first nine years would be replacement costs and credits for the remaining 21 years of the water supply payments would be based on 41 years of hydropower revenue foregone that would be amortized over the 21 years of remaining Treasury revenue from the water storage agreement payments.

The SWPA reimbursements to the power customers would be limited to the term of the existing hydropower contracts. As such, those reimbursements would represent a fair compensation for higher replacement power purchases than would have been expected under the terms of the current contract. Reimbursements related to the water storage reallocation would not extend to subsequent hydropower contracts because those new contracts would be predicated on the remaining storage available for hydropower production. Replacement power purchases may still be necessary under the term of future contracts, but those purchases would be due to unanticipated hydrologic conditions and not related to past storage reallocations to water supply.

The power customers will need to find alternate sources for power, but the current contract with the SWPA does not guarantee an amount of power for future contracts – or make any guarantee concerning future contracts. When the current contract expires, the power customers will likely continue to purchase hydropower produced at Lake Texoma, but those future contracts would be for a lesser amount of power. The electric cooperatives already have other sources for power and as power demands in the region increase, the cooperatives would inherently have to rely more heavily on alternate sources – even without the implementation of storage reallocation. The increment of power that will need to be replaced by alternate sources is relatively small compared to the total needs of the power customers. Hydropower has been a low cost source of peaking energy and the power customers have been able to utilize that low cost power in their system operations for many years. But reallocation of a portion of the storage used to produce hydropower has been shown to have a higher value for water supply customers, and water supply revenues to the Treasury will equal or exceed the hydropower revenues over the period of evaluation.

**7.2.2 Applicable Credit Conditions - Provisions of Section 838.** Because the fundamental principle of credits is to compensate the power marketing agency for a reduction in hydropower revenue and therefore a reduction in their ability to reimburse the Treasury, the replacement power purchase credit should be limited to the actual reimbursement the power marketing agency makes to the power customers – if that reimbursement amount is less than the credit defined by Sec 838.

The historic purchase of replacement power under the current power contract would normally form a financial baseline of replacement power acquisition from which to measure the impacts of future storage reallocations. Such historic financial accounting would provide a simple and factual baseline from which to measure future purchases of replacement power that might be impacted by water supply storage reallocation. Through this baseline approach, the average annual historic cost of replacement power could be established and future annual replacement costs in excess of the historic average would be identified as the impact of water supply storage reallocation on hydropower production. The process would be relatively simple. Unfortunately, the SWPA has informed the Corps those records of replacement power acquisition by the SWPA or the cooperatives do not exist, or are too complicated to produce.

The lack of these financial records significantly complicates the determination of hydropower account credit. Under traditional policy the Secretary would only assign hydropower credits based on documentation of actual replacement power purchases (for the prior year). Section 838 similarly states that preference customers are to be reimbursed "for an amount equal to the customer's actual replacement cost for hydropower lost as a result of the implementation of such contract, less the cost such customer would have had to pay the Southwestern Power Administration for such hydropower." To address the financial record data gap, the Corps has estimated the baseline purchase of replacement power by proxy using a computer model. The estimation of replacement power purchases by proxy is a normal study practice in anticipation of a storage reallocation. The estimation process provides decision makers with reliable information. However, adjusting the hydropower account based on an estimation of credits would be contrary to the traditional policy of applying credits based on documented actual costs of replacement power and contrary to the provision of Section 838.

It is the Corps understanding that in exchange for a discounted cost in the current hydropower contract, the SWPA has transferred responsibility for the purchase of replacement power to the electric cooperatives, which are now wholly responsible for purchase of replacement power to fulfill the capacity terms of the power contract. The Corps understanding is based on discussions with the SWPA, review of the hydropower contracts, and by reference in Sec 838 that stipulate the reimbursement of preference customer costs as "an amount equal to the customer's actual replacement cost for hydropower." The provision of the contract between the SWPA and the electric cooperatives wherein the cooperatives assume the responsibility to purchase replacement power in exchange for a reduced contract price, is presumably for the benefit of the government and acceptable to the cooperatives. Therefore, the forecast conditions for 2019 and beyond assume future power contracts would contain the same provision.

Table 25 shows an estimate of the incremental replacement power purchases assuming the full impact of a storage reallocation to water supply of 150,000 acre-feet (the proposed

immediate need reallocation to Texas). The power values were developed by the HAC and are presented in Appendix E. The SWPA has already received or will receive full credit for the prior 150,000 acre-feet of storage reallocated in 1983, 1985, 1992, 1997, and 2004.

**TABLE 25**

**ESTIMATED REPLACEMENT POWER PURCHASES IMMEDIATE NEED WATER SUPPLY REALLOCATION (150,000 ACRE-FEET) 2009 THROUGH 2018**

**(October 2008 Prices, 4.625% Interest)**

| Capacity and Energy Category | Average Annual Cost ($) |
|---|---|
| Denison Capacity | $317,000 |
| Peak Energy | $335,000 |
| On-Peak Energy | $501,000 |
| Off-Peak Energy | $194,000 |
| Total Annual Value | $1,347,000 |

**7.3** **<u>The Hydropower Project Account Credit Process</u>**. All the water storage agreement revenue received from the NTMWD for 100,000 acre-feet of storage and the GTUA for 50,000 acre-feet of storage would be deposited into the U.S. Treasury by the Corps of Engineers. The SWPA would be notified in writing within 30 days after the agreement between the United States of America and the NTMWD and the GTUA for the proposed agreements and future water storage agreements.

The estimated first nine (9) years of credit (between 2009 and 2018) would be replacement costs valued at about $1,347,000 per year. Credits for the remaining 21 years (30 years minus 9 years) of the water supply payments are estimated based on 41 years (50 years minus 9 years) of estimated revenue foregone with a present value (PV) of $11,471,226.34. The present value of revenue foregone would be amortized over 21 years (n). Interest equals 4.625% (i).

The estimated average annual value, A, for revenue foregone is $865,418.

Solving for annual payment or cost.

$$A = \frac{PV}{\frac{(1+i)^n - 1}{i(1+i)^n}}$$

Therefore, the estimated hydropower credit would be $1,347,256 annually for the first nine years (replacement costs), and $865,418 annually for 21 years (revenue foregone), for a total of 30 years of credits.

Credit estimates may be reestablished periodically by the Corps Hydropower Analysis Center at the discretion of the Secretary or his designee throughout the term of credit period.

The estimates above may be refined for development of a memorandum of agreement that further defines the credit terms between the power marketing agency and the Corps.

Upon receipt of annual documentation from the Tex-La Electric Cooperative of Texas, Inc., and Rayburn Country Electric Cooperative, Inc., SWPA will reimburse these customers the difference between the actual replacement costs for hydropower lost as a result of the reallocation and the amounts these customers would have paid SWPA for such hydropower, as specified by Section 838. The reimbursement will be consistent with the project account transfer (credit) by the Secretary from the water supply account to the hydropower account.

## 7.4 Corps and SWPA Methodology Differences

The SWPA and the Corps of Engineers Hydropower Analysis Center have had numerous discussions concerning the appropriate methodologies used for evaluating impacts to energy and capacity benefits when hydropower storage is reallocated to other uses. Differences center primarily on six issues:

(1) Computation of dependable capacity
(2) Energy value used to compute power benefits foregone
(3) SWPA's contract rates used to compute revenue forgone
(4) Calculation of energy loss
(5) Value applied to the capacity
(6) Time period used when calculating the SWPA credit

Attached in Appendix F are comments and position papers that outline or express concerns of the SWPA regarding the Corps' determinations of energy, power, and capacity.

(1) Draft Water Storage Reallocation – Hydropower Impacts, July 2005.
(2) Comparison of Actual Energy Purchases with Platts Power Outlook Research Service Values, October 2008.
(3) Development of Hydropower Loads for SUPER Runs, October 2008.
(4) 1980 Final Power Allocations and Term of Compensation for Reallocations, October 2008.
(5) Portion of Customer's Load, November 2008.
(6) GDS Associates Letter, Denison Power Customers' capacity replacement intentions, January 2009.
(7) Comparison Summary of Hydropower Impacts due to 150,000 acre-feet reallocation, January 2009.

An introduction to each of the seven documents in included in Appendix F. The introductions provide insight to how the information in these documents was used or considered in the development of study assumptions, identification of data sources, or the assessment and selection of evaluation methodologies.

**8.0 ADMINISTRATION GOALS** The identification of measures and the evaluation of measures and alternatives were guided by the Corps' Environmental Operating (EOP) and the 12 Actions for Change.

**8.1. Environmental Operating Principles.** In conducting plan formulation and in consideration of environmental impacts, the project delivery team utilized the Corps' Environmental Operating Principles (EOP's). A brief summary of the study considerations is presented below.

| Environmental Operating Principles | Study Considerations |
|---|---|
| 1. Strive to achieve Environmental Sustainability. An environment maintained in a healthy, diverse, and sustainable condition is necessary to support life. | Two principal storage reallocation measures were considered: flood control storage and conservation storage reallocation. The flood control storage reallocation measures were not found to be economically justified and serious environmental issues had been identified for that measure. The conservation storage reallocation measure was found to have no significant impacts and was identified as the more environmentally sustainable measure. |
| 2. Recognize the interdependence of life and the physical environment, and consider environmental consequences of Corps programs and activities in all appropriate circumstances. | The potential for the implementation of storage reallocation to impact many stakeholders was an important aspect of the study. The potential benefits of the reallocation were considered for those stakeholders, including the hydropower cooperatives and their customers, recreation businesses, the recreating public, environmental aspects in Lake Texoma and downstream, downstream flood control stakeholders, water purveyors and their customers, and American Indian interests regarding cultural resources in the flood control pool boundary of the lake. The conservation storage measure was found to have the least impact on stakeholders collectively. The potential environmental consequences of the potential reallocation measures were carefully weighed and the selection of the conservation storage measure for reallocation to water supply storage provided no significant impact to the physical environment. |
| 3. Seek balance and synergy among human development activities and natural systems by designing economic and environmental solutions that support and reinforce one another. | Economic and environmental issues were found to be similarly influenced by the two principle measures considered. The flood control storage reallocation measure considered had great potential risks for environmental and economic issues. The selection of the conservation storage measure provided a solution that minimized economic impacts and had no significant environmental impacts. The selection of the conservation storage reallocation measure provided the most economic and environmental balance among human development and natural systems. |

| Environmental Operating Principles | Study Considerations |
|---|---|
| 4. Continue to accept corporate responsibility and accountability under the law for activities and decisions under our control that impact human health and welfare and the continued viability of natural systems. | The purpose of the study was to evaluate the feasibility of providing water supply storage that would meet immediate needs for a large portion of northern Texas. The principal impact of implementing the storage reallocation, under the conservation storage reallocation measure, would be the reduction in hydropower generation from Lake Texoma. The potential immediate impact would be a reduction of about 15% of the storage currently available for hydropower production. That production, while economically advantageous to two rural electric cooperatives, is a minor impact to a generation in the ERCOT power market in northern Texas. All hydropower in the ERCOT region is only 1% of the total power resources. The reallocation of storage to water supply is the responsible corporate decision. |
| 5. Seek ways and means to assess and mitigate cumulative impacts to the environment; bring systems approaches to the full life cycle of our processes and work. | The consideration of cumulative impacts of a reallocation would have been required if the flood control storage reallocation measure had been found to be economically viable. Because only the two scales of the conservation storage reallocation measure were found to be economically justified, those two scales were evaluated for potential environmental impacts. Neither scale of the conservation storage reallocation measure was found to have significant environmental impacts. The potential impacts were considered over a 50-year evaluation period. |
| 6. Build and share an integrated scientific, economic & social knowledge base that supports a greater understanding of the environment and impacts of our work. | The Lake Texoma Storage Reallocation study will provide valuable information for use in other ongoing Corps studies in the Red River Basin. The report findings, data, HQUSACE guidance, and evaluation methodologies will be utilized in those studies. In addition the guidance provided for the determination of hydropower credits will be shared as a case study in a regional water supply workshop to assist others in the formulation and presentation of storage reallocation studies. |
| 7. Respect the views of individuals and groups interested in Corps activities; listen to them actively and learn from their perspective in the search to find win-win solutions to the Nation's problems that also protect & enhance the environment. | The coordination with rural electric cooperatives, water supply purveyors, the power marketing agency, the Corps center of expertise for hydropower, and other north Texas and Red River Basin interests was well beyond the level of coordination considered routine for a storage reallocation study. While the vast majority of the coordination was related to economic issues, the issues related to potential environmental impacts were maintained at an equal status with the economic issues. |

**8.2. The 12 Actions for Change.** On 24 August 2006 the commander of the United States Army Corps of Engineers, Lt. Gen. Carl A. Strock, signed and released the "12 Actions for Change," a set of actions that the Corps will focus on to transform its priorities, processes and planning.

"Hurricane Katrina's disastrous impact upon the Gulf Coast and the New Orleans region served as a very sobering wakeup call for the Corps and the nation in how we have prepared for natural disasters and where we have accepted risk," said Lt. Gen. Strock.

"Exhaustive analysis by the Corps and other investigative teams into the performance of the Greater New Orleans Hurricane Protection System during hurricanes Katrina and Rita pointed to the need to transform the way the Corps serves the nation and its Armed Forces across all our mission areas.

"These 12 actions were developed from that analysis and from other internal and external examinations of the Corps in the recent past. We will use the 12 Actions to guide our ongoing and future work, and to ensure we have an organization that is adaptable, flexible and responsive to the needs of the nation," said Strock.

The "12 Actions for Change" fall within four overarching themes: (1) Comprehensive Systems Approach; (2) Risk-Informed Decision Making; (3) Communication of Risk to the Public, and (4) Professional and Technical Expertise.

Theme 1 - Comprehensive Systems Approach. The reallocation study followed the Comprehensive Systems Approach through the use the SUPER model, consideration of regional power production and distribution systems such as ERCOT and SPA, utilization of Texas regional water plans and forecasts, consideration of the basin environmental issues, and through economic evaluation of hydropower, recreation, water supply needs, and potential impacts to in-pool and downstream flood control issues.

Theme 2 - Risk-Informed Decision Making. The objective of the theme was met by analyzing the potential impacts of the two primary measures, reallocation from conservation pool and reallocation from flood control storage; and by evaluating the potential impacts associated with each measure. Denison Dam and the Cumberland Levee System embankments were assessed as was the risk of increased downstream flooding impacts. Information developed for previous studies, SUPER model information, and information from the District periodic inspections were all used in the determination of potential risks. The project delivery team included the regional technical specialist for floodplain management and the dam safety officer.

Theme 3 - Communication of Risk to the Public. The communication of risk objective was met through public scoping meetings, agency coordination, and stakeholder meetings including a 45-day public comment period on an Environmental Assessment. The District coordinated extensively with the SWPA, power users, the water purveyors, and other stakeholders.

Theme 4 - Professional and Technical Expertise. The objective of the theme was met through the use of a project delivery team which included engineers, biologists, economists, archaeologists, the District dam safety officer, the District flood plain management regional

technical specialist, and the District water supply regional specialist. Extensive oversight and support were provided by the Hydropower Analysis Center, the SWPA, the Platts Power Outlook Research Service, and the North Texas Municipal Water District and the Greater Texoma Utility Authority. A vertical team, including representatives from Corps Headquarters (HQUSACE), Southwestern Division (SWD), and the project delivery team developed and followed detailed implementation guidance. Multiple technical reviews were conducted by Corps staff from the Little Rock District.

**9.0 DAM SAFETY** The Lake Texoma Dam Safety Analysis indicated a Dam Safety Action Class (DSAC) rating of Marginally Safe, per EC 1110-2-6064. The analysis conducted for this study does not anticipate a change to this rating under the foreseeable conditions with implementation of the Lake Texoma Reallocation action.

Complete stability analyses have not been performed for projected probably maximum flood (PMF) levels. Preliminary estimates indicate that the dam is stable. However formalized calculations will be performed as funds are made available. The reallocation would not affect dam nor Cumberland Levee stability during the PMF load condition. These project flood control structures will have updated stability analysis performed, as funding is available.

## 10.0 CONCLUSIONS

Authorization of reallocation of 300,000 acre-feet to set aside storage for water supply is the most efficient means to satisfy the projected water demands in Oklahoma and Texas in accordance with the Red River Compact. Of the 300,000 acre-feet identified, 150,000 acre-feet has been identified for immediate reallocation to satisfy water supply needs for the state of Texas.

The rapid growth in the North Texas Region C as expressed in the *Initially Prepared 2006 Region C Water Plan* identified the need for establishing future water sources because of a projected 50% population increase within the region. The demand for additional water supply sources resulted in Congressional authorization through the 1986 WRDA (Public Law 99-662), Section 838.

The Secretary of the Army was authorized by Sec 838 to reallocate up to 150,000 acre-feet each for Oklahoma and Texas for municipal, industrial, and agricultural water uses. The potential impacts of reallocating 150,000 acre-feet to Texas under Sec 838 were evaluated. The potential impacts of reallocating 300,000 acre-feet to Oklahoma and Texas were evaluated in consideration of the provisions of the Red River Compact for equal distribution of Lake Texoma storage between the states. Authorizations for storage reallocation prior to Sec 838 consist of 150,000 acre-feet of storage which was considered as part of the conditions for cumulative impacts.

A reallocation of water supply storage from conservation storage does not occur until water storage agreements are signed by all parties and the water supply user starts to pay for the storage. Therefore, the actual reallocation is often incremental and is implemented upon execution of water storage agreements. The storage authorized for reallocation, but not under

agreement, is considered by the Corps to be hydropower storage and is considered to be available when estimating a project's dependable power production.

An Environmental Assessment and a Supplement to the Environmental Assessment were conducted. Both assessments determined that no significant environmental impacts are anticipated to occur as a result of the reallocation authorized by Sec 838 for 150,000 acre-feet or 300,000 acre-feet of storage from the conservation pool.

Hydropower impacts for the reallocation of 150,000 acre-feet of storage would consist of reduced energy and capacity that the SWPA could market. The average annual impact measured as the cost of replacement power from alternative sources, evaluated over a 50-year economic evaluation period and a discount rate of 4.625%, would be $1,416,784 (Presented in Appendix E, 50-year Economic Evaluation Period). (This is an economic value and does not represent the annual value of hydropower credits amortized over the 30-year credit period and is not an estimate of the reimbursement to be provided by the SWPA to the preferred customers.)

Average annual water supply benefits for the reallocation of 150,000 acre-feet of storage (about 150 mgd), evaluated over a 50-year economic evaluation period and a discount rate of 4.625%, would be $3,021,654 (including O&M). (This is an economic evaluation value suitable for comparison to the estimated economic value of hydropower impacts, but does not represent the annual water storage agreement payments amortized over 30 years.) The revenue provided to the Treasury from the sale of water supply storage would be slightly more than twice the value of the hydropower impact as defined by Sec 838.

To test the financial feasibility of Lake Texoma storage reallocation, the annual cost of the reallocated storage was compared to the annual cost of the most likely, least costly, water supply source that would provide an equivalent quality and quantity of water if storage reallocation at Lake Texoma was not an option for the water supply customer. The planned project, Lower Bois D'Arc, would be the most likely and least costly water supply alternative to Lake Texoma storage reallocation. The Lower Bois D'Arc project is estimated to supply about 110 mgd for the NTMWD and would have an estimated average annual cost of about $35,000,000. The Lake Texoma storage reallocation, with an average annual cost of $3,021,654, passes the test of financial feasibility.

Hydropower production at Denison Dam would tend to be reduced by the authorized water supply storage reallocation, but water storage agreement revenue would exceed the incremental loss of hydropower revenue to the Treasury.

NEPA evaluations of future reallocation proposals must consider cumulative effects.

## 11.0 RECOMMENDATION

This storage reallocation study has been prepared under the authority of the 1986 Water Resources Development Act, Public Law 99-662, Section 838. The reallocation of 300,000 acre-feet of storage between elevations 590.0 and 617.0 feet NGVD in Lake Texoma has been authorized for current and future reallocation from hydropower storage to water supply storage to meet municipal, industrial, and agricultural needs of Oklahoma and Texas. Of the 300,000 acre-feet of storage authorized for reallocation, 100,000 acre-feet of storage is identified for reallocation for the North Texas Municipal Water District (NTMWD) and 50,000 acre-feet of storage is identified for reallocation for the Greater Texoma Utility Authority (GTUA), both in Texas. The remaining 150,000 acre-feet of storage authorized for reallocation and evaluated in this study is for future reallocation to water supply for Oklahoma. No Oklahoma water needs were identified in the planning horizon and no current or near term interest was identified for Oklahoma water storage agreements.

The NTMWD has requested a water storage agreement for 100,000 acre-feet of storage and the GTUA has requested a water storage agreement for 50,000 acre-feet of storage. Their intent to immediately begin payment for the storage is the definition of an immediate water supply need.

Based on the conclusion of this storage reallocation study and the conclusions of the Final 2005 Environmental Assessment and Draft 2009, Supplemental Environmental Assessment I find that appropriate consideration has been given to economic, environmental, and social impacts of the requested reallocation. Future reallocations for Oklahoma must consider cumulative effects and updates to the EA/FONSI may or may not be sufficient to fulfill requirements of NEPA.

Sufficient conservation storage remains in Lake Texoma to fulfill the provisions of equal storage distribution between Texas and Oklahoma under the Red River Compact.

The water supply storage cost allocated to the NTMWD and GTUA is the "updated cost of storage".

The value of the 100,000 acre-feet of storage requested by NTMWD for reallocation is calculated to be $38,134,060 based on updated cost of storage for fiscal year 2009. The annual value would be $2,270,639 based on a 30-year repayment period with an interest rate of 4.625%. Using actual O&M expenses for FY 2008, the estimated annual operation and maintenance cost would be about $45,073. The total annual payment during the 30 year repayment period would be $2,315,712. An annual payment for O&M would continue to be made by the NTMWD following the 30-year storage repayment period.

The value of the 50,000 acre-feet of storage requested by GTUA for reallocation is calculated to be $19,073,891 based on updated cost of storage for fiscal year 2009. The annual value would be $1,135,728 based on a 30-year repayment period with an interest rate of 4.625%. Using actual O&M expenses for FY 2008, the estimated annual operation and maintenance cost would be about $22,545. The total annual payment during the 30 year repayment period would be

$1,158,273. An annual payment for O&M would continue to be made by the GTUA following the 30-year storage repayment period.

I recommend that under the authority of Section 838 of the Water Resources Development Act of 1986 (Public Law 99-662) and in accordance with the authority of the Water Supply Act of 1958 (Public Law 85-500, Section 301(b), as amended) storage agreements be executed for storage reallocation to meet the immediate needs of 100,000 acre-feet of storage for NTMWD and 50,000 acre-feet of storage for GTUA. Draft agreements have been prepared and accompany this storage reallocation report, SEA, and other documentation required by guidance.

Date 21 APR 2009

Anthony C. Funkhouser, P.E.
Colonel, U.S. Army
District Commander

The recommendations contained herein reflect the information available at this time and current Departmental policies governing formulation of individual projects. They do not reflect program and budgeting priorities inherent in the formulation of a national Civil Works construction program nor the perspective of higher review levels within the Executive Branch.

# APPENDIX A

# RED RIVER COMPACT

Title 82. Waters and Water Rights

# Oklahoma Statutes Citationized

## Title 82. Waters and Water Rights

### Chapter 20B - Red River Compact

#### Section 1431 - Approval and Ratification - Text of Compact

Cite as: O.S. §, __ __

---

The following Interstate Compact is hereby approved and ratified.

RED RIVER COMPACT

ARKANSAS-LOUISIANA-OKLAHOMA-TEXAS, 1978

PREAMBLE

The States of Arkansas, Louisiana, Oklahoma, and Texas, pursuant to the acts of their respective Governors or Legislatures, or both, being moved by considerations of interstate comity, have resolved to compact with respect to the water of the Red River and its tributaries. By Act of Congress, Public Law No. 346 (84th Congress, First Session), the consent of the United States has been granted for said states to negotiate and enter into a compact providing for an equitable apportionment of such water; and pursuant to that Act the President has designated the representative of the United States.

Further, the consent of Congress has been given for two or more states to negotiate and enter into agreements relating to water pollution control by the provisions of the Federal Water Pollution Control Act (P.L. 92-500, 33 U.S.C. §§ 1251 et seq.).

The Signatory States acting through their duly authorized Compact Commissioners, after several years of negotiations, have agreed to an equitable apportionment of the water of the Red River and its tributaries and do hereby submit and recommend that this Compact be adopted by the respective Legislatures and approved by Congress as hereinafter set forth:

ARTICLE I

PURPOSES

SECTION 1.01 The principal purposes of this Compact are:

(a) To promote interstate comity and remove causes of controversy between each of the affected states by governing the use, control and distribution of the interstate water of the Red River and its tributaries;

(b) To provide an equitable apportionment among the Signatory States of the water of the Red River and its tributaries;

(c) To promote an active program for the control and alleviation of natural deterioration and pollution of the water of the Red River Basin and to provide for enforcement of the laws related thereto;

(d) To provide the means for an active program for the conservation of water, protection of lives and property from floods, improvement of water quality, development of navigation and regulation of flows in the Red River Basin; and

(e) To provide a basis for state or joint state planning and action by ascertaining and identifying each state's share in the interstate water of the Red River Basin and the apportionment thereof.

ARTICLE II

GENERAL PROVISIONS

SECTION 2.01 Each Signatory State may use the water allocated to it by this Compact in any manner deemed beneficial by that state. Each state may freely administer water rights and uses in accordance with the laws of that state, but such uses shall be subject to the availability of water in accordance with the apportionments made by this Compact.

SECTION 2.02 The use of water by the United States in connection with any individual Federal project shall be in accordance with the Act of Congress authorizing the project and the water shall be charged to the state or states receiving the benefit therefrom.

SECTION 2.03 Any Signatory State using the channel of Red River or its tributaries to convey stored water shall be subject to an appropriate reduction in the amount which may be withdrawn at the point of removal to account for transmission losses.

SECTION 2.04 The failure of any state to use any portion of the water allocated to it shall not constitute relinquishment or forfeiture of the right to such use.

SECTION 2.05 Each Signatory State shall have the right to:

(a) Construct conservation storage capacity for the impoundment of water allocated by this Compact;

(b) Replace within the same area any storage capacity recognized or authorized by this Compact made unusable by any cause, including losses due to sediment storage;

(c) Construct reservoir storage capacity for the purposes of flood and sediment control as well as storage of water which is either imported or is to be exported if such storage does not adversely affect the delivery of water apportioned to any other Signatory State; and

(d) Use the bed and banks of the Red River and its tributaries to convey stored water, imported or exported water, and water apportioned according to this Compact.

SECTION 2.06 Signatory States may cooperate to obtain construction of facilities of joint benefits to such states.

SECTION 2.07 Nothing in this Compact shall be deemed to impair or affect the powers, rights, or obligations of the United States, or those claiming under its authority, in, over and to water of the Red River Basin.

SECTION 2.08 Nothing in this Compact shall be construed to include within the water apportioned by this Compact any water consumed in each state by livestock or for domestic purposes; provided, however, the storage of such water is in accordance with the laws of the respective states but any such impoundment shall not exceed 200 acre-feet, or such smaller quantity as may be provided for by the laws of each state.

SECTION 2.09 In the event any state shall import water into the Red River Basin from any other river basin, the Signatory State making the importation shall have the use of such imported water.

SECTION 2.10 Nothing in this Compact shall be deemed to:

(a) Interfere with or impair the right or power of any Signatory State to regulate within its boundaries the appropriation, use, and control of water, or quality of water, not inconsistent with its obligations under this Compact;

(b) Repeal or prevent the enactment of any legislation or the enforcement of any requirement by any Signatory State imposing any additional conditions or restrictions to further lessen or prevent the pollution or natural deterioration of water within its jurisdiction; provided nothing contained in this paragraph shall alter any provisions of this Compact dealing with the apportionment of water or the rights thereto; or

(c) Waive any state's immunity under the Eleventh Amendment of the Constitution of the United States, or as constituting the consent of any state to be sued by its own citizens.

SECTION 2.11 Accounting for apportionment purposes on interstate streams shall not be mandatory under the terms of the Compact until one or more affected states deem the accounting necessary.

SECTION 2.12 For the purposes of apportionment of the water among the Signatory States, the Red River is hereby divided into the following major subdivisions:

(a) Reach I - the Red River and tributaries from the New Mexico-Texas state boundary to Denison Dam;

(b) Reach II - the Red River from Denison Dam to the point where it crosses the Arkansas-Louisiana state boundary and all tributaries which contribute to the flow of the River within this reach;

(c) Reach III - the tributaries west of the Red River which cross the Texas-Louisiana state boundary, the Arkansas-Louisiana state boundary, and those which cross both the Texas-Arkansas state boundary and the Arkansas-Louisiana state boundary;

(d) Reach IV - the tributaries east of the Red River in Arkansas which cross the Arkansas-Louisiana state boundary; and

(e) Reach V - that portion of the Red River and tributaries in Louisiana not included in Reach III or in Reach IV.

SECTION 2.13 If any part or application of this Compact shall be declared invalid by a court of competent jurisdiction, all other severable provisions and applications of this Compact shall remain in full force and effect.

SECTION 2.14 Subject to the availability of water in accordance with this Compact, nothing in this Compact shall be held or construed to alter, impair, or increase, validate, or prejudice any existing water right or right of water use that is legally recognized on the effective date of this Compact by either statutes or courts of the Signatory State within which it is located.

## ARTICLE III

## DEFINITIONS

SECTION 3.01 In this Compact:

(a) The States of Arkansas, Louisiana, Oklahoma, and Texas are referred to as "Arkansas", "Louisiana", "Oklahoma", and "Texas", respectively, or individually as "State" or "Signatory State", collectively as "States" or "Signatory States."

(b) The term "Red River" means the stream below the crossing of the Texas-Oklahoma state boundary at longitude 100 degrees west.

(c) The term "Red River Basin" means all of the natural drainage area of the Red River and its tributaries east of the New Mexico-Texas state boundary and above its junction with Atchafalaya and Old Rivers.

(d) The term "water of the Red River Basin" means the water originating in any part of the Red River Basin and flowing to or in the Red River or any of its tributaries.

(e) The term "tributary" means any stream which contributes to the flow of the Red River.

(f) The term "interstate tributary" means a tributary of the Red River, the drainage area of which includes portions of two (2) or more Signatory States.

(g) The term "intrastate tributary" means a tributary of the Red River, the drainage area of which is entirely within a single Signatory State.

(h) The term "Commission" means the agency created by Article IX of this Compact for the administration

thereof.

(i) The term "pollution" means the alteration of the physical, chemical, or biological characteristics of water by the acts or instrumentalities of man which create or are likely to result in a material and adverse effect upon human beings, domestic or wild animals, fish and other aquatic life, or adversely affect any other lawful use of such water; provided, that for the purposes of this Compact, "pollution" shall not mean or include "natural deterioration."

(j) The term "natural deterioration" means the material reduction in the quality of water resulting from the leaching of solubles from the soils and rocks through or over which the water flows naturally.

(k) The term "designated water" means water released from storage, paid for by non-Federal interests, for delivery to a specific point of use or diversion.

(l) The term "undesignated water" means all water released from storage other than "designated water."

(m) The term "conservation storage capacity" means that portion of the active capacity of reservoirs available for the storage of water for subsequent beneficial use, and it excludes any portion of the capacity of reservoirs allocated solely to flood control and sediment control, or either of them.

(n) The term "runoff" means both the portion of precipitation which runs off the surface of a drainage area and that portion of the precipitation that enters the streams after passing through the portions of the earth.

ARTICLE IV

APPORTIONMENT OF WATER - REACH I

OKLAHOMA - TEXAS

Subdivision of Reach I and apportionment of water therein.

Reach I of the Red River is divided into topographical subbasins, with the water therein allocated as follows:

SECTION 4.01 Subbasin 1- Interstate streams - Texas.

(a) This includes the Texas portion of Buck Creek, Sand (Lebos) Creek, Salt Fork Red River, Elm Creek, North Fork Red River, Sweetwater Creek, and Washita River, together with all their tributaries in Texas which lie west of the 100th Meridian.

(b) The annual flow within this subbasin is hereby apportioned sixty percent (60%) to Texas and forty percent (40%) to Oklahoma.

SECTION 4.02 Subbasin 2 - Intrastate and interstate streams - Oklahoma.

(a) This subbasin is composed of all tributaries of the Red River in Oklahoma and portions thereof upstream to the Texas-Oklahoma state boundary at longitude one hundred degrees west, beginning from Denison Dam and upstream to and including Buck Creek.

(b) The State of Oklahoma shall have free and unrestricted use of the water of this subbasin.

SECTION 4.03 Subbasin 3 - Intrastate streams - Texas.

(a) This includes the tributaries of the Red River in Texas, beginning from Denison Dam and upstream to and including Prairie Dog Town Fork Red River.

(b) The State of Texas shall have free and unrestricted use of the water in this subbasin.

SECTION 4.04 Subbasin 4 - Main stem of the Red River and Lake Texoma.

(a) This subbasin includes all of Lake Texoma and the Red River beginning at Denison Dam and continuing

upstream to the Texas-Oklahoma state boundary at longitude one hundred degrees west.

(b) The storage of Lake Texoma and flow from the main stem of the Red River into Lake Texoma is apportioned as follows:

(1) Oklahoma 200,000 acre-feet and Texas 200,000 acre-feet, which quantities shall include existing allocations and uses; and (2) Additional quantities in a ratio of fifty percent (50%) to Oklahoma and fifty percent (50%) to Texas. SECTION 4.05 Special Provisions. (a) Texas and Oklahoma may construct, jointly or in cooperation with the United States, storage or other facilities for the conservation and use of water; provided that any facilities constructed on the Red River boundary between the two states shall not be inconsistent with the Federal legislation authorizing Denison Dam and Reservoir project.

(b) Texas shall not accept for filing, or grant a permit, for the construction of a dam to impound water solely for irrigation, flood control, soil conservation, mining and recovery of minerals, hydroelectric power, navigation, recreation and pleasure, or for any other purpose other than for domestic, municipal, and industrial water supply, on the main stem of the North Fork Red River or any of its tributaries within Texas above Lugert-Altus Reservoir until the date that imported water sufficient to meet the municipal and irrigation needs of Western Oklahoma is provided, or until January 1, 2000, whichever occurs first.

ARTICLE V

APPORTIONMENT OF WATER - REACH II

ARKANSAS, OKLAHOMA, TEXAS AND LOUISIANA

Subdivision of Reach II and allocation of water therein. Reach II of the Red River is divided into topographic subbasins, and the water therein is allocated as follows:

SECTION 5.01 Subbasin 1 - Intrastate streams - Oklahoma.

(a) This subbasin includes those streams and their tributaries above existing, authorized or proposed last downstream major damsites, wholly in Oklahoma and flowing into Red River below Denison Dam and above the Oklahoma-Arkansas state boundary. These streams and their tributaries with existing, authorized or proposed last downstream major damsites are as follows: Location Stream Site Ac-ft Latitude Longitude Island-Bayou Albany 85,200 33 51.5'N 96 11.4'W Blue River Durant 147,000 33 55.5'N 96 04.2'W Boggy River Boswell 1,243,800 34 01.6'N 95 45.0'W Kiamichi River Hugo 240,700 34 01.0'N 95 22.6'W

(b) Oklahoma is apportioned the water of this subbasin and shall have unrestricted use thereof.

SECTION 5.02 Subbasin 2 - Intrastate streams - Texas.

(a) This subbasin includes those streams and their tributaries above existing authorized or proposed last downstream major damsites, wholly in Texas and flowing into Red River below Denison Dam and above the Texas-Arkansas state boundary. These streams and their tributaries with existing, authorized or proposed last downstream major damsites are as follows: Location Stream Site Ac-ft Latitude Longitude Shawnee Creek Randall Lake 5,400 33 48.1'N 96 34.8'W Brushy Creek Valley Lake 15,000 33 38.7'N 96 21.5'W New Bonham Bois d'Arc Creek Reservoir 130,600 33 42.9'N 95 58.2'W Coffee Mill Coffee Mill Creek Lake 8,000 33 44.1'N 95 58.0'W Sandy Creek Lake Crockett 3,900 33 44.5'N 95 55.5'W Sanders Creek Pat Mayse 124,500 33 51.2'N 95 32.9'W Pine Creek Lake Crook 11,011 33 43.7'N 95 34.0'W Big Pine Creek Big Pine Lake 138,600 33 52.0'N 95 11.7'W Pecan Bayou Pecan Bayou 625,000 33 41.1'N 94 58.7'W Mud Creek Liberty Hill 97,700 33 33.0'N 94 29.3'W KVW Ranch Mud Creek Lakes (3) 3,440 33 34.8'N 94 27.3'W

(b) Texas is apportioned the water of this subbasin and shall have unrestricted use thereof.

SECTION 5.03 Subbasin 3 - Interstate Streams - Oklahoma and Arkansas.

(a) This subbasin includes Little River and its tributaries above Millwood Dam.

(b) The States of Oklahoma and Arkansas shall have free and unrestricted use of the water of this subbasin

within their respective states, subject, however, to the limitation that Oklahoma shall allow a quantity of water equal to forty percent (40%) of the total runoff originating below the following existing, authorized or proposed last downstream major damsites in Oklahoma to flow into Arkansas: Location Stream Site Ac-ft Latitude Longitude Little River Pine Creek 70,500 34 06.8'N 95 04.9'W Glover Creek Lukfata 258,600 34 08.5'N 94 55.4'W Mountain Fork River Broken Bow 470,100 34 08.9'N 94 41.2'W

(c) Accounting will be on an annual basis unless otherwise deemed necessary by the States of Arkansas and Oklahoma.

SECTION 5.04 Subbasin 4 - Interstate streams - Texas and Arkansas.

(a) This subbasin shall consist of those streams and their tributaries above existing, authorized or proposed last downstream major damsites, originating in Texas and crossing the Texas-Arkansas state boundary before flowing into the Red River in Arkansas. These streams and their tributaries with existing, authorized or proposed last downstream major damsites are as follows: Location Stream Site Ac-ft Latitude Longitude McKinney Bayou Trib. Bringle Lake 3,052 33 30.6'N 94 06.2'W Barkman Barkman Creek Reservoir 15,900 33 29.7'N 94 10.3'W Sulphur River Texarkana 386,900 33 18.3'N 94 09.6'W

(b) The State of Texas shall have the free and unrestricted use of the water of this subbasin.

SECTION 5.05 Subbasin 5 - Main stem of the Red River and tributaries.

(a) This subbasin includes that portion of the Red River, together with its tributaries, from Denison Dam down to the Arkansas-Louisiana state boundary, excluding all tributaries included in the other four subbasins of Reach II.

(b) Water within this subbasin is allocated as follows:

(1) The Signatory States shall have equal rights to the use of runoff originating in subbasin 5 and undesignated water flowing into subbasin 5, so long as the flow of the Red River at the Arkansas-Louisiana state boundary is 3,000 cubic feet per second or more, provided no state is entitled to more than twenty-five percent (25%) of the water in excess of 3,000 cubic feet per second.

(2) Whenever the flow of the Red River at the Arkansas-Louisiana state boundary is less than 3,000 cubic feet per second, but more than 1,000 cubic feet per second, the States of Arkansas, Oklahoma, and Texas shall allow to flow into the Red River for delivery to the State of Louisiana a quantity of water equal to forty percent (40%) of the total weekly runoff originating in subbasin 5 and forty percent (40%) of undesignated water flowing into subbasin 5; provided, however, that this requirement shall not be interpreted to require any state to release stored water.

(3) Whenever the flow of the Red River at the Arkansas-Louisiana state boundary falls below 1,000 cubic feet per second, the States of Arkansas, Oklahoma, and Texas shall allow a quantity of water equal to all the weekly runoff originating in subbasin 5 and all undesignated water flowing into subbasin 5 within their respective states to flow into the Red River as required to maintain a 1,000 cubic foot per second flow at the Arkansas-Louisiana state boundary.

(c) Whenever the flow at Index, Arkansas, is less than 526 cfs, the States of Oklahoma and Texas shall each allow a quantity of water equal to forty percent (40%) of the total weekly runoff originating in subbasin 5 within their respective states to flow into the Red River; provided however, this provision shall be invoked only at the request of Arkansas, only after Arkansas has ceased all diversions from the Red River itself in Arkansas above Index, and only if the provisions of subsections 5.05 (b) (2) and (3) have not caused a limitation of diversions in subbasin 5.

(d) No state guarantees to maintain a minimum low flow to a downstream state.

SECTION 5.06 Special Provisions.

(a) Reservoirs within the limits of Reach II, subbasin 5, with a conservation storage capacity of 1,000 acre-feet or less in existence or authorized on the date of the Compact pursuant to the rights and privileges granted by a Signatory State authorizing such reservoirs, shall be exempt from the provisions of Section 5.05; provided, if any right to store water in, or use water from, an existing exempt reservoir expires or is cancelled after the effective date of the Compact the exemption for such rights provided by this section shall be lost.

(b) A Signatory State may authorize a change in the purpose or place of use of water from a reservoir exempted by subparagraph (a) of this section without losing that exemption, if the quantity of authorized use and storage is not increased.

(c) Additionally, exemptions from the provisions of Section 5.05 shall not apply to direct diversions from Red River to off-channel reservoirs or lands.

ARTICLE VI

APPORTIONMENT OF WATER - REACH III

ARKANSAS, LOUISIANA, AND TEXAS

Subdivision of Reach III and allocation of water therein. Reach III of the Red River is divided into topographic subbasins, and the water therein allocated, as follows:

SECTION 6.01 Subbasin 1 - Interstate streams - Arkansas and Texas.

(a) This subbasin includes the Texas portion of those streams crossing the Arkansas-Texas state boundary one or more times and flowing through Arkansas into Cypress Creek-Twelve Mile Bayou watershed in Louisiana.

(b) Texas is apportioned sixty percent (60%) of the runoff of this subbasin and shall have unrestricted use thereof; Arkansas is entitled to forty percent (40%) of the runoff of this subbasin.

SECTION 6.02 Subbasin 2 - Interstate streams - Arkansas and Louisiana.

(a) This subbasin includes the Arkansas portion of those streams flowing from subbasin 1 into Arkansas, as well as other streams in Arkansas which cross the Arkansas-Louisiana state boundary one or more times and flow into Cypress Creek-Twelve Mile Bayou watershed in Louisiana.

(b) Arkansas is apportioned sixty percent (60%) of the runoff of this subbasin and shall have unrestricted use thereof; Louisiana is entitled to forty percent (40%) of the runoff of this subbasin.

SECTION 6.03 Subbasin 3 - Interstate streams - Texas and Louisiana.

(a) This subbasin includes the Texas portion of all tributaries crossing the Texas-Louisiana state boundary one or more times and flowing into Caddo Lake, Cypress Creek-Twelve Mile Bayou or Cross Lake, as well as the Louisiana portion of such tributaries.

(b) Texas and Louisiana within their respective boundaries shall each have the unrestricted use of the water of this subbasin subject to the following allocation:

(1) Texas shall have the unrestricted right to all water above Marshall, Lake O' the Pines, and Black Cypress damsites; however, Texas shall not cause runoff to be depleted to a quantity less than that which would have occurred with the full operation of Franklin County, Titus County, Ellison Creek, Johnson Creek, Lake O' the Pines, Marshall, and Black Cypress Reservoirs constructed, and those other impoundments and diversions existing on the effective date of this Compact. Any depletions of runoff in excess of the depletions described above shall be charged against Texas' apportionment of the water in Caddo Reservoir.

(2) Texas and Louisiana shall each have the unrestricted right to use fifty percent (50%) of the conservation storage capacity in the present Caddo Lake for the impoundment of water for

state use, subject to the provision that supplies for existing uses of water from Caddo Lake, on date of Compact, are not reduced.

(3) Texas and Louisiana shall each have the unrestricted right to fifty percent (50%) of the conservation storage capacity of any future enlargement of Caddo Lake, provided, the two states may negotiate for the release of each state's share of the storage space on terms mutually agreed upon by the two states after the effective date of this Compact.

(4) Inflow to Caddo Lake from its drainage area downstream from Marshall, Lake O' the Pines, and Black Cypress damsites and downstream from other last downstream dams in existence on the date of the signing of the Compact document by the Compact Commissioners, will be allowed to continue flowing into Caddo Lake except that any man-made depletions to this inflow by Texas will be subtracted from the Texas share of the water in Caddo Lake.

(c) In regard to the water of interstate streams which do not contribute to the inflow to Cross Lake or Caddo Lake, Texas shall have the unrestricted right to divert and use this water on the basis of a division of runoff above the state boundary of sixty percent (60%) to Texas and forty percent (40%) to Louisiana.

(d) Texas and Louisiana will not construct improvements on the Cross Lake Watershed in either state that will affect the yield of Cross Lake; provided, however, this subsection shall be subject to the provisions of Section 2.08.

SECTION 6.04 Subbasin 4 - Intrastate streams - Louisiana.

(a) This subbasin includes that area of Louisiana in Reach III not included within any other subbasin.

(b) Louisiana shall have free and unrestricted use of the water of this subbasin.

ARTICLE VII

APPORTIONMENT OF WATER - REACH IV ARKANSAS AND LOUISIANA

Subdivision of Reach IV and allocation of water therein. Reach IV of the Red River is divided into topographic subbasins, and the water therein allocated as follows:

SECTION 7.01 Subbasin 1 - Intrastate streams - Arkansas.

(a) This subbasin includes those streams and their tributaries above last downstream major damsites originating in Arkansas and crossing the Arkansas-Louisiana state boundary before flowing into the Red River in Louisiana. Those major last downstream damsites are as follows: Location Stream Site Ac-ft Latitude Longitude Lake Ouachita River Catherine 19,000 34 26.6'N 93 01.6'W Caddo River DeGray Lake 1,377,000 34 13.2'N 93 06.6'W Little Missouri River Lake Greeson 600,000 34 08.9'N 93 42.9'W Alum Fork, Saline River Lake Winona 63,264 32 47.8'N 92 51.0'W

(b) Arkansas is apportioned the waters of this subbasin and shall have unrestricted use thereof.

SECTION 7.02 Subbasin 2 - Interstate Streams - Arkansas and Louisiana.

(a) This subbasin shall consist of Reach IV less subbasin 1 as defined in Section 7.01 (a) above.

(b) The State of Arkansas shall have free and unrestricted use of the water of this reach subject to the limitation that Arkansas shall allow a quantity of water equal to forty percent (40%) of the weekly runoff originating below or flowing from the last downstream major damsite to flow into Louisiana. Where there are no designated last downstream damsites, Arkansas shall allow a quantity of water equal to forty percent (40%) of the total weekly runoff originating above the state boundary to flow into Louisiana. Use of water in this subbasin is subject to low flow provisions of subparagraph 7.03 (b).

SECTION 7.03 Special Provisions.

(a) Arkansas may use the beds and banks of segments of Reach IV for the purpose of conveying its share of water to designated downstream diversions.

(b) The State of Arkansas does not guarantee to maintain a minimum low flow for Louisiana in Reach IV. However, on the following streams when the use of water in Arkansas reduces the flow at the Arkansas-Louisiana state boundary to the following amounts:

(1) Ouachita - 780 cfs

(2) Bayou Bartholomew - 80 cfs

(3) Boeuf River - 40 cfs

(4) Bayou Macon - 40 cfs the State of Arkansas pledges to take affirmative steps to regulate the diversions of runoff originating or flowing into Reach IV in such a manner as to permit an equitable apportionment of the runoff as set out herein to flow into the State of Louisiana. In its control and regulation of the water of Reach IV any adjudication or order rendered by the State of Arkansas or any of its instrumentalities or agencies affecting the terms of this Compact shall not be effective against the State of Louisiana nor any of its citizens or inhabitants until approved by the Commission.

ARTICLE VIII

APPORTIONMENT OF WATER - REACH V

SECTION 8.01 Reach V of the Red River consists of the main stem Red River and all of its tributaries lying wholly within the State of Louisiana. The State of Louisiana shall have free and unrestricted use of the water of this subbasin.

ARTICLE IX

ADMINISTRATION OF THE COMPACT

SECTION 9.01 There is hereby created an interstate administrative agency to be known as the "Red River Compact Commission", hereinafter called the "Commission". The Commission shall be composed of two representatives from each Signatory State who shall be designated or appointed in accordance with the laws of each state, and one Commissioner representing the United States, who shall be appointed by the President. The Federal Commissioner shall be the Chairman of the Commission but shall not have the right to vote. The failure of the President to appoint a Federal Commissioner will not prevent the operation or effect of this Compact, and the eight representatives from the Signatory States will elect a Chairman for the Commission.

SECTION 9.02 The Commission shall meet and organize within sixty (60) days after the effective date of this Compact. Thereafter, meetings shall be held at such times and places as the Commission shall decide.

SECTION 9.03 Each of the two Commissioners from each state shall have one vote; provided, however, that if only one representative from a state attends he is authorized to vote on behalf of the absent Commissioner from that state. Representatives from three states shall constitute a quorum. Any action concerned with administration of this Compact or any action requiring compliance with specific terms of this Compact shall require six concurring votes. If a proposed action of the Commission affects existing water rights in a state, and that action is not expressly provided for in this Compact, eight concurring votes shall be required.

SECTION 9.04 (a) The salaries and personal expenses of each state's representative shall be paid by the government that it represents, and the salaries and personal expenses of the Federal Commissioner will be paid for by the United States.

(b) The Commission's expenses for any additional stream flow gauging stations shall be equitably apportioned among the states involved in the reach in which the stream flow gauging stations are located.

(c) All other expenses incurred by the Commission shall be borne equally by the Signatory States and shall be paid by the Commission out of the "Red River Compact Commission Fund". Such fund shall be initiated and maintained by equal payments of each state into the fund. Disbursement shall be made from the fund in

such manner as may be authorized by the Commission. Such fund shall not be subject to audit and accounting procedures of the state; however, all receipts and disbursements of the fund by the Commission shall be audited by a qualified independent public accountant at regular intervals, and the report of such audits shall be included in and become a part of the annual report of the Commission. Each state shall have the right to make its own audit of the accounts of the Commission at any reasonable time.

ARTICLE X

POWERS AND DUTIES OF THE COMMISSION

SECTION 10.01 The Commission shall have the power to:

(a) Adopt rules and regulations governing its operation and enforcement of the terms of the Compact;

(b) Establish and maintain an office for the conduct of its affairs and, if desirable, from time to time, change its location;

(c) Employ or contract with such engineering, legal, clerical and other personnel as it may determine necessary for the exercise of its functions under this Compact without regard to the Civil Service Laws of any Signatory State; provided that such employees shall be paid by and be responsible to the Commission and shall not be considered employees of any Signatory State;

(d) Acquire, use and dispose of such real and personal property as it may consider necessary;

(e) Enter into contracts with appropriate state or Federal agencies for the collection, correlation and presentation of factual data, for the maintenance of records and for the preparation of reports;

(f) Secure from the head of any department or agency of the Federal or state government such information as it may need or deem to be useful for carrying out its functions and as may be available to or procurable by the department or agency to which the request is addressed; provided such information is not privileged and the department or agency is not precluded by law from releasing same.

(g) Make findings, recommendations or reports in connection with carrying out the purposes of this Compact, including, but not limited to, a finding that a Signatory State is or is not in violation of any of the provisions of this Compact. The Commission is authorized to make such investigations and studies, and to hold such hearings as it may deem necessary for said purposes. It is authorized to make and file official certified copies of any of its findings, recommendations or reports with such officers or agencies of any Signatory State, or the United States, as may have any interest in or jurisdiction over the subject matter. The making of findings, recommendations, or reports by the Commission shall not be a condition precedent to the instituting or maintaining of any action or proceeding of any kind by a Signatory State in any court or tribunal, or before any agency or officer, for the protection of any right under this Compact or for the enforcement of any of its provisions; and

(h) Print or otherwise reproduce and distribute its proceedings and reports.

SECTION 10.02 The Commission shall:

(a) Cause to be established, maintained, and operated such stream, reservoir and other gauging stations as are necessary for the proper administration of the Compact;

(b) Cause to be collected, analyzed and reported such information on stream flows, water quality, water storage and such other data as are necessary for the proper administration of the Compact;

(c) Perform all other functions required of it by the Compact and do all things necessary, proper and convenient in the performance of its duties thereunder;

(d) Prepare and submit to the Governor of each of the Signatory States a budget covering the anticipated expenses of the Commission for the following fiscal biennium;

(e) Prepare and submit an annual report to the Governor of each Signatory State and to the President of the

United States covering the activities of the Commission for the preceding fiscal year, together with an accounting of all funds received and expended by it in the conduct of its work;

(f) Make available to the Governor or to any official agency of a Signatory State or to any authorized representative of the United States, upon request, any information within its possession;

(g) Not incur any obligation in excess of the unencumbered balance of its funds, nor pledge the credit of any of the Signatory States; and

(h) Make available to a Signatory State or the United States in any action arising under this Compact, without subpoena, the testimony of any officer or employee of the Commission having knowledge of any relevant facts.

ARTICLE XI

POLLUTION

SECTION 11.01 The Signatory States recognize that the increase in population and the growth of industrial, agricultural, mining and other activities combined with natural pollution sources may lead to a diminution of the quality of water in the Red River Basin which may render the water harmful or injurious to the health and welfare of the people and impair the usefulness or public enjoyment of the water for beneficial purposes, thereby resulting in adverse social, economic, and environmental impacts.

SECTION 11.02 Although affirming the primary duty and responsibility of each Signatory State to take appropriate action under its own laws to prevent, diminish, and regulate all pollution sources within its boundaries which adversely affect the water of the Red River Basin, the states recognize that the control and abatement of the naturally-occurring salinity sources as well as, under certain circumstances, the maintenance and enhancement of the quality of water in the Red River Basin may require the cooperative action of all states.

SECTION 11.03 The Signatory States agree to cooperate with agencies of the United States to devise and effectuate means of alleviating the natural deterioration of the water of the Red River Basin.

SECTION 11.04 The Commission shall have the power to cooperate with the United States, the Signatory States and other entities in programs for abating and controlling pollution and natural deterioration of the water of the Red River Basin, and to recommend reasonable water quality objectives to the states.

SECTION 11.05 Each Signatory State agrees to maintain current records of waste discharges into the Red River Basin and the type and quality of such discharges, which records shall be furnished to the Commission upon request.

SECTION 11.06 Upon receipt of a complaint from the Governor of a Signatory State that the interstate water of the Red River Basin in which it has an interest are being materially and adversely affected by pollution and that the state in which the pollution originates has failed after reasonable notice to take appropriate abatement measures, the Commission shall make such findings as are appropriate and thereafter provide such findings to the Governor of the state in which such pollution originates and request appropriate corrective action. The Commission, however, shall not take any action with respect to pollution which adversely affects only the state in which such pollution originates.

SECTION 11.07 In addition to its other powers set forth under this Article, the Commission shall have the authority, upon receipt of six concurring votes, to utilize applicable Federal statutes to institute legal action in its own name against the person or entity responsible for interstate pollution problems; provided, however, sixty (60) days before initiating legal action the Commission shall notify the Governor of the state in which the pollution source is located to allow that state an opportunity to initiate action in its own name.

SECTION 11.08 Without prejudice to any other remedy available to the Commission, or any Signatory State, any state which is materially and adversely affected by the pollution of the water of the Red River Basin by pollution originating in another Signatory State may institute a suit against any individual, corporation, partnership, or association, or against any Signatory State or political or governmental subdivision thereof, or against any officer, agency, department, bureau, district or instrumentality of or in any Signatory State contributing to such pollution in accordance with applicable Federal statutes. Nothing herein shall be construed as depriving any person of any rights of action relating to pollution which such person would have if this Compact had not been made.

ARTICLE XII

TERMINATION AND AMENDMENT OF COMPACT

SECTION 12.01 This Compact may be terminated at any time by appropriate action of the Legislatures of all of the four Signatory States. In the event of such termination, all rights established under it shall continue unimpaired.

SECTION 12.02 This Compact may be amended at any time by appropriate action of the Legislatures of all Signatory States that are affected by such amendment. The consent of the United States Congress must be obtained before any such amendment is effective.

ARTICLE XIII

RATIFICATION AND EFFECTIVE DATE OF COMPACT

SECTION 13.01 Notice of ratification of this Compact by the Legislature of each Signatory State shall be given by the Governor thereof to the Governors of each of the other Signatory States and to the President of the United States. The President is hereby requested to give notice to the Governors of each of the Signatory States of the consent to this Compact by the Congress of the United States.

SECTION 13.02 This Compact shall become effective, binding and obligatory when, and only when:

(a) It has been duly ratified by each of the Signatory States; and

(b) It has been consented to by an Act of the Congress of the United States, which Act provides that: Any other statute of the United States to the contrary notwithstanding, in any case or controversy:

i. which involves the construction or application of this Compact;

ii. in which one or more of the Signatory States to this Compact is a plaintiff or plaintiffs; and

iii. which is within the judicial power of the United States as set forth in the Constitution of the United States; and without any requirement, limitation or regard as to the sum or value of the matter in controversy, or of the place of residence or citizenship of, or of the nature, character or legal status of, any of the other proper parties plaintiff or defendant in such case of controversy:

The consent of Congress is given to name and join the United States as a party defendant or otherwise in any such case or controversy in the Supreme Court of the United States if the United States is an indispensable party thereto.

SECTION 13.03 The United States District Courts shall have original jurisdiction (concurrent with that of the Supreme Court of the United States, and concurrent with that of any other Federal or state court, in matters in which the Supreme Court, or other court has original jurisdiction) of any case or controversy involving the application or construction of this Compact; that said jurisdiction shall include, but not be limited to, suits between Signatory States; and that the venue of such case or controversy may be brought in any judicial district in which the acts complained of (or any portion thereof) occur.

***Historical Data***

---

Laws 1979, c. 136, § 1, eff. May 3, 1979.

***Citationizer© Summary of Documents Citing This Document***

---

| Cite | Name | Level |
|---|---|---|
| None Found. | | |

***Citationizer: Table of Authority***

---

# APPENDIX B

# LETTER REQUESTS FROM NTMWD AND GTUA FOR WATER STORAGE AGREEMENTS

# NORTH TEXAS MUNICIPAL WATER DISTRICT

*Regional Service Through Unity*

March 17, 2004

Colonel Robert L. Suthard, Jr.
Department of Army
Corps of Engineers, Tulsa District
1645 South 101st East Ave.
Tulsa, Oklahoma 74128-4609

Re: Reallocation of Conservation Storage in Lake Texoma

Dear Colonel Suthard:

I am in receipt of your November 25, 2003 letter wherein you have outlined the status of the U.S. Army Corps of Engineer's ("USACE") reallocation of storage in Lake Texoma pursuant to the Water Resources Development Act of 1986. After receiving your letter, District staff met with Ms. Jan Hotubbee to further explore the option of purchasing additional water in Lake Texoma from the USACE. Based on our meeting with Ms. Hotubbee, and based on subsequent meetings with the Texas Commission on Environmental Quality (the "Commission") regarding authorization of a state water right to divert and use stored water from Lake Texoma, the District would like to accept your offer to develop and submit a draft Water Supply Contract in conjunction with the draft Reallocation Report. As you have suggested, District staff will work with Ms. Hotubbee to develop a draft contract, and to coordinate efforts to obtain a surface water right from the Commission upon approval of the Reallocation Report.

The District appreciates the spirit of cooperation exhibited by the USACE on this matter, and looks forward to continuing its relationship with the USACE for stored water in Lake Texoma. If you have any questions regarding this matter, please feel free to contact me at your convenience.

Sincerely,

James M. Parks
Executive Director

cc: Ms. Jan Hotubbee
Mr. Martin C. Rochelle

505 E. Brown St., P.O. Box 2408, Wylie, Texas 75098-2408 Telephone: 972/442-5405 Fax: 972/442-5405

**DEPARTMENT OF ARMY**
CORPS OF ENGINEERS, TULSA DISTRICT
1645 SOUTH 101ST EAST AVENUE
TULSA, OKLAHOMA 74128-4609

December 16, 2004

Planning, Environmental, and Regulatory Division
Planning Branch

Mr. James Parks
North Texas Municipal Water District
505 East Brown Street
P.O. Box 2408
Wylie, Texas 75098

Dear Mr. Parks:

This is in response to a conversation between Mr. Brad Castleberry, Mr. Martin Rochelle and Ms. Janet Hotubbee on December 15, 2004, regarding the North Texas Municipal Water Districts request for a water storage contract at Lake Texoma.

As discussed, I have enclosed a prototype agreement that the Federal government will use to negotiate an agreement with the North Texas Municipal Water District (the "District") for additional water supply storage in Lake Texoma. As you have previously indicated, the District is seeking the right to acquire an additional 100,000 acre-feet of water supply storage in Lake Texoma pursuant to the reallocation authorization in Section 838 of the Water Resources Development Act of 1986. We will forward the District's request and a draft water storage agreement to our higher authorities when we submit the draft Reallocation Report for approval. Ms. Hotubbee will prepare a draft water storage agreement in early 2005 that will include estimated costs and other matters specific to the District's acquisition of such storage. Until then, please review and consider the enclosed document in preparation of the draft agreement. The draft will have to be approved by our Headquarters in Washington, D.C. before we can finalize the agreement.

If you have any questions, please contact Ms. Janet Hotubbee at (918) 669-7089.

Sincerely,

G. David Steele, P.E.
Chief, Planning, Environmental
and Regulatory Division

Enclosure

# GREATER TEXOMA UTILITY AUTHORITY

**5100 AIRPORT DRIVE**
**DENISON, TEXAS 75020-8448**
**903/786-4433**
**FAX: 903/786-8211**
**www.gtua.org**


September 19, 2008

CERTIFIED MAIL: 7006 2150 0001 2998 5265
RETURN RECEIPT REQUESTED

Ms. Jan Hotubbee
U.S. Army Corps of Engineers
1645 S 101st East Ave
Tulsa OK 74128

RE: Water Storage Contract – Lake Texoma

Dear Jan:

On April 19, 2006, I sent you a letter regarding the portion of the 50,000 acre-feet of water storage that was to become available to the Authority under a provision of the Water Resources Act of 1986. At that time, I requested that we pursue storage of 5,000 acre-feet.

Since that time, I have discussed this matter with our member cities and other municipal water users. We have determined that it is in our best interest to pursue the entire 50,000 acre-feet of water storage made available to the Authority under the Reallocation Report and the federal legislation that authorized the report.

Please accept this letter as our official notification that we intend to pursue the entire 50,000 acre-feet of storage. Should you or Mrs. Kitchens need additional documentation regarding this matter, please advise and I will provide it to you.

Sincerely,

Jerry W. Chapman

Jerry W. Chapman
General Manager

JWC:cc

cc: Cynthia Kitchens, USACE

CERTIFIED MAIL: 7006 2150 0001 2998 5258
RETURN RECEIPT REQUESTED

# APPENDIX C

## LETTER FROM OKLAHOMA WATER RESOURCES BOARD TO U.S. ARMY CORPS OF ENGINEERS REGARDING PROPOSED REALLOCATION APPORTIONMENT

DUANE A. SMITH
EXECUTIVE DIRECTOR

BRAD HENRY
GOVERNOR

**STATE OF OKLAHOMA**
**WATER RESOURCES BOARD**

May 25, 2004

Mr. Larry Hogue, P.E.
Chief, Planning, Environmental,
and Regulatory Division
Environmental Analysis and Compliance Branch
Department of the Army
Corps of Engineers, Tulsa District
Tulsa, OK 74128-4609

Re: Proposed reallocation – Lake Texoma

Dear Mr. Hogue:

Thank you for the opportunity to comment on the proposed reallocation of the storage at Lake Texoma.

As you know, the State of Oklahoma is a party to the Red River Compact. Accordingly, the State of Oklahoma has a significant interest in ensuring compliance with the apportionment provisions of the Red River Compact. Article IV of the Compact, specifically Section 4.04, apportions the water of the mainstem of the Red River and Lake Texoma between the State of Oklahoma and the State of Texas. Basically, the Compact apportions the storage of Lake Texoma and flow of the mainstem of the Red River into Lake Texoma on a 50/50 basis between Oklahoma and Texas. Any reallocation of storage at Lake Texoma must be consistent with the apportionment provisions of the Compact.

Unfortunately, the Compact Commission has not finalized rules to implement the apportionment provisions of the Compact. Until such rules are adopted by the Commission, it will not be possible to determine whether a proposed reallocation of storage is consistent with the Compact's apportionment provisions. The Oklahoma Commissioners and Texas Commissioners of the Red River Compact Commission are aware of the need for rules, and we hope to consider proposed rules at the Commission's annual meeting scheduled during April, 2005. Staff of the Corps' Tulsa District are routinely invited to the Commission's annual meetings, and therefore, will be notified of the Commission's determination regarding the apportionment rules.

A related issue that should be addressed in the reallocation study is the costs of the water supply storage. It is our understanding that the original water supply storage allocation for Lake Texoma was 150,000 acre-feet. Therefore, under the terms of the 50/50 apportionment provision, the Compact apportions 75,000 acre-feet of the original water supply storage

OWRB
3800 N. CLASSEN BOULEVARD • OKLAHOMA CITY, OKLAHOMA 73118 • TELEPHONE (405) 530-8800 • FAX (405) 530-8900

Grady Grandstaff, Chairman • Glenn Sharp, Vice Chairman • Evan Mitchell, Secretary
Dennis L. Farmer • Mark Nelson • Bill Seiber • Harry Currie • Richard [illegible] • Jack Bass

allocation to Oklahoma and the other 75,000 acre-feet to Texas. Based on plain readings of the Water Supply Act of 1986 and the Red River Compact, we believe that Oklahoma users remain entitled to enter into contracts for up to a total of 75,000 acre-feet of water supply storage under terms and conditions available prior to the Water Supply Act of 1986. An explanation is in order.

Section 838 of the Water Resources Development Act of 1986 provides authority for the Corps to reallocate 300,000 acre-feet of storage in Lake Texoma from hydropower to water supply, with 150,000 acre-feet for Oklahoma users and 150,000 acre-feet for Texas users (this is consistent with the 50/50 apportionment provision of the Compact). Paragraph (d)(1) of Section 838 then indicates that all contracts for the reallocated storage shall be under the new water supply contract terms set forth in Section 932, which terms are substantially less favorable than terms in contracts entered pursuant to the Water Supply Act of 1958. However, paragraph (e) of Section 838 controls the situation by providing that nothing in Section 838 of the Water Resources Development Act of 1986 shall be construed as amending or altering in any way the Red River Compact. As noted above, the Red River Compact split the storage at Lake Texoma and flow from the mainstem of the Red River on a 50/50 basis, as follows: "Oklahoma 200,000 acre-feet and Texas to 200,000 acre-feet, which quantities shall include existing allocations and uses" (emphasis added). The emphasized language in the Compact makes it clear that the 50/50 apportionment provision of the Compact applies to the original 150,000 acre-feet allocation for water supply storage. Therefore, Oklahoma users are entitled to contract for up to 75,000 acre-feet of the original allocation amount without triggering less favorable repayment terms that will apply to contracts for the reallocated storage.

The Environmental Assessment should address both the apportionment rules to be adopted by the Compact Commission and the costs of the storage.

Please keep us informed of the progress of the Environmental Assessment work. Thank you again for the opportunity to provide input.

Sincerely,

Duane A. Smith
Executive Director

cc: Secretary Miles Tolbert
Charles Dobbs, Oklahoma Commissioner
Mark Nichols
Gordon W. Fassett, Federal Commissioner
William A. Abney, Texas Commissioner
Randy Young, Arkansas Commissioner

# APPENDIX D

# RED RIVER SUPER MODEL,
# LAKE TEXOMA YIELD ANALYSIS,
# AND
# WATER SUPPLY REALLOCATION ALTERANTIVES

# APPENDIX D

## Red River SUPER Model, Lake Texoma Yield Analysis, and Water Supply Reallocation Alternatives

In response to requests by north Texas municipalities and water users near Lake Texoma, Congress authorized the Assistant Secretary of the Army for Civil Works (ASA (CW)) to reallocate conservation storage to water supply up to 150,000 acre-feet each for Oklahoma and Texas. This authorization was in Section 838 of the 1986 Water Resources Development Act (1986 WRDA) (Public Law 99-662). The authorization is referred to as Sec 838 throughout this report. Many of the communities and water users in north Texas are served by the North Texas Municipal Water District (NTMWD) and the Greater Texoma Utility Authority (GTUA). The potential impacts of reallocation were evaluated using SUPER to model yield and impact analysis of reallocation alternatives.

### Overview of SUPER Model

The SUPER Model is a suite of computer programs written for use in the Southwestern Division of the U.S. Army Corps of Engineers to model multi-purpose reservoir system regulation. The programs were developed over a thirty-year period by Ronald L. Hula, primarily as a planning tool to perform period-of-record analysis, to evaluate changes in operational scenarios. The model was developed to simulate flood control and conservation pool operations, including: hydropower, water supply, water quality, and water diversions and returns. In addition to period-of-record analysis, the program was developed to perform conservation pool yield analyses and firm energy analyses. The program is used to estimate water resources system conditions prior to anthropomorphic impacts, such as reservoir systems; including runoff, storage, flow modification, and diversion conditions. SUPER is also used to for economic analyses of impacts of alternatives that can be compared to a set of existing conditions. Output includes tabular or graphical formats of hydrographs, duration plots, and frequency curves at reservoirs and other control points in the system model.

SUPER is a daily simulation model that assumes all reservoirs are in place for the entire period of record specified for each model, based on data availability. For each SUPER model, a complex set of intervening area flows is developed for the period of record. The development of intervening area flow data is a pre-processing requirement for a SUPER model simulation. When simulation is begun, headwater reservoir inflows and subsequent derived releases based on current and future forecast conditions are then routed through the system on a daily basis. These routed flows are combined with intervening area flows at all control point locations. Reservoir releases are made for flood control, hydroelectric power generation, water supply requirements, and stream flow requirements such as water quality and irrigation. Other regulating considerations include channel capacities and bank stability. All releases are analyzed to determine their impact on current and future forecasted conditions, and are adjusted as needed to meet predefined system constraints. In addition to the above requirements, SUPER works to achieve a target uniform balance between all competing reservoirs during the draw down of system flood storage, and a target uniform balance in system conservation storage remaining during a conservation pool draw down. SUPER has evolved to meet the complex challenge of

modeling system operations while meeting system and local constraints, and balancing requirements.

## SUPER Hydrologic Development

Prior to this study, the Red River SUPER model had a hydrologic period-of-record from January 1938 to December 1990. Although there had not been any significant floods along the Red River through most of the 1990's, there had been some drier years, and enough additional years of record, that the model needed to be updated. The goal of this update was to extend the period of record to 2000.

This required collecting and formatting an additional ten years of daily inflows for the 20 reservoirs within the model, and daily flows for numerous flow gages used to develop the period-of-record hydrology. Monthly evaporation and precipitation at numerous locations was also collected and formatted. The data was extracted as much as possible from the USGS published data. Reservoir inflows, data for unpublished gages, and some evaporation data was taken from the internal Corps of Engineers databases. All required data was input into the Red River SUPER database.

After the Red River SUPER database was updated and complete, extensive editing of the hydrologic files was done to incorporate and utilize the additional ten years of daily data that was available. Hydrologic building files were then run through a series of programs to develop the updated period-of-record hydrology or local flows.

With the updated hydrology files, a natural conditions run, simulating no reservoirs in place, was made. As a final check to spot errors in building the hydrology file, a volume checking program was run, which performs a volume comparison between the natural condition flows developed from SUPER and observed gaged flow data. This required building an extensive input file to perform the volume checking analysis. Problems were corrected as required.

## Texoma Yield and Impact Analysis Using SUPER

### A. Conservation Pool Reallocation Alternatives

With the updated SUPER model, it was desired to determine the true yield of the conservation storage available at the end of the project life. The yield of the conservation storage is required to determine the critical dependable water supply demand that will occur if the entire reallocated storage is used for water supply. This will provide a worse case demand for water supply during the critical drought. At Lake Texoma, the existing conservation storage lies between El. 590 and 617. The end of the project life at Texoma is the year 2044. The water supply yield run was made using an updated elevation-area-capacity table based on the 2002 sediment resurvey of Lake Texoma, with projected future sedimentation to the year 2044. This projected future storage is considered "usable storage". The true yield of the conservation storage at Lake Texoma for the projected 2044 conditions was determined to be 1502.5 cfs. The critical dependable yield for the conservation storage allocated to water supply ($Y_{Critical}$) is

determined by multiplying true yield ($Y_{true}$) of the conservation storage times the ratio of the total allocated water supply storage ($S_{Allocated}$) to the total usable conservation storage ($S_{Total}$).

| Critical Dependable Yield Calculation<br>Conservation Storage Allocated To Water Supply | |
|---|---|
| Total "Usable" Conservation Storage, forecast to 2044 ($S_{Total}$) | 986,730 acre-feet<br>(Table 1) |
| Total Allocated Water Supply Storage ($S_{Allocated}$)<br><br>(Prior water supply storage reallocation plus<br>the potential reallocation authorized by Sec 838)<br>(150,000 acre-feet + 300,000 acre-feet total) | 450,000 acre-feet |
| True Yield ($Y_{true}$) | 1502.5 cfs |
| Critical Dependable Yield for $S_{Allocated}$. ($Y_{Critical}$)<br>($S_{Allocated}$ / $S_{Total}$) x $Y_{true}$ =<br>(450,000 acre-feet / 986,730 acre-feet) x 1502.5 cfs | 685.2 cfs<br><br>(= 442.1 mgd) |

Current water storage agreements based on the 1985 sediment survey with sediment projections to the year 2044 will need to be updated to the current "usable storage" based on the 2002 sediment survey at Texoma.

The initial storage requests which prompted the reallocation study came from North Texas Municipal Water District (NTMWD) which requested 100,000 acre-feet of additional storage, and Greater Texoma Utility Authority (GTUA) which requested 50,000 acre-feet of additional storage. This will provide a total of 150,000 acre-feet for Texas users. No Oklahoma users have requested storage, although an equal amount of storage was identified as available for water supply to Oklahoma, based on the Red River Compact. Therefore, the conservation pool reallocations modeled are 150,000 acre-feet for Texas use only and 300,000 acre-feet for Texas and Oklahoma use. Therefore, three SUPER runs were made to model impacts at Texoma due to the proposed reallocation of hydropower to water supply. The critical dependable water supply demand is the only input parameter that varies between the runs. The runs made are as follows:

(1) Existing conditions in which the full 150,000 acre-feet previously reallocated from hydropower to water supply at Texoma is utilized. The water supply demand modeled = 228.4 cfs

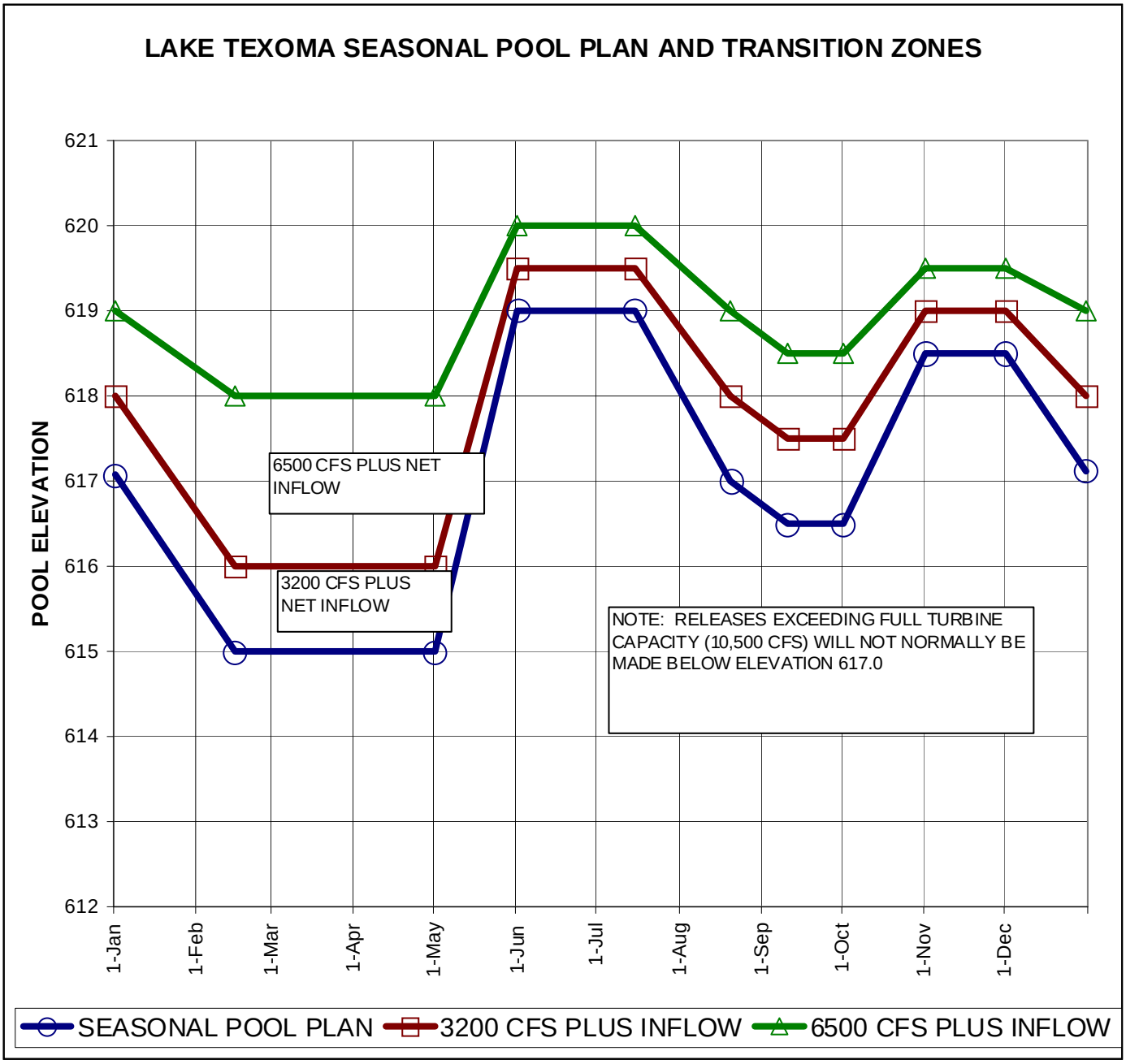
(2) Modified conditions in which the previous 150,000 acre-feet of reallocated water supply storage is utilized at Texoma plus half of the current Texoma water supply reallocation of 300,000 acre-feet (150,000 acre-feet for Texas and 150,000 acre-feet for Oklahoma). Therefore the total water supply storage for Texoma modeled in this run is 300,000 acre-feet. This modified conditions run basically models Texas fully utilizing their water supply demand. The water supply demand modeled = 456.8 cfs

(3) Modified conditions in which the previous 150,000 acre-feet of reallocated water supply storage is utilized at Texoma plus all of the current Texoma water supply reallocation of 300,000 acre-feet. The total water supply storage for Texoma modeled in this run is 450,000 acre-feet. This run models fully utilized water supply conditions at Texoma or the worst case scenario, for demands on Texoma. The water supply demand modeled = 685.2 cfs.

These runs were all done with the updated 2002 Lake Texoma Elevation-Area-Capacity table, with the updated Texoma seasonal pool guide curve (see Figure 1), and the extended period of record hydrology through 2000. To avoid too large a drawdown at Texoma with the larger water supply demands, Southwest Power Administration modified their hydropower loads input into SUPER, to reflect more realistically how they would operate, given the greater water supply demands. Therefore, these runs reflect modified hydropower loads for each scenario. The water supply demand at Texoma is modeled as a constant year-round demand. Results of the runs including frequency and duration curves both at the lake, and at downstream control points are provided in Figures 2 -9.

Legislation, specifically, Public Law 99-662, Sec. 838, dated November 17, 1986, initially guided the reallocation efforts to a reallocation from hydropower storage to water supply. An additional analysis was done to determine if reallocating from the flood control pool would be more cost effective. Flood control reallocation analysis is described in section B below.

*Figure 1  Texoma Seasonal Pool*



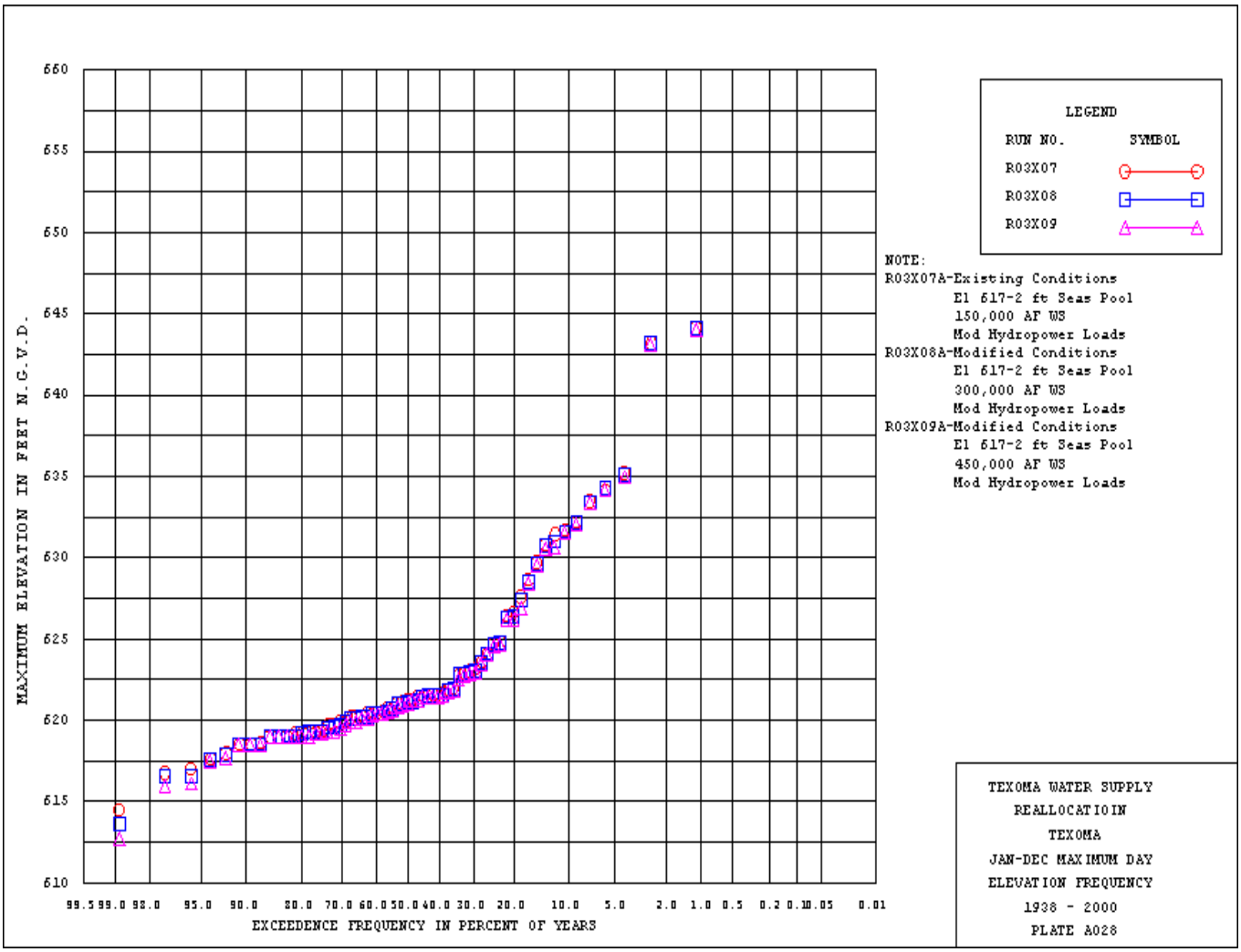



**Figure 2- Comparative Texoma Elevation-Frequency Curves for Reallocation from Hydropower**

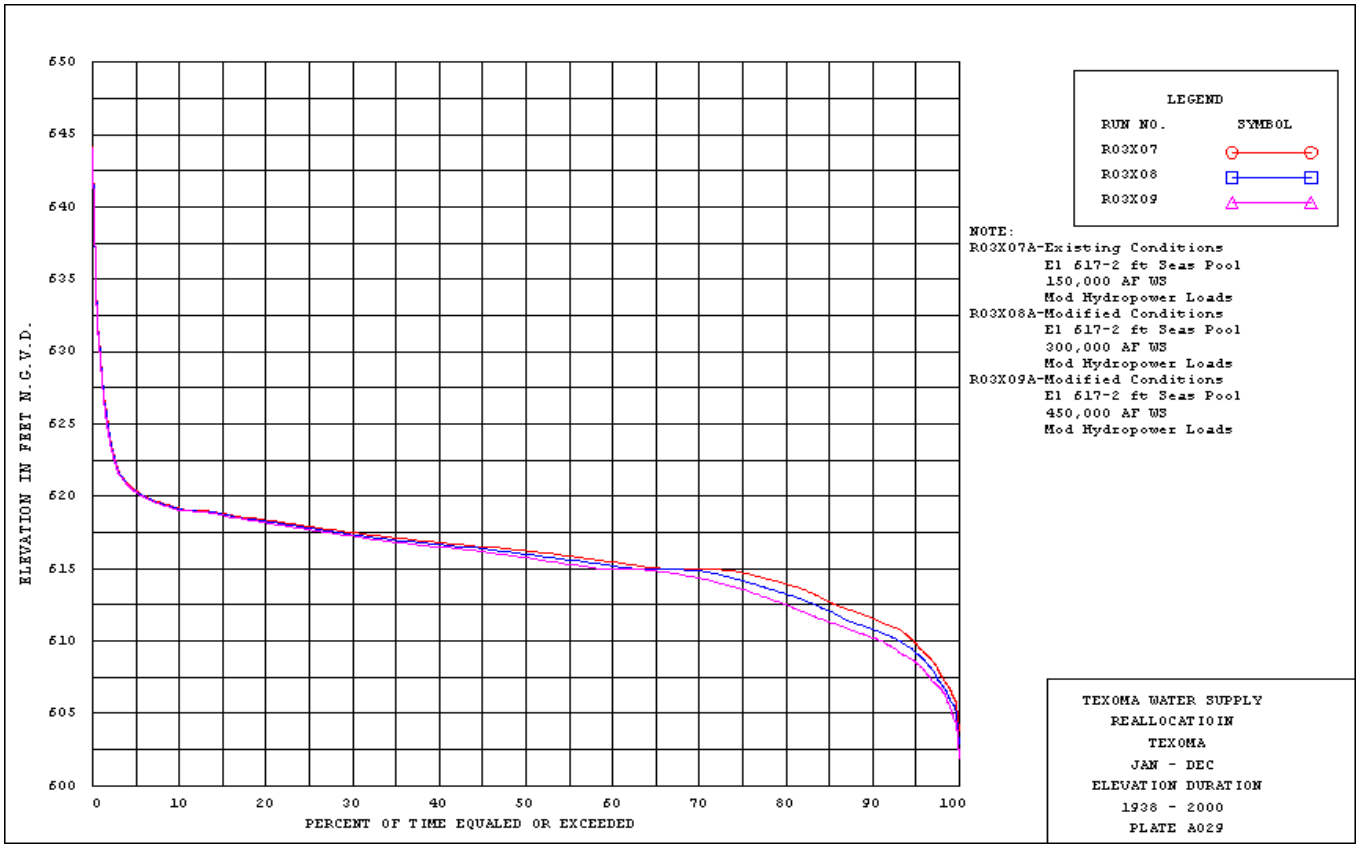



**Figure 3 - Comparative Texoma Elevation –Duration Curves for Reallocation from Hydropower**

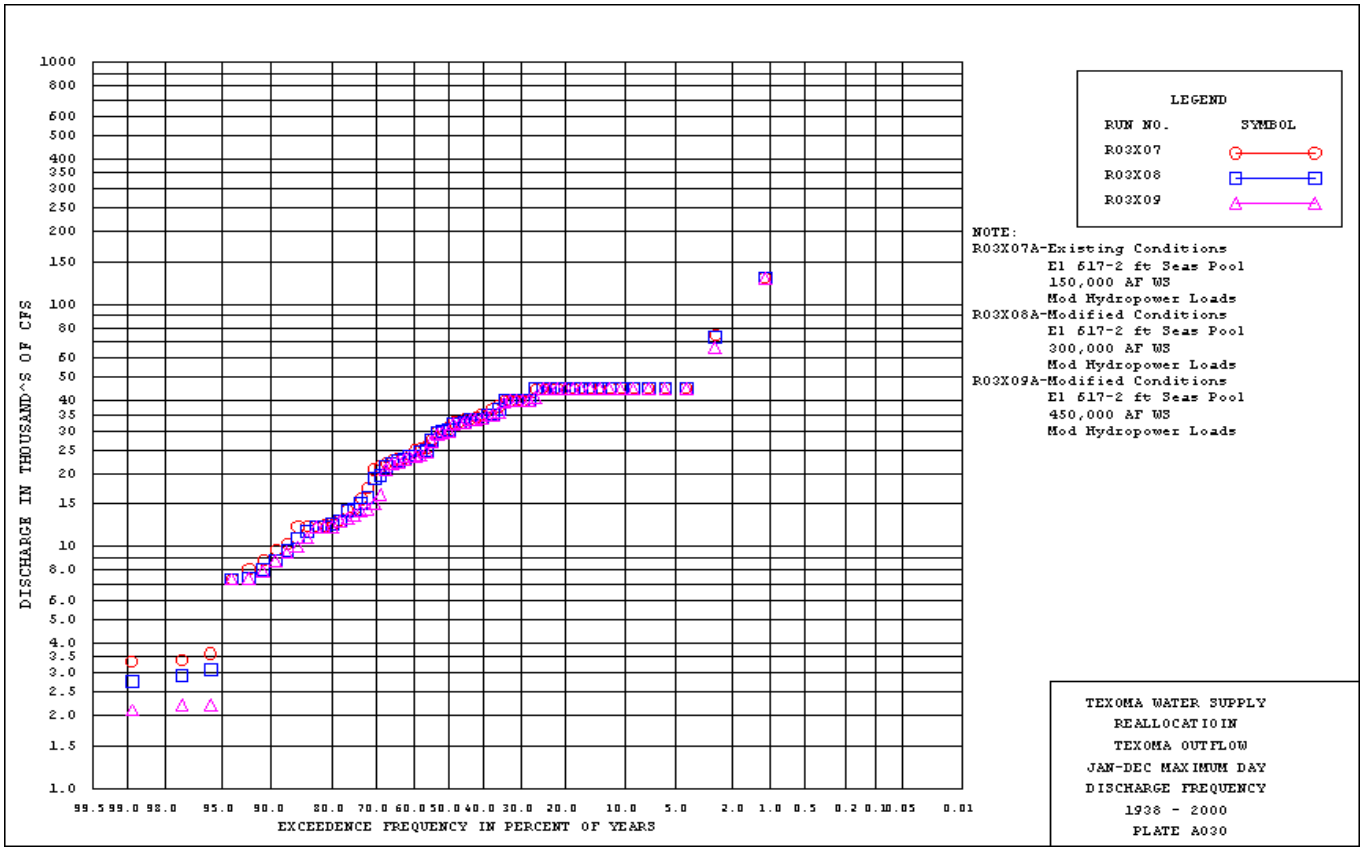



**Figure 4 - Comparative Texoma Outflow-Frequency Curves for Reallocation from Hydropower**

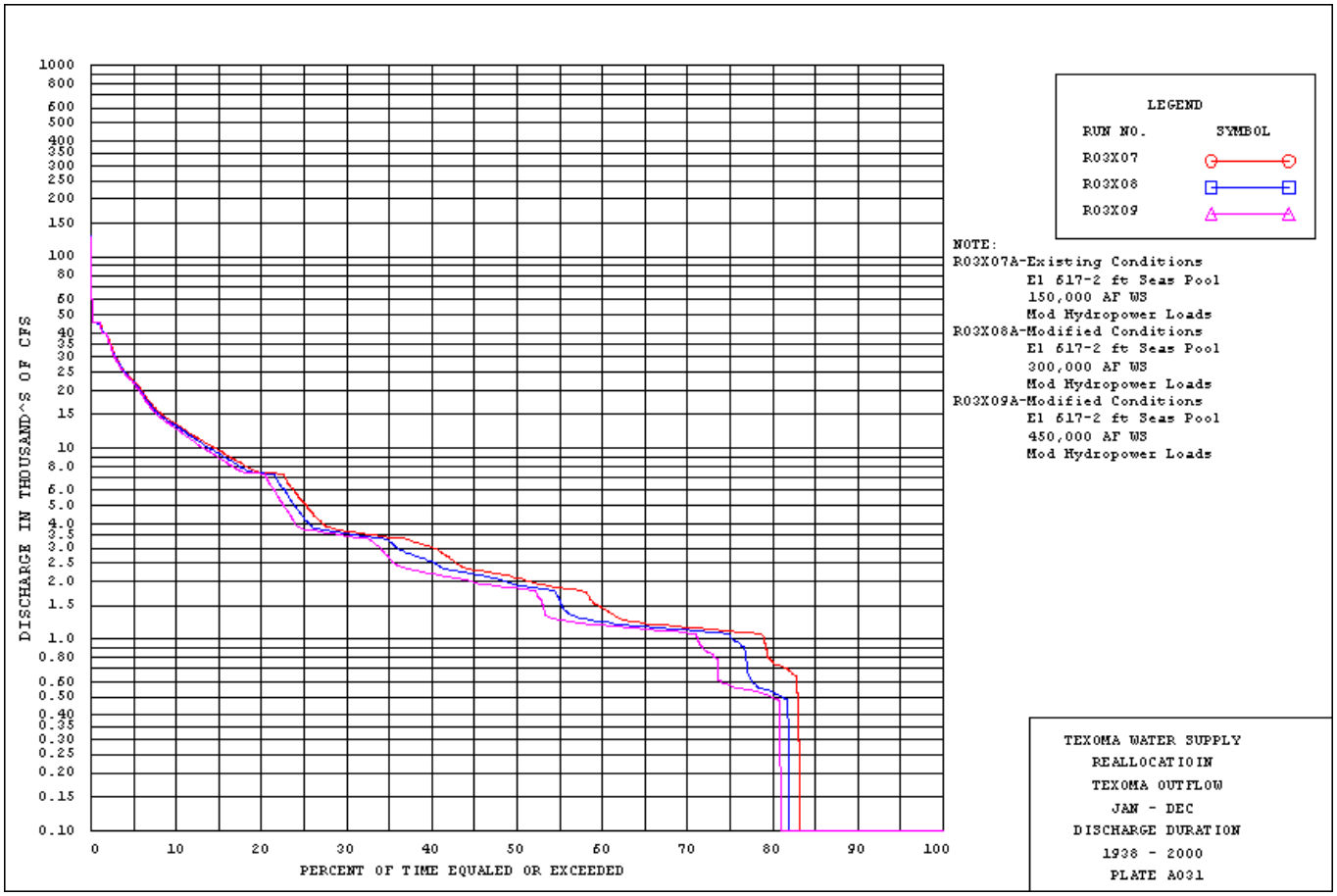



**Figure 5 - Comparative Texoma Outflow-Duration Curves for Reallocation from Hydropower**

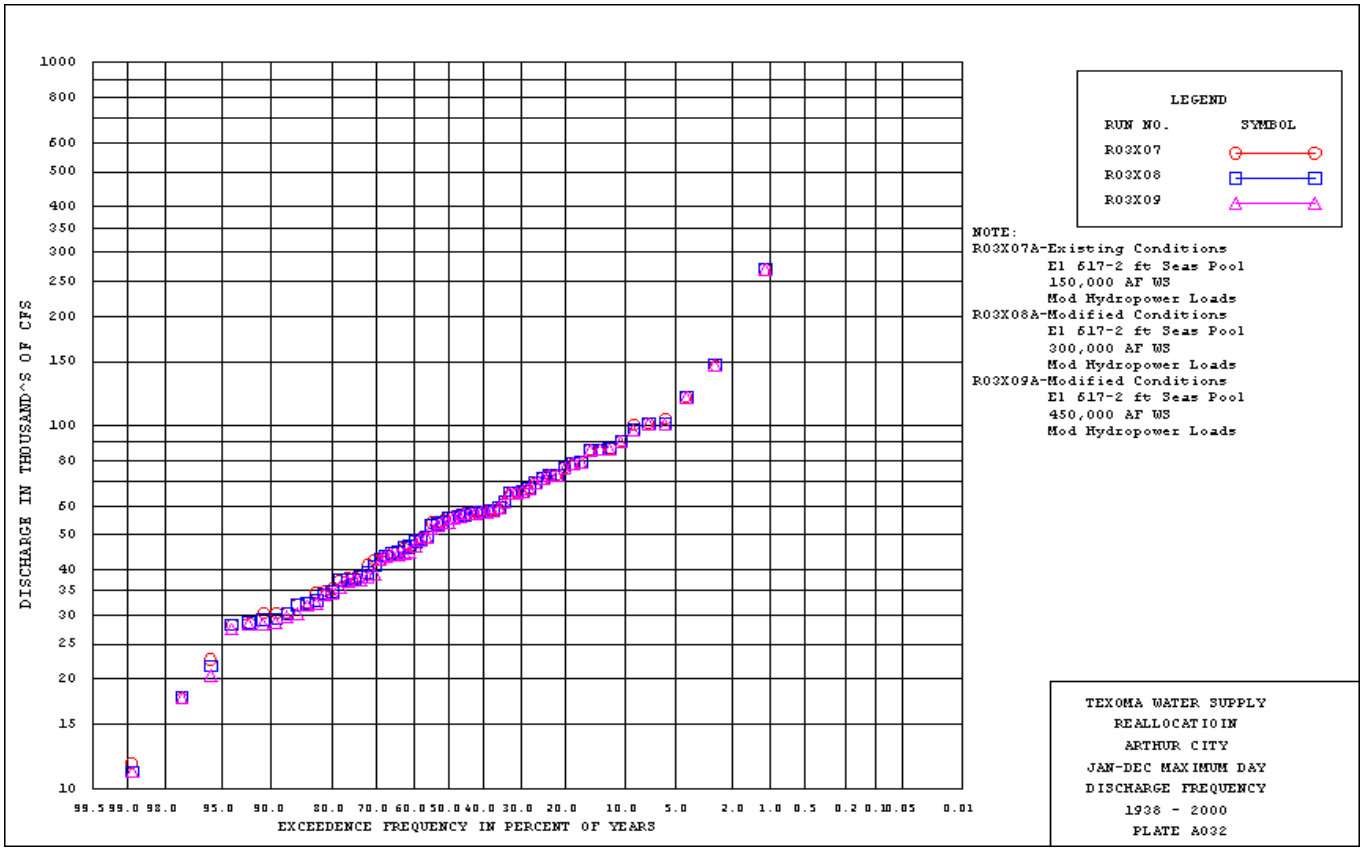



*Figure 6 - Comparative Arthur City Discharge-Frequency Curves*

*for Reallocation from Hydropower*

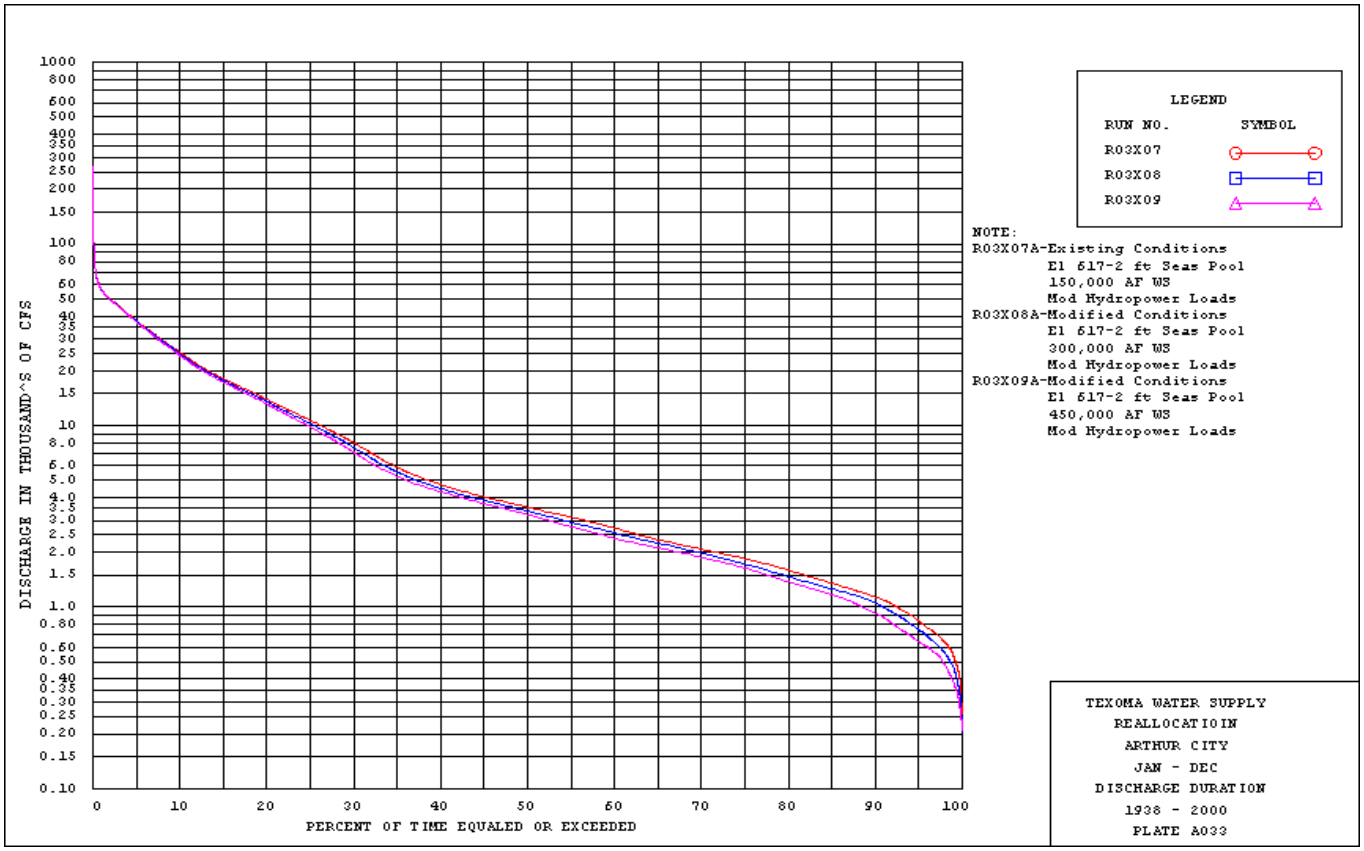



**Figure 7 - Comparative Arthur City Discharge-Frequency Curves for Reallocation from Hydropower**

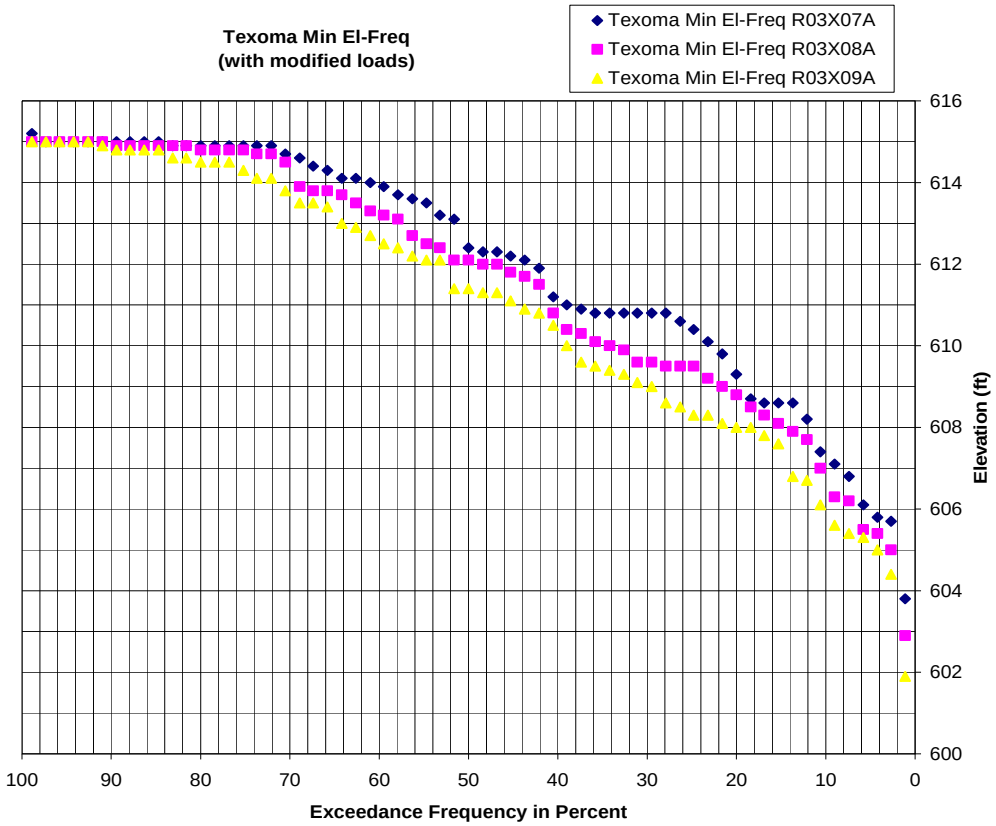



**Figure 8 - Comparative Texoma Minimum Elevation-Frequency Curves for Reallocation from Hydropower**

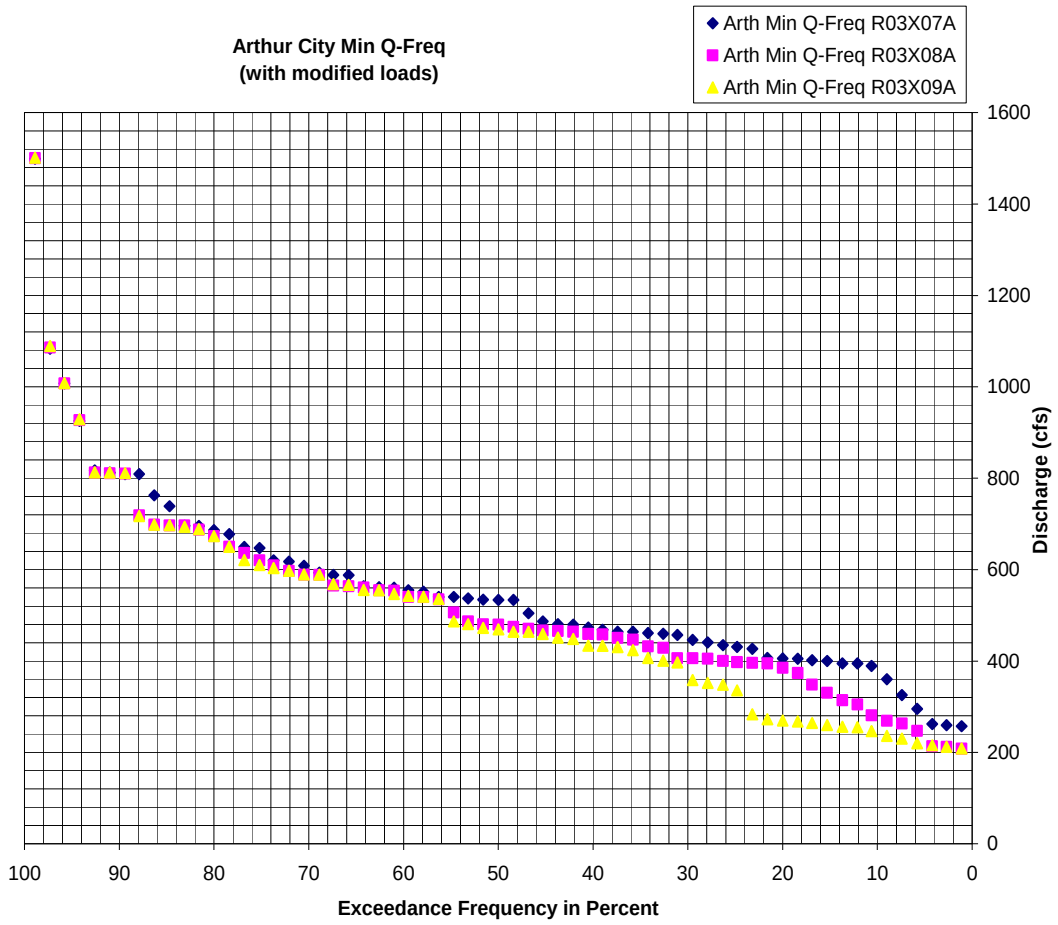



**Figure 9 - Comparative Arthur City Minimum Flow-Frequency Curves for Reallocation from Hydropower**

## B. Flood Control Pool Reallocation Alternatives

To minimize impacts to hydropower, two additional alternatives reallocating flood control pool to water supply were developed. The flood control reallocation alternatives modeled for this study included reallocation of both 150,000 and 300,000 acre-feet from the flood pool for water supply use. When reallocating from the flood pool, the conservation pool becomes expanded and the critical period dependable yield per unit of storage (produced from storage and inflow) is reduced. This is because storage increases but inflow does not, and more users are sharing the same inflow. Therefore, existing users find that their allocated storage produces less yield. To mitigate for the impact to current users, new users are required to purchase additional storage to make current users "whole" and this is called dependable yield mitigation storage (DYMS). The flood pool reallocations modeled are 150,000 acre-feet for Texas use only and 300,000 acre-feet for Texas and Oklahoma use, with DYMS for the current users only. For each alternative, hydropower storage was held constant and the amount of storage required to provide either 150,000 or 300,000 acre-feet with DYMS, was determined based on 2044 conditions. The pool elevation was determined to the nearest hundredth of a foot

for each alternative. Storage and yield allocation tables for each alternative are shown in Table 1 and 2 below. A final period of record run was made for each alternative based on the expanded conservation storage and assuming a flat pool. The period of record runs were performed to model pool and downstream impacts due to the proposed flood control pool reallocations, and were based on 2002 survey conditions. Each of the period of record runs was made with a run specific load file to more accurately model how the lake would be operated for hydropower, under the proposed reallocation scenario. The critical dependable water supply demand is the only input parameter that varies between the runs, along with the run specific load file. The runs made are as follows:

(1) Modified conditions in which the previous 150,000 acre-feet of reallocated water supply storage is utilized at Texoma plus half of the current Texoma water supply reallocation of 300,000 acre-feet (150,000 acre-feet for Texas and 150,000 acre-feet for Oklahoma). This also includes DYMS for current water supply users only. Therefore the total water supply storage for Texoma modeled in this run is 300,000 acre-feet. This modified conditions run basically models Texas fully utilizing their water supply demand with DYMS for current water supply users only. The water supply demand modeled = 425.9 cfs or 275 mgd.

(2) Modified conditions in which the previous 150,000 acre-feet of reallocated water supply storage is utilized at Texoma plus all of the current Texoma water supply reallocation of 300,000 acre-feet. This also includes DYMS for current water supply users only. The total water supply storage for Texoma modeled in this run is 450,000 acre-feet. This run models fully utilized water supply conditions at Texoma or the worst case scenario, for demands on Texoma, with DYMS for current water supply users only. The water supply demand modeled = 603.6 cfs or 389.4 mgd.

To determine the economic feasibility of reallocating from the flood pool, comparative SUPER economic analyses were developed for all of the flood control alternatives and for existing conditions. Results of the economic analyses were provided to economists for further evaluation and updating from 1993 to present value.

**Table 1**

**Flood Control Alternative 1**
**Lake Texoma Storage**
**Reallocate 150,000 acre-feet**
**from**
**Flood Control Storage to Water Supply Storage**
**(Includes DYMS for current WS users)**
**(Includes a flat 618.51 ft pool)**
**Based on 2002 Sediment Survey Forecast to 2044**

| Storage Allocation | Usable Storage For 2044 Conditions (arec-feet) | Yield (mgd) | Percent of | |
|---|---|---|---|---|
| | | | Usable Total Storage (%) | Usable Conservation Storage (%) |
| Flood Control (618.51-640) | 2,461,439 | | 68.408 | |
| Conservation (590-618.51) | 1,136,730 | 1041.4 | 31.592 | 100.000 |
| Water Supply | 300,000 | 274.8 | 8.338 | 26.391 |
| Denison | 22,813 | 20.9 | 0.634 | 2.007 |
| TP&L | 17,587 | 16.1 | 0.489 | 1.547 |
| RRAT | 483 | 0.4 | 0.013 | 0.042 |
| RRAT | 2,183 | 2.0 | 0.061 | 0.192 |
| NTMWD | 91,580 | 83.9 | 2.545 | 8.056 |
| GTUA | 5,894 | 5.4 | 0.164 | 0.519 |
| GTUA | 5,894 | 5.4 | 0.164 | 0.519 |
| Buncombe Creek View | 0.3 | 0.0003 | 0.000008 | 0.00003 |
| GTUA | 12,444 | 11.4 | 0.346 | 1.095 |
| OTRD | 327 | 0.3 | 0.009 | 0.029 |
| Future Agreements | 1,626 | 1.49 | 0.045 | 0.143 |
| NTMWD (pending) | 93,243 | 85.4 | 2.591 | 8.203 |
| GTUA (pending) | 45,926 | 42.0 | 1.276 | 4.04 |
| Hydropower | 836,730 | 766.6 | 23.254 | 73.609 |
| Total Usable Storage | 3,598,169 | | 100.000 | |

**Table 2**

**Flood Control Alternate 2**
**Lake Texoma Storage**
**Reallocate 300,000 acre-feet**
**From**
**Flood Control Storage to Water Supply Storage**
**(Includes DYMS for current WS Users only)**
**(Includes a flat 619.99 ft pool)**
**Based on 2002 Sediment Survey Forecast to 2044**

| Storage Allocation | Usable Storage (acre-feet) | Yield (mgd) | Percent of | |
|---|---|---|---|---|
| | | | Usable Total Storage (%) | Usable Conservation Storage (%) |
| Flood Control (619.99-640) | 2,311,439 | | 64.239 | |
| Conservation (590-619.99) | 1,286,730 | 1113.0 | 35.761 | 100.000 |
| Water Supply | 450,000 | 389.4 | 12.506 | 34..972 |
| Denison | 24,154 | 20.9 | 0.671 | 1.877 |
| TP&L | 18,621 | 16.1 | 0.518 | 1.447 |
| RRAT | 511 | 0.4 | 0.014 | 0.040 |
| RRAT | 2,311 | 2.0 | 0.064 | 0.180 |
| NTMWD | 96,963 | 83.9 | 2.695 | 7.536 |
| GTUA | 6,241 | 5.4 | 0.173 | 0.485 |
| GTUA | 6,241 | 5.4 | 0.173 | 0.485 |
| Buncombe Creek View | 0.3 | 0.0003 | 0.000008 | 0.00002 |
| GTUA | 13,175 | 11.4 | 0.366 | 1.024 |
| OTRD | 347 | 0.3 | 0.010 | 0.027 |
| NTMWD (pending) | 93,238 | 80.7 | 2.591 | 7.246 |
| GTUA (pending) | 46,619 | 40.3 | 1.296 | 3.623 |
| Future Agreements | 141,579 | 122.5 | 3.935 | 11.003 |
| Hydropower | 836,730 | 723.6 | 23.254 | 65.028 |
| Total Usable Storage | 3,598,169 | | 100.000 | |

# APPENDIX E

# HYDROPOWER ANALYSIS CENTER REPORTS

**1. Estimate of Hydropower Value Report**
**(50-Year Economic Evaluation Period)**

**2. Estimate of Hydropower Value Report**
**(9-Year and 30-Year Replacement Power Evaluation Periods)**

US Army Corps of Engineers

# Estimate of Hydropower Value

(50-Year Economic Evaluation Period)

## Lake Texoma, Oklahoma and Texas Reservoir Storage Reallocation Study

December 2008

# Estimate of Hydropower Value

(50-Year Economic Evaluation Period)

Lake Texoma, Oklahoma and Texas
Reservoir Storage Reallocation Study

The Hydropower Analysis Center is the Corps of Engineers center of expertise for hydropower planning and analysis[1]. The HAC was formed in 1949 as Hydropower Evaluation Section then gained National Hydropower MCX Status in 1996. HAC was established to maintain the expertise and capability to perform power systems analysis regarding hydropower project output and economic benefit evaluations of existing and new hydroelectric plants.

The HAC was contacted by the Tulsa District to assist in estimating the wholesale value of hydropower that would potentially be lost due to reallocation of water in conservation storage currently used for hydropower production to the purpose of water supply storage. The purpose of estimating the value of hydropower potentially lost is to establish a proxy for the conditions of the 1986 Water Resources Development Act, Sec 838, subparagraph d. (3) (B) that states "the replacement cost of the hydropower lost (where replacement cost is defined as the cost to purchase power from existing alternative sources). If hydropower is lost as a result of the implementation of such contract, the Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement costs. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower." Summarized below is a description of cooperative efforts and methods employed.

SUPER, a sequential daily stream flow routing computer model, was used by SWT to simulate multipurpose reservoir operations at the Denison project. Hydropower generation portion of the simulation is governed by an electrical load schedule developed by SWPA. The reduction in hydropower generation was determined by simulations using a 63-year period of inflow records. Hydropower generation was determined for the existing reservoir condition that includes water supply storage of 150,000 acre-feet; and two potential reallocations from the conservation pool, as authorized by Sec 838,: of 150,000 acre-feet, and 300,000 acre-feet. The process of running the SUPER model, its input and output is documented in the Appendix D, Red River SUPER Model, Texoma Yield Analysis, and Water Supply Reallocation at Texoma.

SWPA integrates and dispatches generation at the Denison Dam hydropower plant to optimize its value to the regional power system through their preference customers. Power sales products include both firm and supplemental energy. Firm energy is based on 1,200 KW/yr for each KW of capacity purchased.

[1] https://w3.nwp.usace.army.mil/HDC/hac/home.asp

Platts Power Outlook Research Service (Platts) electrical power wholesale price forecast is the basis for determining the value of hydropower impact due to the diversion of water to municipal water supply.

Use of wholesale prices in this evaluation is required because power rates developed by SWPA reflect a Federal mandate to sell the power from Federal hydropower projects at a cost which is lower than the wholesale price. Sec 838 authorizes the determination of hydropower account credit as the actual cost of replacement power (market prices).

Platts provides a regional forecast of the wholesale price for electrical power. Platts uses $\text{Aurora}_{\text{XMP}}$, an econometric model, to simulate the interaction of principal factors influencing the wholesale price electrical power in an unconstrained market. Forecast wholesale prices for both capacity and energy, are developed on an hourly basis and summarized as monthly and annual prices. The model integrates the generation resources to meet the hourly, daily, seasonal demand using the least costly resources available. As the hourly demand increases more expensive resources must be added which increases the wholesale price of the power. The model determines the least cost capacity (existing, planned additions and new construction) and required reserves to maintain system reliability. The weekly cycle of electrical power demand is commonly classified into peak and off-peak periods of the day. The peak demand period is 6am to 10pm each day, Monday through Friday (5x16) or (80hr/wk). Platts provides its forecast prices for both capacity and energy, expressed in units of $/MWh, in the peak and off-peak periods monthly over a 20-yr period. Energy and capacity prices are combined into all-hours price as well.

Hydropower resources available at Denison are limited by seasonal fluctuations in river flow and the amount of reservoir storage. Firm energy (guaranteed energy, 1,200KWh/KW annually) is strategically scheduled for the highest valued hours of the peak period (Table below). At the Denison Dam hydropower plant firm energy is dispatched at 70 MW (marketable capacity), though the plant is operated at as much as 80MW. Generation during the summer is only about half the duration of the peak period (~40 hrs/wk).

**Figure 1** displays the annual dispatch plan for Denison power plant firm generation. For example, in July, generation is prioritized for the hours from noon to 7pm, for a total of 155 hours for the month.

**Figure 1. Denison Powerplant Dispatch**

# SWPA Generalized Dispatch
# Denison Powerplant

| Month | Peak AM Across Hr | Peak AM Ending Hr | Peak AM # Hrs | Peak PM Across Hr | Peak PM Ending Hr | Peak PM # Hrs | Hours/ weekday | Hours / month | HAC Mod hrs/mo |
|---|---|---|---|---|---|---|---|---|---|
| **Jan** | 700 | 900 | 2 | 1800 | 2100 | 3 | 5 | 111 | 111 |
| **Feb** | 700 | 900 | 2 | 1800 | 2000 | 2 | 4 | 80 | 80 |
| **Mar** | 700 | 1000 | 3 | 0 | 0 | 0 | 3 | 66 | 66 |
| **Apr** | 0 | 0 | 0 | 1400 | 1700 | 3 | 3 | 64 | 64 |
| **May** | 0 | 0 | 0 | 1500 | 1800 | 3 | 3 | 66 | 66 |
| **Jun** | 0 | 0 | 0 | 1300 | 1900 | 6 | 6 | 129 | 129 |
| **Jul** | 0 | 0 | 0 | 1200 | 1900 | 7 | 7 | 155 | 157 |
| **Aug** | 0 | 0 | 0 | 1200 | 2000 | 8 | 8 | 177 | 177 |
| **Sep** | 0 | 0 | 0 | 1300 | 1800 | 5 | 5 | 107 | 109 |
| **Oct** | 0 | 0 | 0 | 1400 | 1700 | 3 | 3 | 66 | 66 |
| **Nov** | 0 | 0 | 0 | 1800 | 2100 | 3 | 3 | 64 | 64 |
| **Dec** | 700 | 900 | 2 | 1800 | 2100 | 3 | 5 | 111 | 111 |
| | | | | | | | Sum = | 1,196 | 1,200 |

SWPA's power purchases to support firm energy sales are higher than the Platts' peak energy and capacity prices which are applied over the 5x16 peak period published in the standard forecast. To compensate for SWPA's higher purchase prices, Platts provided a custom forecast of wholesale prices for the schedule of firm energy for Denison that was optimized by SWPA in coordination with their customers. The results of the custom forecast produced prices that more accurately reflect the value of energy during the segment of the market for which the dispatch schedule of Denison hydropower generation was optimized.

Platts provided the 20-yr forecast monthly prices in current dollars. The stream of forecast prices was extended to the customary USACE 50-year economic analysis period by repeating the monthly prices in the last year of the forecast. Standard USACE procedures were used to develop an equivalent annual price for the period of analysis at an annual interest rate of 4.625%. This is the Federal Water Resources interest rate in effect at the time of the study.

SWPA power purchases are a proxy for the purchases actually made by the Tex-La Electric Cooperative of Texas and the Rayburn Country Electric Cooperative, Inc. In exchange for a discounted contract price the electric cooperatives assume full responsibility for the purchase of

replacement power. SWPA has informed the HAC that there are no records of electric cooperative purchases.

**Figure 2. Platts Power Outlook Research Service Power Prices**

# Platts PORS Power Prices
# (constant 2008$, annualized @ 4.625% interest)

Derived from Platts-Nov 2008 20-yr monthly forecast base case
Denison monthly peak periods defined by SWPA
Denison Peak values derived by Platts' Special Study-21Nov08

| *Denison Capacity* | *Peak Energy* | month | Denison Peak Energy + Capacity | On Peak Energy | Off Peak Energy |
|---|---|---|---|---|---|
| *$/MWh* | *$/MWh* | | $/MWh | $/MWh | $/MWh |
| *47.04* | *77.12* | 1 | 124.17 | 76.04 | 72.31 |
| *64.15* | *79.71* | 2 | 143.86 | 79.00 | 74.89 |
| *78.41* | *78.68* | 3 | 157.08 | 78.83 | 71.13 |
| *78.41* | *86.78* | 4 | 165.19 | 82.74 | 75.02 |
| *78.41* | *129.04* | 5 | 207.45 | 96.04 | 75.71 |
| *39.20* | *119.36* | 6 | 158.56 | 98.76 | 76.70 |
| *33.60* | *247.65* | 7 | 281.25 | 164.58 | 83.17 |
| *29.40* | *248.23* | 8 | 277.63 | 170.40 | 84.82 |
| *47.04* | *94.33* | 9 | 141.37 | 85.87 | 73.75 |
| *78.41* | *83.72* | 10 | 162.13 | 79.32 | 70.82 |
| *78.41* | *76.68* | 11 | 155.09 | 75.04 | 70.53 |
| *47.04* | *74.71* | 12 | 121.76 | 73.80 | 71.06 |

Simulated daily generation was reduced to annual average generation in three categories that correspond to those price categories described above, for each month as follows;

Denison Peak Energy + Capacity: Generation is supplied as firm energy, as the first priority, which is valued at Platts custom study prices for energy and capacity in the optimized SWPA schedule.

On Peak Energy: Excess energy in the peak period is valued at Platts standard forecast peak energy price. Capacity has little or no value most of the year, except July and August.

Off Peak Energy: Any remaining energy is valued at Platts' standard off-peak price.

**Figure 3. Annual Existing Condition Generation, Denison Powerhouse**

# Generation for Existing Condition

## (Existing water supply storage of 150,000 acre-feet)

| Existing1 | | | |
|---|---|---|---|
| | Denison Peak | On-Peak | Off-Peak |
| month | MWh | MWh | MWh |
| 1 | 7,770 | 6,829 | 4,520 |
| 2 | 5,135 | 7,225 | 3,760 |
| 3 | 4,481 | 9,428 | 6,419 |
| 4 | 4,402 | 10,313 | 6,672 |
| 5 | 4,552 | 11,846 | 7,716 |
| 6 | 8,497 | 10,586 | 12,919 |
| 7 | 10,885 | 7,228 | 4,881 |
| 8 | 12,264 | 4,005 | 1,489 |
| 9 | 7,233 | 4,492 | 2,096 |
| 10 | 4,391 | 5,458 | 2,729 |
| 11 | 4,325 | 5,992 | 3,479 |
| 12 | 7770 | 6997.544 | 3532.4111 |
| sum | 81,704 | 90,401 | 60,212 |

| | generation |
|---|---|
| total | 232,317 |

**Figure 4. Annual Generation, Denison Powerhouse, 300KAF Reallocation**

# Generation for Potential 150,000 acre-feet Reallocation

## (A total potential reallocation of 300,000 acre-feet)

| MOD3001 | | | |
|---|---|---|---|
| | Denison Peak | On-Peak | Off-Peak |
| month | MWh | MWh | MWh |
| 1 | 7,464 | 6,265 | 4,226 |
| 2 | 4,907 | 6,732 | 3,540 |
| 3 | 4,246 | 9,146 | 6,603 |
| 4 | 4,119 | 9,843 | 6,666 |
| 5 | 4,072 | 11,379 | 7,804 |
| 6 | 7,800 | 10,590 | 12,938 |
| 7 | 10,859 | 6,354 | 4,383 |
| 8 | 12,065 | 3,488 | 1,079 |
| 9 | 6,963 | 3,812 | 1,764 |
| 10 | 4,025 | 5,064 | 1,961 |
| 11 | 4,050 | 5,335 | 3,276 |
| 12 | 7,334 | 6,562 | 3,257 |
| sum | 77,904 | 84,570 | 57,498 |
| | generation | | |
| total | 219,971 | | |

**Figure 5. Annual Generation, Denison Powerhouse, 450KAF Reallocation**

# Generation for
# Potential 300,000 acre-feet Reallocation
## (A total potential reallocation of 450,000 acre-feet)

| MOD4501 | | | |
|---|---|---|---|
| | Denison Peak | On-Peak | Off-Peak |
| month | MWh | MWh | MWh |
| 1 | 6,985 | 5,677 | 3,965 |
| 2 | 4,769 | 6,106 | 3,301 |
| 3 | 4,082 | 8,525 | 6,351 |
| 4 | 4,110 | 9,165 | 6,261 |
| 5 | 3,992 | 10,997 | 7,539 |
| 6 | 7,631 | 10,153 | 12,404 |
| 7 | 10,112 | 5,888 | 4,099 |
| 8 | 11,565 | 3,175 | 1,038 |
| 9 | 6,903 | 3,435 | 1,662 |
| 10 | 3,890 | 4,868 | 1,815 |
| 11 | 3,894 | 5,007 | 3,062 |
| 12 | 6,903 | 6,074 | 2,857 |
| sum | 74,836 | 79,069 | 54,352 |
| | generation | | |
| total | 208,257 | | |

The annual wholesale value of hydropower generation under Existing reservoir allocation and reallocation of 300KAF and 450KAF of reservoir storage for municipal water supply are determined by multiplying the Platts PORS prices by the generation for each reservoir storage allocation. The results are shown in the Figures 6, 7, and 8.

**Figure 6. Value of Generation, Existing Condition**

# Generation Value for Existing Condition

## (Existing water supply storage of 150,000 acre-feet)

| | | | Existing1 | | |
|---|---|---|---|---|---|
| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
| 1 | *$365,528.95* | *$599,247.10* | **$964,776.05** | **$519,230.90** | **$326,821.37** |
| 2 | *$329,412.38* | *$409,321.54* | **$738,733.92** | **$570,824.28** | **$281,595.17** |
| 3 | *$351,334.35* | *$352,553.11* | **$703,887.46** | **$743,209.68** | **$456,581.16** |
| 4 | *$345,167.40* | *$382,044.62* | **$727,212.02** | **$853,307.45** | **$500,552.59** |
| 5 | *$356,878.90* | *$587,363.99* | **$944,242.89** | **$1,137,661.97** | **$584,170.20** |
| 6 | *$333,100.03* | *$1,014,164.05* | **$1,347,264.08** | **$1,045,452.77** | **$990,879.54** |
| 7 | *$365,773.03* | *$2,695,703.40* | **$3,061,476.43** | **$1,189,538.99** | **$405,968.78** |
| 8 | *$360,578.27* | *$3,044,151.10* | **$3,404,729.36** | **$682,529.93** | **$126,268.07** |
| 9 | *$340,261.23* | *$682,252.85* | **$1,022,514.08** | **$385,755.43** | **$154,545.92** |
| 10 | *$344,270.59* | *$367,611.24* | **$711,881.83** | **$432,947.71** | **$193,279.88** |
| 11 | *$339,071.52* | *$331,617.65* | **$670,689.17** | **$449,654.80** | **$245,378.95** |
| 12 | *$365,528.95* | *$580,525.13* | **$946,054.08** | **$516,406.41** | **$251,011.64** |
| sum | *$4,196,905.60* | *$11,046,555.78* | **$15,243,461.39** | **$8,526,520.31** | **$4,517,053.28** |
| | | | **Annualized** | **$28,287,034.97** | |

**Figure 7. Value of Generation, 300KAF Reallocation Condition**

# Generation Value for
# Potential 150,000 acre-feet Reallocation
## (A total potential reallocation of 300,000 acre-feet)

| | | | MOD3001 | | |
|---|---|---|---|---|---|
| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
| 1 | *$351,114.19* | *$575,615.58* | **$926,729.77** | **$476,378.23** | **$305,603.34** |
| 2 | *$314,817.56* | *$391,186.29* | **$706,003.84** | **$531,805.18** | **$265,087.06** |
| 3 | *$332,928.22* | *$334,083.13* | **$667,011.36** | **$721,027.49** | **$469,675.80** |
| 4 | *$322,964.43* | *$357,469.51* | **$680,433.94** | **$814,368.87** | **$500,074.37** |
| 5 | *$319,238.28* | *$525,413.71* | **$844,651.99** | **$1,092,780.67** | **$590,862.77** |
| 6 | *$305,784.17* | *$930,997.56* | **$1,236,781.74** | **$1,045,802.34** | **$992,323.59** |
| 7 | *$364,876.10* | *$2,689,093.19* | **$3,053,969.30** | **$1,045,687.30** | **$364,543.80** |
| 8 | *$354,731.32* | *$2,994,788.78* | **$3,349,520.10** | **$594,369.12** | **$91,540.48** |
| 9 | *$327,556.54* | *$656,778.86* | **$984,335.40** | **$327,364.71** | **$130,079.61** |
| 10 | *$315,591.77* | *$336,988.08* | **$652,579.85** | **$401,658.69** | **$138,911.77** |
| 11 | *$317,564.37* | *$310,583.30* | **$628,147.67** | **$400,367.03** | **$231,028.52** |
| 12 | *$345,026.15* | *$547,963.02* | **$892,989.16** | **$484,285.08** | **$231,470.37** |
| sum | *$3,972,193.11* | *$10,650,961.01* | **$14,623,154.12** | **$7,935,894.72** | **$4,311,201.48** |
| | | | **Annualized** | **$26,870,250.32** | |

**Figure 8. Value of Generation, 450KAF Reallocation Condition**

# Generation Value for Potential 300,000 acre-feet Reallocation

## (A total potential reallocation of 450,000 acre-feet)

| | | | MOD4501 | | |
|---|---|---|---|---|---|
| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
| 1 | *$328,580.29* | *$538,673.58* | **$867,253.87** | **$431,671.98** | **$286,691.94** |
| 2 | *$305,922.04* | *$380,132.88* | **$686,054.92** | **$482,352.43** | **$247,198.55** |
| 3 | *$320,057.19* | *$321,167.45* | **$641,224.63** | **$672,017.50** | **$451,720.12** |
| 4 | *$322,267.49* | *$356,698.11* | **$678,965.60** | **$758,326.01** | **$469,728.22** |
| 5 | *$313,024.29* | *$515,186.51* | **$828,210.80** | **$1,056,099.72** | **$570,787.94** |
| 6 | *$299,140.20* | *$910,769.15* | **$1,209,909.35** | **$1,002,675.43** | **$951,400.61** |
| 7 | *$339,794.17* | *$2,504,242.36* | **$2,844,036.53** | **$969,061.84** | **$340,880.87** |
| 8 | *$340,030.19* | *$2,870,675.73* | **$3,210,705.92** | **$540,954.23** | **$88,014.25** |
| 9 | *$324,721.22* | *$651,093.82* | **$975,815.05** | **$294,935.87** | **$122,544.58** |
| 10 | *$305,016.92* | *$325,696.27* | **$630,713.19** | **$386,114.60** | **$128,535.41** |
| 11 | *$305,315.61* | *$298,603.80* | **$603,919.41** | **$375,712.31** | **$215,939.25** |
| 12 | *$324,757.07* | *$515,772.10* | **$840,529.17** | **$448,279.75** | **$202,984.50** |
| sum | *$3,828,626.66* | *$10,188,711.76* | **$14,017,338.42** | **$7,418,201.68** | **$4,076,426.23** |
| | | | **Annualized** | **$25,511,966.33** | |

The impact on hydropower generation for the potential reallocations of 150,000 acre-feet (MOD3001) and 300,000 acre-feet (MOD4501) would be the difference in the value of generation compared to the Existing Conditions. The value of lost hydropower would be the proxy for the value of replacement power purchases based on annual wholesale prices. The results are summarized in **Figure 9**.

**Figure 9. Total Annual Value Comparison**

## Annual Value of Lost Hydropower

(constant 2008$, interest 4.625%, 50-year)

| Alternative | *Denison Peak Capacity* | *Denison Peak Energy* | Denison Peak Capacity + Energy | On-Peak Energy | Off-Peak Energy | Annual Value |
|---|---|---|---|---|---|---|
| **Existing1** | *$4,196,905.60* | *$11,046,555.78* | **$15,243,461.39** | **$8,526,520.31** | **$4,517,053.28** | **$28,287,034.97** |
| **MOD3001** | *$3,972,193.11* | *$10,650,961.01* | **$14,623,154.12** | **$7,935,894.72** | **$4,311,201.48** | **$26,870,250.32** |
| **MOD4501** | *$3,828,626.66* | *$10,188,711.76* | **$14,017,338.42** | **$7,418,201.68** | **$4,076,426.23** | **$25,511,966.33** |
| | Loss | | | **Loss** | | **Annual Loss** |
| **Existing1** | --- | --- | **---** | **---** | **---** | **---** |
| **MOD3001** | ($224,712.50) | ($395,594.77) | **($620,307.27)** | **($590,625.59)** | **($205,851.80)** | **($1,416,784.66)** |
| **MOD4501** | ($368,278.94) | ($857,844.03) | **($1,226,122.97)** | **($1,108,318.63)** | **($440,627.05)** | **($2,775,068.65)** |

The potential impact to hydropower of a reallocation of 150,000 acre-feet of storage would have an average annual value of approximately $1,417,000. The potential impact to hydropower of a reallocation of 300,000 acre-feet of storage would have an average annual value of approximately $2,775,000.

Platts wholesale prices

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2008 | 1 | 74.74 | 77.69 | 78.83 | 63.27 |
| ERCOT | ERCOT-North | 2008 | 2 | 76.47 | 80.91 | 82.07 | 86.27 |
| ERCOT | ERCOT-North | 2008 | 3 | 80.02 | 83.79 | 83.57 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 4 | 80.87 | 87.88 | 92.79 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 5 | 88.06 | 108.31 | 121.14 | 105.44 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2008 | 6 | 88.62 | 108.56 | 119.77 | 52.72 |
| ERCOT | ERCOT-North | 2008 | 7 | 93.41 | 115.54 | 125.66 | 45.19 |
| ERCOT | ERCOT-North | 2008 | 8 | 95.15 | 117.96 | 127.66 | 39.54 |
| ERCOT | ERCOT-North | 2008 | 9 | 83.16 | 99.66 | 110.49 | 63.27 |
| ERCOT | ERCOT-North | 2008 | 10 | 81.23 | 89.86 | 96.52 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 11 | 78.47 | 82.62 | 84.87 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 12 | 76.30 | 78.70 | 79.88 | 63.27 |
| ERCOT | ERCOT-North | 2009 | 1 | 77.39 | 80.41 | 81.68 | 62.33 |
| ERCOT | ERCOT-North | 2009 | 2 | 77.53 | 81.29 | 82.09 | 84.99 |
| ERCOT | ERCOT-North | 2009 | 3 | 77.41 | 81.05 | 80.63 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 4 | 79.72 | 87.63 | 92.90 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 5 | 83.41 | 102.24 | 114.72 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 6 | 83.12 | 102.37 | 113.24 | 51.94 |
| ERCOT | ERCOT-North | 2009 | 7 | 87.84 | 108.96 | 118.89 | 44.52 |
| ERCOT | ERCOT-North | 2009 | 8 | 89.17 | 110.05 | 119.45 | 38.95 |
| ERCOT | ERCOT-North | 2009 | 9 | 77.90 | 92.51 | 102.03 | 62.33 |
| ERCOT | ERCOT-North | 2009 | 10 | 77.52 | 86.90 | 94.05 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 11 | 73.73 | 77.49 | 79.40 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 12 | 72.49 | 74.67 | 75.61 | 62.33 |
| ERCOT | ERCOT-North | 2010 | 1 | 72.86 | 75.34 | 76.23 | 61.33 |
| ERCOT | ERCOT-North | 2010 | 2 | 73.14 | 76.34 | 76.90 | 83.63 |
| ERCOT | ERCOT-North | 2010 | 3 | 72.47 | 76.13 | 75.65 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 4 | 74.28 | 80.21 | 84.62 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 5 | 69.20 | 82.70 | 96.58 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 6 | 69.49 | 84.38 | 95.80 | 51.11 |
| ERCOT | ERCOT-North | 2010 | 7 | 74.99 | 96.92 | 113.64 | 43.81 |
| ERCOT | ERCOT-North | 2010 | 8 | 74.78 | 93.39 | 104.06 | 38.33 |
| ERCOT | ERCOT-North | 2010 | 9 | 65.72 | 73.99 | 80.19 | 61.33 |
| ERCOT | ERCOT-North | 2010 | 10 | 65.95 | 71.48 | 74.73 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 11 | 65.86 | 68.43 | 69.22 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 12 | 66.21 | 67.85 | 68.45 | 61.33 |
| ERCOT | ERCOT-North | 2011 | 1 | 67.16 | 69.44 | 70.28 | 60.34 |
| ERCOT | ERCOT-North | 2011 | 2 | 67.78 | 70.82 | 71.36 | 82.29 |
| ERCOT | ERCOT-North | 2011 | 3 | 67.91 | 70.85 | 70.65 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 4 | 67.70 | 72.39 | 75.34 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 5 | 60.23 | 71.14 | 83.35 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 6 | 60.97 | 73.88 | 84.16 | 50.29 |
| ERCOT | ERCOT-North | 2011 | 7 | 66.53 | 86.95 | 103.51 | 43.10 |
| ERCOT | ERCOT-North | 2011 | 8 | 65.42 | 82.10 | 91.79 | 37.72 |
| ERCOT | ERCOT-North | 2011 | 9 | 58.94 | 66.37 | 72.35 | 60.34 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2011 | 10 | 58.29 | 62.78 | 65.53 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 11 | 59.52 | 61.89 | 62.82 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 12 | 59.74 | 61.42 | 62.03 | 60.34 |
| ERCOT | ERCOT-North | 2012 | 1 | 60.70 | 62.77 | 63.55 | 59.37 |
| ERCOT | ERCOT-North | 2012 | 2 | 61.08 | 64.32 | 64.70 | 80.95 |
| ERCOT | ERCOT-North | 2012 | 3 | 62.64 | 65.02 | 64.92 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 4 | 64.24 | 70.22 | 75.36 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 5 | 59.20 | 71.02 | 83.68 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 6 | 59.55 | 71.75 | 82.00 | 49.47 |
| ERCOT | ERCOT-North | 2012 | 7 | 64.43 | 82.77 | 96.52 | 42.40 |
| ERCOT | ERCOT-North | 2012 | 8 | 63.49 | 78.37 | 87.59 | 37.10 |
| ERCOT | ERCOT-North | 2012 | 9 | 56.82 | 62.74 | 67.44 | 59.37 |
| ERCOT | ERCOT-North | 2012 | 10 | 55.77 | 60.17 | 62.59 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 11 | 58.75 | 61.00 | 61.69 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 12 | 59.57 | 61.33 | 62.03 | 59.37 |
| ERCOT | ERCOT-North | 2013 | 1 | 60.39 | 62.42 | 63.18 | 58.41 |
| ERCOT | ERCOT-North | 2013 | 2 | 66.07 | 68.81 | 69.43 | 79.65 |
| ERCOT | ERCOT-North | 2013 | 3 | 64.67 | 68.86 | 68.64 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 4 | 65.49 | 69.11 | 70.42 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 5 | 59.64 | 71.72 | 84.89 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 6 | 61.22 | 73.58 | 84.23 | 48.67 |
| ERCOT | ERCOT-North | 2013 | 7 | 64.78 | 86.36 | 103.92 | 41.72 |
| ERCOT | ERCOT-North | 2013 | 8 | 65.77 | 87.94 | 102.95 | 36.50 |
| ERCOT | ERCOT-North | 2013 | 9 | 59.05 | 68.99 | 76.79 | 58.41 |
| ERCOT | ERCOT-North | 2013 | 10 | 57.24 | 62.29 | 65.34 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 11 | 58.79 | 61.39 | 62.31 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 12 | 59.36 | 61.13 | 61.77 | 58.41 |
| ERCOT | ERCOT-North | 2014 | 1 | 60.35 | 62.44 | 63.19 | 57.51 |
| ERCOT | ERCOT-North | 2014 | 2 | 63.01 | 65.62 | 66.14 | 78.42 |
| ERCOT | ERCOT-North | 2014 | 3 | 62.88 | 65.90 | 65.53 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 4 | 62.50 | 66.33 | 67.94 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 5 | 58.09 | 70.09 | 82.34 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 6 | 58.46 | 70.87 | 80.93 | 47.92 |
| ERCOT | ERCOT-North | 2014 | 7 | 62.63 | 95.80 | 127.42 | 41.08 |
| ERCOT | ERCOT-North | 2014 | 8 | 63.68 | 91.87 | 112.78 | 35.94 |
| ERCOT | ERCOT-North | 2014 | 9 | 55.73 | 64.71 | 71.52 | 57.51 |
| ERCOT | ERCOT-North | 2014 | 10 | 55.47 | 60.74 | 64.10 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 11 | 57.39 | 60.07 | 61.18 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 12 | 57.86 | 59.58 | 60.25 | 57.51 |
| ERCOT | ERCOT-North | 2015 | 1 | 59.00 | 61.25 | 62.09 | 56.64 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2015 | 2 | 64.35 | 67.81 | 68.45 | 77.23 |
| ERCOT | ERCOT-North | 2015 | 3 | 63.48 | 67.02 | 66.69 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 4 | 63.93 | 68.86 | 71.76 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 5 | 58.49 | 70.23 | 82.92 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 6 | 59.34 | 73.12 | 82.79 | 47.20 |
| ERCOT | ERCOT-North | 2015 | 7 | 63.13 | 112.97 | 164.89 | 40.45 |
| ERCOT | ERCOT-North | 2015 | 8 | 63.98 | 93.09 | 115.06 | 35.40 |
| ERCOT | ERCOT-North | 2015 | 9 | 56.34 | 66.23 | 73.01 | 56.64 |
| ERCOT | ERCOT-North | 2015 | 10 | 55.03 | 59.79 | 62.92 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 11 | 56.34 | 59.01 | 60.21 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 12 | 56.91 | 58.64 | 59.39 | 56.64 |
| ERCOT | ERCOT-North | 2016 | 1 | 57.63 | 59.94 | 60.82 | 55.73 |
| ERCOT | ERCOT-North | 2016 | 2 | 57.80 | 60.85 | 61.39 | 76.00 |
| ERCOT | ERCOT-North | 2016 | 3 | 59.47 | 62.19 | 62.14 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 4 | 59.65 | 64.88 | 68.88 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 5 | 54.36 | 66.13 | 77.93 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 6 | 55.08 | 68.31 | 77.43 | 46.44 |
| ERCOT | ERCOT-North | 2016 | 7 | 60.22 | 119.65 | 185.10 | 39.81 |
| ERCOT | ERCOT-North | 2016 | 8 | 59.15 | 99.50 | 132.03 | 34.83 |
| ERCOT | ERCOT-North | 2016 | 9 | 52.59 | 60.48 | 66.51 | 55.73 |
| ERCOT | ERCOT-North | 2016 | 10 | 51.73 | 56.40 | 59.56 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 11 | 53.62 | 56.56 | 58.10 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 12 | 54.96 | 56.98 | 57.95 | 55.73 |
| ERCOT | ERCOT-North | 2017 | 1 | 55.38 | 57.62 | 58.47 | 54.80 |
| ERCOT | ERCOT-North | 2017 | 2 | 61.05 | 64.30 | 64.79 | 74.73 |
| ERCOT | ERCOT-North | 2017 | 3 | 60.49 | 63.61 | 63.21 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 4 | 61.73 | 67.10 | 71.37 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 5 | 55.38 | 68.24 | 81.15 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 6 | 56.77 | 71.05 | 80.28 | 45.67 |
| ERCOT | ERCOT-North | 2017 | 7 | 60.90 | 126.70 | 199.64 | 39.14 |
| ERCOT | ERCOT-North | 2017 | 8 | 59.95 | 100.49 | 133.14 | 34.25 |
| ERCOT | ERCOT-North | 2017 | 9 | 52.98 | 60.37 | 66.11 | 54.80 |
| ERCOT | ERCOT-North | 2017 | 10 | 51.92 | 56.64 | 59.59 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 11 | 54.00 | 56.64 | 57.96 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 12 | 55.01 | 56.96 | 57.84 | 54.80 |
| ERCOT | ERCOT-North | 2018 | 1 | 55.86 | 57.85 | 58.67 | 53.86 |
| ERCOT | ERCOT-North | 2018 | 2 | 63.02 | 66.24 | 66.94 | 73.45 |
| ERCOT | ERCOT-North | 2018 | 3 | 61.75 | 65.70 | 65.68 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 4 | 63.09 | 67.73 | 70.53 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 5 | 56.55 | 69.62 | 81.68 | 89.77 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2018 | 6 | 57.00 | 70.32 | 80.22 | 44.88 |
| ERCOT | ERCOT-North | 2018 | 7 | 61.97 | 114.26 | 169.58 | 38.47 |
| ERCOT | ERCOT-North | 2018 | 8 | 62.64 | 144.91 | 218.10 | 33.66 |
| ERCOT | ERCOT-North | 2018 | 9 | 55.46 | 65.10 | 72.42 | 53.86 |
| ERCOT | ERCOT-North | 2018 | 10 | 53.86 | 59.66 | 63.73 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 11 | 55.61 | 59.29 | 60.59 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 12 | 56.29 | 58.27 | 59.14 | 53.86 |
| ERCOT | ERCOT-North | 2019 | 1 | 57.39 | 59.61 | 60.47 | 52.94 |
| ERCOT | ERCOT-North | 2019 | 2 | 65.26 | 68.61 | 69.60 | 72.19 |
| ERCOT | ERCOT-North | 2019 | 3 | 64.84 | 68.17 | 68.13 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 4 | 64.65 | 68.70 | 70.65 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 5 | 57.79 | 75.13 | 104.70 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 6 | 59.97 | 75.32 | 87.73 | 44.12 |
| ERCOT | ERCOT-North | 2019 | 7 | 64.37 | 134.18 | 210.42 | 37.81 |
| ERCOT | ERCOT-North | 2019 | 8 | 65.84 | 161.72 | 248.54 | 33.09 |
| ERCOT | ERCOT-North | 2019 | 9 | 57.96 | 70.20 | 78.70 | 52.94 |
| ERCOT | ERCOT-North | 2019 | 10 | 55.79 | 62.00 | 66.78 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 11 | 57.55 | 60.76 | 62.32 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 12 | 58.25 | 60.40 | 61.34 | 52.94 |
| ERCOT | ERCOT-North | 2020 | 1 | 58.82 | 61.15 | 62.06 | 52.04 |
| ERCOT | ERCOT-North | 2020 | 2 | 59.37 | 62.28 | 62.91 | 70.96 |
| ERCOT | ERCOT-North | 2020 | 3 | 60.00 | 64.75 | 64.70 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 4 | 61.86 | 67.21 | 70.75 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 5 | 58.95 | 76.03 | 106.81 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 6 | 60.21 | 77.40 | 90.89 | 43.37 |
| ERCOT | ERCOT-North | 2020 | 7 | 64.94 | 147.49 | 239.80 | 37.17 |
| ERCOT | ERCOT-North | 2020 | 8 | 66.40 | 151.09 | 227.49 | 32.52 |
| ERCOT | ERCOT-North | 2020 | 9 | 57.54 | 69.71 | 78.10 | 52.04 |
| ERCOT | ERCOT-North | 2020 | 10 | 55.94 | 61.67 | 65.22 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 11 | 57.93 | 61.07 | 62.69 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 12 | 58.81 | 60.86 | 61.73 | 52.04 |
| ERCOT | ERCOT-North | 2021 | 1 | 60.15 | 62.76 | 63.76 | 51.16 |
| ERCOT | ERCOT-North | 2021 | 2 | 68.30 | 72.74 | 73.67 | 69.77 |
| ERCOT | ERCOT-North | 2021 | 3 | 64.61 | 71.28 | 71.38 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 4 | 67.44 | 74.53 | 80.19 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 5 | 63.72 | 83.66 | 114.77 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 6 | 65.10 | 87.08 | 106.62 | 42.64 |
| ERCOT | ERCOT-North | 2021 | 7 | 71.36 | 168.72 | 273.43 | 36.54 |
| ERCOT | ERCOT-North | 2021 | 8 | 72.55 | 170.92 | 260.68 | 31.98 |
| ERCOT | ERCOT-North | 2021 | 9 | 61.41 | 72.87 | 80.83 | 51.16 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2021 | 10 | 60.29 | 66.53 | 70.61 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 11 | 62.35 | 65.98 | 67.80 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 12 | 63.47 | 65.75 | 66.73 | 51.16 |
| ERCOT | ERCOT-North | 2022 | 1 | 64.78 | 67.86 | 68.99 | 50.30 |
| ERCOT | ERCOT-North | 2022 | 2 | 73.70 | 78.44 | 79.31 | 68.59 |
| ERCOT | ERCOT-North | 2022 | 3 | 68.09 | 77.09 | 77.24 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 4 | 75.85 | 83.94 | 90.10 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 5 | 74.71 | 110.35 | 184.69 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 6 | 74.24 | 97.02 | 115.32 | 41.91 |
| ERCOT | ERCOT-North | 2022 | 7 | 81.80 | 185.21 | 295.78 | 35.93 |
| ERCOT | ERCOT-North | 2022 | 8 | 82.80 | 179.42 | 267.01 | 31.44 |
| ERCOT | ERCOT-North | 2022 | 9 | 69.94 | 82.04 | 90.57 | 50.30 |
| ERCOT | ERCOT-North | 2022 | 10 | 68.32 | 75.50 | 79.66 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 11 | 70.91 | 75.09 | 77.07 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 12 | 72.05 | 74.62 | 75.66 | 50.30 |
| ERCOT | ERCOT-North | 2023 | 1 | 72.13 | 75.67 | 76.73 | 31.79 |
| ERCOT | ERCOT-North | 2023 | 2 | 73.00 | 77.16 | 77.77 | 43.35 |
| ERCOT | ERCOT-North | 2023 | 3 | 63.66 | 76.91 | 76.94 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 4 | 75.21 | 83.32 | 88.59 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 5 | 79.65 | 109.06 | 167.37 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 6 | 79.54 | 100.97 | 118.29 | 26.49 |
| ERCOT | ERCOT-North | 2023 | 7 | 86.62 | 185.41 | 293.85 | 22.71 |
| ERCOT | ERCOT-North | 2023 | 8 | 86.34 | 166.62 | 237.97 | 19.87 |
| ERCOT | ERCOT-North | 2023 | 9 | 76.12 | 87.29 | 95.57 | 31.79 |
| ERCOT | ERCOT-North | 2023 | 10 | 72.83 | 82.61 | 87.58 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 11 | 71.39 | 75.73 | 77.30 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 12 | 71.35 | 75.19 | 76.14 | 31.79 |
| ERCOT | ERCOT-North | 2024 | 1 | 69.77 | 75.63 | 76.66 | 31.38 |
| ERCOT | ERCOT-North | 2024 | 2 | 73.61 | 77.50 | 78.28 | 42.79 |
| ERCOT | ERCOT-North | 2024 | 3 | 67.34 | 77.33 | 77.33 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 4 | 71.77 | 79.48 | 81.20 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 5 | 77.33 | 96.79 | 129.59 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 6 | 79.90 | 99.42 | 117.68 | 26.15 |
| ERCOT | ERCOT-North | 2024 | 7 | 85.61 | 160.32 | 238.29 | 22.41 |
| ERCOT | ERCOT-North | 2024 | 8 | 88.76 | 199.59 | 302.36 | 19.61 |
| ERCOT | ERCOT-North | 2024 | 9 | 77.32 | 90.57 | 99.94 | 31.38 |
| ERCOT | ERCOT-North | 2024 | 10 | 72.12 | 83.57 | 89.19 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 11 | 68.87 | 76.06 | 77.53 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 12 | 71.60 | 75.63 | 76.59 | 31.38 |
| ERCOT | ERCOT-North | 2025 | 1 | 69.80 | 76.53 | 77.64 | 30.96 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2025 | 2 | 74.79 | 78.73 | 79.51 | 42.22 |
| ERCOT | ERCOT-North | 2025 | 3 | 65.12 | 78.00 | 77.74 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 4 | 71.02 | 80.23 | 82.61 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 5 | 78.20 | 96.84 | 130.04 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 6 | 79.74 | 100.42 | 119.67 | 25.80 |
| ERCOT | ERCOT-North | 2025 | 7 | 86.03 | 172.12 | 260.34 | 22.11 |
| ERCOT | ERCOT-North | 2025 | 8 | 89.44 | 199.87 | 303.25 | 19.35 |
| ERCOT | ERCOT-North | 2025 | 9 | 74.29 | 88.99 | 96.91 | 30.96 |
| ERCOT | ERCOT-North | 2025 | 10 | 70.00 | 82.77 | 87.35 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 11 | 67.49 | 76.42 | 77.91 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 12 | 69.94 | 74.71 | 75.61 | 30.96 |
| ERCOT | ERCOT-North | 2026 | 1 | 72.81 | 78.69 | 79.78 | 31.27 |
| ERCOT | ERCOT-North | 2026 | 2 | 76.33 | 80.53 | 81.29 | 42.64 |
| ERCOT | ERCOT-North | 2026 | 3 | 64.26 | 79.91 | 79.73 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 4 | 70.87 | 83.15 | 86.09 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 5 | 80.53 | 100.36 | 137.58 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 6 | 81.57 | 102.92 | 122.98 | 26.06 |
| ERCOT | ERCOT-North | 2026 | 7 | 88.22 | 189.58 | 296.71 | 22.33 |
| ERCOT | ERCOT-North | 2026 | 8 | 91.92 | 197.27 | 296.85 | 19.54 |
| ERCOT | ERCOT-North | 2026 | 9 | 75.31 | 90.65 | 98.26 | 31.27 |
| ERCOT | ERCOT-North | 2026 | 10 | 70.93 | 84.89 | 88.97 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 11 | 69.11 | 78.78 | 80.60 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 12 | 73.78 | 77.36 | 78.45 | 31.27 |
| ERCOT | ERCOT-North | 2027 | 1 | 76.34 | 81.01 | 82.23 | 31.58 |
| ERCOT | ERCOT-North | 2027 | 2 | 77.30 | 81.98 | 82.68 | 43.07 |
| ERCOT | ERCOT-North | 2027 | 3 | 71.10 | 81.72 | 81.63 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 4 | 77.06 | 86.47 | 90.72 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 5 | 83.08 | 107.55 | 153.54 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 6 | 84.23 | 113.21 | 144.12 | 26.32 |
| ERCOT | ERCOT-North | 2027 | 7 | 92.01 | 208.58 | 327.54 | 22.56 |
| ERCOT | ERCOT-North | 2027 | 8 | 95.05 | 222.49 | 343.55 | 19.74 |
| ERCOT | ERCOT-North | 2027 | 9 | 82.13 | 95.59 | 104.85 | 31.58 |
| ERCOT | ERCOT-North | 2027 | 10 | 77.32 | 87.70 | 92.35 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 11 | 75.53 | 80.83 | 82.74 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 12 | 75.52 | 78.67 | 79.61 | 31.58 |

US Army Corps of Engineers

# Estimate of Hydropower Value

(9-Year and 30-Year Replacement Power Evaluation Periods)

## Lake Texoma, Oklahoma and Texas Reservoir Storage Reallocation Study

December 2008

# Estimate of Hydropower Value

(9-Year and 30-Year Replacement Power Evaluation Periods)

Lake Texoma, Oklahoma and Texas
Reservoir Storage Reallocation Study

This report presents a determination of the value of replacement power of equal annual amounts over periods of 9-years and 30-years. The periods of evaluation are described below.

9-YEAR PERIOD. Current power sales contracts held by users with the Energy Department's Southwestern Power Administration (SWPA) expire on December 31, 2018. This evaluation estimates the value of replacement power over the period remaining in the contract for two storage reallocation conditions Those conditions are for reallocation of 150,000 or 300,000 acre-feet from the conservation pool, as authorized by Sec 838 of the 1986 Water Resources Development Act. Equal annual amounts were computed over a period of 9 years, assuming implementation of a water storage agreement in 2009. The evaluation of replacement power traditionally serves as an interim proxy for the actual documentation of replacement power purchases where the proxy is used for initial evaluation purposes and the estimation of hydropower account credit. Corps regulations require documentation of replacement power purchases before the Secretary of the Army for Civil Works may direct a credit to the hydropower project account.

30-YEAR PERIOD. Water storage agreement payments are made over a period not to exceed 30 years. The 30-year equal annual value of compensation was computed and is displayed along with the values for the 9-year term as well.

---

The Hydropower Analysis Center is the Corps of Engineers center of expertise for hydropower planning and analysis[1]. The HAC was formed in 1949 as Hydropower Evaluation Section then gained National Hydropower MCX Status in 1996. HAC was established to maintain the expertise and capability to perform power systems analysis regarding hydropower project output and economic benefit evaluations of existing and new hydroelectric plants.

The HAC was contacted by the Tulsa District to assist in estimating the wholesale value of hydropower that would potentially be lost due to reallocation of water in conservation storage currently used for hydropower production to the purpose of water supply storage. The purpose of estimating the value of hydropower potentially lost is to establish a proxy for the conditions of the 1986 Water Resources Development Act, Sec 838, subparagraph d. (3) (B) that states "the replacement cost of the hydropower lost (where replacement cost is defined as the cost to purchase power from existing alternative sources). If hydropower is lost as a result of the implementation of such contract, the Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement costs. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated

[1] https://w3.nwp.usace.army.mil/HDC/hac/home.asp

to hydropower." Summarized below is a description of cooperative efforts and methods employed .

The program SUPER is a sequential daily stream flow routing computer model used by the Tulsa District to simulate multipurpose reservoir operations at the Denison project. Hydropower generation portion of the simulation is governed by an electrical load schedule developed by SWPA. The reduction in hydropower generation was determined by simulations using a 63-year period of inflow records. Hydropower generation was determined for the existing water supply allocation of about 150 thousand acre-feet (KAF), reallocation of 300KAF (a 150KAF addition to the existing water supply allocation) and 450KAF (a 300KAF addition to the existing water supply allocation) to water supply storage. The process of running the SUPER model, its input and output is documented in the appendix: Red River SUPER Model, Texoma Yield Analysis, and Water Supply Reallocation at Texoma.

SWPA integrates and dispatches generation at the Denison Dam hydropower plant to optimize its value to the regional power system through their preference customers. Power sales products include both firm and supplemental energy. Firm energy is based on 1,200 KW/yr for each KW of capacity purchased.

Platts Power Outlook Research Service electrical power wholesale price forecast is the basis for determining the value of hydropower impact due to the diversion of water to municipal water supply.

Use of wholesale prices in this evaluation is required because power rates developed by SWPA reflect a Federal mandate to sell the power from Federal hydropower projects at a cost which is lower than the wholesale price. Federal law requires crediting SWPA for the power replacement at market prices.

Platts provides a regional forecast of the wholesale price for electrical power. Platts uses $\text{Aurora}_{\text{XMP}}$, an econometric model, to simulate the interaction of principal factors influencing the wholesale price electrical power in an unconstrained market. Forecast wholesale prices for both capacity and energy, are developed on an hourly basis and summarized as monthly and annual prices. The model integrates the generation resources to meet the hourly, daily, seasonal demand using the least costly resources available. As the hourly demand increases more expensive resources must be added which increases the wholesale price of the power. The model determines the least cost capacity (existing, planned additions and new construction) and required reserves to maintain system reliability. The weekly cycle of electrical power demand is commonly classified into peak and off-peak periods of the day. The peak demand period is 6am to 10pm each day, Monday through Friday (5x16) or (80hr/wk). Platts provides its forecast prices for both capacity and energy, expressed in units of $/MWh, in the peak and off-peak periods monthly over a 20-yr period. Energy and capacity prices are combined into all-hours price as well..

Hydropower resources available at Denison are limited by seasonal fluctuations in river flow and the amount of reservoir storage. Firm energy (guaranteed energy, 1,200KWh/KW annually) is strategically scheduled for the highest valued hours of the peak period (Table below). At the

Denison Dam hydropower plant firm energy is dispatched at 70 MW (marketable capacity), though the plant is operated at as much as 80MW. Generation during the summer is only about half the duration of the peak period (~40 hrs/wk).

Figure 1 displays the annual dispatch plan for Denison Powerplant firm generation. For example, in July, generation is prioritized for the hours from noon to 7pm, for a total of 155 hours for the month.

**Figure 1. Denison Powerplant Dispatch**

## SWPA Generalized Dispatch
## Denison Powerplant

| Month | Peak AM | | | Peak PM | | | Hours/ weekday | Hours / month | HAC Mod |
|---|---|---|---|---|---|---|---|---|---|
| | Across Hr | Ending Hr | # Hrs | Across Hr | Ending Hr | # Hrs | | | hrs/mo |
| **Jan** | 700 | 900 | 2 | 1800 | 2100 | 3 | 5 | 111 | 111 |
| **Feb** | 700 | 900 | 2 | 1800 | 2000 | 2 | 4 | 80 | 80 |
| **Mar** | 700 | 1000 | 3 | 0 | 0 | 0 | 3 | 66 | 66 |
| **Apr** | 0 | 0 | 0 | 1400 | 1700 | 3 | 3 | 64 | 64 |
| **May** | 0 | 0 | 0 | 1500 | 1800 | 3 | 3 | 66 | 66 |
| **Jun** | 0 | 0 | 0 | 1300 | 1900 | 6 | 6 | 129 | 129 |
| **Jul** | 0 | 0 | 0 | 1200 | 1900 | 7 | 7 | 155 | 157 |
| **Aug** | 0 | 0 | 0 | 1200 | 2000 | 8 | 8 | 177 | 177 |
| **Sep** | 0 | 0 | 0 | 1300 | 1800 | 5 | 5 | 107 | 109 |
| **Oct** | 0 | 0 | 0 | 1400 | 1700 | 3 | 3 | 66 | 66 |
| **Nov** | 0 | 0 | 0 | 1800 | 2100 | 3 | 3 | 64 | 64 |
| **Dec** | 700 | 900 | 2 | 1800 | 2100 | 3 | 5 | 111 | 111 |
| | | | | | | | Sum = | 1,196 | 1,200 |

SWPA's power purchases to support firm energy sales are higher than the Platts' peak energy and capacity prices which are applied over the 5x16 peak period published in the standard forecast. To compensate for SWPA's higher purchase prices, Platts provided a custom forecast of wholesale prices for the schedule of firm energy for Denison that was optimized by SWPA in coordination with their customers. The results of the custom forecast produced prices that more accurately reflect the value of energy during the segment of the market for which the dispatch schedule of Denison hydropower generation was optimized.

Platts provided the 20-yr forecast monthly prices in current dollars. The stream of forecast prices was extended to the customary USACE 50-year analysis period by repeating the monthly prices in the last year of the forecast *(also in the 30-yr period of analysis)*. Standard USACE procedures were used to develop an equivalent annual price for the period of analysis at an annual interest rate of 4.625%. This is the current Federal Water Resources interest rate.

**Figure 2A. Platts Power Outlook Research Service Power Prices (annualized over 9-yrs, until 2018)**

# Platts PORS Power Prices (constant 2008$, annualized @ 4.625% interest, 2018)

Derived from Platts-Nov 2008 20-yr monthly forecast base case
Denison monthly peak periods defined by SWPA
Denison Peak values derived by Platts' Special Study-21Nov08

| *Denison Capacity* | *Peak Energy* | month | Denison Peak Energy + Capacity | On Peak Energy | Off Peak Energy |
|---|---|---|---|---|---|
| *$/MWh* | *$/MWh* | | **$/MWh** | **$/MWh** | **$/MWh** |
| 66.46 | 75.93 | **1** | **142.38** | **74.93** | **72.31** |
| 90.62 | 79.50 | **2** | **170.12** | **78.83** | **75.23** |
| 110.76 | 78.53 | **3** | **189.29** | **78.83** | **75.06** |
| 110.76 | 86.18 | **4** | **196.94** | **82.17** | **76.14** |
| 110.76 | 100.12 | **5** | **210.88** | **85.73** | **70.95** |
| 55.38 | 99.20 | **6** | **154.58** | **87.56** | **71.64** |
| 47.47 | 153.19 | **7** | **200.66** | **116.13** | **76.96** |
| 41.53 | 135.17 | **8** | **176.70** | **110.59** | **77.04** |
| 66.46 | 86.22 | **9** | **152.67** | **78.55** | **68.21** |
| 110.76 | 77.61 | **10** | **188.37** | **73.52** | **67.26** |
| 110.76 | 72.85 | **11** | **183.61** | **71.52** | **68.33** |
| 66.46 | 71.75 | **12** | **138.21** | **70.89** | **68.80** |

**Figure 3B. Platts Power Outlook Research Service Power Prices (annualized over (30-yrs)**

# Platts PORS Power Prices (constant 2008$, annualized @ 4.625% interest, 30-yrs)

Derived from Platts-Nov 2008 20-yr monthly forecast base case
Denison monthly peak periods defined by SWPA
Denison Peak values derived by Platts' Special Study-21Nov08

| *Denison Capacity* | *Peak Energy* | month | Denison Peak Energy + Capacity | On Peak Energy | Off Peak Energy |
|---|---|---|---|---|---|
| *$/MWh* | *$/MWh* | | $/MWh | $/MWh | $/MWh |
| 50.24 | 76.07 | 1 | 126.31 | 75.01 | 71.48 |
| 68.50 | 79.10 | 2 | 147.60 | 78.39 | 74.40 |
| 83.73 | 78.07 | 3 | 161.80 | 78.24 | 71.13 |
| 83.73 | 85.97 | 4 | 169.70 | 81.97 | 74.60 |
| 83.73 | 123.98 | 5 | 207.71 | 93.66 | 74.19 |
| 41.86 | 114.25 | 6 | 156.11 | 95.77 | 75.15 |
| 35.88 | 231.15 | 7 | 267.03 | 155.49 | 81.34 |
| 31.40 | 228.54 | 8 | 259.94 | 159.65 | 82.71 |
| 50.24 | 92.15 | 9 | 142.39 | 83.86 | 72.01 |
| 83.73 | 81.94 | 10 | 165.67 | 77.59 | 69.48 |
| 83.73 | 75.43 | 11 | 159.16 | 73.85 | 69.49 |
| 50.24 | 73.70 | 12 | 123.94 | 72.79 | 70.14 |

Simulated daily generation was reduced to annual average generation in three categories that correspond to those price categories described above, for each month as follows;

Denison Peak Energy + Capacity: Generation is supplied as firm energy, as the first priority, which is valued at Platts custom study prices for energy and capacity in the optimized SWPA schedule.

On Peak Energy: Excess energy in the peak period is valued at Platts standard forecast peak energy price. Capacity has little or no value most of the year, except July and August.

Off Peak Energy: Any remaining energy is valued at Platts' standard off-peak price.

**Figure 4. Annual Existing Condition Generation, Denison Powerhouse**

## Generation for Existing Condition

### (Existing water supply storage of 150,000 acre-feet)

| Existing1 | | | |
|---|---|---|---|
| | Denison Peak | On-Peak | Off-Peak |
| month | MWh | MWh | MWh |
| 1 | 7,770 | 6,829 | 4,520 |
| 2 | 5,135 | 7,225 | 3,760 |
| 3 | 4,481 | 9,428 | 6,419 |
| 4 | 4,402 | 10,313 | 6,672 |
| 5 | 4,552 | 11,846 | 7,716 |
| 6 | 8,497 | 10,586 | 12,919 |
| 7 | 10,885 | 7,228 | 4,881 |
| 8 | 12,264 | 4,005 | 1,489 |
| 9 | 7,233 | 4,492 | 2,096 |
| 10 | 4,391 | 5,458 | 2,729 |
| 11 | 4,325 | 5,992 | 3,479 |
| 12 | 7770 | 6997.544 | 3532.4111 |
| sum | 81,704 | 90,401 | 60,212 |

| | generation |
|---|---|
| total | 232,317 |

**Figure 5. Annual Generation, Denison Powerhouse, 300KAF Reallocation**

# Generation for Potential 150,000 acre-feet Reallocation

## (A total potential reallocation of 300,000 acre-feet)

| MOD3001 | | | |
|---|---|---|---|
| | Denison Peak | On-Peak | Off-Peak |
| month | MWh | MWh | MWh |
| 1 | 7,464 | 6,265 | 4,226 |
| 2 | 4,907 | 6,732 | 3,540 |
| 3 | 4,246 | 9,146 | 6,603 |
| 4 | 4,119 | 9,843 | 6,666 |
| 5 | 4,072 | 11,379 | 7,804 |
| 6 | 7,800 | 10,590 | 12,938 |
| 7 | 10,859 | 6,354 | 4,383 |
| 8 | 12,065 | 3,488 | 1,079 |
| 9 | 6,963 | 3,812 | 1,764 |
| 10 | 4,025 | 5,064 | 1,961 |
| 11 | 4,050 | 5,335 | 3,276 |
| 12 | 7,334 | 6,562 | 3,257 |
| sum | 77,904 | 84,570 | 57,498 |
| | generation | | |
| total | 219,971 | | |

**Figure 6. Annual Generation, Denison Powerhouse, 450KAF Reallocation**

# Generation for
# Potential 300,000 acre-feet Reallocation
## (A total potential reallocation of 450,000 acre-feet)

| MOD4501 | | | |
|---|---|---|---|
| | Denison Peak | On-Peak | Off-Peak |
| month | MWh | MWh | MWh |
| 1 | 6,985 | 5,677 | 3,965 |
| 2 | 4,769 | 6,106 | 3,301 |
| 3 | 4,082 | 8,525 | 6,351 |
| 4 | 4,110 | 9,165 | 6,261 |
| 5 | 3,992 | 10,997 | 7,539 |
| 6 | 7,631 | 10,153 | 12,404 |
| 7 | 10,112 | 5,888 | 4,099 |
| 8 | 11,565 | 3,175 | 1,038 |
| 9 | 6,903 | 3,435 | 1,662 |
| 10 | 3,890 | 4,868 | 1,815 |
| 11 | 3,894 | 5,007 | 3,062 |
| 12 | 6,903 | 6,074 | 2,857 |
| sum | 74,836 | 79,069 | 54,352 |
| | generation | | |
| total | 208,257 | | |

The annual wholesale value of hydropower generation under Existing reservoir allocation and reallocation of 300KAF and 450KAF of reservoir storage for municipal water supply are determined by multiplying the Platts PORS prices *(annualized over 9-yrs and 30-yrs)* by the generation for each reservoir storage allocation. The results are shown in the Figures 6A&B, 7A&B, and 8A&B.

**Figure 6A. Value of Generation, Existing Condition (annualized over 9-yrs, until 2018)**

## Generation Value for Existing Condition

### (Existing water supply storage of 150,000 acre-feet)

(constant 2008$, 4.625%, 9-yrs, x $1,000 )

| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
|---|---|---|---|---|---|
| 1 | *$516* | *$590* | **$1,106** | **$512** | **$327** |
| 2 | *$465* | *$408* | **$874** | **$570** | **$283** |
| 3 | *$496* | *$352* | **$848** | **$743** | **$482** |
| 4 | *$488* | *$379* | **$867** | **$847** | **$508** |
| 5 | *$504* | *$456* | **$960** | **$1,016** | **$547** |
| 6 | *$471* | *$843* | **$1,313** | **$927** | **$926** |
| 7 | *$517* | *$1,667* | **$2,184** | **$839** | **$376** |
| 8 | *$509* | *$1,658* | **$2,167** | **$443** | **$115** |
| 9 | *$481* | *$624* | **$1,104** | **$353** | **$143** |
| 10 | *$486* | *$341* | **$827** | **$401** | **$184** |
| 11 | *$479* | *$315* | **$794** | **$429** | **$238** |
| 12 | *$516* | *$558* | **$1,074** | **$496** | **$243** |
| sum | *$5,929* | *$8,190* | **$14,119** | **$7,576** | **$4,370** |
| | | | **Annualized** | **$26,064** | |

**Figure 6B. Value of Generation, Existing Condition (annualized over 30-yrs)**

# Generation Value for Existing Condition

## (Existing water supply storage of 150,000 acre-feet)

(constant 2008$, 4.625%, 30-yrs, x $1,000 )

| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
|---|---|---|---|---|---|
| 1 | *$390* | *$591* | **$981** | **$515** | **$325** |
| 2 | *$352* | *$406* | **$758** | **$568** | **$280** |
| 3 | *$375* | *$350* | **$725** | **$740** | **$457** |
| 4 | *$369* | *$378* | **$747** | **$848** | **$499** |
| 5 | *$381* | *$564* | **$945** | **$1,120** | **$577** |
| 6 | *$356* | *$971* | **$1,326** | **$1,026** | **$978** |
| 7 | *$391* | *$2,516* | **$2,907** | **$1,149** | **$400** |
| 8 | *$385* | *$2,803* | **$3,188** | **$656** | **$124** |
| 9 | *$363* | *$667* | **$1,030** | **$380** | **$152** |
| 10 | *$368* | *$360* | **$727** | **$427** | **$191** |
| 11 | *$362* | *$326* | **$688** | **$445** | **$243** |
| 12 | *$390* | *$573* | **$963** | **$512** | **$249** |
| sum | *$4,482* | *$10,505* | **$14,986** | **$8,387** | **$4,476** |
| | | | **Annualized** | **$27,849** | |

**Figure 7A. Value of Generation, Potential 150,000 acre-feet Reallocation** ***(annualized over 9-yrs, until 2018)***

# Generation Value for
# Potential 150,000 acre-feet Reallocation
## (A total potential reallocation of 300,000 acre-feet)

(constant 2008$, 4.625%, 9-yrs, x $1,000 )

| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
|---|---|---|---|---|---|
| 1 | *$496* | *$567* | **$1,063** | **$469** | **$306** |
| 2 | *$445* | *$390* | **$835** | **$531** | **$266** |
| 3 | *$470* | *$333* | **$804** | **$721** | **$496** |
| 4 | *$456* | *$355* | **$811** | **$809** | **$508** |
| 5 | *$451* | *$408* | **$859** | **$976** | **$554** |
| 6 | *$432* | *$774* | **$1,206** | **$927** | **$927** |
| 7 | *$515* | *$1,663* | **$2,179** | **$738** | **$337** |
| 8 | *$501* | *$1,631* | **$2,132** | **$386** | **$83** |
| 9 | *$463* | *$600* | **$1,063** | **$299** | **$120** |
| 10 | *$446* | *$312* | **$758** | **$372** | **$132** |
| 11 | *$449* | *$295* | **$744** | **$382** | **$224** |
| 12 | *$487* | *$526* | **$1,014** | **$465** | **$224** |
| sum | *$5,611* | *$7,855* | **$13,466** | **$7,075** | **$4,176** |
| | | | **Annualized** | **$24,717** | |

**Figure 7B. Value of Generation, Potential 150,000 acre-feet Reallocation *(annualized over 30-yrs)***

# Generation Value for
# Potential 150,000 acre-feet Reallocation
## (A total potential reallocation of 300,000 acre-feet)
(constant 2008$, 4.625%, 30-yrs, x $1,000 )

| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
|---|---|---|---|---|---|
| 1 | *$375* | *$568* | **$943** | **$470** | **$302** |
| 2 | *$336* | *$388* | **$724** | **$528** | **$263** |
| 3 | *$356* | *$331* | **$687** | **$716** | **$470** |
| 4 | *$345* | *$354* | **$699** | **$807** | **$497** |
| 5 | *$341* | *$505* | **$846** | **$1,066** | **$579** |
| 6 | *$327* | *$891* | **$1,218** | **$1,014** | **$972** |
| 7 | *$390* | *$2,510* | **$2,900** | **$988** | **$357** |
| 8 | *$379* | *$2,757* | **$3,136** | **$557** | **$89** |
| 9 | *$350* | *$642* | **$991** | **$320** | **$127** |
| 10 | *$337* | *$330* | **$667** | **$393** | **$136** |
| 11 | *$339* | *$306* | **$645** | **$394** | **$228** |
| 12 | *$368* | *$541* | **$909** | **$478** | **$228** |
| sum | *$4,242* | *$10,122* | **$14,364** | **$7,729** | **$4,249** |
| | | | **Annualized** | **$26,342** | |

**Figure 8A. Value of Generation, Potential 300,000 acre-feet Reallocation** ***(annualized over 9-yrs, until 2018)***

# Generation Value for Potential 300,000 acre-feet Reallocation

## (A total potential reallocation of 450,000 acre-feet)

(constant 2008$, 4.625%, 9-yrs, x $1,000 )

| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
|---|---|---|---|---|---|
| 1 | *$464* | *$530* | **$994** | **$425** | **$287** |
| 2 | *$432* | *$379* | **$811** | **$481** | **$248** |
| 3 | *$452* | *$321* | **$773** | **$672** | **$477** |
| 4 | *$455* | *$354* | **$809** | **$753** | **$477** |
| 5 | *$442* | *$400* | **$842** | **$943** | **$535** |
| 6 | *$423* | *$757* | **$1,180** | **$889** | **$889** |
| 7 | *$480* | *$1,549* | **$2,029** | **$684** | **$315** |
| 8 | *$480* | *$1,563* | **$2,044** | **$351** | **$80** |
| 9 | *$459* | *$595* | **$1,054** | **$270** | **$113** |
| 10 | *$431* | *$302* | **$733** | **$358** | **$122** |
| 11 | *$431* | *$284* | **$715** | **$358** | **$209** |
| 12 | *$459* | *$495* | **$954** | **$431** | **$197** |
| sum | *$5,408* | *$7,529* | **$12,938** | **$6,615** | **$3,948** |
| | | | **Annualized** | **$23,501** | |

**Figure 8B. Value of Generation, Potential 300,000 acre-feet Reallocation *(30-yrs)***

# Generation Value for Potential 300,000 acre-feet Reallocation

## (A total potential reallocation of 450,000 acre-feet)

(constant 2008$, 4.625%, 30-yrs, x $1,000 )

| month | *Denison Peak Capacity* | *Denison Peak Energy* | **Denison Peak Capacity + Energy** | **On-Peak Energy** | **Off-Peak Energy** |
|---|---|---|---|---|---|
| 1 | *$351* | *$531* | **$882** | **$426** | **$283** |
| 2 | *$327* | *$377* | **$704** | **$479** | **$246** |
| 3 | *$342* | *$319* | **$660** | **$667** | **$452** |
| 4 | *$344* | *$353* | **$697** | **$751** | **$467** |
| 5 | *$334* | *$495* | **$829** | **$1,030** | **$559** |
| 6 | *$319* | *$872* | **$1,191** | **$972** | **$932** |
| 7 | *$363* | *$2,337* | **$2,700** | **$916** | **$333** |
| 8 | *$363* | *$2,643* | **$3,006** | **$507** | **$86** |
| 9 | *$347* | *$636* | **$983** | **$288** | **$120** |
| 10 | *$326* | *$319* | **$644** | **$378** | **$126** |
| 11 | *$326* | *$294* | **$620** | **$370** | **$213** |
| 12 | *$347* | *$509* | **$856** | **$442** | **$200** |
| sum | *$4,088* | *$9,685* | **$13,774** | **$7,225** | **$4,017** |
| | | | **Annualized** | **$25,016** | |

The impact on hydropower generation for the potential reallocations of 150,000 acre-feet (MOD3001) and 300,000 acre-feet (MOD4501) would be the difference in the value of generation compared to the Existing Conditions. The value of lost hydropower would be the proxy for the value of replacement power purchases based on annual wholesale prices. The results are summarized in **Error! Reference source not found.**A and 9B.

**Figure 9A. Total Annual Value Comparison** ***(annualized over 9 years, until 2018)***

# Annual Value of Lost Hydropower

(constant 2008$, 4.625%, 9-yrs, x $1,000 )

| Alternative | *Denison Peak Capacity* | *Denison Peak Energy* | Denison Peak Capacity + Energy | On-Peak Energy | Off-Peak Energy | Annual Value |
|---|---|---|---|---|---|---|
| Existing1 | *$5,929* | *$8,190* | $14,119 | $7,576 | $4,370 | $26,064 |
| MOD3001 | *$5,611* | *$7,855* | $13,466 | $7,075 | $4,176 | $24,717 |
| MOD4501 | *$5,408* | *$7,529* | $12,938 | $6,615 | $4,017 | $23,501 |
| | | | loss | | | |
| MOD3001 | *($317)* | *($335)* | ($653) | ($501) | ($194) | ($1,347) |
| MOD4501 | *($520)* | *($661)* | ($1,181) | ($961) | ($353) | ($2,563) |

| Alternative | Denison Peak Capacity Value | Denison Peak Energy Value | On-Peak Energy Value | Off-Peak Energy Value | Annual Capacity Value | Annual Energy Value | Annual Value |
|---|---|---|---|---|---|---|---|
| Existing1 | $5,929 | $8,190 | $7,576 | $4,370 | $5,929 | $20,136 | $26,064 |
| MOD3001 | $5,611 | $7,855 | $7,075 | $4,176 | $5,611 | $19,106 | $24,717 |
| MOD4501 | $5,408 | $7,529 | $6,615 | $4,017 | $5,408 | $18,161 | $23,501 |
| | | | loss | | | | |
| MOD3001 | ($317) | ($335) | ($501) | ($194) | ($317) | ($1,030) | ($1,347) |
| MOD4501 | ($520) | ($661) | ($961) | ($353) | ($520) | ($1,974) | ($2,563) |

SUMMARY 9-yr Term: The annual impact to hydropower generation over 9 years for 150,000 acre-feet of potential storage reallocation would be equivalent to replacement power purchases of approximately $1,347,000. The annual impact to hydropower generation over 9 years for 300,000 acre-feet of potential storage reallocation would be equivalent to replacement power purchases of approximately $2,563,000.

**Figure 9B Total Annual Value Comparison** ***(annualized over 30 years)***

# Annual Value of Lost Hydropower

(constant 2008$, 4.625%, 30-yrs, x $1,000 )

| Alternative | *Denison Peak Capacity* | *Denison Peak Energy* | Denison Peak Capacity + Energy | On-Peak Energy | Off-Peak Energy | Annual Value |
|---|---|---|---|---|---|---|
| Existing1 | *$4,482* | *$10,505* | $14,986 | $8,300 | $4,451 | $27,737 |
| MOD3001 | *$4,242* | *$10,122* | $14,364 | $7,729 | $4,249 | $26,342 |
| MOD4501 | *$4,088* | *$9,685* | $13,774 | $7,225 | $4,017 | $25,016 |
| | | | loss | | | |
| MOD3001 | *($240)* | *($382)* | ($622) | ($571) | ($202) | ($1,396) |
| MOD4501 | *($393)* | *($820)* | ($1,213) | ($1,075) | ($433) | ($2,721) |

| Alternative | Denison Peak Capacity Value | Denison Peak Energy Value | On-Peak Energy Value | Off-Peak Energy Value | Annual Capacity Value | Annual Energy Value | Annual Value |
|---|---|---|---|---|---|---|---|
| Existing1 | $4,482 | $10,505 | $8,300 | $4,451 | $4,482 | $23,256 | $27,737 |
| MOD3001 | $4,242 | $10,122 | $7,729 | $4,249 | $4,242 | $22,100 | $26,342 |
| MOD4501 | $4,088 | $9,685 | $7,225 | $4,017 | $4,088 | $20,927 | $25,016 |
| | | | loss | | | | |
| MOD3001 | ($240) | ($382) | ($571) | ($202) | ($240) | ($1,156) | ($1,396) |
| MOD4501 | ($393) | ($820) | ($1,075) | ($433) | ($393) | ($2,328) | ($2,721) |

SUMMARY 30-yr Term. The annual impact to hydropower generation over 30 years for 150,000 acre-feet of potential storage reallocation would be equivalent to replacement power purchases of approximately $1,396,000. The annual impact to hydropower generation over 30 years for 300,000 acre-feet of potential storage reallocation would be equivalent to replacement power purchases of approximately $2,721,000.

EXHIBIT 1. Platts wholesale prices

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2008 | 1 | 74.74 | 77.69 | 78.83 | 63.27 |
| ERCOT | ERCOT-North | 2008 | 2 | 76.47 | 80.91 | 82.07 | 86.27 |
| ERCOT | ERCOT-North | 2008 | 3 | 80.02 | 83.79 | 83.57 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 4 | 80.87 | 87.88 | 92.79 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 5 | 88.06 | 108.31 | 121.14 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 6 | 88.62 | 108.56 | 119.77 | 52.72 |
| ERCOT | ERCOT-North | 2008 | 7 | 93.41 | 115.54 | 125.66 | 45.19 |
| ERCOT | ERCOT-North | 2008 | 8 | 95.15 | 117.96 | 127.66 | 39.54 |
| ERCOT | ERCOT-North | 2008 | 9 | 83.16 | 99.66 | 110.49 | 63.27 |
| ERCOT | ERCOT-North | 2008 | 10 | 81.23 | 89.86 | 96.52 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 11 | 78.47 | 82.62 | 84.87 | 105.44 |
| ERCOT | ERCOT-North | 2008 | 12 | 76.30 | 78.70 | 79.88 | 63.27 |
| ERCOT | ERCOT-North | 2009 | 1 | 77.39 | 80.41 | 81.68 | 62.33 |
| ERCOT | ERCOT-North | 2009 | 2 | 77.53 | 81.29 | 82.09 | 84.99 |
| ERCOT | ERCOT-North | 2009 | 3 | 77.41 | 81.05 | 80.63 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 4 | 79.72 | 87.63 | 92.90 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 5 | 83.41 | 102.24 | 114.72 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 6 | 83.12 | 102.37 | 113.24 | 51.94 |
| ERCOT | ERCOT-North | 2009 | 7 | 87.84 | 108.96 | 118.89 | 44.52 |
| ERCOT | ERCOT-North | 2009 | 8 | 89.17 | 110.05 | 119.45 | 38.95 |
| ERCOT | ERCOT-North | 2009 | 9 | 77.90 | 92.51 | 102.03 | 62.33 |
| ERCOT | ERCOT-North | 2009 | 10 | 77.52 | 86.90 | 94.05 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 11 | 73.73 | 77.49 | 79.40 | 103.88 |
| ERCOT | ERCOT-North | 2009 | 12 | 72.49 | 74.67 | 75.61 | 62.33 |
| ERCOT | ERCOT-North | 2010 | 1 | 72.86 | 75.34 | 76.23 | 61.33 |
| ERCOT | ERCOT-North | 2010 | 2 | 73.14 | 76.34 | 76.90 | 83.63 |
| ERCOT | ERCOT-North | 2010 | 3 | 72.47 | 76.13 | 75.65 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 4 | 74.28 | 80.21 | 84.62 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 5 | 69.20 | 82.70 | 96.58 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 6 | 69.49 | 84.38 | 95.80 | 51.11 |
| ERCOT | ERCOT-North | 2010 | 7 | 74.99 | 96.92 | 113.64 | 43.81 |
| ERCOT | ERCOT-North | 2010 | 8 | 74.78 | 93.39 | 104.06 | 38.33 |
| ERCOT | ERCOT-North | 2010 | 9 | 65.72 | 73.99 | 80.19 | 61.33 |
| ERCOT | ERCOT-North | 2010 | 10 | 65.95 | 71.48 | 74.73 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 11 | 65.86 | 68.43 | 69.22 | 102.22 |
| ERCOT | ERCOT-North | 2010 | 12 | 66.21 | 67.85 | 68.45 | 61.33 |
| ERCOT | ERCOT-North | 2011 | 1 | 67.16 | 69.44 | 70.28 | 60.34 |
| ERCOT | ERCOT-North | 2011 | 2 | 67.78 | 70.82 | 71.36 | 82.29 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2011 | 3 | 67.91 | 70.85 | 70.65 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 4 | 67.70 | 72.39 | 75.34 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 5 | 60.23 | 71.14 | 83.35 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 6 | 60.97 | 73.88 | 84.16 | 50.29 |
| ERCOT | ERCOT-North | 2011 | 7 | 66.53 | 86.95 | 103.51 | 43.10 |
| ERCOT | ERCOT-North | 2011 | 8 | 65.42 | 82.10 | 91.79 | 37.72 |
| ERCOT | ERCOT-North | 2011 | 9 | 58.94 | 66.37 | 72.35 | 60.34 |
| ERCOT | ERCOT-North | 2011 | 10 | 58.29 | 62.78 | 65.53 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 11 | 59.52 | 61.89 | 62.82 | 100.57 |
| ERCOT | ERCOT-North | 2011 | 12 | 59.74 | 61.42 | 62.03 | 60.34 |
| ERCOT | ERCOT-North | 2012 | 1 | 60.70 | 62.77 | 63.55 | 59.37 |
| ERCOT | ERCOT-North | 2012 | 2 | 61.08 | 64.32 | 64.70 | 80.95 |
| ERCOT | ERCOT-North | 2012 | 3 | 62.64 | 65.02 | 64.92 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 4 | 64.24 | 70.22 | 75.36 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 5 | 59.20 | 71.02 | 83.68 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 6 | 59.55 | 71.75 | 82.00 | 49.47 |
| ERCOT | ERCOT-North | 2012 | 7 | 64.43 | 82.77 | 96.52 | 42.40 |
| ERCOT | ERCOT-North | 2012 | 8 | 63.49 | 78.37 | 87.59 | 37.10 |
| ERCOT | ERCOT-North | 2012 | 9 | 56.82 | 62.74 | 67.44 | 59.37 |
| ERCOT | ERCOT-North | 2012 | 10 | 55.77 | 60.17 | 62.59 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 11 | 58.75 | 61.00 | 61.69 | 98.94 |
| ERCOT | ERCOT-North | 2012 | 12 | 59.57 | 61.33 | 62.03 | 59.37 |
| ERCOT | ERCOT-North | 2013 | 1 | 60.39 | 62.42 | 63.18 | 58.41 |
| ERCOT | ERCOT-North | 2013 | 2 | 66.07 | 68.81 | 69.43 | 79.65 |
| ERCOT | ERCOT-North | 2013 | 3 | 64.67 | 68.86 | 68.64 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 4 | 65.49 | 69.11 | 70.42 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 5 | 59.64 | 71.72 | 84.89 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 6 | 61.22 | 73.58 | 84.23 | 48.67 |
| ERCOT | ERCOT-North | 2013 | 7 | 64.78 | 86.36 | 103.92 | 41.72 |
| ERCOT | ERCOT-North | 2013 | 8 | 65.77 | 87.94 | 102.95 | 36.50 |
| ERCOT | ERCOT-North | 2013 | 9 | 59.05 | 68.99 | 76.79 | 58.41 |
| ERCOT | ERCOT-North | 2013 | 10 | 57.24 | 62.29 | 65.34 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 11 | 58.79 | 61.39 | 62.31 | 97.35 |
| ERCOT | ERCOT-North | 2013 | 12 | 59.36 | 61.13 | 61.77 | 58.41 |
| ERCOT | ERCOT-North | 2014 | 1 | 60.35 | 62.44 | 63.19 | 57.51 |
| ERCOT | ERCOT-North | 2014 | 2 | 63.01 | 65.62 | 66.14 | 78.42 |
| ERCOT | ERCOT-North | 2014 | 3 | 62.88 | 65.90 | 65.53 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 4 | 62.50 | 66.33 | 67.94 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 5 | 58.09 | 70.09 | 82.34 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 6 | 58.46 | 70.87 | 80.93 | 47.92 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2014 | 7 | 62.63 | 95.80 | 127.42 | 41.08 |
| ERCOT | ERCOT-North | 2014 | 8 | 63.68 | 91.87 | 112.78 | 35.94 |
| ERCOT | ERCOT-North | 2014 | 9 | 55.73 | 64.71 | 71.52 | 57.51 |
| ERCOT | ERCOT-North | 2014 | 10 | 55.47 | 60.74 | 64.10 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 11 | 57.39 | 60.07 | 61.18 | 95.85 |
| ERCOT | ERCOT-North | 2014 | 12 | 57.86 | 59.58 | 60.25 | 57.51 |
| ERCOT | ERCOT-North | 2015 | 1 | 59.00 | 61.25 | 62.09 | 56.64 |
| ERCOT | ERCOT-North | 2015 | 2 | 64.35 | 67.81 | 68.45 | 77.23 |
| ERCOT | ERCOT-North | 2015 | 3 | 63.48 | 67.02 | 66.69 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 4 | 63.93 | 68.86 | 71.76 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 5 | 58.49 | 70.23 | 82.92 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 6 | 59.34 | 73.12 | 82.79 | 47.20 |
| ERCOT | ERCOT-North | 2015 | 7 | 63.13 | 112.97 | 164.89 | 40.45 |
| ERCOT | ERCOT-North | 2015 | 8 | 63.98 | 93.09 | 115.06 | 35.40 |
| ERCOT | ERCOT-North | 2015 | 9 | 56.34 | 66.23 | 73.01 | 56.64 |
| ERCOT | ERCOT-North | 2015 | 10 | 55.03 | 59.79 | 62.92 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 11 | 56.34 | 59.01 | 60.21 | 94.39 |
| ERCOT | ERCOT-North | 2015 | 12 | 56.91 | 58.64 | 59.39 | 56.64 |
| ERCOT | ERCOT-North | 2016 | 1 | 57.63 | 59.94 | 60.82 | 55.73 |
| ERCOT | ERCOT-North | 2016 | 2 | 57.80 | 60.85 | 61.39 | 76.00 |
| ERCOT | ERCOT-North | 2016 | 3 | 59.47 | 62.19 | 62.14 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 4 | 59.65 | 64.88 | 68.88 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 5 | 54.36 | 66.13 | 77.93 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 6 | 55.08 | 68.31 | 77.43 | 46.44 |
| ERCOT | ERCOT-North | 2016 | 7 | 60.22 | 119.65 | 185.10 | 39.81 |
| ERCOT | ERCOT-North | 2016 | 8 | 59.15 | 99.50 | 132.03 | 34.83 |
| ERCOT | ERCOT-North | 2016 | 9 | 52.59 | 60.48 | 66.51 | 55.73 |
| ERCOT | ERCOT-North | 2016 | 10 | 51.73 | 56.40 | 59.56 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 11 | 53.62 | 56.56 | 58.10 | 92.89 |
| ERCOT | ERCOT-North | 2016 | 12 | 54.96 | 56.98 | 57.95 | 55.73 |
| ERCOT | ERCOT-North | 2017 | 1 | 55.38 | 57.62 | 58.47 | 54.80 |
| ERCOT | ERCOT-North | 2017 | 2 | 61.05 | 64.30 | 64.79 | 74.73 |
| ERCOT | ERCOT-North | 2017 | 3 | 60.49 | 63.61 | 63.21 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 4 | 61.73 | 67.10 | 71.37 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 5 | 55.38 | 68.24 | 81.15 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 6 | 56.77 | 71.05 | 80.28 | 45.67 |
| ERCOT | ERCOT-North | 2017 | 7 | 60.90 | 126.70 | 199.64 | 39.14 |
| ERCOT | ERCOT-North | 2017 | 8 | 59.95 | 100.49 | 133.14 | 34.25 |
| ERCOT | ERCOT-North | 2017 | 9 | 52.98 | 60.37 | 66.11 | 54.80 |
| ERCOT | ERCOT-North | 2017 | 10 | 51.92 | 56.64 | 59.59 | 91.34 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2017 | 11 | 54.00 | 56.64 | 57.96 | 91.34 |
| ERCOT | ERCOT-North | 2017 | 12 | 55.01 | 56.96 | 57.84 | 54.80 |
| ERCOT | ERCOT-North | 2018 | 1 | 55.86 | 57.85 | 58.67 | 53.86 |
| ERCOT | ERCOT-North | 2018 | 2 | 63.02 | 66.24 | 66.94 | 73.45 |
| ERCOT | ERCOT-North | 2018 | 3 | 61.75 | 65.70 | 65.68 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 4 | 63.09 | 67.73 | 70.53 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 5 | 56.55 | 69.62 | 81.68 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 6 | 57.00 | 70.32 | 80.22 | 44.88 |
| ERCOT | ERCOT-North | 2018 | 7 | 61.97 | 114.26 | 169.58 | 38.47 |
| ERCOT | ERCOT-North | 2018 | 8 | 62.64 | 144.91 | 218.10 | 33.66 |
| ERCOT | ERCOT-North | 2018 | 9 | 55.46 | 65.10 | 72.42 | 53.86 |
| ERCOT | ERCOT-North | 2018 | 10 | 53.86 | 59.66 | 63.73 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 11 | 55.61 | 59.29 | 60.59 | 89.77 |
| ERCOT | ERCOT-North | 2018 | 12 | 56.29 | 58.27 | 59.14 | 53.86 |
| ERCOT | ERCOT-North | 2019 | 1 | 57.39 | 59.61 | 60.47 | 52.94 |
| ERCOT | ERCOT-North | 2019 | 2 | 65.26 | 68.61 | 69.60 | 72.19 |
| ERCOT | ERCOT-North | 2019 | 3 | 64.84 | 68.17 | 68.13 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 4 | 64.65 | 68.70 | 70.65 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 5 | 57.79 | 75.13 | 104.70 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 6 | 59.97 | 75.32 | 87.73 | 44.12 |
| ERCOT | ERCOT-North | 2019 | 7 | 64.37 | 134.18 | 210.42 | 37.81 |
| ERCOT | ERCOT-North | 2019 | 8 | 65.84 | 161.72 | 248.54 | 33.09 |
| ERCOT | ERCOT-North | 2019 | 9 | 57.96 | 70.20 | 78.70 | 52.94 |
| ERCOT | ERCOT-North | 2019 | 10 | 55.79 | 62.00 | 66.78 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 11 | 57.55 | 60.76 | 62.32 | 88.23 |
| ERCOT | ERCOT-North | 2019 | 12 | 58.25 | 60.40 | 61.34 | 52.94 |
| ERCOT | ERCOT-North | 2020 | 1 | 58.82 | 61.15 | 62.06 | 52.04 |
| ERCOT | ERCOT-North | 2020 | 2 | 59.37 | 62.28 | 62.91 | 70.96 |
| ERCOT | ERCOT-North | 2020 | 3 | 60.00 | 64.75 | 64.70 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 4 | 61.86 | 67.21 | 70.75 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 5 | 58.95 | 76.03 | 106.81 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 6 | 60.21 | 77.40 | 90.89 | 43.37 |
| ERCOT | ERCOT-North | 2020 | 7 | 64.94 | 147.49 | 239.80 | 37.17 |
| ERCOT | ERCOT-North | 2020 | 8 | 66.40 | 151.09 | 227.49 | 32.52 |
| ERCOT | ERCOT-North | 2020 | 9 | 57.54 | 69.71 | 78.10 | 52.04 |
| ERCOT | ERCOT-North | 2020 | 10 | 55.94 | 61.67 | 65.22 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 11 | 57.93 | 61.07 | 62.69 | 86.73 |
| ERCOT | ERCOT-North | 2020 | 12 | 58.81 | 60.86 | 61.73 | 52.04 |
| ERCOT | ERCOT-North | 2021 | 1 | 60.15 | 62.76 | 63.76 | 51.16 |
| ERCOT | ERCOT-North | 2021 | 2 | 68.30 | 72.74 | 73.67 | 69.77 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2021 | 3 | 64.61 | 71.28 | 71.38 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 4 | 67.44 | 74.53 | 80.19 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 5 | 63.72 | 83.66 | 114.77 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 6 | 65.10 | 87.08 | 106.62 | 42.64 |
| ERCOT | ERCOT-North | 2021 | 7 | 71.36 | 168.72 | 273.43 | 36.54 |
| ERCOT | ERCOT-North | 2021 | 8 | 72.55 | 170.92 | 260.68 | 31.98 |
| ERCOT | ERCOT-North | 2021 | 9 | 61.41 | 72.87 | 80.83 | 51.16 |
| ERCOT | ERCOT-North | 2021 | 10 | 60.29 | 66.53 | 70.61 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 11 | 62.35 | 65.98 | 67.80 | 85.27 |
| ERCOT | ERCOT-North | 2021 | 12 | 63.47 | 65.75 | 66.73 | 51.16 |
| ERCOT | ERCOT-North | 2022 | 1 | 64.78 | 67.86 | 68.99 | 50.30 |
| ERCOT | ERCOT-North | 2022 | 2 | 73.70 | 78.44 | 79.31 | 68.59 |
| ERCOT | ERCOT-North | 2022 | 3 | 68.09 | 77.09 | 77.24 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 4 | 75.85 | 83.94 | 90.10 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 5 | 74.71 | 110.35 | 184.69 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 6 | 74.24 | 97.02 | 115.32 | 41.91 |
| ERCOT | ERCOT-North | 2022 | 7 | 81.80 | 185.21 | 295.78 | 35.93 |
| ERCOT | ERCOT-North | 2022 | 8 | 82.80 | 179.42 | 267.01 | 31.44 |
| ERCOT | ERCOT-North | 2022 | 9 | 69.94 | 82.04 | 90.57 | 50.30 |
| ERCOT | ERCOT-North | 2022 | 10 | 68.32 | 75.50 | 79.66 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 11 | 70.91 | 75.09 | 77.07 | 83.83 |
| ERCOT | ERCOT-North | 2022 | 12 | 72.05 | 74.62 | 75.66 | 50.30 |
| ERCOT | ERCOT-North | 2023 | 1 | 72.13 | 75.67 | 76.73 | 31.79 |
| ERCOT | ERCOT-North | 2023 | 2 | 73.00 | 77.16 | 77.77 | 43.35 |
| ERCOT | ERCOT-North | 2023 | 3 | 63.66 | 76.91 | 76.94 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 4 | 75.21 | 83.32 | 88.59 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 5 | 79.65 | 109.06 | 167.37 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 6 | 79.54 | 100.97 | 118.29 | 26.49 |
| ERCOT | ERCOT-North | 2023 | 7 | 86.62 | 185.41 | 293.85 | 22.71 |
| ERCOT | ERCOT-North | 2023 | 8 | 86.34 | 166.62 | 237.97 | 19.87 |
| ERCOT | ERCOT-North | 2023 | 9 | 76.12 | 87.29 | 95.57 | 31.79 |
| ERCOT | ERCOT-North | 2023 | 10 | 72.83 | 82.61 | 87.58 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 11 | 71.39 | 75.73 | 77.30 | 52.98 |
| ERCOT | ERCOT-North | 2023 | 12 | 71.35 | 75.19 | 76.14 | 31.79 |
| ERCOT | ERCOT-North | 2024 | 1 | 69.77 | 75.63 | 76.66 | 31.38 |
| ERCOT | ERCOT-North | 2024 | 2 | 73.61 | 77.50 | 78.28 | 42.79 |
| ERCOT | ERCOT-North | 2024 | 3 | 67.34 | 77.33 | 77.33 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 4 | 71.77 | 79.48 | 81.20 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 5 | 77.33 | 96.79 | 129.59 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 6 | 79.90 | 99.42 | 117.68 | 26.15 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2024 | 7 | 85.61 | 160.32 | 238.29 | 22.41 |
| ERCOT | ERCOT-North | 2024 | 8 | 88.76 | 199.59 | 302.36 | 19.61 |
| ERCOT | ERCOT-North | 2024 | 9 | 77.32 | 90.57 | 99.94 | 31.38 |
| ERCOT | ERCOT-North | 2024 | 10 | 72.12 | 83.57 | 89.19 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 11 | 68.87 | 76.06 | 77.53 | 52.30 |
| ERCOT | ERCOT-North | 2024 | 12 | 71.60 | 75.63 | 76.59 | 31.38 |
| ERCOT | ERCOT-North | 2025 | 1 | 69.80 | 76.53 | 77.64 | 30.96 |
| ERCOT | ERCOT-North | 2025 | 2 | 74.79 | 78.73 | 79.51 | 42.22 |
| ERCOT | ERCOT-North | 2025 | 3 | 65.12 | 78.00 | 77.74 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 4 | 71.02 | 80.23 | 82.61 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 5 | 78.20 | 96.84 | 130.04 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 6 | 79.74 | 100.42 | 119.67 | 25.80 |
| ERCOT | ERCOT-North | 2025 | 7 | 86.03 | 172.12 | 260.34 | 22.11 |
| ERCOT | ERCOT-North | 2025 | 8 | 89.44 | 199.87 | 303.25 | 19.35 |
| ERCOT | ERCOT-North | 2025 | 9 | 74.29 | 88.99 | 96.91 | 30.96 |
| ERCOT | ERCOT-North | 2025 | 10 | 70.00 | 82.77 | 87.35 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 11 | 67.49 | 76.42 | 77.91 | 51.60 |
| ERCOT | ERCOT-North | 2025 | 12 | 69.94 | 74.71 | 75.61 | 30.96 |
| ERCOT | ERCOT-North | 2026 | 1 | 72.81 | 78.69 | 79.78 | 31.27 |
| ERCOT | ERCOT-North | 2026 | 2 | 76.33 | 80.53 | 81.29 | 42.64 |
| ERCOT | ERCOT-North | 2026 | 3 | 64.26 | 79.91 | 79.73 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 4 | 70.87 | 83.15 | 86.09 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 5 | 80.53 | 100.36 | 137.58 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 6 | 81.57 | 102.92 | 122.98 | 26.06 |
| ERCOT | ERCOT-North | 2026 | 7 | 88.22 | 189.58 | 296.71 | 22.33 |
| ERCOT | ERCOT-North | 2026 | 8 | 91.92 | 197.27 | 296.85 | 19.54 |
| ERCOT | ERCOT-North | 2026 | 9 | 75.31 | 90.65 | 98.26 | 31.27 |
| ERCOT | ERCOT-North | 2026 | 10 | 70.93 | 84.89 | 88.97 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 11 | 69.11 | 78.78 | 80.60 | 52.11 |
| ERCOT | ERCOT-North | 2026 | 12 | 73.78 | 77.36 | 78.45 | 31.27 |
| ERCOT | ERCOT-North | 2027 | 1 | 76.34 | 81.01 | 82.23 | 31.58 |
| ERCOT | ERCOT-North | 2027 | 2 | 77.30 | 81.98 | 82.68 | 43.07 |
| ERCOT | ERCOT-North | 2027 | 3 | 71.10 | 81.72 | 81.63 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 4 | 77.06 | 86.47 | 90.72 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 5 | 83.08 | 107.55 | 153.54 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 6 | 84.23 | 113.21 | 144.12 | 26.32 |
| ERCOT | ERCOT-North | 2027 | 7 | 92.01 | 208.58 | 327.54 | 22.56 |
| ERCOT | ERCOT-North | 2027 | 8 | 95.05 | 222.49 | 343.55 | 19.74 |
| ERCOT | ERCOT-North | 2027 | 9 | 82.13 | 95.59 | 104.85 | 31.58 |
| ERCOT | ERCOT-North | 2027 | 10 | 77.32 | 87.70 | 92.35 | 52.64 |

**FORECAST PRICES - Hydropower Special Study**

Nov'08

**MARKET AREA PRICES (CONSTANT 2008 $/MWH) - ERCOT**

| Regional Planning Area | Market Area | Year | Month | Off Peak Energy | Peak Energy | Dennison Super Peak Energy | Equivalent capacity value each month<br>Dennison Super Peak Capacity |
|---|---|---|---|---|---|---|---|
| | | | | $/MWh | $/MWh | $/MWh | $/MWh |
| ERCOT | ERCOT-North | 2027 | 11 | 75.53 | 80.83 | 82.74 | 52.64 |
| ERCOT | ERCOT-North | 2027 | 12 | 75.52 | 78.67 | 79.61 | 31.58 |

# APPENDIX F

# SOUTHWESTERN POWER ADMINISTRATION DOCUMENTS

**(1) Draft Water Storage Reallocation – Hydropower Impacts, July 2005.**

**(2) Comparison of Actual Energy Purchases with Platts Power Outlook Research Service Values, October 2008.**

**(3) Development of Hydropower Loads for SUPER Runs, October 2008.**

**(4) 1980 Final Power Allocations and Term of Compensation for Reallocations, October 2008.**

**(5) Portion of Customer's Load, November 2008.**

**(6) GDS Associates Letter, Denison Power Customers' capacity replacement intentions, January 2009.**

**(7) Comparison Summary of Hydropower Impacts due to 150,000 acre-feet reallocation, January 2009.**

## Introduction

**During the Lake Texoma Reallocation, study issues have been raised by the Southwestern Power Administration concerning Corps' assessment of hydropower impacts that would potentially result from the proposed storage reallocation from hydropower storage to water supply storage. Issues have been raised by the SWPA for both the magnitude and value of potential hydropower impacts. The SWPA was invited to prepare "white papers" on issues that were raised during the course of the study.**

**The Corps appreciates the assistance and cooperation the SWPA has provided throughout the reallocation study. The final assessment of potential hydropower impacts conducted by the Corps' Hydropower Analysis Center benefited from the input of the SWPA.**

**There are issues that were not resolved between the Corps and the SWPA. A brief statement introduces the issue or context for each of the following seven papers the SWPA requested be included in the reallocation report.**

## SWPA Document (1)
## Draft Water Storage Reallocation – Hydropower Impacts, July 2005

**This "white paper" was SWPA's response to the initial HAC Draft report prepared for SWT in which methods and results of the initial hydropower impact assessment were described.**

**The USACE policy and procedures, in effect at that time, were followed. The interim product was a traditional storage reallocation approach for the assessment of potential hydropower impacts. The interim HAC evaluation included estimates of hydropower benefits foregone (equivalent to replacement costs) and revenues foregone. The HAC evaluation was included in a draft reallocation report provided to the HQUSACE for review.**

**Subsequent HQUSACE guidance directed further evaluation of replacement costs as defined by Section 838 of the 1986 Water Resources Development Act. Guidance indicated that Section 838 would result in a non-traditional evaluation. HQUSACE guidance also directed further coordination with the SWPA, concerning impacts to hydropower generation. Further coordination with the SWPA was conducted and more detailed hydropower evaluations were conducted by the HAC. The HAC evaluation methodology evolved as a result of the coordination and through assistance by the Platts Power Outlook Research Service analytical service. The evolution of the methodology, reassessment of the value of capacity, and market price increases for power through 2008 resulted in an increase in the estimate of benefits foregone.**

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

DRAFT

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.

DRAFT

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) Southwestern's Method: 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

DRAFT

that capacity through the Federal power sales contracts. (Special allowance is made for forced outages that are expected to return to service). If Southwestern cannot market the capacity on a long-term basis, then it is not available to the region as a generating resource and must be replaced in the long-term with the construction of thermal plant capacity. Therefore, benefits from the hydropower capacity that was marketed and now lost are no longer a benefit to the Nation.

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

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

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

DRAFT

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

DRAFT

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) <u>On-peak energy</u>: 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) <u>HAC's Method</u>: HAC uses the computer model PROSYM, which is developed and maintained by Henwood Energy Services, to develop the

DRAFT

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

DRAFT

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.

## SWPA Document (2)
## Comparison of Actual Energy Purchases with Platts Power Outlook Research Service Values, October 2008

**This "white paper" was requested to support the SWPA's use of the Platts PORS forecast high-fuel cost scenario, which gave a 34% upward bias to the long-term forecast base case scenario. SWPA's power purchases in recent years were at higher prices than the base case scenario. The high-fuel cost scenario and low-fuel cost scenario are both presented by Platts as "Sensitivity Analyses" which "...allow readers to adjust Platts' base-case wholesale power price projections in any given year in which fuel prices deviate significantly from the base case."(Platts - Outlook for Power in North America Winter 2008). HAC believes the base case scenario is intended for use as the 20-year forecast for wholesale power prices.**

# Southwestern Power Administration
# Comparison of Actual Energy Purchases with
# Platts Power Outlook Research Service Values

## Southwestern Power Administration

Southwestern Power Administration (Southwestern) was established in 1943 as an agency of the U.S. Department of the Interior. In 1977, Southwestern was transferred to the U.S. Department of Energy. Southwestern markets hydroelectric power from 24 multi-purpose reservoir projects constructed and operated by the U.S. Army Corps of Engineers (Corps), located in the states of Arkansas, Missouri, Oklahoma, and Texas. Southwestern markets this power in those four states as well as Kansas and Louisiana. Section 5 of the Flood Control Act of 1944 provides that this power and energy be transmitted and disposed of so as to encourage the most widespread use at the lowest possible rates to consumers consistent with sound business principles. Section 5 further requires that preference in the sale of such power and energy be given to public bodies and cooperatives. Southwestern has over one hundred such "preference" customers, and those customers ultimately serve over eight million end-use customers.

## Hydropower Marketing Plan

Southwestern's original contract energy sales obligations were about 4,000 hours of energy for each unit of marketed capacity. However, it became apparent that the hydroelectric projects under Southwestern's marketing responsibility had relatively limited storage available for hydropower production and depended heavily on replenishment of that storage by frequent inflows. Inflows in Southwestern's region typically result from largely unpredictable thunderstorms. Since the inflows and water storage were limited, hydropower projects in Southwestern's area were more suited for providing primarily low-plant factor peaking power than base load power.

These considerations led Southwestern to conclude that the most dependable and marketable use of its hydropower resources was as the more valuable peaking power. That conclusion was a prominent factor in Southwestern's formulation of its 1980 final power allocation and marketing policy. Southwestern converted all of its contracts requiring the delivery of full load factor energy to peaking contracts by 1987 in accordance with this policy.

Those peaking contracts reduced Southwestern's contracted energy sales obligation to the current 1,200 hours of energy per unit of marketed capacity (13.7 percent plant factor). The guaranteed 1,200 hours of energy was determined to be about the minimum amount marketable that provides a beneficial and reliable product while assuring repayment of the Federal investment. The Federal energy and capacity represents only a portion of the customers' firm load requirements. Southwestern's customers combine that peaking power with base load power from other sources to meet their electrical needs. The customers provide their own resources and/or purchases for the remainder of their firm loads. Without Federal hydropower as a reliable source of peaking power,

Southwestern's customers would have to build additional generating peaking gas units or otherwise acquire sufficient dependable peaking resources to meet their needs. Such peaking units or resources have a relatively high energy cost as compared to base load energy produced from either coal or nuclear resources. The marketing plan limits the amount of energy (water storage) needed from each project and puts a premium on maintaining higher pools to provide more electrical capacity (the rate of delivering the energy).

**Purchase Power**

In order to meet the 1,200 hours of energy per unit of capacity, the energy produced at the hydropower projects must be supplemented, particularly in below average rainfall periods, by energy from other suppliers on the open market. Therefore, energy is purchased to meet the limited peaking power contractual obligations and the delivery of Federal power. Such purchases are blended with the available Federal hydroelectric power and energy to make a more beneficial and reliable product while assuring repayment of the Federal investment plus interest, thus meeting the expectations of the National Energy Policy (NEP) and the Department of Energy's (DOE) Strategic Plan. It also fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern's program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multi-purpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

Purchases are set to optimize the operation of the hydroelectric facilities marketed by Southwestern. Both the NEP and DOE's Strategic Plan reinforce the importance of domestic, renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers.

Southwestern's customers pay an energy surcharge (purchased power adder) on their 1,200 hours of peaking energy per unit of allocated capacity specifically designed and implemented to cover the purchased power costs needed to fulfill Southwestern's 1,200-hour contractual obligations. Southwestern's customers pay for all of the energy purchases through Southwestern's rates and have often pre-paid for the energy in anticipation of the need to purchase energy.

**Hydropower Drought Operations**

The limited water storage in Southwestern's area requires an operating plan that begins purchases at the first indication of a drought in order to protect the electrical capacity at the hydropower projects. Drought conditions force a higher dependence on the water storage at the projects. Although the hydropower storage can be completely withdrawn from a project in accordance with its design, Southwestern's marketing and operating plans are designed to prevent the water storage from being completely withdrawn.

At the onset of drought conditions, Southwestern begins to purchase energy to help meet the Federal contractual obligations for electricity. That purchased energy replaces

hydropower production and conserves water in the lakes. As the drought continues, the amount of energy purchased increases, replacing more and more of the hydropower produced energy. Because of electrical transmission limitations, downstream release requirements, and marketing considerations, it is not possible to purchase all of the electrical requirements. Some hydropower must continue to be produced at the lakes.

In order to reduce the hydrological risk, Southwestern attempts, to the extent possible, to balance the percent of water storage used at each project in its interconnected system. Although Southwestern has some flexibility in the operation of the projects, it must adhere to various regulations and requirements, including such things as Corps guidelines and Endangered Species Act requirements.

**Purchase Power Guidelines**

Southwestern has developed a non-hydro guide curve to determine when system conditions indicate the need to seek non-hydro resources to meet the contractual peaking energy requirements based on system hydrology and electrical demand. The curve represents the system energy-in-storage, as a percent full, for each month of the year below which purchases will be used to supplement the system's hydro resources. The curve is used in various studies through Southwestern's computer simulation model to determine the need to purchase. In real-time day-to-day operations, Southwestern uses the curve with other indicators, such as inflow trends, drought indicators, long-term weather forecasts, season of the year, amount of storage remaining at each project, price of purchase power, transmission limitations and daily and weekly loads, in determining when and how much electricity to purchase.

**Historical Energy Purchases – Amount and Value**

Southwestern has a long history of purchasing energy at market prices to supplement and firm up energy produced at Federal hydropower projects. Until the issuance of FERC Orders 888 and 889, a large portion of Southwestern's non-hydro requirements were met through the use of "energy bank" arrangements with customers to convert a portion of Southwestern's supplemental energy into peaking energy. On April 24, 1996, FERC issued Order 888 that provided open access to the transmission system. It, along with Order 889, encouraged the development of a competitive electrical market by revealing market-clearing prices of electricity and posting of available transmission capacity. The opening of the competitive energy market eliminated the effectiveness of the "energy banks" as new opportunities opened for the customers' resources.

The loss of the "energy banks" combined with several drought periods of varying severity required Southwestern to considerably increase its energy purchases. In addition to the peaking energy purchases made by Southwestern, energy was purchased to meet regulation (load-following) requirements when resources were not available for use at the hydropower projects. Table 1 shows the peaking and regulation energy purchased by Southwestern.

**Table 1**

| Peaking and Regulation Energy Purchases | | | |
|---|---|---|---|
| **Calendar Year** | **Energy (kWh)** | **Cost ($)** | **Average ($/MWh)** |
| 1998 | 76,488,000 | 3,364,429 | 43.99 |
| 1999 | 13,701,000 | 841,535 | 61.42 |
| 2000 | 90,983,000 | 4,106,407 | 45.13 |
| 2001 | 112,145,000 | 6,232,333 | 55.57 |
| 2002 | 7,475,000 | 340,985 | 45.62 |
| 2003 | 11,634,000 | 832,512 | 71.56 |
| 2004 | 100,000 | 7,300 | 73.00 |
| 2005 | 144,762,000 | 15,266,810 | 105.46 |
| 2006 | 698,588,000 | 55,252,540 | 79.09 |
| 2007 | 10,257,000 | 880,374 | 85.83 |
| **Total** | **1,167,253,000** | **87,143,404** | **74.71** |

Following moderate dry conditions that occurred from 1998 through 2001, Southwestern experienced severe drought conditions in 2005 and 2006 requiring energy purchases well above that normally expected. During dry periods when water storage is being conserved, Southwestern attempts to purchase the energy required for regulation during off-peak periods at reduced rates. The regulation load is not modeled by Southwestern in its computer simulations; however, as experienced during the recent drought, the regulation requirements have increased to the point that they must be considered. Southwestern is exploring other means of providing such energy. Monthly data was available to separate the regulation from the peaking energy for January 2005 through June 2008. In contrast to the annual total energy purchased, the annual peaking energy purchased by Southwestern is shown in Table 2.

**Table 2**

| Peaking Energy Purchases | | | |
|---|---|---|---|
| **Calendar Year** | **Energy (kWh)** | **Cost ($)** | **Average ($/MWh)** |
| 2005 | 125,429,000 | 13,715,340 | 109.35 |
| 2006 | 620,582,000 | 51,108,761 | 82.36 |
| 2007 | 6,276,000 | 688,640 | 109.73 |
| 2008[1] | 1,310,000 | 132,785 | 101.36 |
| **Total** | **753,597,000** | **65,645,526** | **87.11** |

[1]January 2008 through June 2008.

Southwestern's customers typically schedule their Federal power across the highest demand hours, typically six to eight hours per weekday in the high demand months of July and August. Consequently, this is when Southwestern is required to run hydro or purchase the majority of its energy. Industry standard on-peak energy hours are from 6 a.m. to 10 p.m., or 16 hours per day. The common price quoted for on-peak energy refers to the purchase of a 16-hour block of energy. Since Southwestern's customers schedule the limited Federal energy to replace their most expensive alternative, Southwestern must purchase expensive "super peak" energy to meet the customers' energy demands during low water periods according to its contractual obligations. By marketing six to eight hours of energy to Southwestern, the supplier is not able to offer that power as a 16-hour

block into the market. Therefore, the supplier charges a higher price for providing the "super peak" energy. Generally, "super peak" energy is satisfied by combustion gas turbine generated energy. Southwestern has evaluated the purchase of the entire 16-hour block of peaking energy with the intention of selling the energy not needed to meet its contractual obligations as supplemental energy. However, the economic feasibility depends on the difference in price of peaking and "super peaking" energy and it is seldom worthwhile. Also, the purchase of energy other than to satisfy Southwestern's obligations is discouraged by the Office of Management and Budget.

Southwestern must also purchase energy to replace transmission line losses when non-Federal energy is transmitted across Southwestern's transmission system. Line losses are generally assumed to be four percent of the total amount transmitted. Those customers who transmit non-Federal power across Southwestern's transmission lines, and have not elected to self-provide energy losses, pay Southwestern for such energy losses. Southwestern develops a calendar year energy loss rate based on Southwestern's cost to replace the energy for these losses during the previous fiscal year. Purchase of non-Federal line loss energy replacement is typically made during the least expensive periods if possible. It is expected that such energy purchases would closely follow off-peak energy prices. The non-Federal transmission losses rates charged by Southwestern are shown in Table 3.

**Table 3**

| **Non-Federal Transmission Losses** | |
|---|---|
| **Calendar Year[1]** | **Rate ($/MWh)** |
| 2002 | 33.00 |
| 2003 | 23.40 |
| 2004 | 25.80 |
| 2005 | 31.80 |
| 2006 | 30.90 |
| 2007 | 54.80 |
| 2008 | 51.50 |
| 2009[2] | 59.70 |

[1]Although rates are for calendar years, they are based on the previous fiscal year.
[2]Rate that would be in effect if rate provisions had not been changed requiring customers to self-provide losses.

**Planning Studies – Estimated Energy Values**

Southwestern performs planning studies for the purpose of determining the hydropower impacts of operational changes, addition or loss of resources, various contractual arrangement alternatives, and evaluation of actions proposed by others. In order to evaluate impacts and alternatives as a part of those studies, it is necessary to estimate the market value of energy to be purchased as a replacement for energy lost as a result of the proposed action. Southwestern examined available resources to develop the most reasonable estimate possible.

The Corps' Hydropower Analysis Center (HAC) has responsibility for developing the energy and capacity values used by the Corps in their evaluation of hydropower projects. Prior to mid-2005, HAC typically used the PROSYM production cost model, a proprietary computer model, to develop energy values and used procedures developed by Federal Energy Regulatory Commission (FERC) to develop capacity values. The FERC model also computed energy values; however, HAC did not use those values in its computations. With energy purchasing experience, it was obvious to Southwestern that the PROSYM model produced energy values that were considerably below market rates. Although the FERC method energy values were also typically below market rate, they were better than the PROSYM model values. Absent another source, Southwestern would typically use the FERC method energy values when determining the impacts of various changes on hydropower production. Southwestern also, like HAC, used the FERC method in determining the value of capacity losses.

In Southwestern's White River Minimum Flows Draft Determination Report, dated January 2008, the FERC method calculations were used in valuing both the lost energy and capacity for the two Federal projects, Bull Shoals and Norfork, as well at the non-Federal FERC-licensed project. It was recognized that the FERC-based values for energy, particularly off-peak energy, were significantly below real-life market conditions. However, Southwestern used the FERC-based values to be consistent with its previous comments on Corps reallocation studies.

During the study period, the Corps' HAC had already begun exploring other sources to provide realistic energy values. Beginning in late 2005, HAC started using the Platts Power Outlook Research Service (Platts), a North American power market forecast subscription service, for determining energy values. Although FERC no longer supported its model, HAC continued using the FERC model for determination of capacity values by updating input data and indexing values upward to current prices.

With the responsibility of determining the hydropower impacts of the minimum flows to both the Federal and non-Federal projects, Southwestern began searching for appropriate methods for deriving both energy and capacity values. Comments on the draft report from electrical industry participants strongly supported the use of an industry source such as Platts to overcome the wide disparity between the low energy prices used in the initial report and actual market conditions. Southwestern's research revealed that the Platts values for on-peak and off-peak energy are much more reflective of the current market than the FERC values and closely match Southwestern's energy purchases during the 2005-2006 drought period. Like HAC, Southwestern eventually concluded that Platts was the best source for energy values and, because of a lack of other sources, the FERC method would continue to be the best source for determining the capacity value.

Additionally, the Corps and the non-Federal hydropower licensee had agreed to the use of the Platts high-fuel energy values prior to Southwestern's legislative obligation to determine the hydropower impacts. Electrical industry participants also commented that the FERC-based values for capacity were "reasonable" but "conservative". Sources for

valuing energy and capacity are limited. Southwestern attempts to use sources that closely reflect market conditions.

**Platts Power Outlook Research Service**

Southwestern began subscribing to the Platts' Power Outlook Research Service in June 2008 primarily as a source for providing reasonable estimates of replacement energy values for the "super peak" product that Southwestern markets. Platts provides a continuing, detailed forecast of North American power markets for management and investors, supported by proprietary scenario analyses, to evaluate buy, sell, and build investment decisions. It provides a 20-year load and resource price forecast. In addition to its baseline price forecast, Platts provides up to six alternative scenarios for each region: high-fuel, low-fuel, New York Mercantile Exchange gas futures, carbon emissions prices, high-hydro, and low-hydro. The hydro scenarios are applicable to the West only. Southwestern focused on the baseline and high-fuel energy values.

Platts' baseline price forecast is based on a number of underlying assumptions and drivers. Those include: aggregate capacity balance, delivered fuels (natural gas, coal, and oil), electricity demand, emissions-allowance prices, technology costs of new construction, and several financial variables.

In Platts' high-fuel forecast, the gas and oil prices are 30 percent higher than in the base case. That increase is designed to give an estimated 80 percent confidence that prices for these fuels will be within the range defined by the high-fuel and low-fuel forecasts. Because fuel markets in general are so volatile, especially the natural gas market, Platts recognizes that fuel prices may be 30 percent higher or 50 percent lower than the base-case projections in any given year.

Platts provides both annual and monthly values. Since there can be large monthly fluctuations in energy production at hydropower projects, Southwestern found the monthly values to be more appropriate for its study evaluations.

Platts also provides both on-peak and off-peak energy price values. Southwestern typically uses both values in evaluation studies. The on-peak price is typically used to represent the value or replacement costs of the peaking energy required to meet Southwestern's contractual obligations. Supplemental energy not needed to fulfill peaking energy requirements is normally valued at off-peak energy rates.

**Comparison of Experienced and Estimated Energy Values**

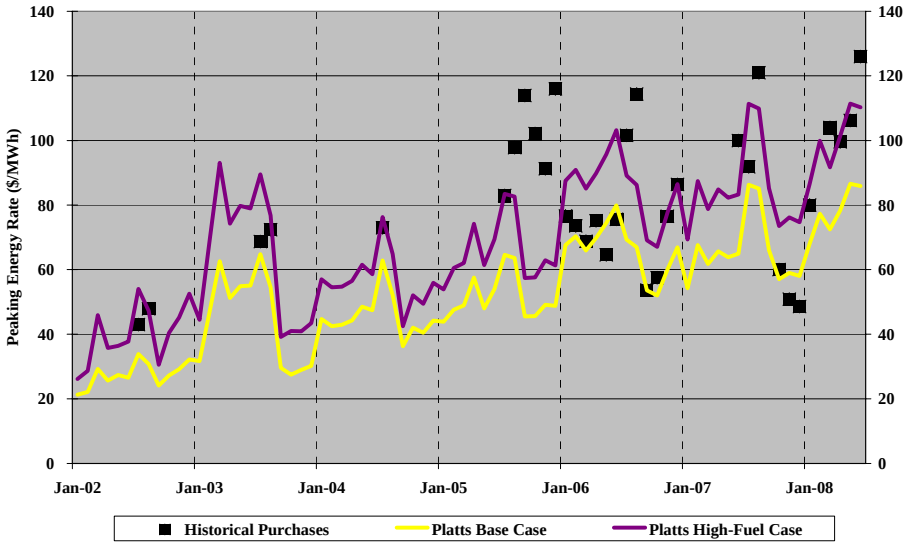
As mentioned, Southwestern must purchase market energy from time to time as a part of its marketing plan to meet contractual obligations. When Southwestern performs planning studies for various purposes, it is necessary to have a reasonable estimate of the value and replacement cost of peaking energy. Southwestern evaluated Platts' energy value products to determine the estimated energy price that would most closely represent the value at which Southwestern has historically purchased energy.

Southwestern examined the existing data to determine where common values were available for comparison. Southwestern's monthly historical energy purchase data were available from 1998 to current. The data, however, included the purchase of both peaking and regulation energy. Sufficient information to separate the two types of energy purchases was only obtainable since January 2005.

Historical Platts' energy price forecasts where available to Southwestern as far back as the first quarter of 2002. Updated forecasts were published periodically throughout the year. In Southwestern's comparison, the latest Platts' forecast available for each year was used.

From the monthly peaking and regulation energy purchased and its costs, Southwestern computed an average monthly price. Those prices were plotted along with the Platts monthly base and high-fuel on-peak values for the period January 2002 through June 2008 as shown in the following figure.

**Actual Energy Purchase Rate versus Platts On-Peak Rates**




The actual energy costs were considerably higher than the high-fuel values in late 2005 and were lower in early 2006. The latest Platts' energy prices that were available for 2005 had been published as second quarter data (likely issued in July 2005). It could not have accounted for the spike in energy prices that occurred in the fall of 2005 as a result of damages to the energy industry from Hurricanes Katrina and Rita. In addition, rail problems greatly reduced the amount of coal available from Wyoming. Southwestern believes that the high volatility of the fall 2005 events resulted in the unusually higher estimates for early 2006.

Considering the available data and that a severe drought in the region required extensive energy purchases in 2005 and 2006, it was decided that the use of the period January 2005 through June 2008 would provide adequate data for the comparison. In order to

better quantify the overall values provided by each alternative, Southwestern multiplied both the base and high-fuel rates by the actual amount of peaking energy that it purchased each month. Those values were then totaled for the entire period and compared as shown in the appendix. For the 3½ years evaluated, Southwestern purchased 753,597 megawatt-hours (MWh) of peaking energy at a cost of $65,645,526 for an average purchase price of $87.11/MWh. Using Platts' monthly base energy prices, the total energy purchase would have been $47,977,443 at an average purchase price of $63.66/MWh. If the purchases were made at Platts' monthly high-fuel prices, the total cost would have been $61,783,871 with an average rate of $81.99. A summary of the annual rates for the actual costs and both Platts' alternatives weighted according to the historical monthly energy purchases is shown in Table 4.

**Table 4**

**Annual Peaking Energy Purchases Rates and Platts On-Peak Rates**

| Calendar Year | Historical Actual Rate ($/MWh) | Platts Base Rate ($/MWh) | Platts High-Fuel Rate ($/MWh) |
|---|---|---|---|
| 2005 | 109.35 | 50.99 | 64.87 |
| 2006 | 82.36 | 65.99 | 85.14 |
| 2007 | 109.73 | 84.34 | 108.86 |
| 2008[1] | 101.36 | 76.29 | 97.29 |
| **Weighted Avg** | **87.11** | **63.66** | **81.99** |

[1]January 2008 through June 2008.

The difficulties associated with developing adequate historical off-peak energy values prevented Southwestern from a detailed comparison of historical off-peak purchases with the Platts' off-peak values. However, as mentioned earlier, Southwestern must purchase replacement energy for the non-Federal line losses. Since those purchases are typically made during the least expensive periods when possible, Southwestern believes that such energy purchases would closely follow off-peak energy prices. Southwestern's rate for the losses energy is determined directly from Southwestern's average purchase price of the losses energy for the previous fiscal year. Southwestern adjusted the time period for those rates to reflect when the actual purchases occurred and compared them with Platts' off-peak energy values in Table 5.

**Table 5**

**Annual Losses Energy Rates and Platts Off-Peak Rates**

| Fiscal Year | Non-Federal Losses Rate ($/MWh) | Platts Base Rate ($/MWh) | Platts High-Fuel Rate ($/MWh) |
|---|---|---|---|
| 2003 | 25.80 | 22.37 | 27.69 |
| 2004 | 31.80 | 21.84 | 25.47 |
| 2005 | 30.90 | 31.39 | 37.19 |
| 2006 | 54.80 | 39.65 | 53.70 |
| 2007 | 51.50 | 41.26 | 52.70 |
| 2008 | 59.70 | 49.96 | 61.51 |

**Conclusions**

Based on preliminary investigations, Southwestern decided to use the Platts high-fuel energy values in its White River Minimum Flows Proposed Determination Report, dated June 2008. In response to that report, the Missouri Public Service Commission (MoPSC) provided the following comments selected from their September 12, 2008 letter regarding the use of Platts' high-fuel values:

> "The MoPSC's Chief Economist, Dr. Michael S. Proctor, has reviewed Platts' forecast of on-peak and off-peak prices used by SWPA for purposes of pricing the lost energy."
>
> "…using natural gas costs as a basis for the forecast of electricity prices is warranted."
>
> "While significant coal-fired and nuclear generation provides a level of base-load generation in SPP, the market-clearing price is determined by the offers from the marginal generating units. In most months, the fuel on margin for the SPP real-time electricity market is natural gas over 70% of the time."
>
> "This high price level forecasted for 2008 has proven to be comparable to prices experienced thus far in the SPP market for 2008, particularly since March."
>
> "Based on this assumption, the resulting estimates for the 2008 prices in the SPP electricity markets are consistent with the Platts forecast for 2008 of $83.93/MWh on-peak and $53.48/MWh off-peak."
>
> "In summary, the apparent high electricity prices forecast for 2008 are justified based on the experience thus far in the SPP energy markets. Whether or not actual prices will decrease in 2009 through 2012 as forecasted by Platts will depend on what happens to natural gas costs in the subsequent years. Thus, on average, the Platts forecast of electricity prices provides a reasonable basis for estimating the economic value of the energy lost by Empire District Electric Company at its Ozark Beach Hydroelectric Plant on the White River."

Considering these comments in conjunction with the evaluation and comparisons provided in this report, Southwestern believes that the Platts' forecasted monthly high-fuel energy values for on-peak and off-peak energy fairly represent the market prices Southwestern would be charged to replace the hydropower peaking energy in its area. Therefore, Southwestern plans to continue using those values in its studies and evaluation reports.

# Appendix

## Southwestern Power Administration – Monthly Purchase Power Comparison

| Month | Peaking Energy Purchased (MWh) | Cost of Peaking Energy Purchased ($) | Peaking Energy Purchased Rate ($/MWh) | Platts Base Case On-Peak Energy Rate ($/MWh) | Energy Cost at Platts Base Rate ($) | Platts High-Fuel On-Peak Energy Rate ($/MWh) | Energy Cost at Platts High-Fuel Rate ($) |
|---|---|---|---|---|---|---|---|
| Jan-05 | 0 | 0 | | 43.87 | | 53.91 | |
| Feb-05 | 0 | 0 | | 47.59 | | 60.54 | |
| Mar-05 | 0 | 0 | | 48.92 | | 62.03 | |
| Apr-05 | 0 | 0 | | 57.58 | | 74.17 | |
| May-05 | 0 | 0 | | 48.03 | | 61.44 | |
| Jun-05 | 0 | 0 | | 54.01 | | 69.42 | |
| Jul-05 | 6,540 | 548,570 | 83.88 | 64.60 | 422,484 | 83.45 | 545,763 |
| Aug-05 | 17,077 | 1,697,864 | 99.42 | 63.62 | 1,086,439 | 82.63 | 1,411,073 |
| Sep-05 | 14,477 | 1,649,140 | 113.91 | 45.51 | 658,848 | 57.42 | 831,269 |
| Oct-05 | 12,613 | 1,488,090 | 117.98 | 45.63 | 575,531 | 57.63 | 726,887 |
| Nov-05 | 25,809 | 2,344,260 | 90.83 | 49.10 | 1,267,222 | 62.89 | 1,623,128 |
| Dec-05 | 48,913 | 5,987,416 | 122.41 | 48.77 | 2,385,487 | 61.31 | 2,998,856 |
| Jan-06 | 92,933 | 7,337,002 | 78.95 | 67.60 | 6,282,271 | 87.52 | 8,133,496 |
| Feb-06 | 93,943 | 7,093,547 | 75.51 | 70.34 | 6,607,951 | 90.90 | 8,539,419 |
| Mar-06 | 39,123 | 2,799,342 | 71.55 | 65.92 | 2,578,988 | 85.06 | 3,327,802 |
| Apr-06 | 52,329 | 4,050,721 | 77.41 | 69.79 | 3,652,041 | 89.83 | 4,700,714 |
| May-06 | 17,710 | 1,269,110 | 71.66 | 74.44 | 1,318,332 | 95.72 | 1,695,201 |
| Jun-06 | 26,436 | 2,177,392 | 82.36 | 79.88 | 2,111,708 | 103.17 | 2,727,402 |
| Jul-06 | 74,534 | 7,902,566 | 106.03 | 69.29 | 5,164,461 | 89.08 | 6,639,489 |
| Aug-06 | 77,585 | 9,155,191 | 118.00 | 66.96 | 5,195,092 | 86.25 | 6,691,706 |
| Sep-06 | 44,413 | 2,423,691 | 54.57 | 53.60 | 2,380,537 | 69.09 | 3,068,494 |
| Oct-06 | 55,909 | 3,263,100 | 58.36 | 52.01 | 2,907,827 | 67.10 | 3,751,494 |
| Nov-06 | 43,480 | 3,432,776 | 78.95 | 59.95 | 2,606,626 | 77.55 | 3,371,874 |
| Dec-06 | 2,187 | 204,323 | 93.43 | 66.91 | 146,332 | 86.48 | 189,132 |
| Jan-07 | 0 | 0 | | 54.19 | | 69.34 | |
| Feb-07 | 0 | 0 | | 67.57 | | 87.44 | |
| Mar-07 | 0 | 0 | | 61.77 | | 78.77 | |
| Apr-07 | 0 | 0 | | 65.64 | | 84.84 | |
| May-07 | 0 | 0 | | 63.83 | | 82.29 | |
| Jun-07 | 100 | 10,000 | 100.00 | 64.95 | 6,495 | 83.26 | 8,326 |
| Jul-07 | 2,155 | 197,870 | 91.82 | 86.32 | 186,020 | 111.37 | 240,002 |
| Aug-07 | 3,821 | 462,770 | 121.11 | 85.06 | 325,014 | 109.83 | 419,660 |
| Sep-07 | 0 | 0 | | 66.00 | | 85.16 | |
| Oct-07 | 0 | 0 | | 57.05 | | 73.46 | |
| Nov-07 | 200 | 18,000 | 90.00 | 58.98 | 11,796 | 76.18 | 15,236 |
| Dec-07 | 0 | 0 | | 58.01 | | 74.70 | |
| Jan-08 | 200 | 16,000 | 80.00 | 67.97 | 13,594 | 86.55 | 17,310 |
| Feb-08 | 0 | 0 | | 77.31 | | 99.93 | |
| Mar-08 | 635 | 66,025 | 103.98 | 72.47 | 46,018 | 91.67 | 58,210 |
| Apr-08 | 93 | 9,261 | 99.58 | 78.32 | 7,284 | 101.34 | 9,425 |
| May-08 | 335 | 35,579 | 106.21 | 86.59 | 29,008 | 111.40 | 37,319 |
| Jun-08 | 47 | 5,920 | 125.96 | 85.91 | 4,038 | 110.26 | 5,182 |
| **Total/Avg** | **753,597** | **65,645,526** | **87.11** | **63.66** | **47,977,443** | **81.99** | **61,783,871** |

## SWPA Document (3)
## Development of Hydropower Loads for SUPER Runs, October 2008

**The SWPA worked closely with Corps' Tulsa hydrologic engineering staff in developing the SWD-SUPER model input to simulate Lake Texoma power plant operations. The SWPA developed and adjusted the annual expected electrical power load schedule served by the project for the period of record.**

**The SWPA was requested to describe the method by which the electrical power loads for SWD-SUPER model input were prepared. Adjustments were made to the electrical loads to prevent the model simulation of the reallocation alternatives from drawing down the conservation pool elevation (below the reservoir level where the hydropower plant could not operate) during the lowest water conditions in the period of record.**

**The load curves were used by the Corps in the SUPER model to estimate power production for flood control storage and conservation storage reallocation alternative evaluations. After determining that flood control storage reallocation was not economically favorable, the SWPA load curves were used for evaluation of the recommended storage reallocation for immediate needs in Texas, and for the evaluation of potential future reallocation to Oklahoma under the provisions of Section 838 or the 1986 WRDA.**

10/14/08

**Southwestern Power Administration**
**Lake Texoma Water Supply Storage Reallocation**
**Development of Hydropower Loads for SUPER Runs**

## Southwestern Power Administration

Southwestern Power Administration (Southwestern) was established in 1943 as an agency of the U.S. Department of the Interior. In 1977, Southwestern was transferred to the U.S. Department of Energy. Southwestern markets the power and energy 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 those states plus Kansas and Louisiana. Of the 24 hydroelectric projects from which Southwestern markets power, the output of 19 projects is marketed to the interconnected system. The other 5 projects are isolated geographically and electrically and are marketed as "isolated" projects. Hydropower projects in the Red River SUPER model include Broken Bow, a "system" project, and Denison, an "isolated" project.

## System and Isolated Project (Denison) Contracts

Southwestern's power sales contracts provide system customers firm energy of 1,200 megawatt-hours (MWh) per megawatt (MW) of contracted capacity during each year. The contracts have minimum and maximum monthly energy requirements in order to fully utilize the projects while still providing a valuable resource to the customers. Energy produced above the 1,200 MWh/MW firm energy requirements is provided to the customers as supplemental energy. Customers of non-system, isolated projects receive the entire output of the isolated project less any energy needed to meet station service requirements. As an isolated project, the electrical output of Denison is marketed to two specific customers, both electrical cooperatives. The isolation prevents Southwestern from being able to use system support to guarantee a minimum peaking energy equivalent to 1,200 MWh/MW of peaking capacity. Therefore, the two customer cooperatives are contractually responsible for assuming the obligation of obtaining other power supply sources available to them to meet the necessary system support needed to provide 1,200 MWh/MW of energy production from the project. Energy in excess of the 1,200 MWh/MW produced at the project is purchased by the cooperatives as supplemental energy.

## SUPER Overview and Hydropower Operations

The SUPER reservoir simulation program models the operation of a system of multi-purpose reservoirs based on a plan of regulation defined in the input data. Purposes included are flood control, hydropower, water supply, and streamflow requirements such as water quality or irrigation. Pool manipulations for recreation or fish and wildlife purposes are also included in the form of seasonal guide curves. SUPER simulates the operation on a daily basis.

The SUPER run input file defines the projects in the reservoir system, including the characteristic data of the hydropower projects. Daily power loads for the hydropower projects being modeled in the SUPER run are input into a separate file called the Tape9 file. The Tape9 file includes weekday and weekend power loads for each power project defined in the input data. The loads are provided for every month of every year for the period of record being modeled in the SUPER simulation run. For each day of the simulation, SUPER determines the release required to meet the power load at each power project. If water is available in storage for generating and there is room in the channel downstream, SUPER will make the release to meet the power load. Otherwise, a thermal purchase is required to provide the desired generation. If additional releases are required above the release needed to meet the power load, SUPER will utilize those releases to the extent possible to generate additional, or "dump" (supplemental) energy.

## Development of SUPER Hydropower Loads

Southwestern uses its Power Resource Simulation Model (PRSM) in the development of the hydropower loads for SUPER. PRSM is a reservoir simulation program like SUPER, but there are differences in the way the programs work. PRSM simulates project operations in multiple river basins on a monthly basis and has limited flood control capabilities. Also, electrical demands are input for the system of power projects, and not for the individual power projects. System load demands are based on Southwestern's marketing plan, providing firm energy of 1,200 MWh/MW of contracted capacity during each year. The loads are based on a critical loading pattern and contractual requirements, with the heaviest electrical demand occurring June through September and December through January.

For a system project like Broken Bow, the power loads for SUPER are developed using the project generation from a period of record PRSM system run. For each month in the period of record, PRSM determines the amount of generation required from each system project in order to meet the entire system load. The generation that goes toward meeting the system load is called firm generation. Any generation produced at the project above the firm generation requirement is supplemental energy. Even if the project is not needed to help meet the system load in a particular month, some generation will typically occur as the project generates to meet minimum discharge and electrical capacity requirements from the project. The project monthly load is the PRSM firm generation from the project for each month or the PRSM minimum generation requirement from the project for that month, whichever is greater. Thus, the load requirement at system projects is dependent, to an extent, upon system conditions and the individual project's expected loading needed to meet total system requirements. To convert the monthly loads to the Tape9 format, the monthly values are divided by the number of weekdays in each month. All of the power loads in SUPER are typically put on weekdays, and the loads for the weekend days are zero.

The initial loads for Denison Dam were built assuming 1,200 MWh/MW of the 70 MW of marketed capacity during each year. The loads were based on the critical loading pattern. Unlike the loads for Broken Bow, the load pattern for the non-system project Denison was not

influenced by system conditions and remained the same for each year in the period of record. The monthly loads were converted into the Tape9 format loads for use by SUPER as previously described. However, in simulating the reallocation of 300,000 acre-feet of hydropower storage at Lake Texoma, the normal power loads computed using that method along with the increased water supply withdrawals caused the conservation storage to be completely emptied several times during the period of record. Obviously, such an operation was not likely to occur and it was not possible to determine the impacts on hydropower with those results. A different approach was required for developing the loads for Denison.

**Alternative Method for Development of SUPER Hydropower Loads**

One of the measures used in determining the machine capability of the units is the amount of available head (headwater minus tailwater) at the project. Since the tailwater was assumed to be block loaded (fixed), it was decided that adjusting the power loads in order to maintain a certain minimum pool level during the critical summer month, determined to be August 1964, would allow a fair comparison of energy production impacts between alternatives studied. Such reduction of the loads to maintain the critical pool level allows the simulation to correctly model the actual anticipated operations.

Therefore, with the determination of the proper method to evaluate the hydropower impacts of the proposed reallocation at Lake Texoma, Southwestern developed separate load files for each alternative SUPER run. For each alternative, Southwestern performed a single-project PRSM run simulating the operation of Denison Dam with the alternative conservation pool elevations and water supply withdrawals. Starting with the critical loading pattern, Southwestern allowed PRSM to utilize non-hydro resources to replace hydropower generation as necessary in order to maintain a pool level at which the marketed electrical capacity and required capacity reserve were maintained during the critical summer month (August 1964) in the period of record. Monthly loads were developed using the project firm generation from PRSM, and the monthly loads were converted into Tape9 format loads for use by SUPER as previously described.

The use of separate load files for alternative SUPER runs ensures that the full impact of the proposed storage reallocation alternatives on hydropower production is properly quantified. It also correctly models anticipated operations and allows the impacts of project alternatives to be more easily compared and evaluated.

## SWPA Document (4)
## 1980 Final Power Allocations and Term of Compensation for Reallocations, October 2008

**The SWPA and its customers assert that they should be compensated for the cost of replacement power purchased for the duration of the hydropower impact due to the reallocation of reservoir storage to serve water supply and that the impact is permanent.**

- **For the SWPA that compensation is envisioned as credits to the U.S. Treasury in Lake Texoma project account for hydropower. A credit may be implemented by the Secretary under the authority of the 1958 Water Supply Act as an accounting practice between U.S. Treasury project accounts to offset a loss of revenue because of a storage reallocation.**

- **For the power customers, the SWPA envisions financial compensation in the form of reimbursement from the SWPA to the electric cooperatives. Compensation according to the provisions of Sec 838 is to be based on the actual cost of replacement costs, however, the SWPA and the power customers indicate that they cannot provide an accounting of actual costs related to the storage reallocation. Therefore, they must rely on the Corps to develop a computer model proxy to estimate the average annual expected cost of replacement power.**

**The SWPA was requested to describe the basis for the perpetual term position, which is based on <u>1986 Water Resources Development Act, Sec 838</u>, and <u>Final Power Allocations (1980-1988), (45FR 19032).</u>**

**The Corps agrees that Sec 838 provides for power customer reimbursements and SWPA Treasury account credit, but only during the term of the existing hydropower contract between the SWPA and its preferred customers. The existing contract between the SWPA and the preferred power customers provides no guarantee for power beyond the term of the contract. The provisions of Sec 838 that define the method of calculating reimbursement and Treasury account credit, only define a method related to the purchase of replacement power; and the purchase of replacement power only applies to the term of an existing contract. Any reimbursement beyond the term of the existing contract would be a Federal subsidy to a non-Federal electrical cooperative. The Corps did not assume that the Sec 838 provisions were intended to create a permanent Federal power subsidy for the SWPA's preferred customers.**

**The provisions of Sec 838 did not redefine the term of credit for purchase of replacement costs (traditionally limited to the duration of an existing hydropower contract) and therefore the traditional credit term should be applied to this reallocation study. The existing hydropower contract expires midnight, December 31, 2018.**

10/14/2008

# Southwestern Power Administration
# Lake Texoma Storage Reallocation Study
# 1980 Final Power Allocations and Term of Compensation for Reallocation

## Southwestern Power Administration

Southwestern Power Administration (Southwestern) was established in 1943 as an agency of the U.S. Department of the Interior. In 1977, Southwestern was transferred to the U.S. Department of Energy. Southwestern markets hydroelectric power from 24 multi-purpose reservoir projects constructed and operated by the U.S. Army Corps of Engineers (Corps), located in the states of Arkansas, Missouri, Oklahoma, and Texas. Southwestern markets this power in those four states as well as Kansas and Louisiana. Section 5 of the Flood Control Act of 1944 provides that this power and energy be transmitted and disposed of so as to encourage the most widespread use at the lowest possible rates to consumers consistent with sound business principles. Section 5 further requires that preference in the sale of such power and energy be given to public bodies and cooperatives. Southwestern has over one hundred such "preference" customers, and those customers ultimately serve over eight million end-use customers.

## History of the 1980 Final Power Allocations

During the period 1945-1970, many of the power sales contracts Southwestern executed expired and were renewed in accordance with their own terms. During that era, as new hydropower resources were added, additional power sales contracts were executed with Southwestern's original customers and new customers which were acquired from time to time. Southwestern periodically had difficulty marketing some of the available power and energy generated at the Corps projects during that era because the relative high initial investment cost of hydroelectric facilities caused the price to exceed what was available from other resources.

Although cost-based Federal hydropower was not always the most economical source of electricity available in the early years, many towns and cooperatives chose to base their electric infrastructure on available and reliable Federal hydropower despite higher initial prices. Since no fuel costs are incurred in the production of Federal hydropower, this resource was projected to be cheaper than then existing alternatives in the long term.

Prior to the energy crisis of 1971-1973, there was little need to allocate Southwestern's power among its customers. Only after the cost of energy increased dramatically in the 1970's was there any real concern about the long-term availability of Federal power to satisfy demand. Since then, requests for power have far exceeded the resources available to Southwestern.

In the late 1970's, a number of firm and peaking power sales contracts between Southwestern and its customers were scheduled to expire. Also, Southwestern recognized that several newly authorized projects would make a limited quantity of new hydroelectric capacity available. Specifically, two long-term contracts with non-preference entities were expiring. Empire District Electric Company's contract for 45 MW was set to expire on May 31, 1980, and Reynolds Metals Company and Arkansas Power & Light's contract for 150 MW was set to expire on December 31, 1983. In addition, two new hydroelectric projects, Harry S Truman and Clarence Cannon, were planned to be placed in commercial operation.

Since requests for power from preference customers exceeded the actual and forecasted resources available for marketing, Southwestern had to decide which preference customers should receive the power as existing contracts expired. Therefore, Southwestern had to develop an allocation or reallocation of the power for the most equitable distribution of the power among existing and new preference customers in its six-state marketing area.

There was another problem. The projects had relatively limited storage available for hydropower production and depended heavily on replenishment of that storage by frequent inflows. Inflows in Southwestern's region typically result from largely unpredictable thunderstorms. These considerations led Southwestern to conclude that the most dependable and marketable use of the hydropower resource was as peaking capacity. That conclusion was a prominent factor in Southwestern's formulation of its power allocation and marketing policy. Southwestern converted all of its contracts requiring the delivery of full load factor energy to peaking contracts by 1987 in accordance with this policy.

Southwestern's Preliminary Power Allocations (1980-1988) and Opportunities for Public Review and Comment was published in the Federal Register on August 2, 1979 (44FR 45468). Public review forums were held in Baton Rouge, Louisiana; Kansas City, Missouri; and Tulsa, Oklahoma. As a result of that rulemaking process, Southwestern officially adopted its Final Power Allocations (1980-1988) following publication in the Federal Register on March 24, 1980 (45FR 19032).

**Continued Sales to Present Customers**

General. One consideration in the development of the allocation was that the present preference customers with contracts at that time would be allowed to continue to purchase the power they had historically received. Southwestern's practice in the years leading up to the rulemaking had been to renew power sales contracts to preference customers upon the contracts' expirations with no reduction of the capacity under contract without the voluntary consent of the contracting parties.

Southwestern adopted its Final Power Allocations after consideration of the comments and suggestions received as a result of the public participation process. The published criteria included the following:

> "*Continue sales to present customers.* 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.
>
> In the case of isolated project contracts, such as Narrows and Sam Rayburn, the SWPA will negotiate new contract arrangements of each project's production with the preference customer then receiving the benefit of such federal project."

One example representative of comments received concerning the continuation of sales to the existing customer was submitted by the Arizona Municipal Power Users' Association (AMPUA):

> "AMPUA concurs that sales and allocations to present customers…must continue upon contract expirations." "Allocations are not given time limits when originally made, although their implementing contracts usually are limited in time by a term. Consequently, allocations and contracts issued thereunder have become the historic 'embedded cost resources' for municipal and cooperatively owned customers…" "…older allotee customers have created substantial economies, have created substantial investments and subcultures which depend on the continuation of the 'embedded cost resource' represented by the allocation and its contract."

Southwestern's customers must be able to plan into the future to meet their load obligations. The Final Power Allocations provide the customers assurance of the Federal capacity beyond the term of their current contracts. Such assurance helps provide a solid financial picture to the customers' financial loan entities consistent with the "sound business principles" provision of Section 5. Additionally, long lead times are required to plan, finance, develop, and acquire alternative power resources, particularly environmentally sensitive sources of power such as fossil fuels. The necessary transmission capacity to obtain new resources would also have to be acquired. Any storage reallocation that results in the loss of Federal capacity and energy will have to be replaced by alternative sources forever, not just through the term of the existing contract.

Environmental. In the 2003 Environmental Assessment on Southwestern Power Administration System Power Marketing Policy and Subsequent Contracts, Southwestern declared its intent to continue marketing the power and energy as envisioned when it issued its Final Power Allocations. It noted that until additional power resources are made available to Southwestern by the U.S. Army Corps of Engineers or Southwestern's Final Power Allocations change, the existing power allocations will remain in effect. Reallocation of capacity, which was previously under contract, to a customer other than the party previously purchasing it would result in requiring the previous purchaser to install new generating capacity or purchase from another source. Likewise, a new customer may have generating facilities of its own which may become idle as a result of the power reallocation. The net environmental effect of such changes is the possibility that some generating capacity may not need to be constructed by or for existing

preference customers. This generally will include an investment in transmission capacity as well as generating resources. The basis, in part, for determining that the marketing plan and associated contracts would result in no adverse environmental impacts was predicated on the premise of no addition or shifting of major new generation resources.

Rates and Repayment. Southwestern performs annual rate and repayment studies to determine the revenues required to repay the initial Federal investment in the hydroelectric facilities plus interest as well as ongoing capital equipment replacements and operating and maintenance costs for both the Corps and Southwestern. The cost-based rates that Southwestern charges for hydroelectric energy and capacity, approved by the Deputy Secretary of Energy and the Federal Energy Regulatory Commission, are designed to capture those required revenues during a rolling 50-year period and fulfill Southwestern's continuing long-term financial obligations to the U.S. Treasury. Southwestern's rates are designed based on the current allocation of hydroelectric resources to the customers and with the expectation that Southwestern's customers will be receiving and paying for their current capacity allocation for a continuous period into the future. The existing customers' current rates include the recovery of expected future replacements costs as required by DOE Order RA 6120.2. Therefore, through the ratemaking process, the rates paid by the customers are designed to repay the taxpayer investment in the existing costs of the project as well as provide for projected future costs.

**Permanent Rights**

Southwestern recognizes that Public Law 88-140 provides water supply entities permanent rights to storage if certain conditions are met. Such entities must make the required payments during the period of such use as specified in the agreement with the Government, storage must be physically available, and such entities must continue to make payment for their portion of annual operation and maintenance costs and any necessary reconstruction, rehabilitation, or replacement of project features. Public Law 88-140 meets the same financial, planning, and environmental needs that Southwestern's rulemaking provides the power customers.

The Federal power customers have a similar provision of continued benefits under Southwestern's Final Power Allocations. Southwestern's Final Power Allocations state "SWPA will not withdraw any capacity now under contract to a preference customer in order to sell the capacity to another preference customer." The document 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 Final Power Allocations provides the permanent right to the capacity and associated energy to the existing preference customers provided that the "power allotee will accept the amounts allocated with its attendant terms" and "transmission facilities will be available to move this power to load centers." Thus, Southwestern believes that compensation for the loss of hydropower capacity and energy associated with the reallocation of water storage should be based on the replacement costs for the term that the action has an impact on the hydropower

purpose. In accordance with the 1980 rulemaking, the customers have every expectation that the power would be available to them on a permanent basis. Therefore, when hydropower storage is being permanently reallocated and hydropower benefits are permanently lost the compensation to the power customer should be based on the permanent hydropower benefits lost and should continue as long as those water supply benefits are being diverted to the water supply purpose.

**Period of Analysis for Project Evaluation**

Since 1983, planning for Federal water resources projects constructed by the Corps of Engineers has been based on the Principles and Guidelines (P&G) adopted by the Water Resources Council. The P&G is intended to ensure proper and consistent planning by Federal agencies in the formulation and evaluation of water resource implementation studies. The P&G states that "The period of analysis is to be the same for each alternative plan. The period of analysis is to be the time required for implementation plus the lesser of – (1) The period of time over which any alternative plan would have significant beneficial or adverse effects; or (2) A period not to exceed 100 years." In the Denison Reallocation Report, the Corps has used 50 years for the period of analysis for alternatives that are to determine the loss to Federal hydropower. In the alternative analysis to determine the most likely, least cost alternative to reallocation of water storage, the Corps used a 100-year period to determine annual costs. Since the P&G requires that all alternatives be evaluated on the same period of analysis, we will assume the 50-year period to be a reasonable period of time for analysis of the beneficial and adverse impacts of the reallocation alternative. Since the P&G requires consistent analysis periods, it follows that compensation to hydropower as envisioned under paragraph (d)(3), Section 838, of the Water Resources Development Act of 1986 must also be for the same 50-year period of adverse impact.

**1985 Negotiations/1986 Water Resources Development Act**

In 1985, the Corps reallocated 75,000 acre-feet of Lake Texoma storage from hydropower to water supply for the use of the North Texas Municipal Water District (NTMWD). Compensation for the hydropower impacts was based on a negotiated settlement. The negotiations were mediated by two Congressmen. As a result of the negotiations, a letter agreement dated November 29, 1985, was signed by Southwestern's Administrator and the Corps Southwestern Division Engineer detailing the compensation to the hydropower purpose as a result of the 75,000 acre-feet of storage for NTMWD. Among the provisions of the agreement were requirements for credits to hydropower through December 31, 2003, which was the expiration date of Southwestern's contracts with its Lake Texoma hydropower customers. Credit to Southwestern after 2003 remained unresolved in the 1985 letter agreement. The agreement stated that the issue "will be addressed at a later date." The credit beyond 2003 has not yet been addressed.

Authority for the storage reallocations currently under consideration at Lake Texoma was provided by Section 838 of the Water Resources Development Act of 1986 (PL 99-662). Compensation to the hydropower purpose is addressed in the legislation as follows: "If

hydropower is lost as a result of the implementation of such contract, the Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement cost. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower." The law defines the replacement cost of hydropower lost as "the cost to purchase power from existing alternative sources." There is hydropower lost as a result of such water supply contract. The reallocation of storage is permanent according to the legislation. The loss to hydropower is also permanent and impacts the hydropower customers beyond the life of their current contract because of the 1980 rulemaking. Therefore, the credits for "such replacement costs" should be based on the total, permanent impact to the hydropower purpose.

The 1986 legislation was written and enacted based on knowledge gained from the 1985 negotiations. The law was enacted to provide compensation to the hydropower purpose for the impact of future water storage reallocations while avoiding the necessity of further such negotiations. While the 1985 letter agreement failed to clearly deal with the issue of compensation beyond the term of the existing power sales contract, the 1986 legislation is clear on the matter. It states, in part, "If hydropower is lost as a result of implementation of such contract, the Secretary shall provide credits…" The phrase "as a result of implementation of such contract" can only be interpreted to mean for as long as the (water supply) contract is in effect, presumed to be as long as the project is operational. Such credit is intended for the life of the water supply contract's negative impact on Federal hydropower and has nothing to do with any power sales contract duration.

**Term of Replacement Cost**

The proposed reallocation of hydropower storage to water supply storage under current Corps regulations will result in the permanent loss of the hydropower benefit to Southwestern's existing customers. Under those regulations, the term of the replacement costs will be 50 years, consistent with the period of analysis. Southwestern's Final Power Allocations provided for the power customers to continue receiving those hydropower benefits as long as the power allottee can accept the allocated amount and transmission facilities are available. Customers who contract with Southwestern for Federal power understand that as their current contracts expire, they will be able to renew their contracts for the same amount of electrical capacity and associated energy as provided for in their current contracts. The 1986 legislation places no condition on the status of the power sales contract, rather that the compensation to the hydropower purpose be "a result of the implementation of such contract," where "such contract" refers to the water supply contract for the reallocated storage.

The proposed reallocation of storage will be used for another project purpose, and the negative impacts to hydropower will extend through the life of the water supply contract. Southwestern's customers will have to replace the capacity and energy lost as a result of the reallocation forever. Southwestern's customers have argued that such a reallocation without just compensation represents a taking under the Fifth Amendment to the U.S. Constitution.

It is Southwestern's position that any reductions in the capacity and energy available to Southwestern's customers due to a storage reallocation should be compensated based on replacement costs of the lost hydropower capacity and energy for the period of adverse effects, which at a minimum would be the 50-year period of analysis.

**Conclusion**

Based on the above analysis, the credits to Southwestern under paragraph (d)(3), Section 838, of the Water Resources Development Act of 1986 should be the replacement costs for the lost hydropower capacity and energy for the period of adverse impact, which is a minimum of 50 years for the term of compensation.

## SWPA Document (5)
## Portion of Customer's Load, November 2008

**The Corps requested the SWPA to describe the customer's loads and the proportion served by Denison hydropower plant.**

**Replacement power purchases may be necessary if a storage reallocation is implemented during the term of a hydropower contract. A storage reallocation would reduce the capability of the power plant to produce electricity and would therefore impact the provisions of a hydropower contract in place at the time the reallocation was implemented. In this case the actual capability of a power plant would be reduced throughout the remainder of the hydropower contract.**

**If a new hydropower contract is negotiated, then the new contract provisions will account for the storage available for hydropower production and the SWPA will forecast hydrologic conditions over the term of the new contact with the intent of reasonably minimizing the need to purchase replacement power. Replacement power purchases may still be necessary during the term of the new contract, but those purchases will only occur if unexpected hydrologic conditions are experienced.**

**The power customers will need to find alternate sources for power, but the current contract does not guarantee an amount of power for future contracts – or make any guarantee concerning future contracts. When the current contract expires, the power customers will likely continue to purchase hydropower produced at Lake Texoma, but those future contracts will be for a lesser amount of power.**

**The electric cooperatives already have alternate power sources and as power demands in the region increase, the cooperatives will inherently have to rely more heavily on alternate sources of power, including peaking power. The increment of power that will need to be replaced by alternate sources is relatively small compared to the total needs of the power customers. Hydropower has been a low cost source of peaking energy and the power customers have been able to utilize that low cost power in their system operations for many years. But reallocation of a portion of the storage used to produce hydropower (15.02%) has been shown to have a higher value for water supply customers in Texas, and water supply revenues to the Treasury will equal or exceed the hydropower revenues over the period of evaluation.**

**Virtually all other customers in the ERCOT system currently rely exclusively on thermal power production for peaking energy.**

November 17, 2008

# Southwestern Power Administration
# Denison (Lake Texoma)
# Portion of Customers' Load

## Contracts

The Southwestern Power Administration (Southwestern) contracts with two customers for the total electric power and energy generated at the Denison dam hydroelectric project. The Federal power sales contract provides Rayburn Country Electric Cooperative, Inc. (Rayburn) with 42.525 megawatts (MW) of capacity and Tex-La Electric Cooperative of Texas, Inc. (Tex-La) with 27.475 MW of capacity. The installed capacity of the project is 70.0 MW. Historically, from 1950 through 2007, project generation averages about 232 gigawatt-hours of energy annually.

## Total Load

Based on 2006 information from the Platts' Utility Data Institute Directory of Electric Power Producers and Distributors, Southwestern has computed the percentage of capacity and energy the customers receive from Denison relative to their total capacity and energy requirements. For Rayburn, Denison supplies 7.5 percent of its total capacity and 4.8 percent of its total energy needs. The amount of the total capacity and energy needs supplied by Denison for Tex-La is 8.7 percent and 6.4 percent respectively.

## Peak Demand

As is typical of the hydroelectric power projects in Southwestern's area, Denison is normally used to meet short-term peaking power and energy requirements. Therefore, Southwestern attempted to determine the amount of both cooperatives' peaking energy and capacity needs that Denison provides. The amount of data for the determination was limited; however, Southwestern was able to obtain hourly data from the Electric Reliability Council of Texas (ERCOT), whose grid covers 75 percent of Texas and who serves 85 percent of Texas load. Denison power is delivered into the ERCOT region to serve Rayburn and Tex-La loads.

Southwestern combined the ERCOT information with the data available for both customers and the Denison 2007 generation to determine each customer's amount of peaking energy and capacity provided by Denison. From Southwestern's analysis of the 2007 data, Denison provided 14 percent of Rayburn's peaking capacity and 40 percent of its peaking energy needs. For Tex-La in 2007, Denison provided 53 percent of its peaking capacity and 96 percent of its peaking energy requirements.

Several items must be taken into consideration. The information available provided for a more reliable determination of peaking energy rather than peaking capacity requirements. Additionally, it must be noted that 2007 was an extremely wet year for Denison, therefore, providing above normal generation. Since, to the extent possible, the energy produced at the project is used to meet short-term, on-peak energy demands, it is not possible to just prorate the annual energy from the 2007 high inflow year to average

generation conditions. Such a proration would greatly underestimate the contribution of Denison's peaking energy contribution to the electric cooperatives.

**Conclusion**

Denison serves a very critical role in meeting the peaking electrical demands of both cooperatives. The loss of any energy and/or capacity from the project would have to be replaced from resources available within the ERCOT region. Replacement peaking energy would likely be produced by gas-fired combustion turbines at a relatively high energy cost. In addition, firm transmission service for the delivery of replacement capacity and energy to the Cooperatives' load centers must be acquired, which may include incremental transmission upgrade costs in addition to base transmission service charges, ancillary service charges, and congestion charges.

## SWPA Document (6)
## GDS Associates Letter, Denison Power Customers' capacity replacement intentions, January 2009

**The SWPA requested the power customers to furnish a letter confirming their intention to purchase replacement capacity for hydropower impacts of reservoir storage reallocation.**

**GDS Associates is assumed to be the scheduling and purchasing agent for the Tex-La and Rayburn Country electric cooperatives. The terms and cost to purchase capacity and energy were not stated.**

GDS Associates, Inc.
Engineers and Consultants

David M. Brian, P.E.
Vice President

Ph: 770.425.8100
Fax: 770.426.0303
david.brian@gdsassociates.com

January 9, 2009

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

Dear George:

We understand there is an interest in receiving an indication from the Denison power customers regarding their intent with respect to the amount of capacity they would likely purchase or otherwise acquire on a permanent basis as a result of the proposed reallocation. The Denison power customers have asked me to respond and provide you with this letter.

Southwestern Power Administration (SWPA) has indicated that, in a critical drought period, the 150,000 acre-feet reallocation will result in roughly a 12 megawatt decrease in Denison's production capacity; and there will be a reduction of that amount in the capacity marketed by SWPA and sold to the customers. In addition, there will be a reduction in the annual energy output by approximately 12,000 megawatt-hours.

The power customers will procure dependable capacity and associated energy to replace what is lost from Denison. Because Denison is a summer peaking resource, it is relied upon in critical peak load periods, and any loss in Denison's capacity cannot go without replacement. The amount that the customers will purchase will equal the reduction in Denison's net dependable capacity, as prudent utility practice dictates that lost dependable capacity must be replaced to ensure reliability standards are maintained and peak load levels can be served. For planning purposes, net dependable capacity, in this case, would be based on the contract quantity. If there is a reduction of 12 megawatts in what is sold to the customers, the customers will procure that amount of dependable replacement capacity from other sources.

What resource the customers purchase to replace the lost dependable capacity is uncertain, but they will purchase the dependable replacement capacity on a forward basis, well in advance of critical summer peak periods, in order to ensure that dependable capacity and

energy is available to serve loads during these most important times. It is likely that the customers would procure a permanent replacement for the lost dependable capacity, since the reduction in Denison's net dependable capacity will be permanent. The cooperatives routinely rely on long term resources to serve their customer's needs.

Thank you for the opportunity to provide this additional information and I hope it proves helpful.

Sincerely,

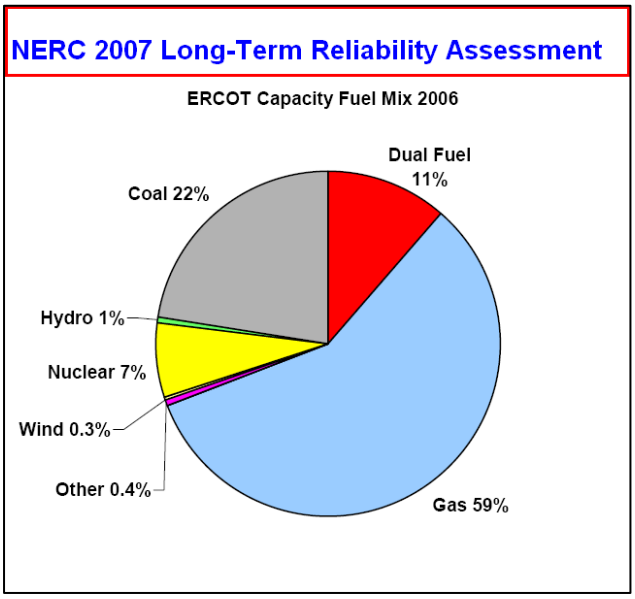
David Brian

David M. Brian, P.E.

cc: Edd Hargett
John Kirkland
Tom Gebhard
Bill Burchette

**SWPA Document (7)**
**Comparison Summary of Hydropower Impacts due to 150,000 acre-feet reallocation, January 2009**

**Amount of credit. SWPA states the U.S. Treasury account credit amount should be based on a hydropower and hydrologic methodology that considers the worst case drought condition during the period of record data because that is how they evaluate power production for marketing purposes. The SWPA compares its 100% hydropower mission to the substantial hydropower contribution of the Pacific Northwest. The Electric Reliability Council of Texas (ERCOT) bulk power system supplies electricity to the Tex-La Electric Cooperative of Texas, Inc., and the Rayburn Country Electric Cooperative, Inc. The ERCOT system is essentially a thermal generation system. The figure below shows hydropower to provide one percent of the system power resources. The thermal generating portion of the system is roughly 98% (including nuclear). http://www.pserc.org/cgi-pserc/getbig/publicatio/specialepr/workforcec/ltra2007.pdf**




**The HAC has considered SWPA's choice of worst case methodology for PMA credits for revenue foregone.. In regions of the country where electrical generating resources are dominated by thermal generating technologies USACE/HAC considers it inappropriate to use an extreme hydrologic event (worst case hydrologic scenario) to define availability of replacement power which will most likely come from thermal generating resources readily available in the region.**

**Term of credit. The SWPA states that a hydropower account credit should continue forever, but the SWPA has also provided a white paper indicating "a minimum of 50 years for the term of compensation" (10/14/2008, Southwestern Power Administration Lake Texoma Storage Reallocation Study 1980 Final Power Allocations and Term of Compensation for Reallocation.)**

**Three assumptions regarding Section 838 were developed by the Corps. Those assumptions, shown below, helped guide the evaluation of credits.**

**The provisions of Sec 838 were not assumed to have been drafted to establish a Federal subsidy for the long term purchase of power from alternative sources**

**by the Tex-La Electric Cooperative of Texas, Inc., and Rayburn Country Electric Cooperative, Inc.**

**The provisions were not assumed to modify the existing contract between the cooperatives and the SWPA to provide any guarantees beyond the term of the existing hydropower contract.**

**The provisions were assumed to establish a methodology to fairly compensate the electric cooperatives for the impacts of storage reallocation on their purchases of replacement power during the term of the existing hydropower contract. Traditional policy would have provided credit to the hydropower project account if the power marketing agency had the responsibility to purchase replacement power, but there are no provisions in traditional policy for compensation of power customers (reimbursement) who have that purchasing responsibility.**

**The purpose of managing accounts, and Federal agency repayment to those accounts, is to assign and assure repayment of the initial Federal investment in the project and in repayment of subsequent operating expenses for those specific or joint use purposes by the appropriate Federal agency. The term of repayment to the Treasury for the initial investment is typically envisioned to be about 50 years. For Lake Texoma it appears that the initial hydropower investment (assets) was repaid through power sales within 50-years since construction Lake Texoma in 1944. Subsequent hydropower purpose assets have been added to the account and include major replacements, such as rewinding turbines. In contrast to the allocated initial project costs, the major replacements are relatively minor and will be repaid in a few years from the sale of hydropower, even if credits were not applied to the hydropower account.**

**Section 838 of the 1986 WRDA defined the methodology for determining hydropower project credits and created a related method for reimbursement of power customer purchases of replacement power. The provisions reaffirm the Secretary's authority to determine the impact of the reallocation on hydropower production. The legislation defines one condition for establishing credit. The one condition deals with the replacement power purchased during the term of the existing contract.**

**The credit term was also the subject of Counsel and policy staff discussion. The conclusion was that provisions of Sec 838 did not redefine the term of credit for purchase of replacement costs (traditionally limited to the duration of an existing hydropower contract) and therefore the traditional credit term for replacement costs should be applied for this reallocation study. The existing hydropower contract expires midnight, December 31, 2018. The Corps has determined that Sec. 838(d)(3) does not bar the application of current policy on hydropower credit, and**

**will therefore follow the policy in Appendix E, Section VIII, of ER 1105-2-100. Under that policy the SWPA would be credited for replacement costs through the remaining period of its current power contracts and thereafter credited for revenues forgone for the remainder of a 50-year credit period. Because the amortization period for water storage agreement (the Treasury source of credits in this instance) is 30 years, the present value of the revenues forgone for the 50-year period would be annualized over 30 years. However, because there are power contracts between the Federal power administration and its customers that require credit based on the cost of acquisition of replacement power through 2018 (9 years), then the credit for revenue foregone would be based on the remaining period within a 50-year total credit period. To summarize, credits for the first nine years would be replacement costs and credits for the remaining 21 years of the water supply payments would be based on 41 years of hydropower revenue foregone that would be amortized over the 21 years of remaining Treasury revenue from the water storage agreement payments. Because the balance of the Lake Texoma hydropower Treasure account will be repaid within only a few years of hydropower revenues (from the sale of power) and hydropower credits (from water storage agreement payments) the Corps has determined that the hydropower credits may be distributed by the SWPA to other projects at their discretion. In this way the water storage agreement payments from Lake Texoma will assist in repaying the cost of hydropower facilities and hydropower operations at projects where the SWPA has generation facilities and has not yet repaid the Treasury debt.**

**Inflation rate. The SWPA indicates that an inflation rate of 5% is appropriate, in part because that rate was used in a 1985 reallocation memorandum of agreement (MOA); and in part because of interim agreements between the Corps and the SWPA to use that rate early in the coordination of the reallocation study. The SWPA proposed application of the 5% rate, compounded annually, without regard to the current inflation rate in 2009 and the SWPA further proposed no alteration of that rate in future years regardless of actual future inflation rates.**

**The Corps' understanding of the inappropriateness of that 24-year old inflation rate and its proposed application in out years grew as the study progressed and as HAC evaluation methodologies evolved during that study progress. In 1985 an inflation rate of 5% might have been reasonable, but a rate that is current at the time of development of an MOA in 2009 would be appropriate. The 5% rate was recognized as excessive for current economic conditions and should not be used for the (MOA) between the Corps and the SWPA that would address U.S. Treasury Credits.**

**While inflation may be considered in an MOA, it is not applicable to water resources studies under Corps of Engineers guidance, including guidance for the evaluation of reallocation studies. Water resources study cost and benefit evaluations use a Federal discount rate derived annually from a formula prescribed by Section 80 of the Water Resources Development Act of 1974. This Act produced**

**an approach based on the cost of government borrowing. The approach effectively represents a compromise between the high and low rate proponents.**

**The concept of using a 24-year old inflation rate that had once been applied in a memorandum of agreement (MOA) between the Corps and the SWPA was replaced, by the Corps, with the concept of using a current and appropriate inflation rate. The inflation rate would be based on accepted industry rates at the time the MOA is developed. Further, the inflation rate would not have to be a fixed rate but could vary annually based on actual inflation. Credits are applied retro actively, following each year of replacement power purchases. There are optional sources for obtaining inflation rates. One of the more appropriate sources would be Platts Power Outlook Research Service through an existing subscription purchased by the Corps Hydropower Analysis Center. The Federal discount rate used in the Corps evaluation already reflects investor's expectations of inflation over the term of 30-year Treasury notes. If a specific inflation factor is to be used in a MOA regarding credits, then the Corps' evaluation of the cost of replacement power would first need to be adjusted to avoid double counting of inflation.**

**Preceding the SWPA Document (7) is a copy of the document annotated by the Corps that provides additional information for clarification.**

# Corps Annotations for Clarification

The SWPA evaluation would be suitable for marketing hydropower with a firm capacity from Lake Texoma. But, replacement power will be purchased from thermal resources, not from hydropower plants. Section 838 of the 1986 WRDA specifies that U.S. Treasury credit will be equal to such replacement power costs. For a predominately thermal production system EM 1110-2-1701 specifies the use of the Average Availability Method (not the Critical Month Method) for determining dependable capacity.

Under Corps criteria credits for the first nine years would be replacement costs and credits for the remaining 21 years of the water supply payments would be based on 41 years of hydropower revenue foregone that would be amortized over the 21 years of remaining Treasury revenue from the water storage agreement payments.

Sec. 838(d)(3) does not bar the application of current policy on hydropower credit under the policy in Appendix E, Section VIII, of ER 1105-2-100. The SWPA would be credited for replacement costs through the remaining period of its current power contract and thereafter credited for revenues forgone for the remainder of a 50-year credit period. The Federal storage resource would be reallocated to water supply storage which will provide more revenue to the Treasury than would the sale of hydropower. The hydropower storage cost has been repaid by the SWPA. There would be no further "repayment" necessary by the SWPA, although revenue from the sale of hydropower is U.S. Treasury revenue whether repaying an initial Federal investment or providing subsequent revenue.

The Corps recommends that a current and appropriate inflation rate would be based on accepted industry rates at the time the MOA is developed. Credits are applied retroactively, following each year of replacement power purchases. Actual inflation rates could be evaluated by the Hydropower Analysis Center. The Federal discount rate used in the Corps evaluation already reflects investor's expectations of inflation over the term of 30-year Treasury notes. If a specific inflation factor is to be used in a MOA regarding credits, then the Corps' evaluation of the cost of replacement power would first need to be adjusted to avoid some increment of double counting of inflation.

**Southwestern Power Administration** 01/09/2009

**Denison (Lake Texoma) - Comparison Summary of SWPA & Corps Determination of Hydropower Impacts from Reallocation of 150,000 acre-feet of Hydropower Storage**

| | Southwestern | | Proposed Corps |
|---|---|---|---|
| | Revenue Foregone Computation | Replacement Cost Computation | Replacement Cost Computation |
| **Energy Loss** | | | |
| Annual Super-Peak Energy Losses (MWh) | 11,995 | 11,995 | 3,800 |
| Annual On-Peak Energy Losses (MWh) | | | 5,831 |
| Annual Off-Peak Energy Losses (MWh) | | | 2,714 |
| Total Annual Energy Losses (MWh) | 11,995 | 11,995 | 12,345 |
| **Energy Rates** | | | |
| Super-Peak Energy value ($/MWh) | 8.20 | 121.92 | 88.16 |
| Super-Peak Capacity value ($/MWh) | | | 83.42 |
| On-Peak Energy value ($/MWh) | | | 85.92 |
| Off-Peak Energy value ($/MWh) | | | 71.48 |
| **Energy Costs** | | | |
| Annual Super-Peak Energy Cost | $98,359 | $1,462,430 | $335,000 |
| Annual Super-Peak Capacity Cost | | | $317,000 |
| Annual On-Peak Energy Cost | | | $501,000 |
| Annual Off-Peak Energy Cost | | | $194,000 |
| **Annual Energy Cost** | **$98,359** | **$1,462,430** | **$1,347,000** |
| **Capacity Losses (kW)[1]** | 11,843 | 11,843 | 3,167 |
| **Capacity Rates ($/kW)** | 42.12 | 60.24 | 0.00 |
| **Annual Capacity Cost** | **$498,827** | **$713,422** | **$0** |
| **Total Annual Cost** | **$597,186** | **$2,175,853** | **$1,347,000** |

[1]To determine capacity losses, SWPA uses the Corps "Critical Month Method" as defined in Engineer Manual 1110-2-1701 typically used in the Pacific Northwest (Bonneville Power Administration) where hydro is a substantial portion of a system's generating capacity. SWPA's marketing system is 100% hydro and it contracts existing capacity to the region based on critical month capacity availability. The Corps used its "Average Availability Method" for determining capacity losses at Denison.

**Term of Compensation**

SWPA recognizes that the proposed action is a permanent reallocation of hydropower storage to water supply storage. While power sales contracts are for a specified term, SWPA, through Federal rulemaking, has established permanent power allocations to each customer. As such, the impacts on the hydropower purpose shall be continuous for as long as the project exists. The authorizing legislation, Section 838 of PL 99-662, states that "the Secretary shall determine (A) the amount of hydropower lost, if any, as a result of the implementation of such contract." The implementation of "such contract," referring to the water supply contract, results in a permanent, continuous loss to hydropower. Therefore, SWPA believes that the referred "replacement cost" in the legislation should be computed and credited for a minimum of 50 years.

The Corps study recommends crediting hydropower for replacement costs only through the year 2018, the end of the existing power sales contract. There are no provisions to even credit the hydropower purpose for the revenues foregone beyond that date. Thus, SWPA will be required to continue repayment for a resource that the Corps has sold to the water supply users and is no longer available to SWPA.

**Inflation**

In order to provide sufficient funds to purchase replacement energy in future years, SWPA recognizes that a reasonable inflation factor must be used in the determination of the hydropower credit. In negotiations with the Corps, agreement was reached to use an escalation rate similar to the one used in the 1985 settlement agreement. However, it is currently unclear if the Corps plans to use an inflation factor, and if so, what the value of the factor might be.

**Notes on values used by SWPA:**

Energy and capacity values for revenue foregone based on SWPA rates as of Oct 2008.
Energy value for replacement cost based on Platts High Fuel Cost 2008 on-peak values for ERCOT - Nov 2008.
Capacity loss based on critical year reliability consistent with SWPA's marketing plan and contracts.
Replacement capacity cost based on FERC values from HAC - Nov 2008 (Combustion Turbine - Texas).

**Notes on values used by the Corps:**

Energy values annualized over a 9-year term of compensation using a 4.625% interest rate.
Capacity loss estimated by the Corps from their calculations using average year losses.
Capacity not valued separately, but included as capacity component of lost super-peak energy.

Computed energy loss is slightly higher than the SWPA estimate.

This is a capacity rate not an energy rate.

This is a capacity loss estimate not an energy loss estimate.

The average annual capacity rate computed by the Corps is $100.09/kW.

The annual capacity loss computed by the Corps is $317,000.

**Southwestern Power Administration** 01/09/2009

## Denison (Lake Texoma) - Comparison Summary of SWPA & Corps Determination of Hydropower Impacts from Reallocation of 150,000 acre-feet of Hydropower Storage

| | Southwestern | | Proposed Corps |
|---|---|---|---|
| | Revenue Foregone Computation | Replacement Cost Computation | Replacement Cost Computation |
| **Energy Loss** | | | |
| Annual Super-Peak Energy Losses (MWh) | 11,995 | 11,995 | 3,800 |
| Annual On-Peak Energy Losses (MWh) | | | 5,831 |
| Annual Off-Peak Energy Losses (MWh) | | | 2,714 |
| Total Annual Energy Losses (MWh) | 11,995 | 11,995 | 12,345 |
| **Energy Rates** | | | |
| Super-Peak Energy value ($/MWh) | 8.20 | 121.92 | 88.16 |
| Super-Peak Capacity value ($/MWh) | | | 83.42 |
| On-Peak Energy value ($/MWh) | | | 85.92 |
| Off-Peak Energy value ($/MWh) | | | 71.48 |
| **Energy Costs** | | | |
| Annual Super-Peak Energy Cost | $98,359 | $1,462,430 | $335,000 |
| Annual Super-Peak Capacity Cost | | | $317,000 |
| Annual On-Peak Energy Cost | | | $501,000 |
| Annual Off-Peak Energy Cost | | | $194,000 |
| **Annual Energy Cost** | **$98,359** | **$1,462,430** | **$1,347,000** |
| **Capacity Losses (kW)[1]** | 11,843 | 11,843 | 3,167 |
| **Capacity Rates ($/kW)** | 42.12 | 60.24 | 0.00 |
| **Annual Capacity Cost** | **$498,827** | **$713,422** | **$0** |
| **Total Annual Cost** | **$597,186** | **$2,175,853** | **$1,347,000** |

[1]To determine capacity losses, SWPA uses the Corps "Critical Month Method" as defined in Engineer Manual 1110-2-1701 typically used in the Pacific Northwest (Bonneville Power Administration) where hydro is a substantial portion of a system's generating capacity. SWPA's marketing system is 100% hydro and it contracts existing capacity to the region based on critical month capacity availability. The Corps used its "Average Availability Method" for determining capacity losses at Denison.

### Term of Compensation

SWPA recognizes that the proposed action is a permanent reallocation of hydropower storage to water supply storage. While power sales contracts are for a specified term, SWPA, through Federal rulemaking, has established permanent power allocations to each customer. As such, the impacts on the hydropower purpose shall be continuous for as long as the project exists. The authorizing legislation, Section 838 of PL 99-662, states that "the Secretary shall determine (A) the amount of hydropower lost, if any, as a result of the implementation of such contract." The implementation of "such contract," referring to the water supply contract, results in a permanent, continuous loss to hydropower. Therefore, SWPA believes that the referred "replacement cost" in the legislation should be computed and credited for a minimum of 50 years.

The Corps study recommends crediting hydropower for replacement costs only through the year 2018, the end of the existing power sales contract. There are no provisions to even credit the hydropower purpose for the revenues foregone beyond that date. Thus, SWPA will be required to continue repayment for a resource that the Corps has sold to the water supply users and is no longer available to SWPA.

### Inflation

In order to provide sufficient funds to purchase replacement energy in future years, SWPA recognizes that a reasonable inflation factor must be used in the determination of the hydropower credit. In negotiations with the Corps, agreement was reached to use an escalation rate similar to the one used in the 1985 settlement agreement. However, it is currently unclear if the Corps plans to use an inflation factor, and if so, what the value of the factor might be.

**Notes on values used by SWPA:**

Energy and capacity values for revenue foregone based on SWPA rates as of Oct 2008.
Energy value for replacement cost based on Platts High Fuel Cost 2008 on-peak values for ERCOT - Nov 2008.
Capacity loss based on critical year reliability consistent with SWPA's marketing plan and contracts.
Replacement capacity cost based on FERC values from HAC - Nov 2008 (Combustion Turbine - Texas).

**Notes on values used by the Corps:**

Energy values annualized over a 9-year term of compensation using a 4.625% interest rate.
Capacity loss estimated by the Corps from their calculations using average year losses.
Capacity not valued separately, but included as capacity component of lost super-peak energy.

# APPENDIX G

**Power Sales Contract**
**No. DE-PM75-00SW00435**
**Between**
**United States of America**
**[The Southwestern Power Administration]**
**and**
**Tex-La Electric Cooperative of Texas, Inc**
**and**
**Rayburn Country Electric Cooperative, Inc**

# Contract No. DE-PM75-00SW00435

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

POWER SALES CONTRACT

Between

UNITED STATES OF AMERICA

and

COPY

TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC.

and

RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.


| Article | Title | Page |
|---|---|---|
| Preamble | | |
| I | DEFINITIONS | |
| | 1. Contract Year | 2 |
| | 2. System of the Cooperatives | 2 |
| | 3. System of Southwestern | 3 |
| | 4. Month and Billing Period | 3 |
| | 5. Uncontrollable Force | 3 |
| | 6. General Contract Provisions | 3 |
| II | SALE OF HYDRO PEAKING POWER AND ASSOCIATED ENERGY BY SOUTHWESTERN | |
| | 1. Sale of Hydro Peaking Power | 4 |
| | 2. Definitions Applicable to the Sale of Hydro Peaking Power | 4 |
| | 3. Sale of Peaking Energy | 5 |
| | 4. Scheduling of Peaking Energy | 5 |
| | 5. Compensation by the Cooperatives to Southwestern for Hydro Peaking Power and Peaking Energy | 6 |
| | 6. Points of Delivery for Power and Energy Purchased by the Cooperatives | 8 |
| | 7. Operational Guidelines and Procedures | 8 |
| III | SCHEDULING AGENT | |
| | 1. Authority of Scheduling Agent | 9 |
| | 2. Changes in Scheduling Agent or in Authority of Scheduling Agent | 9 |

| Article | Title | Page |
|---|---|---|
| IV | CHARACTER OF DELIVERIES AND POWER FACTOR | |
| | 1. Character of Deliveries | 9 |
| | 2. Power Factor | 9 |
| V | METERING, METER READING, AND ADJUSTMENTS | |
| | 1. Metering | 10 |
| | 2. Meter Reading | 10 |
| | 3. Meter Tests and Adjustments | 10 |
| | 4. Station Service for Denison Dam | 11 |
| | 5. Black Start Service | 11 |
| VI | INTEGRATED RESOURCE PLANNING | 11 |
| VII | EFFECTIVE DATE, TERM, START OF SERVICE, CONTINGENCIES, NOTICES, REPORTS, AND INFORMATION | |
| | 1. Effective Date, Term of Contract, and Start of Service | 12 |
| | 2. Lender Approval | 12 |
| | 3. Capacity Increases | 13 |
| | 4. Notice | 13 |
| | 5. Reports and Information | 14 |

Exhibits:

1 - General Contract Provisions (Power Sales dated 101999)
2 - Rate Schedule P-98C

# Contract No. DE-PM75-00SW00435

UNITED STATES
DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

POWER SALES CONTRACT

Between

UNITED STATES OF AMERICA

COPY

and

TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC.

and

RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC.

THIS CONTRACT, made and entered into this 13th day of March, 2000, by and among the UNITED STATES OF AMERICA, represented by the Secretary of Energy, acting by and through the Administrator, Southwestern Power Administration (hereinafter "Southwestern"), an Administration within the Department of Energy, and TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC. (hereinafter "Tex-La"), a cooperative corporation of Nacogdoches, Texas, and RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC. (hereinafter "Rayburn Country"), a cooperative corporation of Rockwall, Texas, both organized and existing under the laws of the State of Texas, acting through their duly authorized officials (hereinafter "the Cooperatives"); WITNESSETH, That,

WHEREAS, pursuant to Section 302(a)(1) of the Department of Energy Organization Act (91 Stat. 578; 42 U.S.C. 7152), and Section 5 of the Flood Control Act of 1944 (58 Stat. 887, 890; 16 U.S.C. 825s), and Public Law 95-456 (92 Stat. 1230; 16 U.S.C. 825s-3), the Secretary of Energy is authorized to transmit and dispose of electric power and energy generated at reservoir projects under the control of the Department of the Army; and

WHEREAS, the Administrator of Southwestern has been delegated the authority to market available hydroelectric power and energy; and

WHEREAS, on February 24, 1984, the Cooperatives entered into a contract (Contract No. DE-MS75-84SW00102, as amended) the term of which expires on December 31, 2003, which provides for the Cooperatives to purchase the total electric power and energy generated at the Denison Dam; and

WHEREAS, pursuant to a letter agreement between the Cooperatives dated February 24, 1984, the Cooperatives' allocation from Denison Dam is split 60.75 percent to Rayburn Country and 39.25 percent to Tex-La.; and

WHEREAS, the Cooperatives desire to continue to purchase the Federally generated power and energy from Denison Dam under the terms and conditions set forth hereunder;

NOW THEREFORE, in consideration of the mutual covenants herein contained, the parties contract and agree as follows:

## ARTICLE I

## DEFINITIONS

Section 1. Contract Year. The Term "Contract Year," as used herein, shall mean the 12-month period beginning on January 1 of each year and extending through December 31 of that year.

Section 2. System of the Cooperatives. The term "System of the Cooperatives," as used herein, shall mean the transmission and related facilities owned by the Cooperatives, and/or the transmission and related facilities owned by others, the capacity of which, by contract, is available to and utilized by the Cooperatives for the receipt and transmission of electric power and energy purchased under this Contract.

Section 3. System of Southwestern. The term "System of Southwestern," as used herein, shall mean the transmission, generation, and related facilities owned by the United States and located at the Denison Dam.

Section 4. Month and Billing Period. The terms "month" and "billing period," as used herein, shall mean the period beginning on the first day and extending through the last day of each calendar month.

Section 5. Uncontrollable Force. The term "Uncontrollable Force," as used herein, shall mean any force which is not within the control of the party affected, including, but not limited to, failure of water supply, failure of facilities, flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, or restraint by court of general jurisdiction, which by exercise of due diligence and foresight such party could not reasonably have been expected to avoid.

Section 6. General Contract Provisions. (a) General Contract Provisions which are applicable to this Contract are set forth in the attached Exhibit "1," and by this reference made a part hereof. Definitions set forth in the articles of this Contract shall also apply to their respective terms used in Exhibit "1," and the term "Customer," used in Exhibit "1," shall mean the Cooperatives.

(b) Any specific terms set forth in the articles of this Contract shall have precedence over any general provision contained in Exhibit "1," to the extent consistent with statutes and regulations of the United States.

## ARTICLE II

## SALE OF HYDRO PEAKING POWER AND ASSOCIATED ENERGY BY SOUTHWESTERN

Section 1. Sale of Hydro Peaking Power. Southwestern shall sell and deliver and the Cooperatives shall purchase and cause to be received 70,000 kilowatts of hydroelectric power (hereinafter "Hydro Peaking Power") with associated energy as set forth in Section 3 of this Article II. The amount of "Hydro Peaking Power" available may be subject to change under the provisions of Section 4 of Article VII contained herein.

Section 2. Definitions Applicable to the Sale of Hydro Peaking Power: (a) The following definitions shall apply to the purchase of Hydro Peaking Power under this Article II:

(i) The "Peaking Contract Demand" shall be the maximum rate in kilowatts at which Southwestern, subject to the provisions of this Section 2, is obligated to deliver energy associated with Hydro Peaking Power as set forth in Section 1 of this Article II.

(ii) The "Peaking Billing Demand" for any month shall be the Peaking Contract Demand.

(b) In order that the Cooperatives may fully utilize the energy associated with the quantities of Hydro Peaking Power set forth in Section 1 of this Article II, the Cooperatives shall be entitled to utilize the generating capacity available from Units 1 and 2 at Denison Dam, including any overload capacity; Provided, That, the Cooperatives shall not be entitled to use such generating capacity in quantities that, in the judgment of Southwestern, based upon criteria of the U.S. Army Corps of Engineers (hereinafter "Corps"), will result in undue wear and tear or will cause electrical and/or mechanical damage to such generators. Said capacity available to the Cooperatives shall be the "Scheduling Capacity." The Scheduling Capacity may, at times and from time to time, be less than or greater than the Peaking Contract Demand as set forth in Section 2(a)(i) of this Article II. The Peaking Billing Demand shall always be equal to the Peaking

Contract Demand, regardless of the amount of Scheduling Capacity, except as provided in Section 2(c) of this Article II.

(c) The quantity of Scheduling Capacity available to the Cooperatives pursuant to Section 2(b) of this Article II shall be reduced by a quantity of capacity equal to any reductions in capacity at Denison Dam due to outages of generating units and related transformation equipment or because of failures caused by an Uncontrollable Force; Provided, That, if the Scheduling Capacity available to the Cooperatives is reduced for a continuous period of 30 days due to Uncontrollable Force affecting generation and related transformation equipment at Denison Dam, the Peaking Contract Demand set forth in Section 2(a)(i) of this Article II shall be reduced thereafter by an amount equal to the generating capacity reduction caused by such equipment outage until the first day of the month following such time as the outage has been corrected and the capacity reduction eliminated.

Section 3. Sale of Peaking Energy. During each Contract Year, Southwestern shall sell and make available and the Cooperatives shall purchase and cause to be received all of the energy generated from Units 1 and/or 2 at Denison Dam in excess of that required for station service as provided in Section 4 of Article V hereof (hereinafter "Peaking Energy").

Section 4. Scheduling of Peaking Energy. (a) The Cooperatives shall be solely responsible for any energy lost at Denison Dam which is the result of improvident scheduling by the Cooperatives. Such lost energy shall be accounted for as Peaking Energy delivered to the Cooperatives by Southwestern. For the purposes of this Section 4(a), "improvident scheduling" shall be considered as scheduling under which the Cooperatives fail to schedule and receive energy necessary to comply with the Corps' operational requirements for other purposes and such energy equivalent is lost through spill.

(b) Southwestern cannot guarantee delivery to the Cooperatives of a particular quantity of capacity from Denison Dam generating unit(s), nor can Southwestern guarantee a minimum of Peaking Energy equivalent to 1,200 kilowatthours per kilowatt of Peaking Contract Demand without system support. It is hereby agreed, Therefore, That:

(i) During those periods when the Scheduling Capacity at Denison Dam is such that the Hydro Peaking Power available to the Cooperatives is less than the Peaking Contract Demand or the energy available from Denison Dam during a particular year is such that the Peaking Energy available to the Cooperatives is less than 1,200 kilowatthours per kilowatt of Peaking Contract Demand, the Cooperatives shall, at no cost, liability, or obligation to Southwestern, obtain from other power supply sources available to the Cooperatives, such additional capacity and/or energy as the Cooperatives require to assume the obligation of providing the necessary system support for a 1,200 kilowatthour per kilowatt of Peaking Contract Demand sale of Peaking Power by Southwestern to the Cooperatives.

(ii) During those periods when the Scheduling Capacity at Denison Dam available to the Cooperatives is greater than the Peaking Contract Demand, such additional capacity, if used by the Cooperatives, shall not be considered as an unauthorized overrun.

(iii) The Cooperatives shall be entitled to receive, during any particular year, all the energy that is generated by Unit 1 and/or Unit 2 as made available under this Contract, less Denison Dam station service requirements. The addition of generating units at Denison Dam shall not reduce the amount of water available for energy production by Units 1 and 2.

(iv) Hydro energy delivered by Southwestern from the Denison Dam shall be purchased by the Cooperatives as Peaking Energy; Provided, That, any such energy in excess of 1,200 kilowatthours per kilowatt of the Cooperatives' Peaking Contract Demand delivered by Southwestern during any Contract Year shall be purchased by the Cooperatives as Supplemental Peaking Energy.

Section 5. Compensation by the Cooperatives to Southwestern for Hydro Peaking Power and Peaking Energy. (a) The Cooperatives shall compensate Southwestern each month for Hydro Peaking Power and Peaking Energy purchased during the preceding month at the rates and under the terms and conditions set forth in Rate Schedule P-98C, attached as

Exhibit "2," and by this reference made a part hereof. The rates and/or terms and conditions set forth in the said rate schedule may, upon confirmation and/or approval by the appropriate authority having responsibility to so confirm and/or approve rate schedules, and whether on an interim basis or as finally confirmed and/or approved, be increased, decreased, modified, or superseded, at any time, and from time to time, and that if so increased, decreased, modified, or superseded, the new rates and terms and conditions shall thereupon become effective and applicable to the purchase and sale under this Contract of Hydro Peaking Power and Peaking Energy, in accordance with and on the effective date specified in the order of the appropriate authority.

(b) Southwestern shall promptly notify the Cooperatives in writing if the rates and/or terms and conditions set forth in the said Rate Schedule P-98C, or the then-effective rate schedule for the sale of Hydro Peaking Power and Peaking Energy, have been increased, decreased, modified, or superseded.

(c) If the rates and/or terms and conditions in the said Rate Schedule P-98C, or the then-effective rate schedule, are increased, decreased, modified, or superseded, as provided in Section 5(a) of this Article II, and if the Cooperatives do not wish to continue the purchase of Hydro Peaking Power and Peaking Energy under this Contract, the Cooperatives shall, within 6 months after receipt of notice from Southwestern under this Section 5, notify Southwestern in writing of the Cooperatives' election to terminate this Contract, such termination to be effective as of midnight, December 31, of the Contract Year specified by the Cooperatives, but not earlier than 6 months nor later than 36 months from the date of receipt by Southwestern of such notice from the Cooperatives. Hydro Peaking Power and Peaking Energy purchased by the Cooperatives during the period until the effective date of such termination shall be paid for at the then-effective rates and terms and conditions whether in effect or an interim basis or as finally confirmed and/or approved by the appropriate authority.

Section 6. Points of Delivery for Power and Energy Purchased by the Cooperatives.

(a) The nominal points of delivery for power and energy sold, delivered, and received under this Contract shall be at the points of electrical interconnection between the System of the Cooperatives and the System of Southwestern.

(b) Power and energy purchased under this Contract will be delivered from the System of Southwestern into the System of the Cooperatives for the account of the Cooperatives, and it is expressly understood and agreed that title to and responsibility for such power and energy passes to and is vested in the Cooperatives when such power and energy is delivered from the System of Southwestern in to the System of the Cooperatives at the nominal points of delivery, and that Southwestern neither has nor assumes any liability, responsibility, or obligation under this Contract for the transmission or displacement of such power and energy from or beyond such points of delivery.

Section 7. Operational Guidelines and Procedures. Operation of the Denison Dam Project is under the control of the Corps in order to facilitate coordination of power plant operation with other project purposes as well as power plant capabilities. Consequently, the project must be operated under certain operational guidelines and procedures as are required by the Corps, which may change from time to time. These operational guidelines and procedures, as may be amended from time to time by the Corps, shall be followed by the Cooperatives for the operation of the Denison Power Project consistent with existing and future requirements of the Corps and other related operational restraints. Southwestern will provide the Cooperatives with a copy of such procedures and, from time to time, with subsequent procedures as are required by the Corps.

## ARTICLE III

## SCHEDULING AGENT

Section 1. Authority of Scheduling Agent. Power and energy purchased, sold, exchanged, transmitted, or displaced by the Cooperatives under this Contract will be scheduled for delivery by the designated Scheduling Agent (hereinafter "Scheduling Agent"), for the Cooperatives, as evidenced by an agreement acceptable to Southwestern.

Section 2. Changes in Scheduling Agent or in Authority of Scheduling Agent. The Cooperatives may change the Scheduling Agent or authority of the Scheduling Agent at any time during the term of this Contract by giving written notice to Southwestern. Such changes shall be effective no sooner than 30 days after notice is given to Southwestern.

## ARTICLE IV

## CHARACTER OF DELIVERIES AND POWER FACTOR

Section 1. Character of Deliveries. Power and energy furnished by Southwestern under this Contract shall be delivered by Southwestern at a nominal voltage of 138 kV as 3-phase alternating current and at a frequency of approximately 60 Hertz.

Section 2. Power Factor. The System of Southwestern and the System of the Cooperatives are interconnected with other electrical systems in the area, neither Southwestern nor the Cooperatives will have complete control at all times of the power factor relating to the power and energy delivered to or received at the points of delivery under this Contract. The Cooperatives shall cause power and energy to be taken from the System of Southwestern at the points of delivery and at such power factor as will, from time to time, best fulfill the requirements of the party receiving such power and energy, but such party shall not impose a

reactive power loading on the System of Southwestern which will result in an overload or impairment of Southwestern's service or facilities. If the reactive power loading imposed at any point of delivery causes such overload or impairment, the party adversely affected shall have the right to open, or to cause the other to open, after notice to the party whose switches are to be opened, such interconnecting switches as may be necessary to eliminate such overload or impairment.

## ARTICLE V

## METERING, METER READING, AND ADJUSTMENTS

Section 1. Metering. Power and energy delivered under this Contract and the flow of power and energy between the System of the Cooperatives and the System of Southwestern shall be metered at the points of delivery set forth in Section 6 of Article II hereof, and accounted for in conformity with the practices of the electrical industry in the area.

Section 2. Meter Reading. Each meter and check meter installed or used under this Contract shall be read by the owner thereof or its authorized representative on or about the first day of each month, and may be simultaneously read by a representative of the other party if the other party so elects.

Section 3. Meter Tests and Adjustments. Metering equipment shall be inspected and tested at least once each year by the party responsible therefor or its authorized representative and at any reasonable time upon request therefor by either party. Metering equipment found to be defective or inaccurate shall be repaired and readjusted or replaced by the owner. A meter shall be considered inaccurate if it is found to deviate from an accurate standard meter in excess of 0.5 percent when tested at 100 percent of load or 1 percent when tested at 10 percent load. If any inspection or test discloses an error exceeding 2 percent, correction based upon the

inaccuracy found shall be made of the records of electric service furnished since the beginning of the monthly billing period immediately preceding the billing period during which the test was made, and such correction when made shall constitute full adjustment of any claim between the parties arising out of such inaccuracy of metering equipment.

Section 4. Station Service for Denison Dam. The Cooperatives shall furnish and deliver without charge such amounts of power and energy as may be required from time to time for station service at the Denison Dam Project. The parties agree that the term "station service," as used herein, shall mean only such service as is required for the operation of the power plant and for service in the immediate area of the dam which is customary and normal at other hydroelectric projects from which Southwestern markets power and energy. The amount of power and energy so furnished and delivered by the Cooperatives shall be netted off against the energy produced by Denison on a kilowatthour-for-kilowatthour basis by Southwestern.

Section 5. Black Start Service. The parties agree that Southwestern may provide Black Start service and associated testing from Denison Dam at some time in the future. Southwestern agrees to take into consideration the services and benefits provided to the Cooperatives pursuant to this Contract when providing such Black Start service and associated testing.

## ARTICLE VI

## INTEGRATED RESOURCE PLANNING

In order to encourage the process of comparing supply and demand options as a mechanism for meeting future electrical power requirements, the Cooperatives covenant and agree to the extent practicable to perform activities associated with Integrated Resource Planning (hereinafter "IRP") in securing future power resources. Such activities shall include the

analyses of both supply-side and demand-side measures in order to evaluate the full range of applicable alternatives for satisfying future load requirements. Such activities shall treat supply-side and demand-side resources on a consistent and integrated basis and shall provide for the inclusion of public participation appropriate to the Cooperatives. In analyzing supply and demand resource options, the Cooperatives shall consider all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, transportation, utilization, waste management, and compliance with environmental laws. The Cooperatives further agree to furnish non-proprietary information relative to its IRP activities as may be requested periodically by Southwestern and agree that such information may be furnished by Southwestern to its other customers in order to promote the IRP process for Southwestern's marketing region. Completion of IRP activities which are required of the Cooperatives by a State or another Federal Agency, shall be acceptable to Southwestern as compliance with this Article VI.

## ARTICLE VII

## EFFECTIVE DATE, TERM, LENDER APPROVAL, START OF SERVICE, CAPACITY INCREASES, NOTICES, REPORTS, AND INFORMATION

Section 1. Effective Date, Term of Contract, and Start of Service. This Contract shall become effective on the date of its execution by the Administrator of Southwestern or his authorized representative, and shall remain in force and effect until midnight, December 31, 2018, unless terminated sooner under other provisions of this Contract. The delivery of power and energy by Southwestern to or for the account of the Cooperatives, pursuant to the provisions of this Contract, shall begin on January 1, 2004.

Section 2. Lender Approvals. This Contract is subject to approval by the Rural Utilities Service (hereinafter "RUS"), and the National Rural Utilities Cooperative Finance Corporation

(hereinafter "CFC"). In the event the Cooperatives have not received approval from RUS and CFC within 60 days after the date of execution of this Contract, any party shall have a continuous right to terminate this Contract upon 30 days' advance written notice, until RUS and CFC approvals are obtained. Southwestern shall retain the right to market capacity and energy for Denison Dam during any interim period under current statutory authority.

Section 3. Capacity Increases. The current capacity rating of the two units at Denison Dam includes 70 megawatts of marketable capacity, as determined by Southwestern, and from time to time up to 10 megawatts of overload capacity. Any additional marketable and overload capacity in excess of 80 megawatts as determined by Southwestern which is made available by unit upgrades shall be made available to and purchased by the Cooperatives. The purchase of any additional marketable and overload capacity shall be made under the same terms, conditions, and rates applicable to the 70 megawatts purchased by the Cooperatives under this Contract, unless prior arrangements acceptable to Southwestern have been made for the marketing of such additional capacity. In no event shall the addition of generating units at Denison Dam reduce the amount of Hydro Peaking Power or Peaking Energy made available to the Cooperatives under this Contract.

Section 4. Notice. Any written notice, demand, or request required or authorized under this Contract shall be deemed properly given to or served on Southwestern if mailed to:

Administrator
Southwestern Power Administration
One West Third, Suite 1400
Williams Tower I
Tulsa, OK 74103

Any such notice, demand, or request shall be deemed properly given to or served on the Cooperatives if mailed to:

General Manager
Tex-La Electric Cooperative of Texas, Inc.
P.O. Box 631623
Nacogdoches, TX 75963-1623

President & General Manager
Rayburn Country Electric Cooperative, Inc.
P.O. Box 37
Rockwall, TX 75087-0037

The designation of the persons to be notified, or the addresses of such persons, may be changed at any time by the parties by written notice to the other parties.

Section 5. Reports and Information. Each party shall furnish to the other such reports and information concerning its operations as the other parties may reasonably request from time to time.

IN WITNESS WHEREOF, the parties have executed this Contract in several counterparts as of the day and year first above written, each of which shall constitute an original.

UNITED STATES OF AMERICA

By _____
Administrator
Southwestern Power Administration

Approved as to Legal
Form and Sufficiency

_____
General Counsel
Southwestern Power Administration

COPY

TEX-LA ELECTRIC COOPERATIVE
OF TEXAS, INC.

By S.W. Carter

Title PRESIDENT

ATTEST:

I, DEBRA ROBINSON, certify that I am the ASST. SECRETARY-TREASURER for TEX-LA ELECTRIC COOPERATIVE OF TEXAS, INC., and that S.W. CARTER, who signed this Contract on behalf of the said Corporation, was then the PRESIDENT of said Corporation, and that the said Contract was duly signed for and on behalf of the said Corporation by authority of its governing body which has within the scope of its corporate powers the authority to legally bind said Corporation under the foregoing agreement.

COPY

(SEAL)

By Debra Robinson

RAYBURN COUNTRY ELECTRIC
COOPERATIVE, INC.

By

Title Board Chairman

ATTEST:

I, Lawson White, certify that I am the Secretary/Treasurer for RAYBURN COUNTRY ELECTRIC COOPERATIVE, INC., and that Jack Schwartz, who signed this Contract on behalf of the said Corporation, was then the Board Chairman of said Corporation, and that the said Contract was duly signed for and on behalf of the said Corporation by authority of its governing body which has within the scope of its corporate powers the authority to legally bind said Corporation under the foregoing agreement.

(SEAL)

By Lawson White

Exhibit "1"

Southwestern Power Administration

# GENERAL CONTRACT PROVISIONS

Power Sales Contract


| Provision | Title | Page |
|---|---|---|
| A. | ACCOUNTING, BILLING, PAYMENT, AND LATE PAYMENT CHARGES | |
| 1. | Billing by Southwestern | 1 |
| 2. | Payment Terms | 1 |
| 3. | Net Billing | 2 |
| 4. | Payments by Southwestern | 2 |
| 5. | Propriety of Rates | 2 |
| 6. | Late Payment Charge | 2 |
| 7. | Late Payment Interest Charge | 3 |
| 8. | Penalty Charge for Late Payment | 3 |
| 9. | Late Payment Administrative Charge | 3 |
| 10. | Partial Payment | 3 |
| 11. | Discontinuance of Service | 3 |
| B. | STANDARD PROVISIONS | |
| 1. | Officials Not to Benefit | 4 |
| 2. | Covenant Against Contingent Fees | 4 |
| 3. | Convict Labor | 4 |
| 4. | Equal Employment Opportunity | 4 |
| 5. | Affirmative Action for Disabled Veterans and Veterans of the Vietnam Era | 4 |
| 6. | Affirmative Action for Handicapped Workers | 4 |
| 7. | Resale Rates | 4 |
| 8. | Availability of Funds to Southwestern | 5 |
| 9. | Termination for Breach | 5 |
| 10. | Waivers | 5 |
| 11. | Reliability and Adequacy of Service | 5 |
| 12. | Continuity of Service | 5 |
| 13. | Transfer of Interest and Abrogation of Rights to Federal Power | 6 |
| C. | FACILITIES SHARED BY THE PARTIES | |
| 1. | Facilities to be Furnished by Southwestern and the Customer | 6 |
| 2. | Reliability, Safety, Health, and Environmental Requirements in Regard to Construction, Operation, and Maintenance of Non-Federal Facilities on U.S. Government Property | 6 |
| 3. | Right of Installation and Access | 8 |
| 4. | Rights for Land Use Acquired by the Customer | 9 |
| 5. | Right of Removal | 9 |
| 6. | Right to Upgrade Facilities | 9 |
| 7. | Limitation of Rights of Entry | 10 |
| 8. | Assistance by Contracting Parties | 10 |

Southwestern Power Administration

# GENERAL CONTRACT PROVISIONS

## POWER SALES CONTRACT

### A. ACCOUNTING, BILLING, PAYMENT, AND LATE PAYMENT CHARGES

1. Billing by Southwestern. (a) Southwestern shall maintain an accurate record of power, energy, and any other services purchased by the Customer under this Contract.

(b) For each billing period in which the Customer makes one or more purchases under this Contract, Southwestern shall prepare an invoice in which such purchases are set forth in necessary detail, including the specific quantities of power, energy, and other services provided to the Customer during such billing period, and in which the compensation due Southwestern for such purchases is specified.

(c) Invoiced quantities may be based on estimates if actual quantities are not available. Adjustments, if any, due to a difference between estimated and actual quantities will be made on an invoice prepared during the billing cycle following the invoice which was based on estimated quantities.

2. Payment Terms. (a) Invoices shall be due and payable by the Customer on or before the close of business 20 calendar days after the invoice date, or shall be due and payable on the next business day thereafter if the said due date should fall on a Saturday, Sunday, or official Federal holiday.

(b) Payment of amounts due to Southwestern may be made through electronic funds transfer (EFT) or may be submitted as checks and mailed to:

Southwestern Power Administration
P.O. Box 845994
Dallas, Texas 75284-5994

(c) EFT payments shall conform to Southwestern protocols for electronic transfer of funds in effect at the time of the transaction.

(d) The designation of the address where payment is to be submitted may be changed by Southwestern upon 30 days' written notice to the Customer.

(e) Invoices shall be considered paid when payment is received into Southwestern's designated depository account or credited to Southwestern's depository account in the U.S. Treasury by the end of the business day; Provided, That payments received by mail are accepted as timely and will not be assessed late charges if a U.S. Postal Service postmark for first class mail shows that the payment was received by the Postal Service at least 2 calendar days before the due date; Provided Further, That payments received through EFT are accepted as timely and will not be assessed late charges if they are credited to Southwestern's depository account in the U.S. Treasury

on or before the third day after the due date or on the next business day thereafter if said third day is a Saturday, Sunday, or official Federal holiday.

3. Net Billing. (a) Whenever the parties agree, payments due Southwestern by the Customer may be offset against payments due the Customer by Southwestern for the sale or exchange of electric power, energy, and other services.

(b) For services included in net billing procedures, payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists.

(c) The parties shall exchange such reports and information as either party requires for billing purposes.

(d) Net billing procedures shall not be used for any amounts which Southwestern determines, in its sole judgment, to be in dispute.

4. Payments By Southwestern. Any payment due the Customer not satisfied by the Net Billing provision of Section 3 of this Part A, shall be made by Southwestern to the banking account of the Customer by Electronic Funds Transfer.

5. Propriety of Rates. (a) Southwestern shall bill the Customer for the Customer's purchases of power, energy, and other services in accordance with the rates placed in effect pursuant to statute.

(b) The Customer hereby agrees to promptly pay Southwestern under such rate schedules, whether or not the Customer agrees with the propriety or the levels of the rates placed into effect pursuant to law, regulation, or the order of an appropriate authority.

(c) In the event that the U.S. Congress amends the manner in which Southwestern calculates or charges for its power sales, the Customer hereby agrees to promptly pay in such an amended manner, subject to the Customer's right to terminate.

6. Late Payment Charge. (a) Southwestern shall assess the Customer a Late Payment Charge for each instance in which the Customer is delinquent in making payment to Southwestern.

(b) Such Late Payment Charge shall be computed by dividing by 12 the then-effective annual interest rate published in the Federal Register by the Department of Treasury, and multiplying the resultant monthly rate times the principal amount past due.

(c) Such Late Payment Charge shall be assessed only once for a particular invoiced amount which is past due, irrespective of the number of days between the due date and the final payment of such particular invoiced amount.

## B. STANDARD PROVISIONS

1. Officials Not to Benefit. No Member of or Delegate to Congress or Resident Commissioner shall be admitted to any share or part of this Contract or to any benefit that may arise therefrom, but this restriction shall not be construed to extend to this Contract if made with a corporation or company for its general benefit.

2. Covenant Against Contingent Fees. (a) The Customer warrants that no person or selling agency has been employed or retained to solicit or secure this Contract upon an agreement or understanding for a commission, percentage, brokerage, or contingent fee, except bona fide employees or bona fide established commercial or selling agencies maintained by the Customer for the purpose of securing business.

(b) For breach or violation of this warranty, the United States shall have the right to annul this Contract without liability, or, at its discretion, to add to the Contract price or consideration the full amount of such commission, percentage, brokerage, or contingent fee.

3. Convict Labor. In connection with the performance of work under this Contract, the Customer agrees not to employ any person undergoing sentence of imprisonment except as provided by Public Law 89-176, September 10, 1965 (18 U.S.C. 4062 (c)(2)), and Executive Order 11755, December 29, 1973.

4. Equal Employment Opportunity. During the performance of this Contract, the Customer agrees to abide by and to fulfill the nondiscrimination requirements of the "equal opportunity clause" contained in Section 202 of Executive Order 11246 dated September 24, 1965 (30 FF 12319), any Executive Order amending such order, and any other Executive Order superseding such order.

5. Affirmative Action for Disabled Veterans and Veterans of the Vietnam Era. During the performance of this Contract, the Customer agrees to comply with Section 402 of the Vietnam Era Veterans Readjustment Assistance Act of 1974, Public Law 93-508 as it amends Public Law 92-540, to take affirmative action to employ and advance in employment qualified disabled veterans and veterans of the Vietnam era, and to fulfill the requirements of the "affirmative action clause," 38 USCA Sections 2011 and 2012 (1979); 41 CFR 60-250 et seq.

6. Affirmative Action for Handicapped Workers. During the performance of this Contract, the Customer agrees to comply with Section 503 of the Rehabilitation Act of 1973, Public Law 93-516, to take affirmative action to employ and advance in employment qualified handicapped individuals, and to otherwise fulfill the requirements of the "affirmative action clause," 29 USCA Section 793 (1979); 41 CFR 60-741 et seq.

7. Resale Rates. The parties hereto understand and agree that the purpose of making federally generated power available is to encourage the most widespread use thereof, and the Customer therefore agrees that the benefits of federally generated power shall be made available at fair and reasonable terms to all of its consumers at the lowest possible rates consistent with sound business principles.

8. Availability of Funds to Southwestern. (a) This Contract and all rights and obligations hereunder, and the expenditure of funds by Southwestern under the provisions hereof, are expressly conditioned and contingent upon the Congress' making available (through direct appropriation, authorization of a revolving fund, the authority to borrow funds, or through such other means as it may provide) the necessary funds to enable Southwestern to carry out the provisions of this Contract, and if such funds are not available, this Contract shall terminate and have no further force or effect as of the last day for which funds were available, and the Customer hereby releases Southwestern from any and all liability for failure to perform and fulfill its obligations under this Contract for that reason.

(b) No obligation contained herein for the future payment of money by Southwestern, or liability on the part of Southwestern for breach of any of the provisions contained herein, shall be binding upon or enforceable against Southwestern unless and until funds, as provided in Section 8(a) of this Provision B, are available out of which such obligations or liability can be legally paid.

(c) Nothing in this Contract may be considered as implying that Congress will, at a later date, appropriate funds sufficient to meet any deficiencies or obligations incurred under this Contract.

9. Termination for Breach. (a) If either party hereto breaches a material provision of this Contract, the other party, at its option, may terminate this Contract upon 30 days' prior written notice of its intention to do so, and this Contract ipso facto shall terminate at the end of such 30-day period unless such violation is corrected within that period.

(c) Neither party hereto shall be considered to be in default or breach with respect to any obligation under this Contract if prevented from fulfilling such obligation by reason of an Uncontrollable Force.

10. Waivers. Waiver at any time of rights with respect to a default or any other matter arising in connection with this Contract shall not be deemed to be a waiver with respect to any subsequent default or matter.

11. Reliability and Adequacy of Service. (a) Electric service rendered by Southwestern under this Contract shall meet accepted standards of reliability and adequacy.

(b) If questions are raised concerning the quality of service, factual data shall be obtained with respect to the character of such service, and appropriate corrective or remedial action shall be promptly taken by the party at fault.

12. Continuity of Service. (a) Services provided by Southwestern to the Customer under this Contract shall be delivered by Southwestern as scheduled, except for interruptions or curtailments in delivery caused by an Uncontrollable Force, by the operation of devices or dispatcher action for system protection, or by the necessary installation, maintenance, repair, and replacement of equipment.

(b) Such interruptions or reductions in service, as hereinbefore set forth, shall not constitute a breach of this Contract, and neither party shall be liable to the other for damages resulting therefrom.

(c) Except in case of an emergency, Southwestern shall give the Customer reasonable advance notice of temporary interruptions or curtailments in service necessary for such installation, maintenance, repair, and replacement of equipment, and shall, insofar as is practicable, schedule such interruptions or curtailments so as to cause the least inconvenience to the Customer.

13. Transfer of Interest and Abrogation of Rights to Federal Power.

(a) No voluntary transfer of this Contract or of the rights of the Customer hereunder shall be made without the written approval of the Administrator, Southwestern; Provided, That any successor to or assignee of the rights of the Customer, whether by voluntary transfer, judicial sale, foreclosure sale, or otherwise, shall be subject to all the provisions and conditions of this Contract to the same extent as though such successor or assignee were the original contractor hereunder; Provided Further, That the execution of a mortgage or trust deed, or judicial or foreclosure sale made thereunder, shall not be deemed voluntary transfers within the meaning of this Section 13.

(b) The Customer will not sell, lease, or otherwise dispose of its electrical distribution system without giving Southwestern at least 120 days' prior written notice.

(c) The Customer's rights to Federal power and concomitant services, as set forth in this Contract and in Southwestern's Final Power Allocations (1980-1988) 45 FF 19032 (1980), come by virtue of the Customer's status as an entity entitled to preference in Southwestern's marketing of Federal power pursuant to Section 5 of the Flood Control Act of 1944 (58 Stat. 887,890; 16 U.S.C. 825s). If the Administrator, Southwestern, determines, in his or her sole judgment, that actions taken by the Customer have abrogated the Customer's status as a "preference" entity, then the Administrator may, at his or her sole option, terminate this Contract, such termination to become effective on the date specified by Southwestern, in an official written notice to the Customer.

## C. FACILITIES AND CONDITIONS OF SERVICE

1. Facilities to be Furnished by Southwestern and the Customer. Southwestern and the Customer shall furnish, install, maintain, and operate, or cause to be furnished, installed, maintained, and operated, such facilities and equipment, including metering equipment, as may be necessary to fulfill their respective obligations under this Contract and to assure reasonable protection to the facilities of others.

2. Reliability, Safety, Health, and Environmental Requirements in Regard to Construction, Operation, and Maintenance of Non-Federal Facilities on U.S. Government Property. (a) The provisions of this Section 2 shall apply only if the Customer, its agents or contractors, or its member entities perform maintenance, operations, or construction on the property of the U.S. Government (Government), or on easements shared by the Government and the Customer.

(b) Such construction, maintenance, and operation shall be performed in accordance with standards at least equal to those provided by the National Electrical Safety Code and shall conform to safety, environmental, and security procedures identified by Southwestern as appropriate to each facility in which such work is performed. Southwestern provides such written procedures in each of the facilities it maintains and to affected customers.

(c) The Customer and/or its member entities shall take all reasonable precautions in the performance of such work to protect the public and the environment. The Customer and/or its member entities shall comply with all applicable local, state, and Federal regulations and requirements in the performance of such work, including, but not limited to, the National Environmental Policy Act, the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Responsibility, Compensation, and Liability Act; the Toxic Substances Control Act; the Resource Conservation and Recovery Act; the Superfund Amendments and Reauthorization Act (SARA); SARA Title III (Emergency Planning and Community Right-to-Know Act of 1986); and the Occupational Safety and Health Act.

(d) In the event that Southwestern, at its sole option and in its sole judgment, determines that construction, maintenance, or operation of facilities which are performed under this Contract by the Customer, and/or one of its member entities, do not meet the standards and/or regulations and requirements specified in this Section 2, or if Southwestern determines, in its sole judgement, that a condition exists which provides a potentially adverse impact (1) on the reliability of services provided by Southwestern to its customers, (2) on the safety and/or health of the public or employees and agents of the parties hereto, and/or (3) on the environment, then Southwestern may provide written notice to the Customer and/or its member entity of the deficient condition; Provided, That, if such condition, in Southwestern's sole judgment and at Southwestern's sole option, requires immediate attention and does not allow time for such notice, Southwestern will remedy the condition and, where appropriate, bill the Customer in accordance with Section 8(b) of this Provision C.

(e) Where, in Southwestern's sole judgment, remedy of the said deficient condition is not time critical, the Customer and/or its member entity shall provide a written plan and schedule to Southwestern within 30 days of receipt of the said written notice. Such plan and schedule shall provide for correction of the said deficiency at the earliest possible time available to the Customer and/or its member entity; Provided, That, the maximum time allowed for the Customer and/or its member entity to correct any such deficiency shall not exceed 18 months from receipt of the said written notice. The Customer shall coordinate or, if applicable, cause its member entity to coordinate, any work and outages which may involve Southwestern's facilities with Southwestern's Dispatch Center (Dispatch Center) in Springfield, Missouri.

(f) Unless otherwise agreed in writing, correction of deficiencies pursuant to this Section 2 shall be at the expense of the Customer.

(g) If the Customer and/or its member entity fails to correct the deficiency within the time provided pursuant to this Section 2, Southwestern shall have the right, at

its sole option and in its sole discretion, to terminate service through the affected facilities until such deficiencies are corrected to the satisfaction of Southwestern.

(h) If, within the time period provided pursuant to this Section 2, an emergency condition occurs which, in the sole judgment of Southwestern, may cause an adverse impact on the reliability of the System of Southwestern and/or on the environment, or which poses a hazard to the safety and/or health of the public or employees and agents of the parties hereto, then Southwestern may, at its sole option, remedy or repair such condition or equipment and bill the Customer in accordance with Section 8(b) of this Provision C, and the Customer agrees to render Southwestern reimbursement as provided in the said Section 8(b).

3. Right of Installation and Access. (a) Each party hereto grants to the other permission, or will obtain such permission for the other party, to install, maintain, and operate, or cause to be installed, maintained, and operated, on the System of Southwestern and on the System of the Customer, at the points of delivery between the System of Southwestern and the System of the Customer described in this Contract, any and all terminal equipment and associated electrical apparatus and devices necessary in the performance of this Contract.

(b) Each party hereto shall permit, or shall obtain permission for, duly authorized representatives and employees of the other party to enter upon the System of Southwestern and the System of the Customer at the said points of delivery for the purpose of reading or checking meters; for inspecting, testing, repairing, renewing, or exchanging any or all of the equipment owned by the other party located on such premises; or for the purpose of performing any other work necessary in the performance of this Contract.

(c) Access for any work performed by one party under this Section 3 which may affect the other party's equipment shall normally be preceded by at least one day's notice to the affected party, except in the event of an emergency, in which case such notice shall be made as soon as possible after such emergency occurrence. Notice to Southwestern pursuant to this Section 3 shall be made to the Dispatch Center.

(d) Any access to property controlled by Southwestern shall include notification to Southwestern at the time of entry. Any employee or agent of the Customer, or of its member entities, who enters a Southwestern facility is expected to call the Dispatch Center from a telephone located in the control building in that facility and to identify himself or herself. Security devices located in the control buildings at Southwestern facilities sound an alarm in the Dispatch Center when the building is entered. Local law enforcement officers may be asked to investigate any unidentified entry.

(e) Any equipment, apparatus, or devices installed on the System of Southwestern by the Customer, as provided under this Section 3, shall be clearly and permanently marked to indicate ownership, and, in addition, a detailed description of each item so installed (including, if applicable, manufacturer's name, serial number, model number, etc.) shall be transmitted to Southwestern to aid in maintenance of plant accounts.

(f) In the event the equipment, apparatus, or devices are not marked in accordance with Section 3(e) of this Provision C, ownership of said equipment, apparatus, or devices shall be presumed to be vested in Southwestern.

(g) The Customer agrees that, if requested by Southwestern, the description required under Section 3(e) of this Provision C shall include a detailed analysis of all dielectrical oil, including, but not limited to, tests for polychlorinated biphenyls (PCBs). If such analysis indicates the presence of a known hazardous substance, which, in Southwestern's sole judgment, presents a significant hazard to the environment or to the health and safety of employees of the parties hereto, Southwestern may require, at its sole option, by written request, removal of any equipment containing such substance, and the Customer agrees to comply with such request for removal at no cost to Southwestern.

4. Rights for Land Use Acquired by the Customer. (a) The System of Southwestern is constructed, operated, and maintained by Southwestern subject to and in accordance with the terms and conditions of certain transmission line right-of-way easements. Rights and privileges granted thereunder to the Government may not be available to the Customer for operations connected with performance of this Contract.

(b) The Customer is therefore responsible for acquiring, or causing to be acquired, from the appropriate landowners, any and all rights and privileges for land use, by good and sufficient legal instruments, to authorize and permit entry by the Customer upon and across tracts affected by such land use as may be necessary and appropriate for performance of this Contract.

5. Right of Removal. Any and all equipment, apparatus, or devices placed or installed or caused to be placed or installed by the parties hereto on or in the System of Southwestern or the System of the Customer shall be and shall remain the property of the party owning and installing such equipment, apparatus, devices, or facilities, regardless of the mode or manner of annexation or attachment to real property, and, upon the termination of this Contract, the owner thereof shall have the right to enter upon the premises or system of the other and shall, within a reasonable time, remove such equipment, apparatus, devices, or facilities, subject to the provisions of Section 3 of this Provision C.

6. Right to Upgrade Facilities. (a) Southwestern reserves the right to modify or upgrade its transmission system and any of the elements which support the Southwestern transmission system, including, but not limited to, changes in: (1) Southwestern's transmission voltages, (2) Southwestern's transmission system components, (3) Southwestern's communications system, (4) Southwestern's Supervisory Control and Data Acquisition (SCADA) System, and (5) other modifications necessary to comply with the standards and/or regulations and requirements mentioned in Section 2 of this Provision C.

(b) If, during the term of this Contract, Southwestern determines, in its sole judgment and at its sole option, that modifications or upgrades to its transmission system and associated facilities are required, then, in that event, the Customer shall be

responsible for any and all costs and expenses incurred by the Customer in order to continue to receive services provided under this Contract.

(c) If the Customer elects not to make changes in its facilities which, in Southwestern's judgement, are required for the Customer to continue to receive reliable service from Southwestern's modified or upgraded facilities, then the Customer will discontinue receipt of the services provided under this Contract which are dependent on such modified or upgraded facilities, and the provisions of this Contract which describe such services shall be terminated or, at Southwestern's sole option, suspended, until the Customer completes the changes in its facilities which Southwestern, in its sole judgment, deems necessary for reliable service to the Customer under the aforesaid provisions.

(d) Southwestern shall notify the Customer of the specific sections or articles of the Contract which are to be terminated or suspended pursuant to Section 6(c) of this Provision C.

(e) The provisions of this Contract which are not specifically terminated or suspended pursuant to Section 6(d) of this Provision C shall not in any way be affected and shall remain in full force and effect except insofar as the services provided pursuant to the terminated or suspended provisions which are reflected in other provisions of this Contract will also be terminated or suspended.

(f) Termination or suspension of specific provisions of this Contract pursuant to Section 6(c) of this Provision C shall be without penalty to either of the parties hereto, except that the rights of the parties hereto, if any, which accrued prior to the date of such termination or suspension shall be and hereby are preserved.

7. Limitation on Rights of Entry. Southwestern reserves the right, upon notice to the Customer, to revoke or cancel the rights of entry granted under this Contract with regard to any particular representative of the Customer, if, in the sole judgment of Southwestern, such revocation or cancellation is required in the interest of national security.

8. Assistance by Contracting Parties. If assistance in maintenance and utilization of their respective systems is rendered by Southwestern and/or the Customer, the following terms and conditions shall apply:

(a) If, in the maintenance or utilization of their respective transmission systems and related facilities for the purpose of this Contract, it becomes necessary by reason of any emergency or extraordinary condition for Southwestern or the Customer to request the other to furnish personnel, materials, tools, and equipment for the maintenance or modification of, or other work on, such transmission systems and related facilities to insure continuity of power and energy deliveries, the party requested shall cooperate with the other and render such assistance as the party requested may determine to be available.

(b) The party making such request, upon receipt of properly itemized bills, shall reimburse the party rendering such assistance, including overhead and

administrative and general expenses. The Customer and Southwestern agree to account for any incurred costs under a Work Order accounting procedure and in accordance with the Uniform System of Accounts prescribed for public utilities by the Federal Energy Regulatory Commission. Billing statements rendered by the Customer and Southwestern for such reimbursement shall be due 20 days from the date thereof.

(c) No laborer or mechanic in the employ of the Customer, or its agents and contractors, for any of the work contemplated by this Section 8 shall be required or permitted to work in excess of 40 hours in any workweek except upon the condition that compensation is paid to such laborer or mechanic in accordance with the provisions of this Section 8.

(d) The wages of each laborer or mechanic employed by the Customer, or its agents and contractors, in the performance of any of the work contemplated by this Section 8 shall be computed on the basis of a standard workweek of 40 hours, and work performed in excess of such standard workweek may be permitted only upon the condition that each laborer or mechanic receives compensation at a rate not less than 1.5 times that worker's basic rate of pay for all hours worked in excess of 40 hours in any such workweek.

(e) For each violation of this Section 8, the Customer, or its agents and contractors, will be liable to the employee for his unpaid wages and, in addition, a penalty shall be imposed upon the Customer in the amount of ten dollars ($10) for each laborer or mechanic for each calendar day in which such laborer or mechanic is required or permitted to work in excess of the standard workweek of 40 hours upon said work without receiving compensation computed in accordance with this Section 8, and all penalties thus imposed shall be withheld for the use and benefit of the Government; Provided, That this Section 8 is subject to the provisions of the Contract Work Hours and Safety Standards Act of 1962 (Public Law 87-581, 76 Stat. 357-360), as amended; Provided Further, That if, from time to time, there is a conflict or inconsistency between the terms and conditions hereinbefore set forth and the provisions of any contract between the Customer and a labor union, the provisions of the labor union contract shall prevail if determined to be in compliance with then-applicable statutes and regulations issued thereunder.

Exhibit "2"

UNITED STATES DEPARTMENT OF ENERGY
SOUTHWESTERN POWER ADMINISTRATION

**RATE SCHEDULE P-98C[1]**
**WHOLESALE RATES FOR**
**HYDRO PEAKING POWER**

**Effective:**

During the period January 1, 2000, through September 30, 2001, in accordance with the Order of the Federal Energy Regulatory Commission issued _____, (_____).

**Available:**

In the marketing area of Southwestern Power Administration (Southwestern), described generally as the States of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

**Applicable:**

To wholesale Customers which have contractual rights from Southwestern to purchase Hydro Peaking Power and associated energy ( Peaking Energy and Supplemental Peaking Energy).

**Character and Conditions of Service:**

Three-phase, alternating current, delivered at approximately 60 Hertz, at the nominal voltage(s), at the points of delivery, and in such quantities as are specified by contract.

**Definitions of Terms:**

"*Customer*" is the entity which is utilizing and/or purchasing services from Southwestern pursuant to this rate schedule.

The "*Demand Period*" used to determine maximum integrated rates of delivery for the purpose of power accounting is the 60-minute period which begins with the change of hour. The term "*peak demand*" means the highest rate of delivery, in kilowatts, for any Demand Period during a particular month, at any particular point of delivery.

For the purposes of this Rate Schedule P-98B, the term "*point of delivery*" is used to mean either a single physical point at which electric power and energy are delivered from the System of Southwestern, or a specified set of delivery points which together form a single, electrically integrated load. "Peak demand" for such set of points is computed as the coincidental highest rate of delivery among the specified points rather than as the sum of peak demands for each individual physical point of delivery.

The term *"Peaking Contract Demand"* means the maximum rate in kilowatts at which Southwestern is, by contract, obligated to deliver Peaking Energy during any Demand

---

[1]**Supersedes Rate Schedules P-98B**

Period. Unless otherwise provided by contract, the *"Peaking Billing Demand"* for any month shall be equal to the "Peaking Contract Demand."

*"Ancillary Services"* are those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the System of Southwestern in accordance with good utility practice.

*"Scheduling, System Control, and Dispatch Service"* (an Ancillary Service) is provided by Southwestern as Control Area operator and is in regard to interchange and load-match scheduling and related system control and dispatch functions.

*"Reactive Supply and Voltage Control from Generation Sources Service"* (an Ancillary Service) is provided at transmission facilities in the System of Southwestern to produce or absorb reactive power and to maintain transmission voltages within specific limits.

*"Regulation and Frequency Response Service"* (an Ancillary Service) is the continuous balancing of generation and interchange resources accomplished by raising or lowering the output of on-line generation as necessary to follow the moment-by-moment changes in load and to maintain frequency within a Control Area.

*"Spinning Operating Reserve Service"* (an Ancillary Service) maintains generating units on-line, but loaded at less than maximum output, which may be used to service load immediately when disturbance conditions are experienced due to a sudden loss of generation or load.

*"Supplemental Operating Reserve Service"* (an Ancillary Service) provides an additional amount of operating reserve sufficient to reduce Area Control Error to zero within 10 minutes following loss of generating capacity which would result from the most severe single contingency.

*"Energy Imbalance Service"* (an Ancillary Service) corrects for differences over a period of time between schedules and actual hourly deliveries of energy to a load. Energy delivered or received within the authorized bandwidth (defined below) for this service is accounted for as an inadvertent flow and is returned to the providing party by the receiving party in accordance with standard utility practice.

**Energy Associated with Hydro Peaking Power:**

PEAKING ENERGY:

1,200 kilowatthours of Peaking Energy per kilowatt of Peaking Contract Demand will be furnished during each contract year.

SUPPLEMENTAL PEAKING ENERGY:

Supplemental Peaking Energy (in addition to Peaking Energy) will be furnished if and when determined by Southwestern to be available, to be provided at rates of delivery which do not exceed the Customer's Peaking Contract Demand.

**Monthly Rates for Peaking Contract Demand:**

CAPACITY CHARGE FOR HYDRO PEAKING POWER:

$2.56 per kilowatt of Peaking Billing Demand.

**Services Associated with Capacity Charge for Hydro Peaking Power**

The capacity charge for Hydro Peaking Power includes such transmission services as are necessary to integrate Southwestern's resources in order to reliably deliver Hydro Peaking Power and associated energy to Customers. This capacity charge also includes Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service.

**Secondary Transmission Service under Capacity Associated with Hydro Peaking Power**

Customers may utilize the capacity associated with Peaking Contract Demand for the transmission of non-Federal energy, on a non-firm, as-available basis, at no additional charge for such transmission service or associated Ancillary Services, under the following terms and conditions:

(1) the sum of the capacity, for any hour, which is used for Peaking Energy, Supplemental Peaking Energy, and Secondary Transmission Service, may not exceed the Peaking Contract Demand.;

(2) the non-Federal energy transmitted under such secondary service is delivered to the Customer's point of delivery for Hydro Peaking Power;

(3) the Customer pays or commits to provide for Real Power Losses associated with such deliveries of non-Federal energy; and

(4) Southwestern determines that sufficient transfer capability exists between the point of receipt into Southwestern's system of such non-Federal energy and the Customer's point of delivery for Hydro Peaking Power for the time period that such secondary transmission service is requested.

**Rates for Energy Associated with Hydro Peaking Power:**

ENERGY CHARGE:

(a) $0.0048 per kilowatthour of Peaking Energy and Supplemental Peaking Energy delivered; plus (b).

(b) A purchased power adder of $0.0011 per kilowatthour of Peaking Energy delivered, as adjusted by the Administrator, Southwestern, in accordance with the procedure within this rate schedule. This adder does not apply to:

Supplemental Peaking Energy, or

Sales to any Customer which, by contract, has assumed the obligation to supply energy to fulfill the minimum of 1,200 kilowatthours of Peaking

Energy per kilowatt of Peaking Contract Demand during a contract year (Contract Support Arrangements).

**Monthly Rates for Transformation Service:**

CAPACITY CHARGES FOR TRANSFORMATION SERVICE: A charge of $0.25 per kilowatt will be assessed for capacity used to deliver energy at any point of delivery at which Southwestern provides transformation for deliveries at voltages of 69 kilovolts or less from higher voltage facilities.

**Application of Capacity Charges for Transformation Service**

For any particular month, charges for transformation service will be assessed on the greater of (1) that month's actual peak demand, or (2) the highest peak demand recorded during the previous 11 months, at any point of delivery. For the purpose of this Rate Schedule P-98C, the peak demand will be based on all deliveries, of both Federal and non-Federal energy, from the system of Southwestern, at such point during such month.

**Rates for Ancillary Services:**

CAPACITY CHARGES FOR ANCILLARY SERVICES:

(a) Regulation and Frequency Response Service
A monthly rate of $0.04 per kilowatt of Peaking Billing Demand

(b) Operating Reserves Service: Spinning Reserve
A monthly rate of $0.0073 per kilowatt of Peaking Billing Demand
A daily rate of $0.00033 per kilowatt for non-Federal generation inside Southwestern's control area.

(c) Operating Reserves Service: Supplemental Reserve
A monthly rate of $0.0073 per kilowatt of Peaking Billing Demand
A daily rate of $0.00033 per kilowatt for non-Federal generation inside Southwestern's control area.

(d) Energy Imbalance Service:
no charge

**Availability of Ancillary Services**

Ancillary Services (a) and (d) listed above are available only for deliveries of power and energy to load centers within Southwestern's Control Area. Ancillary Services (b) and (c) listed above are available only for deliveries of non-Federal power and energy generated by resources located within Southwestern's Control Area and for deliveries of all Hydro Peaking Power and associated energy from and within Southwestern's Control Area. Where available, such Ancillary Services must be taken from Southwestern; unless, subject to Southwestern's approval, they are provided by others.

**Application of Ancillary Services Charges**

For any month, the charges for Ancillary Services (a), (b), (c) and (d) listed above for deliveries of Hydro Peaking Power shall be based on the Peaking Billing Demand.

The daily charge for Ancillary Services (b) and (c) for non-Federal generation inside Southwestern's Control Area shall be applied to the greater of Southwestern's previous day's estimate of the peak, or the actual peak, in kilowatts, of the internal non-Federal

generation. For any particular customer with internal generation, the monthly accumulation of daily charges shall be reduced by the amount that transmission customer(s) are charged for Ancillary Services (b) and (c) for a particular month under rate schedule NFTS-98C when the source of power is such internal generation.

**Provision of Ancillary Services by Others**

Customers for which Ancillary Services (a), (b), (c) and (d) are made available as specified above, must inform Southwestern by written notice of the Ancillary Services which they do not intend to take and purchase from Southwestern, and of their election to provide all or part of such Ancillary Services from their own resources or from a third party.

Subject to Southwestern's approval of the ability of such resources or third parties to meet Southwestern's technical requirements for provision of such Ancillary Services, the Customer may change the Ancillary Services which it takes from Southwestern and/or from other sources at the beginning of any month upon the greater of 60 days notice or upon completion of any necessary equipment modifications necessary to accommodate such change.

**Limitations on Energy Imbalance Service**

Energy Imbalance Service primarily applies to deliveries of power and energy which are required to satisfy a Customer's load. As Hydro Peaking Power and associated energy are limited by contract, the Energy Imbalance Service bandwidth specified in Southwestern's Open Access Transmission Service tariff does not apply to deliveries of Hydro Peaking Power, and therefore Energy Imbalance Service is not charged on such deliveries. Customers which consume a capacity of Hydro Peaking Power greater than their Peaking Contract Demand may be subject to a Capacity Overrun Penalty.

**Application of Capacity Overrun Penalty**

Customers which have loads within Southwestern's Control Area are obligated by contract to provide resources, over and above the Hydro Peaking Power and associated energy purchased from Southwestern, sufficient to meet their loads. A Capacity Overrun Penalty shall be applied only when the formulas provided in Customers' contracts indicate an overrun on Hydro Peaking Power, and investigation determines that all resources, both firm and non-firm, which were available at the time of the apparent overrun were insufficient to meet the Customer's load.

CAPACITY OVERRUN PENALTY

For each hour during which Hydro Peaking Power was provided at a rate greater than that to which the Customer is entitled, the Customer will be charged a capacity overrun penalty at the following rates:

| Months Associated With Charge | Rate per Kilowatt |
|---|---|
| March, April, May, October, November, December | $0.10 |
| January, February, June, July, August, September | $0.30 |

**Application of Energy Overrun Penalty**:

By contract, the Customer is subject to limitations on the maximum amounts of Peaking Energy which may be scheduled during any month or during any four consecutive months. When the Customer schedules amount in excess of such maximum amounts for any month, or schedules more than 1,200 hours of Peaking Energy per kilowatt of Peaking Contract Demand in any contract year, such Customer is subject to the Energy Overrun Penalty.

ENERGY OVERRUN PENALTY:

For each kilowatthour of overrun: $0.053 per kilowatthour

**Rates for Real Power Losses**

The Customer shall purchase real power losses unless it elects to self-provide such losses under the provision detailed below in *Annual Election to Self Provide Real Power Losses.*

Real Power Losses are computed as four (4) percent of the total amount of non-Federal energy transmitted under a particular Customer's Peaking Contract Demand. The monthly charge for such Real Power Losses will be computed on a per kilowatthour basis as follows:

$$MC = .04 \times NFE \times R$$

with the factors defined as follows:

MC = The monthly charge ($) by Southwestern for Real Power Losses of non-Federal energy transmitted under the capacity associated with Hydro Peaking Power;

NFE = The amount of non-Federal energy (kWh) transmitted under a Customer's Peaking Contract Demand during a particular month; and

R = The rate for Real Power Losses ($ per kWh), is equal to the average of Southwestern's actual costs for the purchase of energy to replace Real Power Losses during the previous fiscal year (October through September), as reflected in Southwestern's financial records.

The rate for Real Power Losses will be posted on Southwestern's OASIS by November 1 of each year. This rate will be effective for one year beginning January 1 of each calendar year.

*Annual Election to Self Provide Real Power Losses*: The Customer may elect, on an annual basis, to self-provide all loss energy for which it is responsible subject to the following conditions:

(1) Such election for self-provision shall be for a full calendar year (January through December) for that Customer and shall be exercised by execution of a Real Power Losses service agreement, or equivalent, before December 1 of the prior calendar year;

(2) Unless otherwise specified in the Real Power Losses service agreement, the Customer shall schedule the delivery of real power losses into the System of Southwestern at the rate of one megawatt of real power losses for every 25 megawatts of non-Federal power and energy delivered to Customer's loads served from the points of delivery set forth in the Southwestern/Customer contract;

(3) The initial election for self-provision of real power losses will take place by January 1, 2000, with initial implementation for service beginning February 1, 2000. Thereafter, election for self-provision will occur in accordance with condition (1) above.

(4) For any new customer taking transmission service from Southwestern after January 1, 2000, election to self-provide real power losses shall be made at the time the contract is negotiated. Such service shall be implemented as provided for in the contract and the election to self-provide shall apply through the end of that calendar year for all transmission services.

**Requirements Related to Power Factor**

Any Customer served from facilities owned by or available by contract to Southwestern will be required to maintain a power factor of not less than 95 percent lagging for each electrically integrated load except where point(s) are considered point(s) of system integration for mutual system support.

**Determination of Power Factor**

The power factor may be determined at intervals or continuously, at the option of Southwestern, and shall be computed under the formula:

$$PF = (kWh \times 100) \div \sqrt{(kWh^2 + rkVAh^2)} \quad ,$$

with the factors defined as follows:

PF = the power factor (in percentage) for any Demand Period of the month.

kWh = the total quantity of energy which is delivered during such Demand Period to the Customer's electrically integrated load, through all Southwestern points of delivery other than those points which are points of system integration for mutual system support.

rkVAh = the total quantity of reactive kilovolt-ampere-hours (kvars) delivered during such Demand Period to the Customer's electrically

integrated load through all Southwestern points of delivery other than those points which are points of system integration for mutual system support.

**Power Factor Penalty**

Power factor penalties may be assessed for any month in which the formula above, when calculated for any Demand Period during such month, yields a power factor of less than 95 percent lagging. The penalty is assessed for such month in accordance with the following formula:

PENALTY = PD x PFP x $1.00

with the factors defined as follows:

PENALTY = The amount in dollars to be assessed on the monthly invoice to the Customer as the Power Factor Penalty.

PD = The Customer's peak demand in kilowatts at the point or points of delivery for the month in which a low power factor was calculated.

PFP = The percentage equal to the difference, rounded to the nearest 1 percent, between 95 percent lagging and the computed power factor.

**Application of Power Factor Penalty**

No penalty is assessed for leading power factor. Southwestern, at its sole option, may determine whether power factor calculations should be applied to a single physical point of delivery or to multiple physical points where a Customer has a single, electrically integrated load served through multiple points. The general criteria for such decision shall be that, given the configuration of the Customer's and Southwestern's systems, Southwestern will determine, in its sole judgment, whether the power factor computation more accurately assesses the detrimental impact on Southwestern's system when the above formula is calculated for a single physical point of delivery or for a combination of physical points.

Southwestern, at its sole option, may waive power factor penalties when, in Southwestern's sole judgment, low power factor conditions were not detrimental to the system of Southwestern due to particular loading and voltage conditions at the time power factor dropped below 95 percent lagging.

**Adjustment for Reduction in Service:**

If, during any month, the quantity of Peaking Contract Demand scheduled by the customer for delivery is reduced by Southwestern for a period or periods of not less than two consecutive hours by reason of an outage caused by either an uncontrollable force or by the installation, maintenance, replacement or malfunction of generation, transmission and/or related facilities on the system of Southwestern, the Customer's capacity charges

for such month will be reduced for each such reduction in service by an amount computed under the formula:

$$R = (C \times K \times H) \div S$$

with the factors defined as follows:

R = the dollar amount of reduction in the monthly total capacity charges for a particular reduction of not less than two consecutive hours during any month, except that the total amount of any such reduction shall not exceed the product of the Customer's capacity charges associated with Hydro Peaking Power times the Peaking Billing Demand.

C = the Customer's capacity charges associated with Hydro Peaking Power for the Peaking Billing Demand for such month.

K = the reduction in kilowatts in Peaking Billing Demand for a particular event.

H = the number of hours duration of such particular reduction.

S = the number of hours that Peaking Energy is scheduled during such month, but not less than 60 hours times the Peaking Contract Demand.

**Procedure for Determining Southwestern's Net Purchased Power Adder Adjustment**

Not more than once annually, the Purchased Power Adder of $.0011 (1.1 mills) per kilowatthour of Peaking Energy, as noted in this Rate Schedule, may be adjusted by the Administrator, Southwestern, by an amount up to ±$.0011 (1.1 mills) per kilowatthour, as calculated by the following formula:

$$ADJ = (PURCH - EST + DIF) \div SALES$$

with the factors defined as follows:

ADJ = the dollar amount of the total adjustment, plus or minus, to be applied to the Net Purchased Power Adder, rounded to the nearest $.0001 per kilowatthour, provided that the total ADJ to be applied in any year shall not vary from the then-effective ADJ by more than $.0011 per kilowatthour;

PURCH = the actual total dollar cost of Southwestern's System Direct Purchases as accounted for in the financial records of the Southwestern Federal Power System for the period;

EST = the estimated total dollar cost ($2,563,300 per year) of Southwestern's System Direct Purchases used as the basis for the Purchased Power Adder of $.0011 per kilowatthour of Peaking Energy;

DIF = the accumulated remainder of the difference in the actual and estimated total dollar cost of Southwestern's System Direct Purchases

since the effective date of the currently approved Purchased Power Adder set forth in this rate schedule, which remainder is not projected for recovery through the ADJ in any previous periods;

SALES = the annual Total Peaking Energy sales projected to be delivered (2,240,300,000 KWh per year) from the Southwestern System, which total was used as the basis for the $.0011 per kilowatthour Purchased Power Adder.