APPENDIX A

POWER BENEFITS FOREGONE

US Army Corps of Engineers ®
Northwestern Division

Special Note

Per telephone conversation with Kamau Sadiki on 17 December 2004 the following values were corrected. Please note changes in Table 5-1 on page A-42 from $6,942 and $27,522 to $6,909 and $27,553, respectively. Also, changes in Table 6-2 page A-45 from $1,926 and $7,639 to $1,929 and $7,644, respectively. Note that there are also other locations within this report that these changes may have an impact.

Allen Piner

DEPARTMENT OF THE ARMY
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Reply to
Attention of:

May 14, 2004

Columbia Basin Water Management Division

Mr. Allen Piner
Coastal, Hydrology and Hydraulics Section
US Army Corps of Engineers, Wilmington District
PO Box 1890
Wilmington, North Carolina 28402-1890

Dear Mr. Piner:

Please accept, with my gratitude, the enclosed copies of the John H. Kerr/City of Henderson Water Supply Storage Reallocation Report, Power Benefits Foregone, recently performed by the Corps of Engineers' Hydropower Analysis Center (HAC). The HAC was pleased to work with you on this report. This final report contains an independent technical review and certification for the work performed by HAC.

As your time allows, please complete the short HAC Customer Satisfaction Feedback online at http://www.nwd-wc.usace.army.mil/PB/welcome.html by clicking on the "FEEDBACK" link near the bottom of the page. When the "Submit Comments" tab at the bottom of the survey page is clicked, your comment will be compiled and forwarded to HAC. Your feedback on our processes and products is very valuable to us.

Thank you in advance for your time and consideration. Please don't hesitate to contact the HAC in the future whenever we can be of service to you and your organization.

Sincerely,

Kamau Sadiki
Technical Manager
Hydropower Analysis Center

JOHN H. KERR POWERHOUSE
ROANOKE RIVER
VIRGINIA & NORTH CAROLINA

CITY OF HENDERSON
WATER SUPPLY STORAGE
REALLOCATION

POWER BENEFITS FOREGONE

APRIL 2004

Prepared for

U.S. Army Corps of Engineers
Wilmington District
Wilmington, North Carolina

PREPARED BY
HYDROPOWER ANALYSIS CENTER

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JOHN H. KERR
ROANOKE RIVER, VIRGINIA-NORTH CAROLINA

CITY OF HENDERSON
WATER SUPPLY STROAGE REALLOCATION

POWER BENEFITS FOREGONE

APRIL 2004

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INTRODUCTION

Purpose and Scope

This report, prepared by the Hydropower Analysis Center (HAC), Corps of Engineers, for the Wilmington District (SAW), Corps of Engineers, presents details of the hydropower benefits and economic analysis associated with the proposed water supply storage reallocation from the Corps of Engineer's John H. Kerr Reservoir on the Roanoke River, requested by the City of Henderson, North Carolina. The hydropower impacts of reallocating conservation storage to water supply storage at the John H. Kerr reservoir will be analyzed. Also, hydropower impacts at two privately owned hydropower projects will be evaluated. Hydropower impacts at the John H. Kerr powerhouse will be quantified by computing economic values for the following parameters:

- power benefits foregone
- revenues foregone
- credit to the Federal Power Marketing Agency (Southeastern Power Administration)

Values were computed for each of these parameters for the proposed reallocation of reservoir storage. Only energy impacts (in MWh) were quantified at the downstream privately owned projects. Virginia Power Company, project owners, can apply non-Federal economic or financial parameters to energy impacts quantified here to determine their economic loss.

The scope of this analysis is to determine the Federal economic loss to hydropower due to the reallocation of storage from hydropower to water supply based on the City of Henderson's water withdrawal request of five (5) and twenty (20) million-gallons per day (MGD).

Project Description

The John H. Kerr project is located on the Roanoke River, on the Virginia-North Carolina border, north of the City of Henderson, North Carolina, and east of the city of South Boston, Virginia. The authorized Federal purposes of the project are flood mitigation/reduction in the Roanoke River basin below the project, the production of hydropower and provide recreation resources for the region.

The project was constructed during the years 1946 to 1953. The powerhouse has seven generating units – six 32 MW units and one 12 MW unit, for a total installed capacity of 204 MW. These units generated an average of 448 gigawatt-hours (GWh) of energy annually over the period of 1930 to 2001, yielding an average annual plant factor of 25 percent. The Kerr project has a total of 2,770,000 acre-feet (AF) of storage, of which

1,027,000 AF (elevation 268 ft to 300 ft) is reserved for power storage. A contractual capacity obligation with the Southeastern Power Administration (SEPA) restricts the power operation between elevations 293 feet and 300 feet range with infrequent operation below elevation 293 feet. The subject of this report is to evaluate the impacts to hydropower generation due to the purposed reallocation of a portion of this storage from power generation to water supply.

Downstream of John H. Kerr project are two non-Federal hydropower projects, Gaston and Roanoke Rapids owned and operated by Virginia Power Company.

The Water Supply Act of 1958 established a Federal policy of cooperation in development of municipal water supplies by reallocating the reservoir storage of original authorized purposes to include municipal water supply. Currently, the allocation for water supply storage in the John H. Kerr reservoir conservation pool is about 10,800 acre-feet. The distribution of this storage among existing users is shown in Table 1-1.

Table 1-1: Existing Water Supply Storage Allocations in John H. Kerr Reservoir

Entity	Contract Amounts
Virginia Beach	10,200 AF
Virginia Department of Corrections	23 AF
Mecklenburg Cogeneration Limited Partnership	600 AF
Clarksville (& Burlington Industries)	(3.8 MGD in 1999)
Henderson	(<20 MGD, 5.9 MGD in 2001)

The City of Henderson entered into a water use contract with the Federal Government on February 12, 1974 that will expire in 2004. The contract allows water withdrawal from John H. Kerr Reservoir at a rate not to exceed 20 MGD per day. Usage for 2001 was 5.9 MGD. The City of Henderson has requested a conversion of the current “water use” contract to a ”water storage” agreement. In a “water use” agreement the user pays a fee for water from storage based on availability and do not acquire any permanent rights. Where as, in “water storage” agreement the user pays an amortized fee for a block of storage space in the reservoir and acquires a permanent right to use the storage space for water supply regardless of water availability.

Contracted storage rights for water supply in John H. Kerr Reservoir are from storage in the conservation zone between elevations 268 and 300 feet mean sea level (MSL) as long as water in the storage space is available. Several water supply contracts to use water storage space in Kerr Reservoir are in effect as shown in Table 1-1 above.

Study Participants

This report was prepared by the HAC of the Northwestern Division, North Pacific Region, Corps of Engineers. The primary HAC point of contact was Kamau Sadiki, HAC Technical Manage (telephone: (503) 808-3980; e-mail: kamau.b.sadiki@usace.army.mil). Former HAC engineer Dinh Quan produced the power values and HAC engineer Russ Davidson performed the hydropower benefits analysis. Kamau Sadiki performed the internal technical review and served as overall study coordinator for HAC. Mr. Alan Piner, Wilmington District, server as the project manager.

The Cost of Water Supply

The procedures for computing the cost of storage reallocation addressed in this study are outlined in Appendix E, paragraph E-57, d(2) of ER 1105-2-100, *Planning Guidance Notebook* (22 April 2000). These procedures require that the reallocation cost of the water supply customers be the highest of the following;

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

Although reservoir storage reallocations could result in impacts to other project purposes this report only evaluates the impacts to hydropower. Therefore, power benefits foregone in this evaluation are a power related impact. The revenue foregone and replacement cost of power are also power-related. The updated cost of storage is non-power related and will not be evaluated in this report. The Wilmington District will compute the updated cost of storage based the storage necessary to yield the requested withdrawals.

The following paragraphs briefly describe each of these power-related values.

Power Benefits Foregone

Hydropower benefits are normally based on the cost of the most likely alternative thermal source of power. When conservation storage is reallocated for water supply, the lost hydropower to the electrical system will be replaced with the most likely alternative thermal source of power.

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

In addition, there could be a loss of capacity benefits as a result of a loss in dependable capacity at the project. Loss of dependable capacity could be a result of:

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

The details of energy and capacity benefits computations are described in Chapter 3 and 4, respectively.

Revenues Foregone

The second power-related cost is revenue foregone. This is the value of the lost power based on the power marketing agency's current energy rates. The calculations for revenues foregone are contained in Chapter 6.

Replacement Cost of Power

The third power-related cost is the cost of replacement power. This is an economic or National Economic Development (NED) cost, and is therefore a redundant value in the case of hydropower. This is because the NED power benefits foregone are based on the cost of the most likely thermal alternative, which in fact is the cost of replacement power. Replacement cost is included in the guidance as one of the four alternatives to be evaluated because it has meaning when storage is reallocated from functions other than hydropower. For example, if the objective is to reallocate flood control storage to water supply, the replacement cost of flood control storage would have to be considered, because this storage would have an entirely different value than the flood control benefits foregone. However, for a hydropower/conservation storage reallocation, the replacement cost of hydropower is identical to the power benefits foregone.

Note that Appendix E, d(2)(c)(3), *Planning Guidance Notebook* (22 April 2000), also discusses a replacement cost based on financial or actual market prices, but this is an entirely different value than the replacement cost discussed in the paragraph above. The market-based replacement cost is to be used to compute a possible credit to the power marketing agency. If the water supply reallocation results in less hydropower being available to the marketing agency for delivery to its customers, the marketing agency will receive a credit to offset additional costs that they might incur and to reduce their repayment obligation. The calculation of this value is shown in Chapter 7.

POWER BENEFITS FORGONE

General

The details of energy and capacity benefit computation are described in Chapters 3 and 4, respectively. This chapter describes some of the terminology, methodology, and basic assumptions required for computing these benefits.

Unit Power Values

The power benefits foregone are computed by applying unit power values to the loss in average annual generation and dependable capacity at John H. Kerr hydropower plant. The capacity value, which is applied to the dependable capacity loss, represents the unit cost of constructing an increment of thermal power to replace the lost hydropower capacity. The energy value, which represents the unit cost of producing replacement energy in the area power system in which the John H. Kerr hydropower plant operates, is applied to the loss in average annual generation of hydropower.

These values were derived using NED economic criteria, in accordance with the U.S. Water Resources Council's Economics and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies, previously referenced as ER 1105-2-100, *Planning Guidance Notebook* (22 April 2003).

Interest Rate

The interest rate used in computing power benefits foregone due to water supply storage reallocation is the current (Fiscal Year 2004) Federal interest rate of 5-5/8 percent.

Period of Analysis

The economic period of analysis for this study is 50 years. The “Period of Analysis” as define in *Planning Guidance Notebook*, Section 2-4j, for a multiple-purpose reservoir project, is not to exceed 100 years. In section E-63 i(1)(a)(1), “Benefits Foregone”, defines the period of analysis for storage reallocations as the greater of (a) the remaining economic life of the project, or (b) 50 years. Benefits foregone are computed assuming the water supply contract will be implemented in 2005. The power on-line date, total economic life, and remaining economic life for the project are shown in Table 2-1.

Table 2-1: Pertinent Study Data

Hydropower and Economic Parameters

Power Generation Parametes	
Installed capacity (MW)	204
Average head (ft)	95
Average efficiency (%)	85
Economic Parameters	
Power on-line (POL) date	1953
Total Project life (yrs)	100
Remaining life (yrs)	50

Price Level

The unit capacity value and fuel prices used in determining the unit energy value, was based on August 2003 price levels. Real fuel cost escalation was not utilized in developing annual energy values. Therefore, the August 2003 level fuel prices were assumed to apply over the entire period of analysis.

Most Likely Thermal Alternative

The most likely thermal alternatives to the John H. Kerr hydropower generation is natural gas-fired combustion turbine (59%) and combined cycle (41%), which was determined by using the screening curve analysis method, as described in Section 4.5.5. The thermal replacement alternative will be used to displace the John H. Kerr capacity in the system.

The Kerr-Philpott Model and Determination of Yield

The Wilmington District performed a yield analysis to determine the amount of storage in the conservation pool that should be reallocated to water supply to yield 5 and 20 MGD. The District's Kerr-Philpott streamflow routing model was used to perform the storage-yield analysis. The operation of the reservoir was based on existing operating and water control plans using daily historical flows from 1930 to the year 2000. The results of the simulations are shown in Table 2-2. The storage reallocation needed to yield a 5 MGD

flow is 2,600 acre-feet and 10,700 acre-feet of reallocated storage is needed to yield a flow of 20 MGD.

Table 2-2: Reservoir Yield

Yield (MGD)	Yield (CFS)	Storage Required from Conservation Zone (AF)
5	7.74	2,700
20	30.94	10,700

Study Assumptions

For this water supply evaluation, storage reallocation to meet the requested withdrawals will only be considered from the conservation pool in the John H. Kerr reservoir. Reallocating storage from the flood control pool will not be evaluated at the Wilmington District's request. The John H. Kerr reservoir is operated to a strict flood control rule curve. When the reservoir elevation exceeds the flood control rule, the first priority is to evacuate excess water immediately. The District has determined that the loss of any of the existing flood control storage could cause severe flooding downstream of the project if a 50-year flood event were to occur. Therefore, the reallocation of available storage was limited to the conservation pool.

A major rehabilitation of the John H. Kerr powerhouse is being planned. The recommended alternative in the John H. Kerr Major Rehabilitation Report, dated February 2001 (updated January 2002), would upgrade the existing seven turbines at the power plant. The upgraded units were not considered in this analysis due to funding uncertainties for construction of the recommended rehabilitation alternative. Therefore, the existing powerhouse unit capabilities were used to compute energy and capacity impacts to John H. Kerr power generation due to water withdrawals.

Energy and capacity losses from the station service units were not included in this analysis because the power generated is consumed by the project and does not enter the power grid for distribution and sale.

ENERGY BENEFITS FOREGONE

General

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

The loss of energy benefits can be calculated using several methods. For this analysis, an hourly system production cost model was used to determine the value of a unit of energy, ($/MWh). This approach provides a more accurate measure of energy benefits foregone. The system production cost model performs a detailed economic dispatch of hydropower generation in a particular power system. The difference in system production cost between "with" and "without" project alternatives is converted into an energy value that is used to quantify energy benefits foregone due to water withdrawals from the John H. Kerr Reservoir.

The basic procedure for computing the energy value to quantify energy benefits foregone for the alternatives considered is as follows:

- Determine the average annual energy for a typical operating year for the John H. Kerr power plant,

- simulate the operation of the affected area power system "with" and "without" the John H. Kerr power plant using the production cost model,

- determine the value of John H. Kerr hydropower generation by subtracting (a) the cost of operating the system without the hydropower generation from (b) the cost of operating the system with the hydropower generation,

- differences in production cost is divided by the hydropower generation to obtain the energy value, $/MWh, for the John H. Kerr generation.

These procedures are used to compute an energy value for five future load years, at five-year increments, starting with the project-on-line year. The energy value for intermediate years was computed using linear interpolation. Each of the 25 annual energy values is brought to a present value using present-worth methods. The sum of the present-worth values is amortized to an annualized energy value. The product of the annualized energy value and the energy losses due to water withdrawals represents the annual energy benefits foregone for that alternative.

Water Supply Withdrawal Alternatives Considered

To date there are various water supply contracts in force as listed in Table 1-1. Existing water supply contracts are accounted for in the base case. The City of Henderson requested that their "Water Use" contract with the Corps of Engineers be converted to a "Storage Allocation" contract. In a "Water Use" agreement the user pays a fee for water from storage based on availability and do not acquire any permanent rights. Where as, in "Storage Allocation" agreement the user pays an amortized fee for a block of storage space in the reservoir and acquires a permanent right to use the storage space for water supply regardless of water availability. The "Storage Allocation" contract would provide sufficient storage to yield 20 MGD. The Wilmington District requested a power impact evaluation at the 5 MGD withdrawal level, also. The following alternatives were evaluated:

- Base Case Alternative. Current project operations with existing water withdrawals.

- 5 MGD Alternative. Base case alternative with an additional 2,700 AF (5 MGD yield) reallocated from conservation storage for water supply to the City of Henderson.

- 20 MGD Alternative. Base case alternative with an additional 10,700 AF (20 MGD yield) reallocated from conservation storage for water supply to the City of Henderson.

Congress provides discretionary authority to the Commander, US Army, Corps of Engineers to approve storage allocation requests if the reallocation or addition of storage in a Federal reservoir does not have a severe effect on other authorized purposes. Additionally, the Commander, USACE has Congressional authority to reallocate storage to water supply from other purposes, up to 15 percent of total storage allocated to all authorized project purposes or 50,000 acre-feet, whichever is less. In the case of the John H. Kerr reservoir, 15 percent of the total storage capacity is 415,500 acre-feet. Therefore, the Commander, USACE can reallocate up to 50,000 acre-feet of storage in the reservoir. Existing reallocation storage amounts in the reservoir is 10,800 acre-feet (see Table 1-1). The Commander, USACE, can reallocate an additional 10,700 AF of storage, the larger of the alternatives considered, without Congressional approval.

Energy Benefits Evaluation Assumptions

The evaluation of energy benefits foregone due to water supply withdrawals from the John H. Kerr reservoir was performed with the following assumptions:

- Water withdrawal for each alternative evaluated is assumed to be for consumptive use. None of the withdrawn water would be returned to the reservoir or downstream of the John H. Kerr dam.

- All water supply withdrawals from the John H. Kerr reservoir are assumed to be made at a uniform rate throughout the year.

Computation of Energy Losses

Each of the withdrawal alternatives will impact hydropower generation at the John H. Kerr powerhouse, affecting both energy and plant capacity. To measure these impacts, the Wilmington District simulated each alternative with the Kerr-Philpott streamflow routing model developed in the District. Energy loss associated with the withdrawal alternatives was derived from generation output data from the model. Results indicated that in many years the withdrawal alternatives achieved gains in energy. This inconsistency in the results led to a joint HAC and Wilmington District decision to use only the simulation of the Base Case Alternative and apply the "power equation" to compute the energy loss for the withdrawal alternatives. The performance data of the existing units was obtained from the Hydroelectric Design Center and are identical to those used in the John H. Kerr Major Rehabilitation Evaluation Report. The unit performance data for operations at best gate were used for this analysis. By using the results of the Base Case Alternative simulation, the joint operation of the John H. Kerr and Philpott projects is present in the results.

Energy Loss Computations for John H. Kerr

The energy loss from implementing each withdrawal alternative was computed by applying the "power equation" to summary statistics from the Kerr-Philpott streamflow routing model for existing joint operations (Base Case Alternative) for a 71-year period (1930 to 2000). The average annual energy and other key summary statistics for the Base Case Alternative are shown in Table 3-1.

Table 3-1: Base Case Alternative – Summary Statistics

Summary Statistics		Units
Average Pool Elevation	**300.4059**	**(feet)**
Estimated Average Tailwater	**202.9418**	**(feet)**
Estimated Gross Head	**97.4642**	**(feet)**
Average Annual Generation	**479,305**	**(MWh)**

The annual energy losses were computed as follows:

$$E=QHet/11.81 \qquad \text{(Power Equation)}$$

where :

E = computed energy for historical operations,
Q = withdrawal amounts in cubic feet per second (cfs),
H = net head as a function of gross head (H=f(gross head)).
e = unit efficiency as a function of gross head (e=f(H)),
t = number of hours in a year

Substituting the parameters in Table3-2 for the variables in the equation above the energy loss for the withdrawal alternatives are shown in Table 3-2. The average annual energy loss for the 5 MGD and 20 MGD alternatives is 496 MWh and 1,981 MWh, respectively.

Table 3-2: Energy Losses for Withdrawal Alternatives

Parameters	Units	5 MGD Alternative	20MGD Alternative
Diversion Discharge	(cfs)	7.74	30.94
Head Lost to Reallocation[1]	(feet)	0.0259	0.1027
Gross Head[2]	(feet)	97.4383	97.3615
Net Head[3]	(feet)	97.1020	97.0254
Efficiency[4]		0.8886	0.8887
Annual Energy Loss	(MWh)	496	1981

Notes:
1. Head lost is assumed to be a uniform loss of storage equal to the storage require to yield the uniform withdrawal rate. Head lost is the average cumulative loss of the storage.
2. Gross head adjusted by deducting the head lost due to reallocation from the average head .
3. Net head is the gross head adjusted for losses due to flow through the generation units.
4. Efficiency was estimated from the perfomance testing of the existing units at best gate.

Energy Loss Computations for Gaston and Roanoke Rapids

Downstream effects can also be quantified due to the withdrawal of water from John H. Kerr. The two downstream hydropower projects that will be affected by water supply withdrawals from the John H. Kerr reservoir are Gaston and Roanoke Rapids, both owned and operated by Virginia Power Company. Hydropower generation impacts at these non-Federal projects will be quantified but the economic valuation of the impacts are beyond the scope of this analysis. The investor-owned utility can apply its financial parameters to these losses to determine the economic impact caused by each alternative.

The Wilmington District provided project data to the HAC to quantify hydropower generation losses at the Gaston and Roanoke Rapids projects. An average head of 70.5 feet and an average turbine/generator efficiency of 85% were used in the hydropower equation to compute the losses. Substituting for the variables in the power equation the results follow.

$$P_{5MGD} = \frac{(5\ MGD)\ (1.548\ CFS/MGD)\ (70.5 + 70.5\ feet)\ (0.85)\ (8{,}760\ hours/year)}{(11.81)\ (1{,}000\ kWh/MWh)}$$

$$= 704\ MWh$$

$$P_{20MGD} = \frac{(20\ MGD)\ (1.548\ CFS/MGD)\ (70.5 + 70.5\ feet)\ (0.85)\ (8{,}760\ hours/year)}{(11.81)\ (1{,}000\ kWh/MWh)}$$

$$= 2{,}850\ MWh$$

Thus the average annual energy loss at both Gaston and Roanoke Rapids due to the proposed water supply withdrawal from the John H. Kerr reservoir for 5 MGD is 704 MWh and for 20 MGD the energy loss is 2,850 MWh.

Basis for Computing Energy Benefits

General

The energy benefits for a hydropower project are based on the area power system cost of producing the same amount of thermal replacement energy as the proposed hydropower project. To obtain these values, a power system analysis is performed in which the area power system is modeled under two different conditions, one which includes the proposed hydropower project or hydropower project modification, and one in which the proposed hydropower project or hydropower project modification is removed. The output of each run is the total system energy production cost, which includes primarily fuel and variable O&M costs. The energy unit value is then determined by dividing the difference in system operating costs for the two conditions by the hydropower project's annual energy output

The power from the John H. Kerr power plants is marketed primarily in the Virginia, North Carolina and South Carolina, which is a part of an area known as Virginia-Carolina area, or the VACAR sub region of the Southeastern Reliability Council (SERC) system.

Procedure for Computing Energy Unit Value

The value of energy used in this analysis is based on the cost of thermal generation in the VACAR area power system to replace the energy generated at the John H. Kerr hydropower plant. Energy benefits are computed by utilizing the present-worth of an annual energy unit value averaged over the entire project's economic life.

Annual energy unit values were compute using the PROSYM power system simulation model. Because the system generation resource mix changes with time, simulations were performed for the five representative load years: 2005, 2010, 2015, 2020 and 2025. PROSYM modeling of the VACAR power system was limited to every five years due to the amount of effort required to model the system for a single year. Due to the high

degree of uncertainty in projecting power market conditions in the future (such as system load demand, fuel costs and changes in technology), power system simulations were not performed beyond the year 2025

Sections 3.6.3 through 3.6.8 describe the PROSYM model and studies, and Table 3-3 summarizes the resulting energy value.

PROSYM Production Cost Model

PROSYM is a chronological hourly system production cost model that is used throughout the power industry. It is a proprietary model developed and maintained by Henwood Energy Services of Sacramento, California. The HAC has used the model under a lease agreement with Henwood for more than seventeen years.

The PROSYM model economically dispatches system generating resources to meet hourly system loads in the same manner as a power system dispatcher would in actual system operation, thereby developing system operating costs for the specified load and resource conditions. In PROSYM, one load year is analyzed at a time, with the model dispatching resources hour-by-hour over one-week periods. PROSYM was used to model the "with" and "without" project scenarios for this study.

Power Market Area and Loads

Discussions with Southeastern Power Administration (SEPA) indicated that the power generated at John H. Kerr would be marketed to preference customers located throughout the VACAR sub-region. This modeled region includes the states of Virginia, North Carolina and South Carolina and includes the following utilities:

Carolina Power & Light Company (CAPO)
Duke Power Company (DUPC)
Nantahala Power & Light Company (NANT)
South Carolina Electric & Gas Company (SOCG)
South Carolina Public Service Authority (SCPSA)
Southeastern Power Company (VIEP)
Yadkin, Inc (YADI)
North Carolina Electric Membership Corp.
South Carolina Generating Co., Inc.
Central Power Electric Cooperative, Inc.

System Loads

Current and projected VACAR system loads were extracted from Henwood's National Electric Reliability Council (NERC) database. Henwood's load data is the compellation of Electricity Supply and Demand Projection (EIA-411) and information gathered from private utilities. For this analysis, Henwood NERC database version 6.4.4 was use, last

updated in July of 2003. Load projections for the VACAR system were obtained from Energy Information Administration (EIA) 411 Report. These annual and monthly loads were converted into a synthetic hourly load shape for a typical year. The synthetic hourly load shape in PROSYM represented the VACAR system load to smooth out any imperfection in actual hourly data and Henwood's projected load data leading up to the study year.

The LOADFARM subroutine of the PROSYM model was used to project the hourly load shape for future years. This is done by adjusting the hourly loads shape for the base year (average load data from 1996 to 2001) by the percentage change in the loads, as projected by EIA-411 report and Henwood's projection. For the purpose of this study, a 10 percent load-resource capacity reserve margin criterion was used. This percentage represents the average reserve capacity of the generating supply over demand for the 2005 through 2025 time period.

PROSYM Input Data

The basic PROSYM input data set used for the John H. Kerr analysis was configured by using a database composed of NERC data supplied by Henwood under contract to HAC. Henwood uses the most current and reliable sources of data in the compilation of their regional databases including sources from government agencies, private utilities, industry publications, and other respected information gathering companies. Latest NERC database, version 6.4.4 was last updated in July 2003, most of the information was current through the 2003 calendar year.

Additional generating resources had to be scheduled to insure that loads were met beyond the period covered by the EIA-411 report. Resources were added to the system so that load plus an additional 10 percent reserve was met through 2025, based on VACAR planning criteria. Using projected data from EIA Energy Outlook 2003 (www.eia.doe.gov/oiaf/aeo/supplement/index.html), Table 67, "Electric Power Projections for Electricity Market Module Region Southeastern Reliability Council" and examining current utility practices, a system future thermal resource mix of 75 percent gas-fired combined cycle (CC) and 25 percent gas-fired combustion turbine (CT) capacity was used through out the study years. The characteristics of these assumed new plants were based on the most recent heat rates, efficiencies and the average plant size of currently planned units.

PROSYM accounted for conventional hydropower plants in the system that was modeled as individual hydro-plants. John H. Kerr input data was provided for each week of the year, including the weekly capacity output and the weekly energy output. A number of hydropower projects in addition to John H. Kerr are operated in VACAR system, most of which are Corps of Engineers projects. There are several smaller hydro-projects that are owned by private utilities.

A typical operating year was selected that represent how the John H. Kerr powerhouse operates in the VACAR system to be used as input for the annual simulation in the PROSYM model. In consultations with the Wilmington District, the year 1992 was selected as a typical operating years for hydropower projects in the Roanoke River system. This yearly generation was shaped to a monthly time step for input into the PROSYM model.

Two sets of input data were assembled for each simulated year, one including John H. Kerr hydropower plant and one without. The latter input data set simply removed the John H. Kerr contribution to the total monthly hydropower energy and capacity of the system. The same hydropower data was used for all load year simulations.

Fuel Prices

All fuel prices for individual generation plants within the VACAR region as well as all generic fuel prices for the state of Virginia, North Carolina and South Carolina were brought to 2003 price levels. Henwood obtained these fuel prices from EIA publications for the NERC database. In accordance with Section 2.4i of ER 1105-2-100, *Planning Guidance Notebook*, this study did not utilize real fuel cost escalation. The 2002 fuel prices were held constant over the entire period of power system analysis.

Energy Value Computation

The PROSYM model simulated the VACAR system production cost "with" and "without" the John H. Kerr hydropower generation for five future years. In the "without" condition, the John H. Kerr generation was replaced by the most likely thermal alternative, in most cases, combustion turbines (CT) and combined cycle (CC) generation. CT and CC plants are a more expensive form of power generation, thereby incrementally increasing the system production cost. The incremental increase in production cost is divided by the loss of John H. Kerr generation to derive an energy value in $/MWh. The results of the five yearly simulations and the resulting energy value are summarized in Addendum B of this report.

Table 3-3 shows the annualized energy value over the life of the project. This energy value was applied to the generation loss for each withdrawal alternative described in Section 3.2 to obtain the energy benefits foregone. These computations are summarized in Chapter 5.

Five study years of PROSYM Generation Summary (GENSUM) tables are shown in Addendum B, for both "with" and "without" project conditions. These tables summarized the VACAR system operation by plant types. System cost increases for the with-project condition as a result of an increment of hydropower generation being withdrawn and replaced with thermal generation. This cost is divided by the total hydropower energy loss in order to arrive at the unit hydropower energy value. An examination of these tables will show that, in most years, primarily combustion turbine and combined-cycle plants replaced hydropower generation. The incremental increases

in coal-fired steam replaced the intermediate and base load hydropower while the gas combustion turbine replaces the peaking hydropower generation.

Table 3-3 summarized the annualized unit energy value computation.

Table 3-3: Annualized Energy Value Computation

Interest Rate (%)	5.625%	
JH Kerr project on-line date	1953	JH Kerr project economic life of 50 years
End of JH Kerr project economic life	2054	

Year	Present-Worth Factor	Energy Value ($/Mwh)	Present-Worthed Values Energy Value ($/Mwh)
2005	0.9467	30.01	28.41
2006	0.8963	29.98	26.88
2007	0.8486	29.96	25.42
2008	0.8034	29.93	24.05
2009	0.7606	29.91	22.75
2010	0.7201	29.88	21.52
2011	0.6818	30.68	20.92
2012	0.6455	31.49	20.32
2013	0.6111	32.29	19.73
2014	0.5785	33.10	19.15
2015	0.5477	33.90	18.57
2016	0.5186	34.42	17.85
2017	0.4909	34.94	17.15
2018	0.4648	35.45	16.48
2019	0.4400	35.97	15.83
2020	0.4166	36.49	15.20
2021	0.3944	36.44	14.37
2022	0.3734	36.39	13.59
2023	0.3535	36.35	12.85
2024	0.3347	36.30	12.15
2025	0.3169	36.25	11.49
2026	0.3000	36.25	10.88
2027	0.2840	36.25	10.30
2028	0.2689	36.25	9.75
2029	0.2546	36.25	9.23
2030	0.2410	36.25	8.74
to	---	---	**111.21**
2054	0.0648	36.25	2.35
		Total	**557.12**
		Annualizing Factor @ 5.625, 50 years	**16.63**
		Annualized Value	**33.51**

CAPACITY BENEFITS FOREGONE

General

Capacity benefits foregone are defined as the product of the loss in dependable capacity and a unit capacity value, which represent the capital cost of constructing replacement thermal generation capacity.

Dependable Capacity

General

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

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

Selection of Method

Dependable capacity can be computed in several ways. The method that is most appropriate for evaluating a hydropower plant's dependable capacity in a predominantly thermal-based power system is the average availability method. Hydropower dependable capacity must be based on the capacity available under adverse hydrologic conditions or critical period. Based on consultations between HAC and the Southeastern Power Administration (SEPA), it was determined that the critical period for hydropower generation in the Roanoke River Basin is July and August of each year.

However, since the energy and capacity are to be determined by application of the "power equation" instead of relying on a streamflow routing model, the reduction in dependable capacity will be based on the reduced machine capability due to the reduction in head during the critical period due to reallocation of reservoir storage required to yield 5 MGD (2,700 AF) and 20 MGD (10,700 AF).

Dependable Capacity vs. Marketable Capacity

The average availability method differs from the method used by SEPA in defining the amount of firm hydropower capacity that it can market. SEPA uses the most extreme

approach base on the worst adverse water year because hydropower is its only generating resource. SEPA can only guarantee delivery of hydropower capacity that it can support during adverse water conditions, because it has no thermal plants to back up its hydropower resources. SEPA sometimes purchases thermal power on the open market during periods of low stream flows and high energy demands, but cannot afford to do this very often and still meet its repayment obligations to the Federal treasury.

However, even though SEPA uses a method based on the most adverse year of hydrologic conditions to determine the marketable capacity of the John H. Kerr project, this is not appropriate for measuring the loss in NED capacity benefits at this project. The objective of NED benefits is to measure the gain or loss of benefits to the nation as a whole, not to a single entity, such as SEPA, or to a small group of entities, such as SEPA's customers.

Computation of Dependable Capacity

General

Hydropower projects may occasionally lose capacity due to loss of head or due to inadequate energy to support the available capacity. Similarly, there are periods when the full peaking capacity is both available and usable. The average availability method attempts to measure the average capacity available during the peak demand periods of the year. The Kerr-Philpott routing model simulations for the alternatives were inconsistent. So, the Kerr-Philpott model results for the alternative simulations were not used in this analysis. Reduction in the machine capability, due to head loss caused by the water withdrawals, was used as a measure of the loss in dependable capacity.

Hydrologic Period of Analysis

In order to evaluate the average dependable capacity for a project, a long-term record of project operation must be used. For this analysis, the 1930 – 2000 period of record flows was used. Actual project operating records can be used, but the period of operation may not be long enough to give a statistically reliable value. Furthermore, operating changes may have occurred over the life of the project, which would make actual data somewhat inconsistent.

An alternative method is the use of a period-of-record computer simulation of system operation. As described in Section 2.7, the Wilmington District provided a daily simulation of the Roanoke River projects. This simulation, performed using the Kerr-Philpott model, served as the basis of this study's dependable capacity computations for the Base Case Alternative.

Criteria for Computing Dependability of Capacity

The amount of time that capacity must be sustained (supported with energy) each day or week for it to be usable in the system peak load will be evaluated. SEPA no longer specifies for each individual project the number of hours that capacity must be sustained per week for that project's capacity to be classified as marketable capacity. SEPA markets its power on a system-wide basis rather than an individual project basis. Each project in the system operates somewhat differently from month to month and from year to year in meeting the system power demand. Projects work together depending on water conditions. Furthermore, the amount of generation required to support the capacity that SEPA markets varies from customer to customer, depending on system characteristics in which the capacity is being used.

In the absence of specific SEPA criteria for individual projects, sustained capacity criteria has been approximated by examining each project's contribution to meeting total system capacity requirements in the water year which SEPA uses to measure system marketable capacity. SEPA's current contracts are based on the 1981 water year, which was (prior to the recent drought) the second worst water year in the long-term flow record. The 1981 water year was therefore used as the basis for defining the energy requirements to support dependable capacity. Dependable capacity is normally based on the amount of capacity that can be supported in the peak demand period, which in the VACAR region are the summer months of July and August.

The average weekly energy output at John H. Kerr during this period (weeks 27-35 of the 1981 water year) was obtained from the Kerr-Philpott streamflow routing model base case simulation. The number of hours that the project is require to support was then determined by dividing that average weekly energy by the amount of capacity that SEPA markets from the John H. Kerr project. Thus, the number of hours on peak each week that the John H. Kerr powerhouse can support under the base condition, no new withdrawals, is as follows:

(1) average 1981 weekly energy, Weeks 27-35:	3,696 MWh
(2) SEPA marketable capacity:	225 MW
(3) 1981 machine capability:	216.259 MW
(4) Hours on peak per week [(1)/(2)]	16.42 hours

Dependable Capacity Computation

The John H Kerr powerhouse sustained peaking requirement of 16.42 hours was applied to the average weekly energy available during the critical period weeks 27-35 of each year in the 71-year period of record (1930-2000). This resulted in the capacity that could be supported in each year under existing withdrawal conditions during the critical summer months.

For the Base Case Alternative in Table 4-1, for example, the potential supportable capacity (Column 5) that can be supported is the average weekly energy for weeks 27-37 divided by the 16.42 hour peaking requirement (Column 4 divided by Column 2). Note that (Column 5 & 6) in all years the machine capability limits how much capacity can be actually supported because of the study assumption of operating the units only at "best gate". Machine capability is less than the potential supportable capacity because the analysis was based on performance of the existing units operating at best gate. While the units operating at best gate maximize energy produced, higher capacity is possible but at a lesser efficiency that reduces the amount of potential energy during the critical period.

Computation Procedure for Determining Supportable Capacity

The following example summarized the computations that were performed to determine average supportable (usable) capacity during the peak demand months of 1981 (Table 4-1).

Computed from project data for operation without diversion for water supply:

- Average weekly energy during Jul-Aug 1981 without diversion is 3,696 MWh
- Average weekly machine capability during Jul-Aug 1981 is 216.259 MW
- Potential support capacity during Jul-Aug 1981 is 3,696 MWh / 16.42 hours or 225 MW
- Actual support capacity during Jul-Aug 1981 is the minimum of machine capability or potential support capacity or MIN (216.259 MW, 225 MW) = 216.259 MW

Table 4-1: Supportable Capacity for the Base Case Alternative

(1) Year	(2) Required Hours on Peak	(3) Average Annual Energy	(4) Critical Period Energy	(5) Potential Supportable Capacity	(6) Machine Capability	(7) Supportable Capacity
1930	16.42	260,276	3,623	220.569	216.542	216.542
1931	16.42	280,495	6,763	411.735	218.915	218.915
1932	16.42	421,226	3,793	230.942	216.684	216.684
1933	16.42	419,374	4,969	302.556	220.124	220.124
1934	16.42	467,493	4,590	279.452	219.401	219.401
1935	16.42	546,872	5,488	334.145	219.292	219.292
1936	16.42	726,804	5,418	329.866	219.380	219.380
1937	16.42	808,143	9,840	599.093	221.849	221.849
1938	16.42	532,799	19,296	1,174.810	224.454	224.454
1939	16.42	532,406	12,338	751.172	220.052	220.052
1940	16.42	613,602	20,985	1,277.651	228.373	228.373
1941	16.42	342,487	8,448	514.316	218.912	218.912
1942	16.42	425,011	10,096	614.652	220.681	220.681
1943	16.42	497,286	7,776	473.434	219.620	219.620
1944	16.42	594,434	4,418	268.971	218.938	218.938
1945	16.42	539,982	5,773	351.465	219.764	219.764
1946	16.42	530,227	6,298	383.437	220.104	220.104
1947	16.42	483,537	5,282	321.596	220.012	220.012
1948	16.42	650,406	7,027	427.854	218.248	218.248
1949	16.42	726,538	14,502	882.917	220.844	220.844
1950	16.42	484,419	7,587	461.901	219.297	219.297
1951	16.42	408,167	5,422	330.108	220.409	220.409
1952	16.42	547,355	6,541	398.222	219.992	219.992
1953	16.42	392,121	3,997	243.328	217.491	217.491
1954	16.42	306,101	3,632	221.132	216.064	216.064
1955	16.42	435,227	9,049	550.947	220.348	220.348
1956	16.42	275,323	3,560	216.774	214.733	214.733
1957	16.42	494,425	3,649	222.169	217.171	217.171
1958	16.42	566,126	5,690	346.413	218.219	218.219
1959	16.42	414,388	3,650	222.197	218.680	218.680
1960	16.42	536,977	3,650	222.213	220.034	220.034
1961	16.42	446,371	5,985	364.373	219.910	219.910
1962	16.42	539,834	5,479	333.564	219.534	219.534
1963	16.42	347,703	3,622	220.535	215.480	215.480
1964	16.42	360,550	3,651	222.305	217.967	217.967
1965	16.42	369,386	4,729	287.910	219.704	219.704
1966	16.42	270,388	3,543	215.741	214.741	214.741
1967	16.42	254,348	4,002	243.642	216.334	216.334
1968	16.42	284,458	3,649	222.163	216.212	216.212
1969	16.42	289,597	4,132	251.588	220.312	220.312

Table 4-1: Supportable Capacity for the Base Case Alternative (continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Year	Required Hours on Peak	Average Annual Energy	Critical Period Energy	Potential Supportable Capacity	Machine Capability	Supportable Capacity
1970	16.42	294,601	5,184	315.644	219.007	219.007
1971	16.42	540,468	4,653	283.285	219.901	219.901
1972	16.42	693,088	10,957	667.115	222.499	222.499
1973	16.42	646,654	7,227	439.986	219.634	219.634
1974	16.42	505,828	5,787	352.331	218.715	218.715
1975	16.42	684,690	10,945	666.346	221.479	221.479
1976	16.42	378,821	3,649	222.168	218.303	218.303
1977	16.42	293,145	3,605	219.504	215.316	215.316
1978	16.42	725,281	7,556	460.025	220.448	220.448
1979	16.42	793,644	4,686	285.290	219.621	219.621
1980	16.42	456,493	4,586	279.197	219.000	219.000
1981	16.42	179,379	3,696	225.000	216.259	216.259
1982	16.42	429,599	7,125	433.802	219.499	219.499
1983	16.42	548,700	3,996	243.315	218.254	218.254
1984	16.42	607,102	8,607	524.002	219.619	219.619
1985	16.42	410,793	7,508	457.096	219.040	219.040
1986	16.42	238,821	3,492	212.625	212.065	212.065
1987	16.42	713,637	4,729	287.911	217.957	217.957
1988	16.42	279,798	3,686	224.398	217.832	217.832
1989	16.42	608,718	10,052	612.002	220.916	220.916
1990	16.42	634,383	5,558	338.421	219.406	219.406
1991	16.42	461,743	3,890	236.808	220.409	220.409
1992	16.42	396,209	4,328	263.476	219.971	219.971
1993	16.42	645,542	4,274	260.237	219.254	219.254
1994	16.42	531,728	6,194	377.123	221.191	221.191
1995	16.42	455,933	11,244	684.561	222.839	222.839
1996	16.42	720,799	8,173	497.584	219.770	219.770
1997	16.42	480,362	3,856	234.754	219.632	219.632
1998	16.42	639,563	3,855	234.713	219.104	219.104
1999	16.42	304,747	3,571	217.395	214.370	214.370
2000	16.42	307,689	3,859	234.922	219.227	219.227

Dependable Capacity Looses

The loss of dependable capacity is then the difference between the machine capability of the base case alternative and the machine capability at reduced head of the withdrawal alternatives due to reallocation of storage (Table 4-2). The dependable capacity loss for the 5 MGD Alternative is 82 kW and for the 20 MGD Alternative is 326 kW.

The total system loss in dependable capacity is a measure of how much capacity must be added to the system to make the system whole again in terms of peak load-carrying capability.

Table 4-2: Dependable Capacity Loss for Withdrawal Alternatives

Parameters	Units	EXISTNG Alternative	5 MGD Alternative	20MGD Alternative
Average Pool Elevation [1]	(feet)	299.7725		
Average Estimated Tailwater [2]	(feet)	202.2185		
Average Gross Head	(feet)	97.5541		
Head Lost to Reallocation [3]	(feet)	---	0.0302	0.1198
Gross Head	(feet)	---	97.5238	97.4343
Machine Capability [4]	(MW)	219.065	218.983	218.738
Capacity Loss	(kW)	---	82	327

Notes:
1. Average pool elevation during the critical period of July-August.
2. Average estimated tailwater elevation during the critical period of July-August.
3. Head lost due to reallocation is the average cumulative loss of storage during the critical period of July-August.
4. Machine capability was determined from the existing plant's unit performance data as a function of gross head. Efficiency was estimated from the performance testing of the existing units at best gate.

Capacity Values

General

Hydropower benefits are based on the cost of the most likely thermal generation alternative that would carry the same increment of load as the proposed hydropower project or its modification. Capacity benefits are intended to measure the investment cost

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

Most Likely Thermal Alternative

A screening curve analysis was conducted to determine the mix of thermal generating resources that would be the most likely, least-cost alternative to the John H. Kerr hydropower generation. The type of alternative generating plants considered were coal-fired (CO) steam which displaces base loads, gas-fired combined cycle (CC) which displaces intermediate loads, and gas-fired combustion turbine (CT) which displaces peak loads. The screening curve analysis for John H. Kerr hydropower plant is described in Section 4.5.4.

Capacity and Energy Values Used in Screening Curve Analysis

Capacity unit values for CO, CC, and CT were computed using procedures developed by the Federal Energy Regulatory Commission (FERC). Capacity values were computed for the 3-state VACAR region based on a 5-5/8% interest rate and August 2003 price levels. The adjusted capacity values incorporate adjustments to account for differences in reliability and operating flexibility between hydropower and thermal power plants. Table 4-3 shows the adjusted and unadjusted capacity unit values. The FERC adjustments are flexibility (F), which accounts for the operating flexibility that a hydropower plant has over a thermal plant, and reliability adjustments (TMA & HMA). The TMA (thermal maintenance availability) represents the thermal unit availability rate for each type of thermal unit and the HMA (hydropower mechanical availability) represents the availability of a hydropower unit. The ratio, HMA/TMA, reflects the relative mechanical reliability of hydroelectric unit compared to a thermal one. Essentially, the mechanical availability reflects the forced outage rate of the unit. For further discussion on capacity value adjustments, see Engineering Manual 1110-2-1701, *Hydropower*, Appendix O-2.

The adjusted capacity unit value computed for each of the VACAR states were averaged to derive the values shown in Table 4-3, see Addendum A.

Table 4-3: Unit Capacity Values

Thermal Alternative Plant Type	Adjusted Capacity Value ($/kW-yr)	FERC Adjustments			Unadjusted Capacity Value ($/kW-yr)
		HMA	TMA	F	
Coal-Fired Steam	**209.62**	0.98	0.85	0.050	173.15
Combined Cycle	**116.45**	0.98	0.90	0.025	104.34
Combustion Turbine	**62.13**	0.98	0.90	0.025	55.67

Energy unit values for coal-fired steam, gas-fired combined cycle and gas-fired combustion turbine plants were developed using information obtained from the publication EIA Electric Power Monthly (DOE/EIA-0226) and other sources. The information obtained included fuel costs, heat rates and variable O&M costs. The resulting values, based on 2003 price levels, are shown in Table 4-4. Like the capacity value above, this energy value represent the average energy value for the three states. Since current Corps of Engineers policy does not allow the use of real fuel cost escalation, the values shown in Table 4-4 were assumed to apply over the entire period of analysis.

Table 4-4: Unit Energy Values

Thermal Alternative Plant Type	Energy Value ($/MWh)
Coal-Fired Steam	**18.21**
Combined Cycle	**43.65**
Combustion Turbine	**68.65**

Screening Curve Analysis

The adjusted capacity values shown in Table 4-3 were used to develop a screening curve for the VACAR region for each of the thermal alternatives. A screening curve is a plot of the total plant cost (fixed plus variable) versus the annual plant factor. The unit energy values in Table 4-4 represent the plant's variable cost.

A screening curve analysis consists of the following steps:

- Construct a total plant cost (in $/kW-year) versus annual plant factor (in percent) diagram that includes a curve for each type of thermal plant available for addition to the system.

- Construct an hourly load-duration curve, based on loads for a typical operating year, for the increment of load being analyzed.

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

- Find the points on the load-duration curve where the percent of time load is numerically identical to the plant factor breakpoints defined in the preceding step; these intersection points define the portion of the load that would be carried by each plant type.

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

$$AC = CV + (EV * 0.0876 * PF) \qquad \text{(EQ 3)}$$

where: AC = thermal generating plant total cost ($/kW-year)
CV = Thermal generating plant capacity unit value ($/kW-year)
EV = Thermal generating plant energy unit value ($/MWh)
PF = Annual plant factor (percent)

The resulting curves are shown in Figure 4-1. The point of intersection (breakpoint) between the combined cycle curve and the combustion turbine curve occurs at a plant factor of 22.42 percent and the breakpoint between the coal curve and combined cycle curve occurs at the plant factor of 41.80 percent. Thus, gas-fired combustion turbine plants are more economical for plant factors less than 22.42 percent, gas-fired combined cycle plants are more economical for plant factors greater than 22.42 percent but less than the plant factor 41.80 percent, and coal plants for plant factors greater than 41.80 percent.

Figure 0-1
Thermal Screening Curve

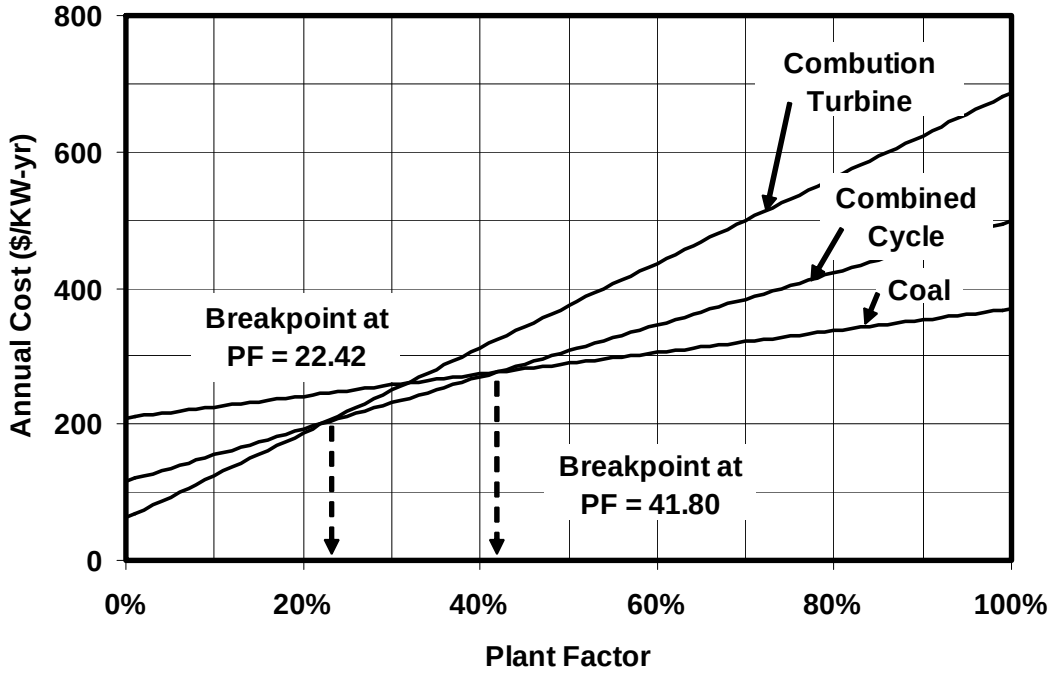
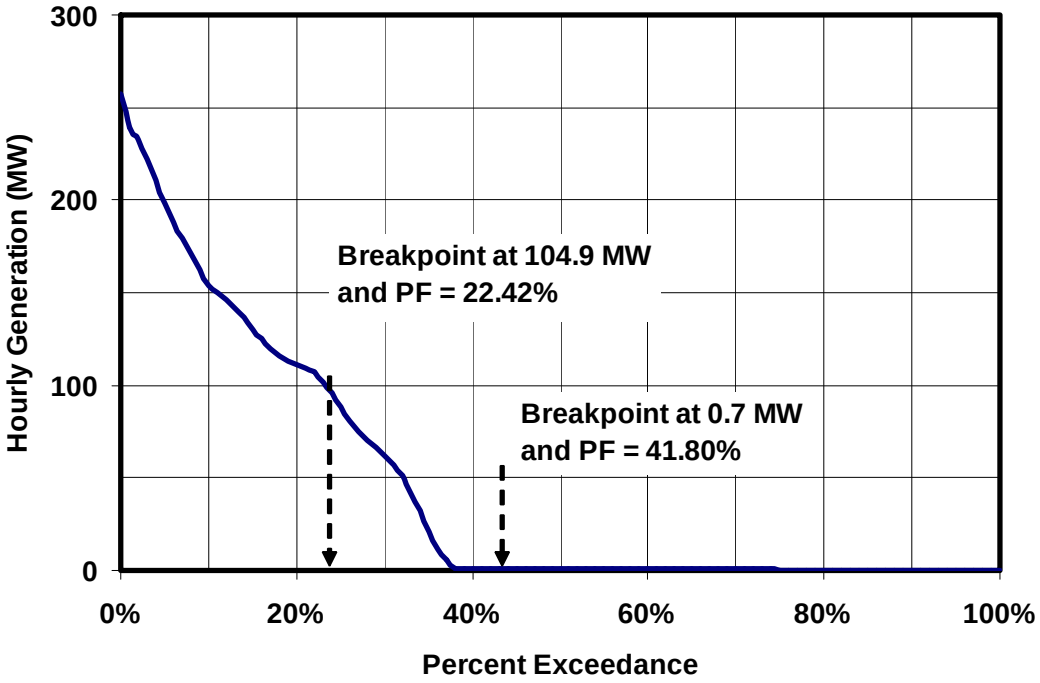


Figure 0-2
Total Hourly Generation Duration Curve for 1992



Least-Cost Thermal Mix

The breakpoint plant factor of 22.42 and 41.80, obtained from the screening curve was matched to the same percent exceedence on the 1992 actual hourly generation-duration curve in order to determine the corresponding megawatts of generation. The Wilmington District considers 1992 to be a typical operating year for the John H. Kerr power plant. It was found that John H. Kerr capacity would be replaced with gas-fired combustion turbine (152.5 MW) and combined cycle generating plants (104.9 MW) because the project is operated at a relatively low plant factor. The most likely least cost thermal generating alternative to the John H. Kerr generation would be 59 percent gas-fired combustion turbine and 41 percent gas-fired combined-cycle plants.

Composite Capacity Unit Value

Using the FERC adjusted capacity value for gas-fired combined cycle and combustion turbine thermal generating plant for John H. Kerr project, $116.45/kW-yr and $62.13/kW-yr, respectively, the derivation of the composite unit capacity value is shown below.

FERC Adjusted Capacity Values (From Table 4-3):

CC	$116.45/kW-yr
CT	$ 62.13/kW-yr
CO	$209.62/kW-yr

Least-Cost Thermal Alternative Capacity (From Section 4.5.5 above):

CC	104.9 MW
CT	152.5 MW
CO	0.0 MW

Calculation of Composite Capacity Value:

CC Capacity Value (Weighted) = $116.45/kW-yr * (104.9 / (104.9 + 152.5 + 0))

= $47.46/kW-yr

CT Capacity Value (Weighted) = $62.13/kW-yr * (152.5 / (104.9 + 152.5 + 0))

= $36.81/kW-yr

CO Capacity Value (Weighted) = $209.62/kW-yr * (0 / (104.9 + 152.5 + 0))

= $0/kW-yr

Composite Capacity Value = $47.46/kW-yr + $36.81/kW-yr + $0/kW-yr

= **$84.26**/kW-yr

Capacity Benefits Foregone

The composite capacity unit value computed in Section 4.5 is applied to the dependable capacity losses to obtain capacity benefits foregone for each withdrawal alternative. Chapter 5 summarized total power benefits foregone for the 5 and 20 MGD alternatives.

TOTAL BENEFITS FOREGONE

General

One of the objectives of this study was to identify power benefits foregone due to the proposed storage reallocation of 2,700 AF (5 MGD withdrawal) and 10,700 AF (20 MGD withdrawal) in the John H. Kerr reservoir conservation pool. Annual energy losses were computed and multiplied by the unit energy value to arrive at annual energy benefits foregone. Annual capacity losses were computed and multiplied by the composite unit capacity value to arrive at annual capacity benefits foregone. Energy benefits foregone and capacity benefits foregone were summed to derive total power benefits foregone for each of the withdrawal alternatives.

Summary of Power Benefits Foregone

Table 5-1 summarizes total hydropower benefits foregone due to reallocating 2,700 AF and 10,700 AF of hydropower (conservation) storage to water supply at John H. Kerr reservoir.

Table 5-1: Hydropower Benefits Foregone - Withdrawal from Conservation Zone

Withdrawal Alternative	**5 MGD**	**20 MGD**
Annual energy losses (MWh)	496	1,981
Energy value ($/MWh)	$33.51	$33.51
Annual energy benefit foregone	**$16,621**	**$66,383**
Capacity losses (kW)	82	327
Capacity value ($/kW)	$84.26	$84.26
Annual capacity benefit foregone	**$6,909**	**$27,553**
Total Annual benefits foregone	**$23,530**	**$93,936**

REVENUES FOREGONE

General

Revenues foregone are based on the current rates of the power marketing agency, which in the case of John H. Kerr project is the Southeastern Power Administration (SEPA). The rates that are in effect for this study are as follows:

Energy charge:	8.25 mills/kWh
Capacity charge:	$23.52 /kW-year

The energy charge would be applied to the average annual energy losses calculated in Chapter 3. The capacity charge would be applied to the loss in dependable capacity in 1981, SEPA's most critical operating year, calculated in Chapter 4.

Energy Revenue Foregone

SEPA's average annual energy revenue foregone would be the product of the average annual energy loss under each withdrawal condition (Table 3-2) and SEPA's energy charge shown in Section 6.1. For the 5 MGD and 20 MGD withdrawal condition, the energy revenue foregone is $4,092 and $16,343, respectively (shown in Table 6-1).

Loss in Marketable Capacity

Under SEPA's current marketing procedures, the amount of capacity that can be marketed is based on the capacity that can be supported during the 1981 peak demand period. As shown in Table 6-1, the loss in marketable capacity for the 5 MGD and 20 MGD withdrawal is 82 kW and 325 kW, respectively.

Table 6-1: 1981 Dependable Capacity Loss for Withdrawal Alternatives

Parameters	Units	EXISTNG Alternative	5 MGD Alternative	20MGD Alternative
Average Pool Elevation [1]	(feet)	297.9943		
Average Estimated Tailwater [2]	(feet)	201.4720		
Average Gross Head	(feet)	96.5223		
Head Lost to Reallocation [3]	(feet)	---	0.0302	0.1198
Gross Head	(feet)	---	96.4921	96.4025
Machine Capability [4]	(MW)	216.259	216.177	215.934
Capacity Loss	(kW)	---	82	325

Notes:
1. Average pool elevation during the critical period of July-August 1981
2. Average estimated tailwater elevation during the 1981 critical period.
3. Head lost due to reallocation is the average cumulative loss of storage during the 1981 critical period.
4. Machine capability was determined from the existing plant's unit performance data as a function of gross head. Efficiency was estimated from the performance testing of the existing units at best gate.

Capacity Revenue Foregone

SEPA's annual capacity revenue foregone would be the product of the loss of marketable capacity during the peak demand period of 1981 (Tables 4-1 and 4-2) and the capacity charge. For the 5 MGD and 20 MGD withdrawal condition, the capacity revenue foregone is $1,929 and $7,644, respectively.

Total Revenues Foregone

The computation of total revenues foregone for withdrawals from John H. Kerr is shown in Table 6-2.

Table 6-2: Hydropower Revenues Foregone - Withdrawal from Conservation Zone

Withdrawal Alternative	5 MGD	20 MGD
Annual energy losses (MWh)[1]	496	1,981
Energy charge ($/MWh)	$8.25	$8.25
Annual energy revenues foregone	**$4,092**	**$16,343**
Capacity losses (kW)[2]	82	325
Capacity charge ($/kW)	$23.52	$23.52
Annual capacity revenues foregone	**$1,929**	**$7,644**
Annual revenues foregone	**$6,021**	**$23,987**

[1] Average annnual energy loss from Table 3-2.
[2] Capacity loss from Table 6-1.

CREDIT TO POWER MARKETING AGENCY

General

The project costs originally allocated to hydropower are being repaid through power revenues which are based on rates designed by the Federal power marketing agency (SEPA) to recover allocated costs plus interest within 50 years of the date of commercial power operation. If a portion of the storage is reallocated from hydropower to water supply, SEPA's repayment obligation must be reduced in proportion to the lost energy and marketable capacity.

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

> "If hydropower revenues are being reduced as a result of the reallocation, the power marketing agency will be credited for the amount of revenues to the Treasury foregone as a result of the reallocation assuming uniform annual repayment."

Paragraph d(2)(b) states that;

> "Revenues foregone to hydropower are the reduction in revenues accruing to the Treasury as a result of the reduction in hydropower outputs based on the Baseline rates charged by the power marketing agency. Revenues foregone from other project purposes are the reduction in revenues accruing to the Treasury based on any Baseline repayment agreements."

For purposes of estimating what this cost will be, energy and capacity charges from Chapter 6 will be used to estimate the revenue foregone for the period of the existing power contracts held by the PMA. No annual escalation rate will be applied to the energy and capacity charges to cover SEPA's estimated real increase in rates in the future, in accordance with paragraph 4-32d(2)(b) of ER 1105-2-100 cited above. Energy and capacity benefits developed in Chapters 3 through 5 will be used to estimate the revenue foregone for the period beginning at the end of the current PMA power contract period until the end of the 50-year economic evaluation period.

ER 1105-2-100 also allows the marketing agency credit for any additional costs above the lost revenue to recover costs of purchased power to meet the obligations of the current power sales contract(s) relating to the marketing of power from the hydropower project(s) where storage is being reallocated. The continuation of Appendix E-57d(3), provides the following guidance:

> "In instances where Baseline contracts 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 contracts, an additional credit to the power marketing agency can be made for such costs incurred during the remaining period of the contracts."

In both cases the credit in each year will be based on the revenue actually lost or the replacement costs actually incurred (and documented) by the power marketing agency. However, for purposes of providing an estimate of this credit, the cost of replacement power will be based on the same power values and energy and average capacity losses as were used in the benefits foregone calculations.

Remaining Period of Contract

The length of time remaining under the current power sales contracts had to be identified to determine how many years the SEPA credit would be based on cost of replacement power. Contract information provided by SEPA indicated that current contracts for all power marketed from the John H. Kerr project will expire in 2018. For this reason, the cost of replacement power will be the basis for the SEPA credit until the present contracts expire in 2018. Following this, the SEPA credit will be based on revenue foregone for the remaining economic life of the projects.

Computation of Credit to Power Marketing Agency

Tables 7-1 and 7-2 show the calculation of the expected average annual SEPA credit for the proposed withdrawal contract from John H. Kerr reservoir analyzed in this report. Lost energy and dependable capacity and the power values were taken from Table 5-1. The lost marketable capacity and current SEPA unit energy and capacity charges were taken from Tables 6-1.

Following are explanations of the columns in Tables 7-1 and 7-2;

- Column 1 - end of the John H. Kerr's economic life is the year 2055
- Column 2 - capacity benefit is from Table 5-1.
- Column 3 - capacity revenue is from Table 6-1.
- Column 4 - power from this project is marketed under a contract that will expire in 2018. Capacity credits are based upon capacity benefits until 2018, and capacity revenues foregone from 2018 to the end of project economic life.
- Column 5 - energy benefit is from Table 5-1.
- Column 6 - energy revenue is from Table 6-1.
- Column 7 - energy credits are calculated as described in Column (4).
- Column 8 - amortization factor at 5-5/8 percent interest
- Column 9 - column 4 X column 8
- Column 10 - column 7 X column 8

- Column 11 - column 9 + column 10

Table 7-1: SEPA Annual Capacity and Energy Credit Calculation - 5 MGD Withdrawal from Conservation Zone

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	Capacity Benefit ($)	Capacity Revenue ($)	Annual Capacity Credit ($)	Energy Benefit ($)	Energy Revenue ($)	Annual Energy Credit ($)	Present-Worth Factor	Present-Worthed Capacity Credit ($)	Present-Worthed Energy Credit ($)	Total Power Credit ($)
2005	$6,942	----	$6,942	$16,621	----	$16,621	1.0000	$6,942	$16,621	$23,563
2006	$6,942	----	$6,942	$16,621	----	$16,621	0.9467	$6,572	$15,736	$22,308
2007	$6,942	----	$6,942	$16,621	----	$16,621	0.8963	$6,222	$14,898	$21,120
2008	$6,942	----	$6,942	$16,621	----	$16,621	0.8486	$5,891	$14,104	$19,995
2009	$6,942	----	$6,942	$16,621	----	$16,621	0.8034	$5,577	$13,353	$18,931
2010	$6,942	----	$6,942	$16,621	----	$16,621	0.7606	$5,280	$12,642	$17,922
2011	$6,942	----	$6,942	$16,621	----	$16,621	0.7201	$4,999	$11,969	$16,968
2012	$6,942	----	$6,942	$16,621	----	$16,621	0.6818	$4,733	$11,332	$16,064
2013	$6,942	----	$6,942	$16,621	----	$16,621	0.6455	$4,481	$10,728	$15,209
2014	$6,942	----	$6,942	$16,621	----	$16,621	0.6111	$4,242	$10,157	$14,399
2015	$6,942	----	$6,942	$16,621	----	$16,621	0.5785	$4,016	$9,616	$13,632
2016	$6,942	----	$6,942	$16,621	----	$16,621	0.5477	$3,802	$9,104	$12,906
2017	$6,942	----	$6,942	$16,621	----	$16,621	0.5186	$3,600	$8,619	$12,219
2018	$6,942	----	$6,942	$16,621	----	$16,621	0.4909	$3,408	$8,160	$11,568
2019	----	$1,926	$1,926	----	$4,092	$4,092	0.4648	$895	$1,902	$2,797
2020	----	$1,926	$1,926	----	$4,092	$4,092	0.4400	$848	$1,801	$2,648
2021	----	$1,926	$1,926	----	$4,092	$4,092	0.4166	$802	$1,705	$2,507
2022	----	$1,926	$1,926	----	$4,092	$4,092	0.3944	$760	$1,614	$2,374
2023	----	$1,926	$1,926	----	$4,092	$4,092	0.3734	$719	$1,528	$2,247
2024	----	$1,926	$1,926	----	$4,092	$4,092	0.3535	$681	$1,447	$2,128
2025	----	$1,926	$1,926	----	$4,092	$4,092	0.3347	$645	$1,370	$2,014
2026	----	$1,926	$1,926	----	$4,092	$4,092	0.3169	$610	$1,297	$1,907
2027	----	$1,926	$1,926	----	$4,092	$4,092	0.3000	$578	$1,228	$1,805
2028	----	$1,926	$1,926	----	$4,092	$4,092	0.2840	$547	$1,162	$1,709
2029	----	$1,926	$1,926	----	$4,092	$4,092	0.2689	$518	$1,100	$1,618
2030	----	$1,926	$1,926	----	$4,092	$4,092	0.2546	$490	$1,042	$1,532
2031	----	$1,926	$1,926	----	$4,092	$4,092	0.2410	$464	$986	$1,450
2032	----	$1,926	$1,926	----	$4,092	$4,092	0.2282	$439	$934	$1,373
2033	----	$1,926	$1,926	----	$4,092	$4,092	0.2160	$416	$884	$1,300
2034	----	$1,926	$1,926	----	$4,092	$4,092	0.2045	$394	$837	$1,231
2035	----	$1,926	$1,926	----	$4,092	$4,092	0.1936	$373	$792	$1,165
2036	----	$1,926	$1,926	----	$4,092	$4,092	0.1833	$353	$750	$1,103
2037	----	$1,926	$1,926	----	$4,092	$4,092	0.1736	$334	$710	$1,045
2038	----	$1,926	$1,926	----	$4,092	$4,092	0.1643	$316	$672	$989
2039	----	$1,926	$1,926	----	$4,092	$4,092	0.1556	$300	$637	$936
2040	----	$1,926	$1,926	----	$4,092	$4,092	0.1473	$284	$603	$886
2041	----	$1,926	$1,926	----	$4,092	$4,092	0.1394	$269	$571	$839
2042	----	$1,926	$1,926	----	$4,092	$4,092	0.1320	$254	$540	$794
2043	----	$1,926	$1,926	----	$4,092	$4,092	0.1250	$241	$511	$752
2044	----	$1,926	$1,926	----	$4,092	$4,092	0.1183	$228	$484	$712
2045	----	$1,926	$1,926	----	$4,092	$4,092	0.1120	$216	$458	$674
2046	----	$1,926	$1,926	----	$4,092	$4,092	0.1061	$204	$434	$638
2047	----	$1,926	$1,926	----	$4,092	$4,092	0.1004	$193	$411	$604
2048	----	$1,926	$1,926	----	$4,092	$4,092	0.0951	$183	$389	$572
2049	----	$1,926	$1,926	----	$4,092	$4,092	0.0900	$173	$368	$542
2050	----	$1,926	$1,926	----	$4,092	$4,092	0.0852	$164	$349	$513
2051	----	$1,926	$1,926	----	$4,092	$4,092	0.0807	$155	$330	$485
2052	----	$1,926	$1,926	----	$4,092	$4,092	0.0764	$147	$313	$460
2053	----	$1,926	$1,926	----	$4,092	$4,092	0.0723	$139	$296	$435
2054	----	$1,926	$1,926	----	$4,092	$4,092	0.0685	$132	$280	$412
								$84,232	$197,773	$282,005
				Years of Analysis				50	50	50
				Annualization Factor				0.06015	0.06015	0.06015
				Annualized Capacity Credit				**$5,066**	**$11,896**	**$16,962**

Explanation of Calculations:
Col (1): Required hours on peak. **Col (2)**: Ave weekly energy before water supply withdrawals is based on the output from the Kerr-Philpott Model for Jul-Aug. **Col (3):** Col (2)/Col(1). **Col (4) & Col (8):** Machine Capability specify in Table 2-1.
Col (5): Lesser of Col (3) and Col(4). **Col (6):** Ave weekly energy after water supply withdrawals is based on the data in Col (2) minus the energy losses computed using the power equation. **Col (7):** Col (6)/Col (1).
Col (9): The lesser of Col (7) and Col (8). Col (10): Col (5) - Col (9)

Table 7-2: SEPA Annual Capacity and Energy Credit Calculation - 20 MGD Withdrawal from Conservation Zone

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	Capacity Benefit ($)	Capacity Revenue ($)	Annual Capacity Credit ($)	Energy Benefit ($)	Energy Revenue ($)	Annual Energy Credit ($)	Present-Worth Factor	Present-Worthed Capacity Credit ($)	Present-Worthed Energy Credit ($)	Total Power Credit ($)
2005	$27,523	----	$27,523	$66,383	----	$66,383	1.0000	$27,523	$66,383	$93,906
2006	$27,523	----	$27,523	$66,383	----	$66,383	0.9467	$26,057	$62,848	$88,905
2007	$27,523	----	$27,523	$66,383	----	$66,383	0.8963	$24,670	$59,501	$84,170
2008	$27,523	----	$27,523	$66,383	----	$66,383	0.8486	$23,356	$56,332	$79,688
2009	$27,523	----	$27,523	$66,383	----	$66,383	0.8034	$22,112	$53,332	$75,444
2010	$27,523	----	$27,523	$66,383	----	$66,383	0.7606	$20,934	$50,492	$71,427
2011	$27,523	----	$27,523	$66,383	----	$66,383	0.7201	$19,820	$47,803	$67,623
2012	$27,523	----	$27,523	$66,383	----	$66,383	0.6818	$18,764	$45,257	$64,022
2013	$27,523	----	$27,523	$66,383	----	$66,383	0.6455	$17,765	$42,847	$60,612
2014	$27,523	----	$27,523	$66,383	----	$66,383	0.6111	$16,819	$40,565	$57,384
2015	$27,523	----	$27,523	$66,383	----	$66,383	0.5785	$15,923	$38,405	$54,328
2016	$27,523	----	$27,523	$66,383	----	$66,383	0.5477	$15,075	$36,360	$51,435
2017	$27,523	----	$27,523	$66,383	----	$66,383	0.5186	$14,272	$34,424	$48,696
2018	$27,523	----	$27,523	$66,383	----	$66,383	0.4909	$13,512	$32,590	$46,103
2019	----	$7,639	$7,639	----	$16,343	$16,343	0.4648	$3,551	$7,596	$11,147
2020	----	$7,639	$7,639	----	$16,343	$16,343	0.4400	$3,362	$7,192	$10,553
2021	----	$7,639	$7,639	----	$16,343	$16,343	0.4166	$3,183	$6,809	$9,991
2022	----	$7,639	$7,639	----	$16,343	$16,343	0.3944	$3,013	$6,446	$9,459
2023	----	$7,639	$7,639	----	$16,343	$16,343	0.3734	$2,853	$6,103	$8,955
2024	----	$7,639	$7,639	----	$16,343	$16,343	0.3535	$2,701	$5,778	$8,478
2025	----	$7,639	$7,639	----	$16,343	$16,343	0.3347	$2,557	$5,470	$8,027
2026	----	$7,639	$7,639	----	$16,343	$16,343	0.3169	$2,421	$5,179	$7,599
2027	----	$7,639	$7,639	----	$16,343	$16,343	0.3000	$2,292	$4,903	$7,195
2028	----	$7,639	$7,639	----	$16,343	$16,343	0.2840	$2,170	$4,642	$6,812
2029	----	$7,639	$7,639	----	$16,343	$16,343	0.2689	$2,054	$4,395	$6,449
2030	----	$7,639	$7,639	----	$16,343	$16,343	0.2546	$1,945	$4,161	$6,105
2031	----	$7,639	$7,639	----	$16,343	$16,343	0.2410	$1,841	$3,939	$5,780
2032	----	$7,639	$7,639	----	$16,343	$16,343	0.2282	$1,743	$3,729	$5,472
2033	----	$7,639	$7,639	----	$16,343	$16,343	0.2160	$1,650	$3,531	$5,181
2034	----	$7,639	$7,639	----	$16,343	$16,343	0.2045	$1,562	$3,343	$4,905
2035	----	$7,639	$7,639	----	$16,343	$16,343	0.1936	$1,479	$3,165	$4,644
2036	----	$7,639	$7,639	----	$16,343	$16,343	0.1833	$1,400	$2,996	$4,397
2037	----	$7,639	$7,639	----	$16,343	$16,343	0.1736	$1,326	$2,837	$4,162
2038	----	$7,639	$7,639	----	$16,343	$16,343	0.1643	$1,255	$2,686	$3,941
2039	----	$7,639	$7,639	----	$16,343	$16,343	0.1556	$1,188	$2,543	$3,731
2040	----	$7,639	$7,639	----	$16,343	$16,343	0.1473	$1,125	$2,407	$3,532
2041	----	$7,639	$7,639	----	$16,343	$16,343	0.1394	$1,065	$2,279	$3,344
2042	----	$7,639	$7,639	----	$16,343	$16,343	0.1320	$1,008	$2,158	$3,166
2043	----	$7,639	$7,639	----	$16,343	$16,343	0.1250	$955	$2,043	$2,997
2044	----	$7,639	$7,639	----	$16,343	$16,343	0.1183	$904	$1,934	$2,838
2045	----	$7,639	$7,639	----	$16,343	$16,343	0.1120	$856	$1,831	$2,687
2046	----	$7,639	$7,639	----	$16,343	$16,343	0.1061	$810	$1,733	$2,544
2047	----	$7,639	$7,639	----	$16,343	$16,343	0.1004	$767	$1,641	$2,408
2048	----	$7,639	$7,639	----	$16,343	$16,343	0.0951	$726	$1,554	$2,280
2049	----	$7,639	$7,639	----	$16,343	$16,343	0.0900	$688	$1,471	$2,158
2050	----	$7,639	$7,639	----	$16,343	$16,343	0.0852	$651	$1,393	$2,044
2051	----	$7,639	$7,639	----	$16,343	$16,343	0.0807	$616	$1,318	$1,935
2052	----	$7,639	$7,639	----	$16,343	$16,343	0.0764	$583	$1,248	$1,832
2053	----	$7,639	$7,639	----	$16,343	$16,343	0.0723	$552	$1,182	$1,734
2054	----	$7,639	$7,639	----	$16,343	$16,343	0.0685	$523	$1,119	$1,642
								$333,978	$789,891	$1,123,869
				Years of Analysis				50	50	50
				Annualization Factor				0.06015	0.06015	0.06015
				Annualized Capacity Credit				**$20,088**	**$47,511**	**$67,599**

Explanation of Calculations:
Col (1): Required hours on peak. **Col (2)**: Ave weekly energy before water supply withdrawals is based on the output from the Kerr-Philpott Model for Jul-Aug. **Col (3):** Col (2)/Col(1). **Col (4) & Col (8):** Machine Capability specify in Table 2-1.
Col (5): Lesser of Col (3) and Col(4). **Col (6):** Ave weekly energy after water supply withdrawals is based on the data in Col (2) minus the energy losses computed using the power equation. **Col (7):** Col (6)/Col (1).
Col (9): The lesser of Col (7) and Col (8). Col (10): Col (5) - Col (9)

Summary of Credits

Following is a summary of credit due the power marketing agency for water withdrawal from the John H. Kerr reservoir.

Table 7-3: Annual Credit Due to Power Marketing Agency

Withdrawal Alternative	5 MGD	20 MGD
Energy credit	$11,896	$47,511
Capacity credit	$5,066	$20,088
Annual credit to PMA	**$16,962**	**$67,599**

SUMMARY OF RESULTS

Power Benefits Foregone

Summarizing the data developed in Chapters 2 through 5, power benefits foregone for a 5 MGD and 20 MGD water withdrawal from the John H. Kerr reservoir are as follows (from Tables 5-1):

Table 8-1: Annual Benefits Foregone

Withdrawal Alternative	5 MGD	20 MGD
Annual energy benefit foregone	$16,621	$66,383
Capacity benefit foregone	$6,934	$27,493
Annual benefit foregone	**$23,555**	**$93,876**

Replacement Cost

As noted in Section 1.7, the replacement cost of power as used in determining the cost of the reallocation to the water supply customer is identical in each case to the hydropower benefits foregone presented in Section 8.1.

Revenues Foregone

Summarizing the data developed in Chapters 6, the power revenues foregone for 5 MGD and 20 MGD water withdrawal from John H. Kerr are as follows (from Tables 6-2)

Table 8-2: Annual Revenues Foregone

Withdrawal Alternative	5 MGD	20 MGD
Annual energy revenue foregone	$4,092	$16,343
Capacity revenue foregone	$1,926	$7,639
Annual revenue foregone	**$6,018**	**$23,982**

SEPA Credit

Summarizing the data developed in Chapter 7, 5 MGD and 20 MGD SEPA credits for the project is as follows (from Tables 7-1)

Table 8-3: Annual SEPA Credit

Withdrawal Alternative	5 MGD	20 MGD
Energy credit	$11,896	$47,511
Capacity credit	$5,066	$20,088
Annual credit to PMA	**$16,962**	**$67,599**

ADDENDUM A

FERC Power Values

Selected Output From FERC Procedures for Coal, Gas CC & Gas CT Plants
for States Within the Virgina/Carolinal area
and at 5.875% Federal Interest Rate and July 2002 Price Level
Fuel Costs Are Computed Using a 60-Month Moving Average Time Frame

Coal-Fired Steam

	State	C_V	E_V	Fuel Cost	Heat Rate	Var. O&M
*	VA	209.59	17.76	146.3	9830	3.38
*	NC	209.65	18.75	156.3	9830	3.38
*	SC	209.61	18.12	150.0	9830	3.38
*						
	Avg.	209.62	18.21	150.9	9830	3.38

Gas CC

	State	C_V	E_V	Fuel Cost	Heat Rate	Var. O&M
*	VA	116.45	39.59	481.0	8030	0.96
*	NC	116.45	39.59	481.0	8030	0.96
*	SC	116.45	44.55	542.8	8030	0.96
*						
	Avg.	116.45	41.24	501.6	8030	0.96

Gas CT

	State	C_V	E_V	Fuel Cost	Heat Rate	Var. O&M
*	VA	62.13	73.73	571.0	12870	0.24
*	NC	62.13	62.14	481.0	12870	0.24
*	SC	62.13	70.09	542.8	12870	0.24
*						
	Avg.	62.13	68.66	531.6	12870	0.24

				Date Run
COAL-FIRED STEAM POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	VIRGINIA		
	FINANCING:	FEDERAL @	5.625%	
Capacity Value		$209.59	per kW-yr	
Energy Value		$17.76	per MWh	
PROGRAM INPUT DATA			State Index Number	47
			State Location	VA
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	600		ROW ($/acre)	2436
Capacity factor	0.65		Clearing % of ROW	0.60
Trans Voltage	345		Rec Sub Land Cost	22914
Transformer MVA	200		Plant Invest	1330
No of Trans	6		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	146.3
Single or Three Phase	1		Heat Rate	9830
Length Line 1	50		Variable O&M	3.38
Length Line 2	0		Fixed O&M	56.90
Line 1: Total Circuits	3		O&M update	2.78
No of Single Circ	1		Plant update	2.40
No of Double Circ	1		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.050
Plant insurance (%)	0.25		Alt Mechanical Avail	0.850
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.153

				Date Run
COAL-FIRED STEAM POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	NORTH CAROLINA		
FINANCING:		FEDERAL @	5.625%	
Capacity Value		$209.65	per kW-yr	
Energy Value		$18.75	per MWh	
PROGRAM INPUT DATA			State Index Number	34
			State Location	NC
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	600		ROW ($/acre)	2436
Capacity factor	0.65		Clearing % of ROW	0.60
Trans Voltage	345		Rec Sub Land Cost	22914
Transformer MVA	200		Plant Invest	1330
No of Trans	6		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	156.3
Single or Three Phase	1		Heat Rate	9830
Length Line 1	50		Variable O&M	3.38
Length Line 2	0		Fixed O&M	56.90
Line 1: Total Circuits	3		O&M update	2.78
No of Single Circ	1		Plant update	2.40
No of Double Circ	1		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.050
Plant insurance (%)	0.25		Alt Mechanical Avail	0.850
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.153

				Date Run
COAL-FIRED STEAM POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	SOUTH CAROLINA		
	FINANCING:	FEDERAL @	5.625%	
Capacity Value		$209.61	per kW-yr	
Energy Value		$18.12	per MWh	
PROGRAM INPUT DATA			State Index Number	41
			State Location	SC
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	600		ROW ($/acre)	2436
Capacity factor	0.65		Clearing % of ROW	0.60
Trans Voltage	345		Rec Sub Land Cost	22914
Transformer MVA	200		Plant Invest	1330
No of Trans	6		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	150.0
Single or Three Phase	1		Heat Rate	9830
Length Line 1	50		Variable O&M	3.38
Length Line 2	0		Fixed O&M	56.90
Line 1: Total Circuits	3		O&M update	2.78
No of Single Circ	1		Plant update	2.40
No of Double Circ	1		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.050
Plant insurance (%)	0.25		Alt Mechanical Avail	0.850
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.153

				Date Run
COMBINED CYCLE POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	VIRGINIA		
FINANCING:		FEDERAL @	5.625%	
Capacity Value		$116.45	per kW-yr	
Energy Value		$46.82	per MWh	
PROGRAM INPUT DATA			State Index Number	47
			State Abbr. (exact)	VA
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	150		ROW ($/acre)	2436
Capacity factor	0.20		Clearing % of ROW	0.60
Trans Voltage	230		Rec Sub Land Cost	22914
Transformer MVA	200		Plant Invest	760
No of Trans	1		FC Mov-Ave Time Frame	60
No of Trans Positions	1		Fuel Cost	571.0
Single or Three Phase	3		Heat Rate	8030
Length Line 1	0		Variable O&M	0.96
Length Line 2	0		Fixed O&M	44.84
Line 1: Total Circuits	0		O&M update	2.78
No of Single Circ	0		Plant update	2.40
No of Double Circ	0		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

				Date Run
COMBINED CYCLE POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	NORTH CAROLINA		
FINANCING:		FEDERAL @	5.625%	
Capacity Value		$116.45	per kW-yr	
Energy Value		$39.59	per MWh	
PROGRAM INPUT DATA			State Index Number	34
			State Abbr. (exact)	NC
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	150		ROW ($/acre)	2436
Capacity factor	0.20		Clearing % of ROW	0.60
Trans Voltage	230		Rec Sub Land Cost	22914
Transformer MVA	200		Plant Invest	760
No of Trans	1		FC Mov-Ave Time Frame	60
No of Trans Positions	1		Fuel Cost	481.0
Single or Three Phase	3		Heat Rate	8030
Length Line 1	0		Variable O&M	0.96
Length Line 2	0		Fixed O&M	44.84
Line 1: Total Circuits	0		O&M update	2.78
No of Single Circ	0		Plant update	2.40
No of Double Circ	0		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

				Date Run
COMBINED CYCLE POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	SOUTH CAROLINA		
	FINANCING:	FEDERAL @	5.625%	
Capacity Value		$116.45	per kW-yr	
Energy Value		$44.55	per MWh	
PROGRAM INPUT DATA			State Index Number	41
			State Abbr. (exact)	SC
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	150		ROW ($/acre)	2436
Capacity factor	0.20		Clearing % of ROW	0.60
Trans Voltage	230		Rec Sub Land Cost	22914
Transformer MVA	200		Plant Invest	760
No of Trans	1		FC Mov-Ave Time Frame	60
No of Trans Positions	1		Fuel Cost	542.8
Single or Three Phase	3		Heat Rate	8030
Length Line 1	0		Variable O&M	0.96
Length Line 2	0		Fixed O&M	44.84
Line 1: Total Circuits	0		O&M update	2.78
No of Single Circ	0		Plant update	2.40
No of Double Circ	0		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mech Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

				Date Run
COMBUSTION TURBINE POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	VIRGINIA		
FINANCING:		FEDERAL @	5.625%	
Capacity Value		$62.13	per kW-yr	
Energy Value		$73.73	per MWh	
PROGRAM INPUT DATA			State Index Number	47
			State Location	VA
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	100		ROW ($/acre)	2319
Capacity Factor	0.10		Clearing % of ROW	0.60
Transmission Voltage	230		Rec Sub Land Cost	21869
Transformer MVA	125		Plant Invest	470
No of Trans	2		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	571.0
Single or Three Phase	3		Heat Rate	12870
Length Line 1	0		Variable O&M	0.24
Length Line 2	0		Fixed O&M	14.71
Line 1: Total Circuits	2		O&M update	2.78
No of Single Circ	2		Plant update	2.40
No of Double Circ	0		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mechanical Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

				Date Run
COMBUSTION TURBINE POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	NORTH CAROLINA		
FINANCING:		FEDERAL @	5.625%	
Capacity Value		$62.13	per kW-yr	
Energy Value		$62.14	per MWh	
PROGRAM INPUT DATA			State Index Number	34
			State Location	NC
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	100		ROW ($/acre)	2319
Capacity Factor	0.10		Clearing % of ROW	0.60
Transmission Voltage	230		Rec Sub Land Cost	21869
Transformer MVA	125		Plant Invest	470
No of Trans	2		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	481.0
Single or Three Phase	3		Heat Rate	12870
Length Line 1	0		Variable O&M	0.24
Length Line 2	0		Fixed O&M	14.71
Line 1: Total Circuits	2		O&M update	2.78
No of Single Circ	2		Plant update	2.40
No of Double Circ	0		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mechanical Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

				Date Run
COMBUSTION TURBINE POWER VALUE				03/04/04
PROJECT NAME:		J.H. KERR W.S.		
	LOCATION:	SOUTH CAROLINA		
FINANCING:		FEDERAL @	5.625%	
Capacity Value		$62.13	per kW-yr	
Energy Value		$70.09	per MWh	
PROGRAM INPUT DATA			State Index Number	41
			State Location	SC
Cost Level Date	8/1/2003		H-W Index Reg No	2
Single unit capacity	100		ROW ($/acre)	2319
Capacity Factor	0.10		Clearing % of ROW	0.60
Transmission Voltage	230		Rec Sub Land Cost	21869
Transformer MVA	125		Plant Invest	470
No of Trans	2		FC Mov-Ave Time Frame	60
No of Trans Pos	2		Fuel Cost	542.8
Single or Three Phase	3		Heat Rate	12870
Length Line 1	0		Variable O&M	0.24
Length Line 2	0		Fixed O&M	14.71
Line 1: Total Circuits	2		O&M update	2.78
No of Single Circ	2		Plant update	2.40
No of Double Circ	0		Transmission update	2.18
Line 2: Total Circuits	0		Depreciation Plant (%)	1.35
No of Single Circ	0		Deprec Sub (%)	1.35
No of Double Circ	0		Deprec Trans Tower (%)	0.39
			Deprec Trans Pole (%)	1.35
Cost of Money (%)	5.625			
Plant Life	30		Fed Inc Tax (%)	0.000
Substation Life	30		Fed Misc Tax (%)	0.000
Trans (towers) Life	50		State & Local Tax (%)	0.000
Trans (poles) life	30			
			Hydro Flex Adjust	0.025
Plant insurance (%)	0.25		Alt Mechanical Avail	0.900
Trans Insurance (%)	0.10		Hydro Mechanical Avail	0.980
Sub insurance (%)	0.25		Mech Avail Adjust	0.089

ADDENDUM B

PROSYM OUTPUT SUMMARY

J. H. KERR : GENSUM TABLE
10/15/2003
STUDY YR. JAN 2005

System with J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 Refuse	873.9	24,671	28.23	111	90.3%
2 Coal-SERC	14,248.1	240,501	16.88	1,903	85.7%
3 NG VACAR	25,324.2	919,123	36.29	18,232	15.9%
4 Coal-VACAR	141,750.7	2,598,771	18.33	22,662	71.6%
5 DCLM	0.0	0	0.00	0	0.0%
6 INTLOAD	0.0	0	0.00	0	0.0%
7 FO#2-SERC	55.2	9,343	169.26	1,053	0.6%
8 Jet Fuel	0.0	2	0.00	0	0.0%
9 Other	1,390.3	48,505	34.89	220	72.2%
10 Uranium	114,419.7	1,611,829	14.09	14,934	87.7%
11 FO#6-SERC	4,910.9	158,140	32.20	1,709	32.9%
12 Wood	279.8	7,617	27.22	39	82.7%
13 Methane	8.2	278	33.90	6	15.6%
14 Pump Storage	4,239.5	8,479	2.00	4,333	11.2%
15 Hydro	4,451.6	22,258	5.00	2,150	23.7%
16 HydroStudy	383.0	1,915	5.00	237	18.5%
17 Transaction	697.0	149	0.21	109	73.4%
Totals	313,032.1	5,651,581	18.05	67,698	52.8%
Unserved Energy	0.0	0	0.00	--	--
Net Total	313,032.1	5,651,581	18.05	--	--

System without J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C
1 Refuse	873.9	24,671	28.23	111	90.3%	0.0	0	0.00	
2 Coal-SERC	14,255.9	240,614	16.88	1,904	85.7%	7.8	113	14.49	
3 NG VACAR	25,336.3	920,841	36.34	18,356	15.8%	12.1	1,718	141.98	
4 Coal-VACAR	142,076.3	2,606,786	18.35	22,746	71.5%	325.6	8,015	24.62	
5 DCLM	0.0	0	0.00	0	0.0%	0.0	0	0.00	
6 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00	
7 FO#2-SERC	55.1	9,340	169.51	1,051	0.6%	-0.1	-3	-30.00	
8 Jet Fuel	0.0	2	0.00	0	0.0%	0.0	0	0.00	
9 Other	1,392.7	48,588	34.89	220	72.3%	2.4	83	34.58	
10 Uranium	114,419.7	1,611,829	14.09	14,934	87.7%	0.0	0	0.00	
11 FO#6-SERC	4,956.2	159,675	32.22	1,709	33.2%	45.3	1,535	33.89	
12 Wood	279.8	7,617	27.22	39	82.7%	0.0	0	0.00	
13 Methane	8.1	275	33.95	6	15.4%	-0.1	-3	30.00	
14 Pump Storage	4,257.6	8,515	2.00	4,351	11.2%	18.1	36	1.99	
15 Hydro	4,451.6	22,258	5.00	2,150	23.7%	0.0	0	0.00	
16 HydroStudy	0.0	0	0.00	0	0.0%	-383.0	0	0.00	
17 Transaction	697.0	149	0.21	109	73.4%	0.0	0	0.00	
Totals	313,060.2	5,661,160	18.08	67,687	52.8%	28.1	11,494	30.01	
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00	
Net Total	313,060.2	5,661,160	18.08	--	--	28.1	11,494	30.01	

HYDROPOWER ENERGY VALUE: 30.01 mills/kWh

HYDROPOWER

J. H. KERR : GENSUM TABLE
10/15/2003
STUDY YR. JAN 2010

System with J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 Refuse	894.8	25,198	28.16	111	92.5%
2 Coal-SERC	14,182.9	236,142	16.65	1,903	85.3%
3 NG VACAR	52,727.6	1,723,922	32.69	25,149	24.0%
4 Coal-VACAR	146,861.3	2,606,828	17.75	21,525	78.1%
5 DCLM	0.0	0	0.00	0	0.0%
6 INTLOAD	0.0	0	0.00	0	0.0%
7 FO#2-SERC	66.1	10,240	154.92	946	0.8%
8 Jet Fuel	0.0	2	0.00	0	0.0%
9 Other	1,372.0	48,246	35.16	220	71.3%
10 Uranium	114,736.9	1,577,615	13.75	14,959	87.8%
11 FO#6-SERC	5,390.1	177,455	32.92	1,619	38.1%
12 Wood	305.7	8,312	27.19	39	90.4%
13 Methane	13.0	431	33.15	6	24.8%
14 Pump Storage	4,896.9	9,794	2.00	4,345	12.9%
15 Hydro	4,451.6	22,258	5.00	2,150	23.7%
16 HydroStudy	383.0	1,915	5.00	237	18.5%
17 Transaction	697.7	0	0.00	109	73.4%
Totals	346,979.6	6,448,358	18.58	73,318	54.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	346,979.6	6,448,358	18.58	--	--

System without J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	%
1 Refuse	894.8	25,198	28.16	111	92.5%	0.0	0	0.00	
2 Coal-SERC	14,185.8	236,184	16.65	1,904	85.3%	2.9	42	14.48	
3 NG VACAR	53,071.2	1,736,891	32.73	25,313	24.0%	343.6	12,969	37.74	
4 Coal-VACAR	147,026.5	2,609,566	17.75	21,522	78.2%	165.2	2,738	16.57	
5 DCLM	0.0	0	0.00	0	0.0%	0.0	0	0.00	
6 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00	
7 FO#2-SERC	66.1	10,245	154.99	946	0.8%	0.0	5	50.00	
8 Jet Fuel	0.0	2	0.00	0	0.0%	0.0	0	0.00	
9 Other	1,364.6	48,012	35.18	220	70.9%	-7.4	-234	31.62	
10 Uranium	114,736.9	1,577,615	13.75	14,959	87.8%	0.0	0	0.00	
11 FO#6-SERC	5,280.8	173,280	32.81	1,616	37.4%	-109.3	-4,175	38.20	
12 Wood	305.7	8,312	27.19	39	90.4%	0.0	0	0.00	
13 Methane	13.1	435	33.21	6	25.0%	0.1	4	40.00	
14 Pump Storage	4,945.2	9,890	2.00	4,354	13.0%	48.3	96	1.99	
15 Hydro	4,451.6	22,258	5.00	2,150	23.7%	0.0	0	0.00	
16 HydroStudy	0.0	0	0.00	0	0.0%	-383.0	0	0.00	
17 Transaction	697.7	0	0.00	109	73.4%	0.0	0	0.00	
Totals	347,040.0	6,457,888	18.61	73,248	54.1%	60.4	11,445	29.88	
Unserved Energy	0.0	0	0.00	--	--	0.0	0.0	0.00	
Net Total	347,040.0	6,457,888	18.61	--	--	60.4	11,445	29.88	

HYDROPOWER ENERGY VALUE: 29.88 mills/kWh

HYDROPOWER

J. H. KERR : GENSUM TABLE
10/15/2003
STUDY YR. JAN 2015

System with J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 Refuse	931.4	26,155	28.08	111	96.3%
2 Coal-SERC	14,010.4	230,387	16.44	1,905	84.2%
3 NG VACAR	90,723.2	3,026,134	33.36	34,274	30.3%
4 Coal-VACAR	141,057.7	2,447,433	17.35	20,108	80.3%
5 DCLM	0.0	0	0.00	0	0.0%
6 INTLOAD	0.0	0	0.00	0	0.0%
7 FO#2-SERC	63.3	9,926	156.81	1,035	0.7%
8 Jet Fuel	0.0	2	0.00	0	0.0%
9 Other	1,526.5	51,442	33.70	220	79.3%
10 Uranium	116,028.0	1,553,406	13.39	14,957	88.8%
11 FO#6-SERC	7,970.6	248,951	31.23	1,618	56.4%
12 Wood	312.2	8,485	27.18	39	92.3%
13 Methane	19.7	642	32.59	6	37.4%
14 Pump Storage	5,542.2	11,084	2.00	4,345	14.6%
15 Hydro	4,451.6	22,258	5.00	2,150	23.7%
16 HydroStudy	383.0	1,915	5.00	237	18.5%
17 Transaction	697.7	0	0.00	109	73.4%
Totals	383,717.5	7,638,220	19.91	81,113	54.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	383,717.5	7,638,220	19.91	--	--

System without J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh
1 Refuse	931.4	26,155	28.08	111	96.3%	0.0	0	0.00
2 Coal-SERC	14,010.8	230,393	16.44	1,905	84.2%	0.4	6	15.00
3 NG VACAR	90,970.6	3,035,868	33.37	34,481	30.2%	247.4	9,734	39.35
4 Coal-VACAR	141,146.4	2,448,938	17.35	20,096	80.4%	88.7	1,505	16.97
5 DCLM	0.0	0	0.00	0	0.0%	0.0	0	0.00
6 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00
7 FO#2-SERC	63.3	9,926	156.81	1,035	0.7%	0.0	0	0.00
8 Jet Fuel	0.0	2	0.00	0	0.0%	0.0	0	0.00
9 Other	1,524.0	51,381	33.71	220	79.2%	-2.5	-61	24.40
10 Uranium	116,028.0	1,553,406	13.39	14,957	88.8%	0.0	0	0.00
11 FO#6-SERC	8,028.8	250,674	31.22	1,618	56.8%	58.2	1,723	29.60
12 Wood	312.2	8,485	27.18	39	92.3%	0.0	0	0.00
13 Methane	19.7	644	32.69	6	37.5%	0.0	2	0.00
14 Pump Storage	5,579.8	11,160	2.00	4,345	14.7%	37.6	76	2.02
15 Hydro	4,451.6	22,258	5.00	2,150	23.7%	0.0	0	0.00
16 HydroStudy	0.0	0	0.00	0	0.0%	-383.0	0	0.00
17 Transaction	697.7	0	0.00	109	73.4%	0.0	0	0.00
Totals	383,764.3	7,649,290	19.93	81,071	54.0%	46.8	12,985	33.90
Unserved Energy	0.0	0	0.00	--	--	0.0	0.0	0.00
Net Total	383,764.3	7,649,290	19.93	--	--	46.8	12,985	33.90

HYDROPOWER ENERGY VALUE: 33.90 mills/kWh

HYDROPOW

J. H. KERR : GENSUM TABLE
10/15/2003
STUDY YR. JAN 2020

System with J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 Refuse	928.3	26,080	28.09	111	95.7%
2 Coal-SERC	13,976.5	227,132	16.25	1,909	83.8%
3 NG VACAR	127,537.5	4,385,364	34.38	43,065	33.9%
4 Coal-VACAR	142,015.0	2,417,848	17.03	19,946	81.5%
5 DCLM	0.0	0	0.00	0	0.0%
6 INTLOAD	0.0	0	0.00	0	0.0%
7 FO#2-SERC	57.2	9,426	164.79	935	0.7%
8 Jet Fuel	0.0	2	0.00	0	0.0%
9 Other	1,658.9	54,823	33.05	221	85.9%
10 Uranium	116,969.8	1,530,516	13.08	14,994	89.3%
11 FO#6-SERC	8,967.9	276,912	30.88	1,622	63.3%
12 Wood	313.1	8,511	27.18	39	92.3%
13 Methane	27.2	879	32.32	6	51.7%
14 Pump Storage	6,117.2	12,234	2.00	4,349	16.1%
15 Hydro	4,452.4	22,262	5.00	2,150	23.7%
16 HydroStudy	383.0	1,915	5.00	237	18.5%
17 Transaction	698.5	0	0.00	109	73.5%
Totals	424,102.5	8,973,904	21.16	89,694	54.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	424,102.5	8,973,904	21.16	--	--

System without J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh
1 Refuse	928.3	26,080	28.09	111	95.7%	0.0	0	0.00
2 Coal-SERC	13,976.5	227,131	16.25	1,909	83.8%	0.0	-1	#DIV/0!
3 NG VACAR	127,842.9	4,397,188	34.40	43,296	33.8%	305.4	11,824	38.72
4 Coal-VACAR	142,053.6	2,418,501	17.03	19,952	81.5%	38.6	653	16.92
5 DCLM	0.0	0	0.00	0	0.0%	0.0	0	0.00
6 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00
7 FO#2-SERC	57.2	9,426	164.79	935	0.7%	0.0	0	0.00
8 Jet Fuel	0.0	2	0.00	0	0.0%	0.0	0	0.00
9 Other	1,657.3	54,799	33.07	221	85.8%	-1.6	-24	15.00
10 Uranium	116,969.8	1,530,516	13.08	14,994	89.3%	0.0	0	0.00
11 FO#6-SERC	9,016.7	278,371	30.87	1,623	63.6%	48.8	1,459	29.90
12 Wood	313.1	8,511	27.18	39	92.3%	0.0	0	0.00
13 Methane	27.2	878	32.28	6	51.6%	0.0	-1	0.00
14 Pump Storage	6,149.6	12,299	2.00	4,372	16.1%	32.4	65	2.01
15 Hydro	4,452.4	22,262	5.00	2,150	23.7%	0.0	0	0.00
16 HydroStudy	0.0	0	0.00	0	0.0%	-383.0	0	0.00
17 Transaction	698.5	0	0.00	109	73.5%	0.0	0	0.00
Totals	424,143.1	8,985,964	21.19	89,717	54.0%	40.6	13,975	36.49
Unserved Energy	0.0	0	0.00	--	--	0.0	0.0	0.00
Net Total	424,143.1	8,985,964	21.19	--	--	40.6	13,975	36.49

HYDROPOWER ENERGY VALUE: 36.49 mills/kWh

HYDROPOW

J. H. KERR : GENSUM TABLE
10/15/2003
STUDY YR. JAN 2025

System with J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 Refuse	906.5	25,510	28.14	111	93.7%
2 Coal-SERC	14,177.8	230,051	16.23	1,905	85.2%
3 NG VACAR	175,085.0	6,194,065	35.38	53,161	37.7%
4 Coal-VACAR	140,388.6	2,374,332	16.91	19,432	82.7%
5 DCLM	0.0	0	0.00	0	0.0%
6 INTLOAD	0.0	0	0.00	0	0.0%
7 FO#2-SERC	60.1	7,307	121.58	625	1.1%
8 Other	1,766.3	58,282	33.00	220	91.7%
9 Uranium	114,205.9	1,485,769	13.01	14,958	87.4%
10 FO#6-SERC	9,598.1	292,813	30.51	1,618	67.9%
11 Wood	299.2	8,138	27.20	39	88.5%
12 Methane	38.5	1,232	32.00	6	73.3%
13 Pump Storage	6,631.5	13,263	2.00	4,338	17.5%
14 Hydro	4,451.6	22,258	5.00	2,150	23.7%
15 HydroStudy	383.0	1,915	5.00	237	18.5%
16 Transaction	698.0	0	0.00	109	73.4%
Totals	468,690.1	10,714,935	22.86	98,909	54.1%
Unserved Energy	0.0	0	0.00	--	--
Net Total	468,690.1	10,714,935	22.86	--	--

System without J. H. Kerr Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh
1 Refuse	906.5	25,510	28.14	111	93.7%	0.0	0	0.00
2 Coal-SERC	14,177.8	230,051	16.23	1,905	85.2%	0.0	0	0.00
3 NG VACAR	175,514.7	6,211,266	35.39	53,433	37.6%	429.7	17,201	40.03
4 Coal-VACAR	140,390.1	2,374,362	16.91	19,432	82.7%	1.5	30	20.00
5 DCLM	0.0	0	0.00	0	0.0%	0.0	0	0.00
6 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00
7 FO#2-SERC	60.0	7,305	121.75	624	1.1%	-0.1	-2	-20.00
8 Other	1,767.8	58,322	32.99	220	91.8%	1.5	40	26.67
9 Uranium	114,205.9	1,485,769	13.01	14,958	87.4%	0.0	0	0.00
10 FO#6-SERC	9,556.7	291,276	30.48	1,618	67.6%	-41.4	-1,537	37.13
11 Wood	299.2	8,138	27.20	39	88.5%	0.0	0	0.00
12 Methane	38.5	1,232	32.00	6	73.3%	0.0	0	0.00
13 Pump Storage	6,664.1	13,328	2.00	4,359	17.5%	32.6	65	1.99
14 Hydro	4,451.6	22,258	5.00	2,150	23.7%	0.0	0	0.00
15 HydroStudy	0.0	0	0.00	0	0.0%	-383.0	-1,915	5.00
16 Transaction	698.0	0	0.00	109	73.4%	0.0	0	0.00
Totals	468,730.9	10,728,817	22.89	98,964	54.1%	40.8	13,882	-36.25
Unserved Energy	0.0	0	0.00	--	--	0.0	0.0	0.00
Net Total	468,730.9	10,728,817	22.89	--	--	40.8	13,882	36.25

HYDROPOWER ENERGY VALUE: 36.25 mills/kWh

HYDROPOW