RECEIVED

DEC 17 2004

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, AND A SITE COMPATIBILITY CERTIFICATE, FOR THE EXPANSION OF THE TRIMBLE COUNTY GENERATING STATION	)	**CASE NO: 2004-**00507

VOLUME II

EXHIBIT JPM-1.
EXHIBIT JPM-3,
AND
EXHIBIT SLD-4

Filed: **December 17, 2004**

RECEIVED

DEC 1 7 2004

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS	)	
AND ELECTRIC COMPANY AND KENTUCKY	)	
UTILITIES COMPANY FOR A CERTIFICATE	)	
OF PUBLIC CONVENIENCE AND NECESSITY,	)	CASE NO: 2004-00507
AND A SITE COMPATIBILITY CERTIFICATE,	)	
FOR THE EXPANSION OF THE TRIMBLE	)	
COUNTY GENERATING STATION	)	

VOLUME II

EXHIBIT JPM-1.
EXHIBIT JPM-3,
AND
EXHIBIT SLD-4

Filed: December 17, 2004

Exhibit JPM-1 – Resource Assessment

Louisville Gas & Electric Company

And

Kentucky Utilities Company

Resource Assessment

Prepared by

Generation Systems Planning

November 2004

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Since the merger on May 4 1998, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), (collectively the "Companies"), have conducted joint generation and expansion planning for the Companies as a single entity. The culmination of that planning process is the Integrated Resource Plan ("IRP"), which the Companies filed with the Kentucky Public Service Commission most recently on October 1, 2002. The IRP is a complete resource assessment and acquisition plan that considers all utility supply-side and demand-side resource alternatives but does not consider the dynamic purchase power market. The recommendation in the 2002 IRP includes the installation of two simple-cycle combustion turbine ("CT") units in 2004, one CT in 2005 and 2006, two CTs in 2007 and a coal unit in 2008 followed by additional CTs in 2012-2014, and a combined-cycle unit in 2016. The 2002 IRP also calls for the implementation of an additional small Demand-Side Management ("DSM") program as part of the resource acquisition plan phased in over the 2004-2008 timeframe.

The expansion plan developed as part of the 2002 IRP did not consider any purchase power market opportunities. Because the purchase power market is dynamic, the Companies continually review the "buy versus build" decision. This study serves as an evaluation of the opportunities available to the Companies to meet the resource needs shown in the 2002 IRP and demonstrates that the decision to construct a coal unit or purchase a base load option is made on an economic basis at the time of implementation.

The IRP indicated that a coal unit was necessary in 2008; however, slower economic growth and improved forecasting techniques collectively have decreased the load forecast and deferred the need for new resources. Based on the Companies most current load forecast, additional generating capacity will be required by 2010. The installation of four combustion turbines at the Trimble County facility in 2004 satisfies reserve margin requirements until 2010.

The capacity needs of the Companies, as identified in the 2004 Joint Load Forecast, from 2004 through 2012 for the ends of the reserve margin range of 13% to 15% are specified in the following table.

Scenario		2004	2005	2006	2007	2008	2009	2010	2011	2012
13 % RM	MW Need Before DSM	-827	-647	-486	-313	-103	100	224	419	535
	MW Need After DSM	-877	-722	-588	-437	-237	-35	90	285	401
15 % RM	MW Need Before DSM	-696	-513	-350	-174	40	245	372	570	688
	MW Need After DSM	-747	-590	-453	-300	-97	109	235	434	552

To meet the base load needs of the Companies for 2010 and beyond, the Companies developed a Request for Proposals. The responses to the RFP sent out April 1, 2003 included Purchase Power Agreements ("PPA") and shared unit ownership, and were evaluated against the Companies self-build option at the Trimble County Plant ("TC2").

Given the market conditions at the time of this study, the lowest Net Present Value of Revenue Requirements ("NPVRR") is obtained if the Companies construct TC2 for a 2010 in-service. The data shows that the construction of TC2 is advantageous over the available base load power options considered in this assessment. A summarization of results for the native load only scenario can be found in the following table.

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
5	TC2 2010 and Marketer F's PPA in 2013	16,370,555	1	0
4	Marketer F's PPA in 2010 and TC2 2011	16,377,517	2	6,962
3	TC2 and Marketer F's PPA in 2010	16,399,793	3	29,238
1	TC2 in 2010	16,443,935	4	73,380
2	TC2 in 2011	16,450,735	5	80,180
8	Marketer E's Joint Ownership and Marketer F's PPA in 2010	16,462,347	6	91,792
6	Marketer E's Joint Ownership in 2010	16,508,339	7	137,784
7	Marketer E's Joint Ownership in 2011	16,512,364	8	141,809
9	No Baseload Addition	16,850,301	9	479,746

INTRODUCTION

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), (collectively the "Companies"), merged on May 4, 1998. The two utilities operate a joint generation dispatch system for the benefit of customers of both utilities, as outlined in the Power Supply System Agreement ("PSSA"). That is, the generating units of both companies are dispatched in economic order to meet the combined demands of both KU and LG&E customers.

As a result of the merger and as specified in the PSSA, the two Companies also conduct joint resource planning as a single entity. The culmination of that planning process is the Integrated Resource Plan ("IRP"), which the Companies filed with the Kentucky Public Service Commission ("Commission") most recently on October 1, 2002 in Case No. 2002-00367. The IRP is a complete resource assessment and acquisition plan that considers all utility supply-side and demand-side resource alternatives, including enhancements to existing generation facilities. However, the IRP does not consider the dynamic purchase power market and the opportunities that may exist in the marketplace from time to time.

The recommendation of the 2002 IRP includes the installation of two simple-cycle combustion turbine ("CT") units in 2004, one CT in 2005 and 2006, two CTs in 2007 and a coal unit in 2008 followed by additional CTs in 2012-2014, and a combined-cycle unit in 2016. The 2002 IRP also calls for the implementation of an additional small Demand-Side Management ("DSM") program, as part of the resource acquisition plan, phased in over the 2004-2008 timeframe.

The IRP indicated that a coal unit was necessary in 2008; however, slower economic growth and improved forecasting techniques collectively have decreased the load forecast and deferred the need for new generating resources until 2010.

PURPOSE OF REPORT

The purpose of this report is to review the needs that have been identified in the IRP and to evaluate the current opportunities to meet this need. The evaluation will include the opportunity to construct a second coal unit at the Trimble County Plant ("TC2") and the responses to the Request for Proposals ("RFP") for purchased power.

First, the current need for base load capacity is described. Then, considering the most recent knowledge of the wholesale electric marketplace, reasonable alternatives for how to proceed are identified and evaluated. The evaluation process is described, conclusions are drawn, and a recommendation to either build TC2 or pursue an offer made available through the RFP process is made.

STRUCTURE OF REPORT

This report is organized in the following manner:

- **Background** is provided on the 2002 IRP and energy market products;
- **Discussion of Alternatives** is provided to identify potential solutions to the problem of capacity need;
- **Modeling of Scenarios** is described to highlight the PROSYM Chronological Simulation Model and generation modeling information;
- **Discussion of Results** is provided, collectively and for each scenario, including comparisons of cost advantages and disadvantages of each;
- **Conclusion and Recommendations** are provided to summarize the most desirable course of action based on the analysis herein; and the
- **Appendix** includes a compilation of supporting data relevant to the assessment herein.

BACKGROUND

2002 INTEGRATED RESOURCE PLAN

LG&E and KU historically have maintained adequate reserves to insure reliable least cost generation supply to native load customers. Reserve margin is necessary because additional generation must be available should there be an unexpected loss of generation, reduced supply due to equipment problems, unanticipated load growth, variance in load due to extreme weather conditions, and/or disruptions in contracted purchased power.

On October 1, 2002, the Companies filed their IRP with the Commission. The IRP is a complete resource assessment and acquisition plan that considers all utility supply-side and demand-side resource alternatives, including enhancements to existing generation facilities. However, the IRP does not consider the dynamic purchase power market and the opportunities that may exist in the marketplace from time to time. The expansion plan from the IRP is detailed in Table 1.

Table 1. 2002 Integrated Resource Plan

Year	Resource
2003	
2004	148 MW Trimble County Unit 7 148 MW Trimble County Unit 8 0.1 MW Residential New Construction
2005	148 MW Trimble County Unit 9 0.3 MW Residential New Construction
2006	148 MW Trimble County Unit 10 0.8 MW Residential New Construction
2007	148 MW Greenfield CT Unit 1 148 MW Greenfield CT Unit 2 1.4 MW Residential New Construction
2008	549 MW (75% of 732 MW) Trimble County Unit 2 Super-critical Coal 2.2 MW Residential New Construction
2009	
2010	
2011	
2012	148 MW Greenfield CT Unit 3 148 MW Greenfield CT Unit 4
2013	148 MW Greenfield CT Unit 5
2014	148 MW Greenfield CT Unit 6
2015	
2016	474 MW Combined Cycle CT

Details of the Companies 2002 IRP are on file with the Commission in Case No. 2002-00367. Based on the 2004 Joint Load Forecast, the current capacity needs of the Companies through 2012 for the ends of the reserve margin range of 13% to 15% are specified in Table 2.

Table 2. Capacity Needs for Reserve Margin Range
Revised December 2004
(All values in MW at Summer Peak)

Component		2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak Load		6,632	6,796	6,911	7,051	7,225	7,372	7,483	7,656	7,762
CSR/Interruptible		100	100	100	100	100	100	100	100	100
Existing DSM		44	67	89	108	116	116	116	116	116
2002 IRP DSM Program		0	0	1	1	2	2	2	2	2
Net Load		6,488	6,629	6,722	6,842	7,006	7,153	7,264	7,437	7,543
Existing Capability		7,615	7,608	7,609	7,596	7,582	7,547	7,549	7,550	7,555
Purchases		593	605	574	572	572	571	570	569	568
Total Supply		8,208	8,213	8,183	8,168	8,154	8,118	8,119	8,119	8,123
13 % RM	MW Need Before DSM	-827	-647	-486	-313	-103	100	224	419	535
	MW Need After DSM	-877	-722	-588	-437	-237	-35	90	285	401
15 % RM	MW Need Before DSM	-696	-513	-350	-174	40	245	372	570	688
	MW Need After DSM	-747	-590	-453	-300	-97	109	235	434	552
Existing Reserve Margin, %	Before DSM	25.7%	22.7%	20.1%	17.5%	14.4%	11.6%	10.0%	7.4%	6.0%
	After DSM	26.5%	23.9%	21.7%	19.4%	16.4%	13.5%	11.8%	9.2%	7.7%

The expansion plan developed as part of the 2002 IRP did not consider any purchase power market opportunities. Because the purchase power market is dynamic, the Companies continually review the "buy versus build" decision. This study demonstrates that the decision to construct TC2, purchase base load options, or a combination thereof is made on an economic basis at the time of implementation.

WHY BASE LOAD?

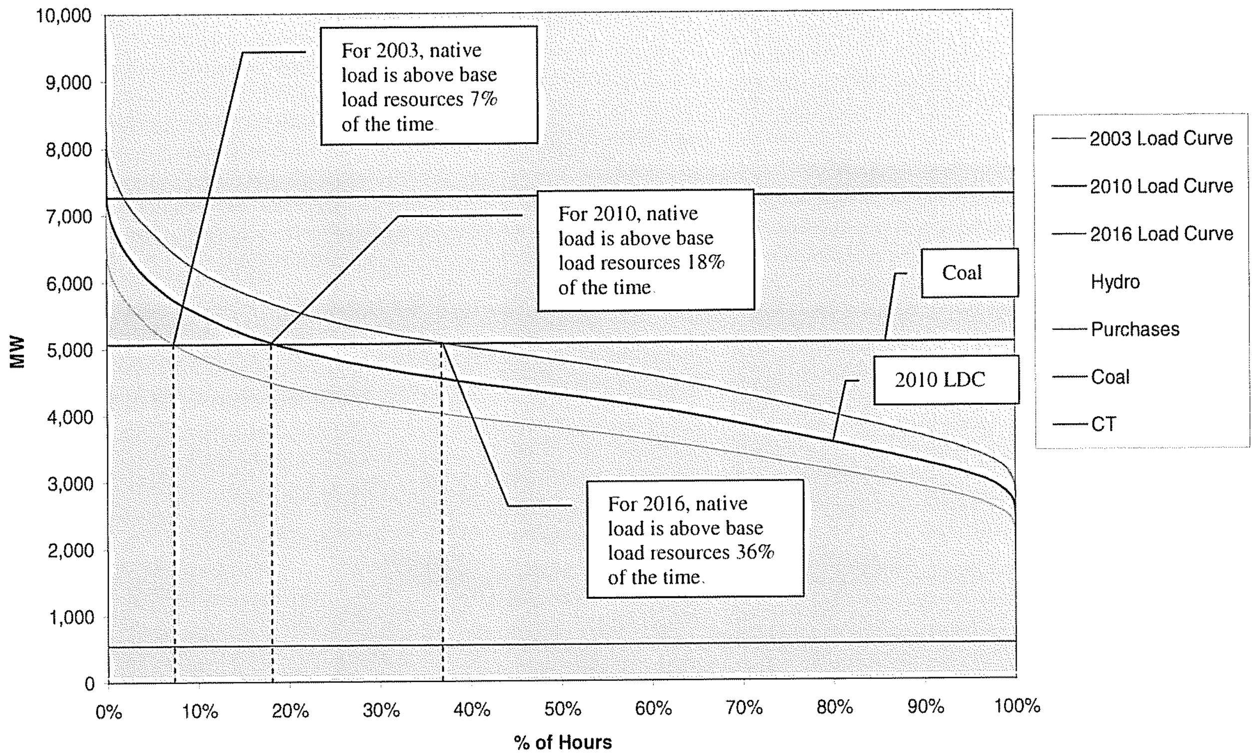
In addition to satisfying reserve margin requirements, the Companies must meet the energy needs of their customers in a least-cost manner. This requires the optimization of the generation portfolio among differing technology and fuel types (i.e., coal, gas, hydro, etc.). The IRP identifies when new resources are needed and provides an analysis of the type of new resource that is likely to offer the lowest lifetime system cost. The future resource mix is optimized such that the revenue requirements of serving load are minimized.

By 2010, it will have been 20 and 26 years, respectively, since LG&E and KU constructed a base load unit. From 1990 to 2010, the Companies' energy needs will have grown by 14,500 GWh or 61%. The addition of 600 MW of simple cycle gas turbines in 2004 has allowed the Companies to meet growing peak load but these units are not economic when compared to a base load coal unit at high capacity factors. Furthermore, the recent increase in natural gas prices and the consensus forecast for the continued price advantage of coal over gas makes it uneconomic by 2010 to run existing gas units for base load energy needs, or add new simple cycle or combined-cycle gas turbines.

The amount of time which the Companies rely upon resources other than base load resources (owned or purchased) is expected to increase substantially from 2003 to 2016 as show in the figure below. Based upon an assumed 85% coal unit availability (2003 actual was 85.1%), the native load energy requirement was above the Companies' base load resources 7% of the time for 2003. That figure increases to 18% by 2010 and 36% by 2016.

In the graph below, horizontal lines represent cumulative resource capabilities in MW. For example, the CT line is the summation of Hydro, Purchases, Coal and CT capacity. The curves are Load Duration Curves ("LDC") and represent load levels for each hour in the respective years.

Load Duration Curve Comparison with Purchases
85% Availability of Base Load Generation



DISCUSSION OF ALTERNATIVES

RFP FOR BASE LOAD CAPACITY

A Request for Proposals ("RFP") was issued April 1, 2003 to over 90 potential energy suppliers of which nine responded with proposals. The nine responses resulted in ten proposals ranging from 10 MW to 500 MW. The RFP indicated specific requirements such as the amount and timing of capacity and energy needed. A copy of the RFP and its recipients is included in Appendix A.

RFP SCREENING ANALYSIS

A screening evaluation was conducted to first assess and rank all viable proposals. The most favorable alternatives from the screening evaluation were then made available to the detailed production cost analysis.

Since all proposals received vary in capacity, a 500 MW capacity was used in the screening evaluation in order to levelize the field. A screening sensitivity study was conducted to determine the impact of varying the run-time on the overall ranking of alternatives in the screening analysis. Such a study allows for a broader view of how the alternatives compare to one another under a full spectrum of operating conditions.

Given the pricing in the responses and the assumptions previously identified, the demand and energy charges for each year from 2007 through 2032 were calculated for each response. The total costs for 2007 through 2032 were also determined. A Net Present Value ("NPV") in year 2003 dollars was determined for the 2007-2021 period ("15-Year Operating NPV"), the 2007-2026 period ("20-Year Operating NPV"), and for the 2007-2031 period ("25-Year Operating NPV"). The 20-Year Operating NPV was the basis for ranking each proposal. This data is tabulated in the RFP for Purchased Power Screening Evaluation in Appendix A.

As previously mentioned, a Screening Sensitivity study was conducted to determine the impact of varying the run-time on the overall ranking of alternatives in the screening analysis. The sensitivity was performed by varying capacity factors from 50%-100%. The ranking of alternatives under the varying run-times is also tabulated in Appendix A.

The top seven alternatives contained in the RFP were included in the preliminary detailed analysis.

MODELING OF SCENARIOS

OVERVIEW OF THE PROSYM CHRONOLOGICAL SIMULATION MODEL

The PROSYM production costing model was used to evaluate the production cost revenue requirements associated with each of the scenarios. PROSYM is a product of *Henwood Energy Services, Inc.* It is a chronological electric utility production simulation modeling system that is designed for performing planning and operational studies on an hourly basis. It uses convergent Monte Carlo analysis to give the least cost and most economical dispatch of generation resources and simulates the PSSA joint dispatch. PROSYM is able to simulate the utilization of typical generation resources and the purchased power alternatives considered in this analysis.

OVERVIEW OF THE CAPITAL EXPENDITURE AND RECOVERY ("CER") MODEL

The CER module of Strategist (formerly called PROSCREEN II) calculates revenue requirements associated with capital expenditures for both the construction and in-service periods. These capital revenue requirements are combined with the production cost revenue requirements to produce a total system revenue requirement for the study period. The CER contains capital information on resource projects associated with the various cases evaluated in this resource assessment. Inputs to the CER include construction cost profiles, depreciation schedules and various economic assumptions.

GENERAL MODELING INFORMATION

The modeled load areas for the analysis were KU, LG&E, and Owensboro Municipal Utilities ("OMU"). The OMU area was simulated to capture the relationship KU has with OMU. Financial data items specific to this analysis are identified in Appendix B. The base evaluation assumes that no off-system sales are made.

PRODUCTION RUNS

In order to provide a meaningful comparison of all cases, the total peak period capacity acquisition in each year of the study must be comparable. This is true whether the additional capacity in each year is acquired via construction of a unit or purchasing an Option on Base load Capacity. The purchase options evaluated in this study are similar in capacity amount to the Companies self-build option with the exception of the amount from Marketer A and Marketer F. The construction of TC2 was not considered avoidable in the cases involving Marketers A and F, but construction was delayed. In the 2002 IRP, the Companies committed to maintain a reserve margin target within the range of 13% to 15%. In this study, the total capacity installed in each year is determined such that the total installed or purchased capacity in each year for each of the six cases is comparable and the reserve margin does not fall below the established minimum of the range established in the 2002 IRP.

CONSIDERATION OF DSM

The DSM programs being implemented by the Companies as part of the DSM plan approved by the Commission in Case No. 2000-049 are modeled in PROSYM as additional resources. As previously mentioned, the 2002 IRP calls for the implementation of an additional DSM program as part of the resource acquisition plan. Table 1 shows that the Residential New Construction program is recommended in various years within the 2004-2016 timeframe as detailed in the 2002 IRP.

For the purposes of this assessment, the additional small DSM program is not explicitly modeled in the production runs. However, the demand reductions provided by this DSM program at peak times are included in this analysis in the calculation of capacity need. In other words, the total capacity need in each year is reduced by the amount of demand reduction expected to be achieved via DSM by the summer period of each year.

PRELIMINARY DETAILED ANALYSIS

There was one self-build option considered in the preliminary detailed analysis along with six power purchase market products. The self-build option, identified as "Case 1", was the opportunity to construct a 750 MW super-critical coal unit at the Trimble County Plant by June 2009. The remaining cases, 2 through 7, are for the six market proposals from Marketers A through F. Identification of the marketers is provided in Appendix C.
The characteristics of each of the alternatives considered for the preliminary detailed analysis are described below. The capital costs associated with TC2 can be found in Appendix D. Further details on Cases 2 through 7 can be found in the actual RFP responses included in Appendix A.

<u>Case 1: Construct TC2</u>

- Super-critical coal-fired unit in 2009
- Summer/winter ratings of 732/750 MW
- Summer/winter Full Load Heat Rate (HHV) of 9079/8651 Btu/kWh
- Availability: 93%
- Location: Trimble County plant within LG&E transmission system

<u>Case 2: Marketer A Option on Base load Capacity</u>

- Term: 6/2007 through 5/2027
- Quantity: 200 MW, unit contingent
- Summer/winter heat rate of 9655/9515 Btu/kWh
- Availability: 95% for Jan, Feb, Jun-Aug; 90% Mar-May and Sep-Dec
- Transmission: Considered a MISO designated resource without incurring transmission costs

- Delivery Point: Station bus

Case 3: Marketer B Option on Base load Capacity

- Term: Starting early 2007 and lasting 30 years
- Quantity: 200 MW starting in 2007 and increasing to 500 MW in 2009, firm
- Availability: 85%-90%
- Delivery Point: First 200 MW into KU/LG&E; additional 300 MW via PJM transmission network
- Transmission: Not considered a MISO designated resource and will require point to point transmission service

Case 4: Marketer C Option on Base load Capacity

- Term: 1/2007 through 12/2021
- Quantity: 500 MW, firm (LD)
- 11,000 BTU/kWh Full Load Heat Rate (HHV)
- Availability: NA
- Delivery Point: Station bus
- Transmission: Considered a MISO designated resource without incurring transmission cost

Case 5: Marketer D Option Unit Ownership

- Term: Starting early 2005
- Quantity: 485 MW
- Availability: 91% average
- Delivery Point:
- Transmission: Considered a MISO designated resource without incurring transmission cost

Case 6: Marketer E Option on Base load Capacity
- Term: 10/2007 through 9/2022
- Quantity: 500 MW
- Availability: 90%
- Delivery Point: Station bus
- Transmission: Not considered a MISO designated resource, point to point transmission service required

Case 7: Marketer F Option on Base load Capacity
- Term: 30 years starting early 2007
- Quantity: 114 MW average summer capacity
- Availability: 716 GWh annually
- Delivery Point: Into KU/LG&E

- Transmission: Considered a MISO designated resource without incurring transmission cost

Marketers A and F are not sufficient in size to replace TC2, but are able to delay its construction based on reserve margin requirements. Results of the preliminary detailed analysis are summarized in Tables 3-a and 3-b. The cases were first evaluated on a native load only basis. A sensitivity considering off-system sales was also performed.

Table 3-a. Preliminary Detailed Analysis – Native Load Only

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
1	Trimble County 2	13,840,307	1	0
7	Marketer F	13,845,862	2	5,555
5	Marketer D	13,949,717	3	109,410
2	Marketer A	14,022,866	4	182,559
3	Marketer B	14,056,639	5	216,332
6	Marketer E	14,149,580	6	309,273
4	Marketer C	14,280,034	7	439,726

Table 3-b. Preliminary Detailed Analysis – With Off-System Sales

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
7	Marketer F	12,562,032	1	0
1	Trimble County 2	12,609,732	2	47,700
2	Marketer A	12,695,304	3	133,272
5	Marketer D	12,768,684	4	206,652
3	Marketer B	12,856,351	5	294,319
6	Marketer E	12,921,773	6	359,741
4	Marketer C	13,087,809	7	525,777

After completion of the preliminary detailed analysis, Marketers A and D elected to withdraw their RFP bids from further analysis. Marketers E and F provided additional RFP responses that considered shared ownership of the potential new generating facilities. Upon final review of the preliminary detailed analysis, Marketer B, Marketer C, and Marketer E's original response were eliminated from further consideration. Therefore, the remaining options for inclusion into the final detailed analysis are the Companies self-build option (TC2), Marketer E's shared ownership, and Marketer F's two proposals (PPA and unit ownership).

FINAL DETAILED ANALYSIS

Prior to performing the final detailed analysis, the remaining participants were asked to update their proposals. Marketer F, after switching design technologies, retracted their unit ownership option, leaving only the PPA for consideration. The cases included in the final detailed analysis were first evaluated on a native load only basis. Then, sensitivity studies were performed on various factors that affect the overall commitment and dispatch of all the generating units in the model. Table 4 summarizes the sensitivity scenarios that were evaluated.. The specific data on what units are installed in each year is presented in tabular form in Appendix E

Table 4. Sensitivity Scenarios

Scenario	Sensitivity Description
Base	Native Load only, other system parameters normal
High Load	Base with 5% increase to native load each hour
High FOR	Base with 5% increase to Forced Outage Rate of all units
High Generation	Simulates a more realistic level of generation through the inclusion of Off-System Sales

DESCRIPTION OF RESULTS FOR FINAL DETAILED ANALYSIS

To determine which of the cases is the least cost alternative, a Net Present Value of Revenue Requirements ("NPVRR") analysis was performed.

The production model was used to determine the following energy-related costs on an annual basis:

- Fuel
- Variable O&M
- Fixed O&M
- Emissions
- Purchases

Additional demand-related costs were then determined on an annual basis for the NPVRR analysis:

- Capital Costs associated with construction

The capital costs were evaluated using the CER module of Strategist and the economic assumptions outlined in Appendix C. The demand costs associated with the purchase options were calculated using the pricing from the RFP responses used in the assessment.

The annual revenue requirements were then determined. The energy-related costs and demand-related costs for each year were summed and the NPV was determined for the full 30 year study period. The NPVRRs for all cases were compared and then ranked, with the lowest NPVRR being ranked first.

The results for all sensitivity scenarios are presented in Table 5-a through 5-d and are discussed in the sections that follow. Production cost details are provided in Appendix F.

Table 5-a. Base Scenario

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
5	TC2 2010 and Marketer F's PPA in 2013	16,370,555	1	0
4	Marketer F's PPA in 2010 and TC2 2011	16,377,517	2	6,962
3	TC2 and Marketer F's PPA in 2010	16,399,793	3	29,238
1	TC2 in 2010	16,443,935	4	73,380
2	TC2 in 2011	16,450,735	5	80,180
8	Marketer E's Joint Ownership and Marketer F's PPA in 2010	16,462,347	6	91,792
6	Marketer E's Joint Ownership in 2010	16,508,339	7	137,784
7	Marketer E's Joint Ownership in 2011	16,512,364	8	141,809
9	No Baseload Addition	16,850,301	9	479,746

Table 5-b. High Load Scenario

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
5	TC2 2010 and Marketer F's PPA in 2013	16,936,923	1	0
4	Marketer F's PPA in 2010 and TC2 2011	16,948,057	2	11,134
3	TC2 and Marketer F's PPA in 2010	16,960,982	3	24,059
8	Marketer E's Joint Ownership and Marketer F's PPA in 2010	17,024,245	4	87,323
1	TC2 in 2010	17,047,026	5	110,104
2	TC2 in 2010	17,069,188	6	132,266
6	Marketer E's Joint Ownership in 2010	17,110,027	7	173,104
7	Marketer E's Joint Ownership in 2011	17,128,324	8	191,401
9	No Baseload Addition	17,597,924	9	661,002

Table 5-c. High FOR Scenario

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
5	TC2 2010 and Marketer F's PPA in 2013	17,542,914	1	0
4	Marketer F's PPA in 2010 and TC2 2011	17,552,098	2	9,184
3	TC2 and Marketer F's PPA in 2010	17,566,840	3	23,926
8	Marketer E's Joint Ownership and Marketer F's PPA in 2010	17,627,598	4	84,684
1	TC2 in 2010	17,638,721	5	95,807
2	TC2 in 2010	17,654,046	6	111,132
6	Marketer E's Joint Ownership in 2010	17,710,514	7	167,600
7	Marketer E's Joint Ownership in 2011	17,722,801	8	179,887
9	No Baseload Addition	18,213,241	9	670,327

Table 5-d. High Generation Scenario

#	Case	NPVRR ($000)	Rank	Delta from Min ($000)
5	TC2 2010 and Marketer F's PPA in 2013	15,740,710	1	0
3	TC2 and Marketer F's PPA in 2010	15,749,192	2	8,482
4	Marketer F's PPA in 2010 and TC2 2011	15,754,520	3	13,810
8	Marketer E's Joint Ownership and Marketer F's PPA in 2010	15,805,322	4	64,612
1	TC2 in 2010	15,866,661	5	125,951
2	TC2 in 2011	15,900,199	6	159,489
6	Marketer E's Joint Ownership in 2010	15,924,041	7	183,331
7	Marketer E's Joint Ownership in 2011	15,954,885	8	214,175
9	No Baseload Addition	16,491,472	9	750,762

Base Scenario

In the Base Scenario, the study is performed for Native Load only conditions with all other modeling parameters set to normal. No off-system sales are included in the scenario.

Construction of TC2 in 2010 (Case 5) is the least cost alternative in this scenario. Results indicate that pursuing Marketer F's PPA in 2013 following the construction of TC2 provides financial benefits. A comparison of Case 5 to all other cases yields the following:

- Construction of TC2 in 2010 is the least cost option for meeting native load energy needs and reserve margin requirements

Thus, it is evident that over the study period, the NPVRR of Case 5 is lower than the NPVRR of all other cases.

High Load Scenario

The High Load Scenario differs from the Base Scenario in that the native load requirement is increased above base by 5% in every hour of every year of the case. (The 5% increase amounts to a total load increase of approximately 370 MW in the peak hour of 2010.) No off-system sales are included in the case.

Case 5 is the least cost alternative in this scenario.

The major difference between this case and the Base Scenario is that more energy is needed to meet the increased native load requirements in every hour. The additional energy in this scenario will be met with higher cost generating units or purchased power when necessary.

High FOR Scenario

The High FOR Scenario differs from the Base Scenario in that the forced outage rates of all units in the case are increased by 5%. No off-system sales are included in this case.

Case 5 is the least cost alternative in this scenario.

The major difference between this case and the Base Scenario is that the units experience more unplanned outage hours in this case. The increase in FOR means that the energy not available due to outage must be replaced, whether by the next available generating unit in the economic dispatch order, or by purchased power at a higher incremental cost. The increase in FOR potentially increases the Companies' overall dependence on purchased power.

HIGH GENERATION SCENARIO

The High Generation Scenario differs from the Base Scenario in that a high generation level is simulated through the use of Off-System Sales.

Case 5 is the least cost alternative in this scenario.

The major difference between this case and the Base Scenario is that more energy is needed in each year to support sales. The fact that more energy is needed merely increases the advantage of Case 5 over the other cases.

CONCLUSION AND RECOMMENDATIONS

Several conclusions can be drawn from the results of the scenario runs described in the section above.

- With market conditions at the time of this study, the lowest NPVRR is obtained if the Companies construct TC2 for a 2010 in-service date

- Case 5 is advantageous over other construction or with purchased power (of any variety considered in this assessment). Low production costs and capital costs are advantages of TC2 when compared with other alternatives considered in this assessment.

- The Companies should continue to review Marketer F's PPA as the next resource following the construction of TC2. Current results indicate that pursuing Marketer F's PPA for 2013 is financially beneficial for the native load customer.

In summary, the analysis shows the decision to construct TC2 in 2010 is the least cost alternative and will allow the Companies to meet reserve margin and energy needs for 2010 and beyond. Construction of TC2 in 2010 produces the lowest revenue requirement of the alternatives considered.

Exhibit JPM-1 – Resource Assessment

Appendix A - Responses to RFP

[*Note:* Most Responses to RFP submitted under Seal with Petition for Confidential Treatment]

W.V. Hydro, Inc.

P.O. Box 903
Gatlinburg, TN 37738
E-mail: jimprice@atlantic.net

Phone: (865) 436-0402
Fax: (865) 436-0592
Cell: (803) 215-4165

June 24, 2003

Charles Freibert, Jr.
Director, Marketing
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202

Revision of Price in Proposal to Sell Power to LGEE from the Cannelton and Smithland Hydroelectric Projects

Dear Mr. Freibert:

The Cannelton Hydroelectric Project, L.P. and Smithland Hydroelectric Partners, Ltd. request that LG&E Energy Corp. (LGEE) allow us to revise the pricing tendered to LGEE in our bid in your RFP on May 29, 2003. Based on contact with the probable lender for the two Projects, we are able to offer more attractive pricing in our bid.

Please use the revised firm prices for each year of planned power sales in our proposed 30-year contract to sell all the delivered output from the Cannelton Hydroelectric Project (Cannelton) and the Smithland Hydroelectric Project (Smithland) to LGEE. The prices are all-inclusive and are in $ per MWh for each MWh delivered at each Project's interconnection with LGEE.

The revised sale prices for power, inclusive of capacity and energy, for each year of the contract are indicated in the enclosed table; these are the prices for both projects. For both projects, the levelized price for 30 years is $36.6 per MWh in 2006. For the 50% capacity factor of the two projects, the cost to LGEE in 2002 dollars is 142 $/kw/yr. This is approximately a 2.7% decrease in the price of power in our bid.

All other terms in our bid letter of May 29, 2003 RFP remain as stated. Please call if there are any questions.

Yours truly,

James B. Price

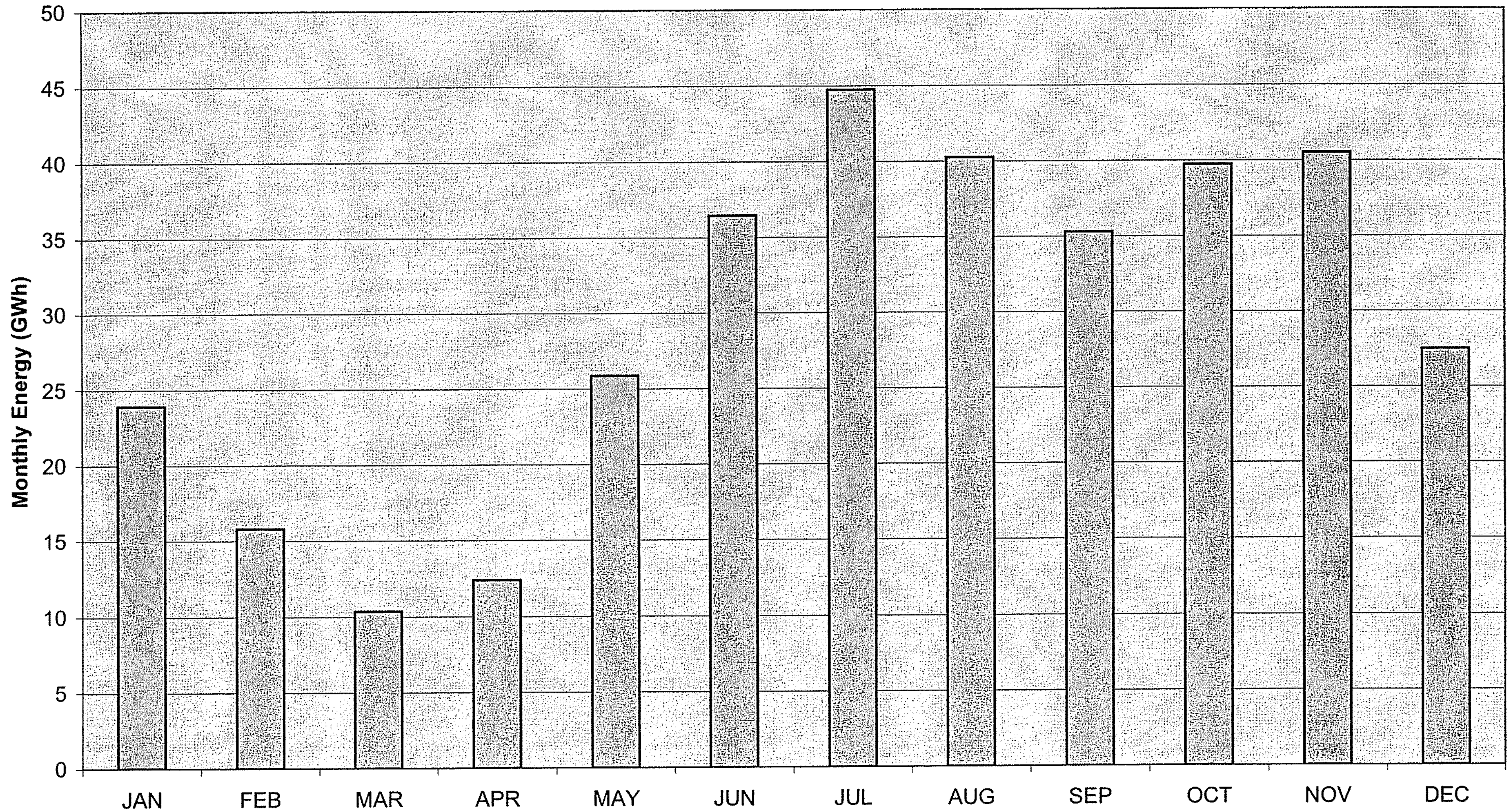
James B. Price
President

Proposed Power Sale Prices from Hydro Projects

	Year	$/MWh	36.61
1	2006	29.0	
2	2007	29.0	
3	2008	32.0	
4	2009	33.0	
5	2010	34.0	
6	2011	35.5	
7	2012	36.5	
8	2013	36.5	
9	2014	39.0	
10	2015	39.0	
11	2016	41.0	
12	2017	41.0	
13	2018	43.0	
14	2019	44.5	
15	2020	44.5	
16	2021	45.0	
17	2022	47.0	
18	2023	48.0	
19	2024	48.0	
20	2025	48.0	
21	2026	48.0	
22	2027	48.0	
23	2028	42.0	
24	2029	30.0	
25	2030	30.9	
26	2031	31.8	
27	2032	32.8	
28	2033	33.8	
29	2034	34.8	
30	2035	35.8	

The levelized price of the power in 2006 dollars is $36.6 per MWh for the 30 years of fixed prices. The Smithland plant begins operation in 2006 and is complete in 2008; the Cannelton plant is complete in late 2008 or early 2009.

SMITHLAND ANNUAL ENERGY
Five Modules; 48 years daily data



Smithland - average monthly energy for 48 years - 1951-1998

JAN	23.916
FEB	15.813
MAR	10.379
APR	12.386
MAY	25.875
JUN	36.460
JUL	44.750
AUG	40.247
SEP	35.290
OCT	39.742
NOV	40.497
DEC	27.493
Annual	352.848

55 MW of average summer capacity

35% of energy in June - August

Smitland VA TECH Bid

MONTHLY AVERGE

Month	GWh	Monnth	GWh
JAN	23.916	JUL	44.75
FEB	15.813	AUG	40.247
MAR	10.379	SEP	35.29
APR	12.386	OKT	39.742
MAI	25.875	NOV	40.497
JUN	36.46	DEZ	27.493

Cannelton - average monthly energy for 48 years - 1951-1998

JAN	28.329
FEB	20.965
MAR	16.302
APR	21.155
MAY	32.479
JUN	37.944
JUL	39.724
AUG	33.946
SEP	29.601
OCT	33.621
NOV	38.215
DEC	30.927
Annual	362.921

51 MW of average summer capacity

31% of energy in June - August

Cannelton VaTech Bid Power

MONTHLY AVERGE			
Month	GWh	Month	GWh
JAN	28.329	JUL	39.724
FEB	20.965	AUG	33.946
MAR	16.302	SEP	29.601
APR	21.155	OKT	33.621
MAI	32.479	NOV	38.215
JUN	37.944	DEZ	30.927

Ann Energy

1951-1998

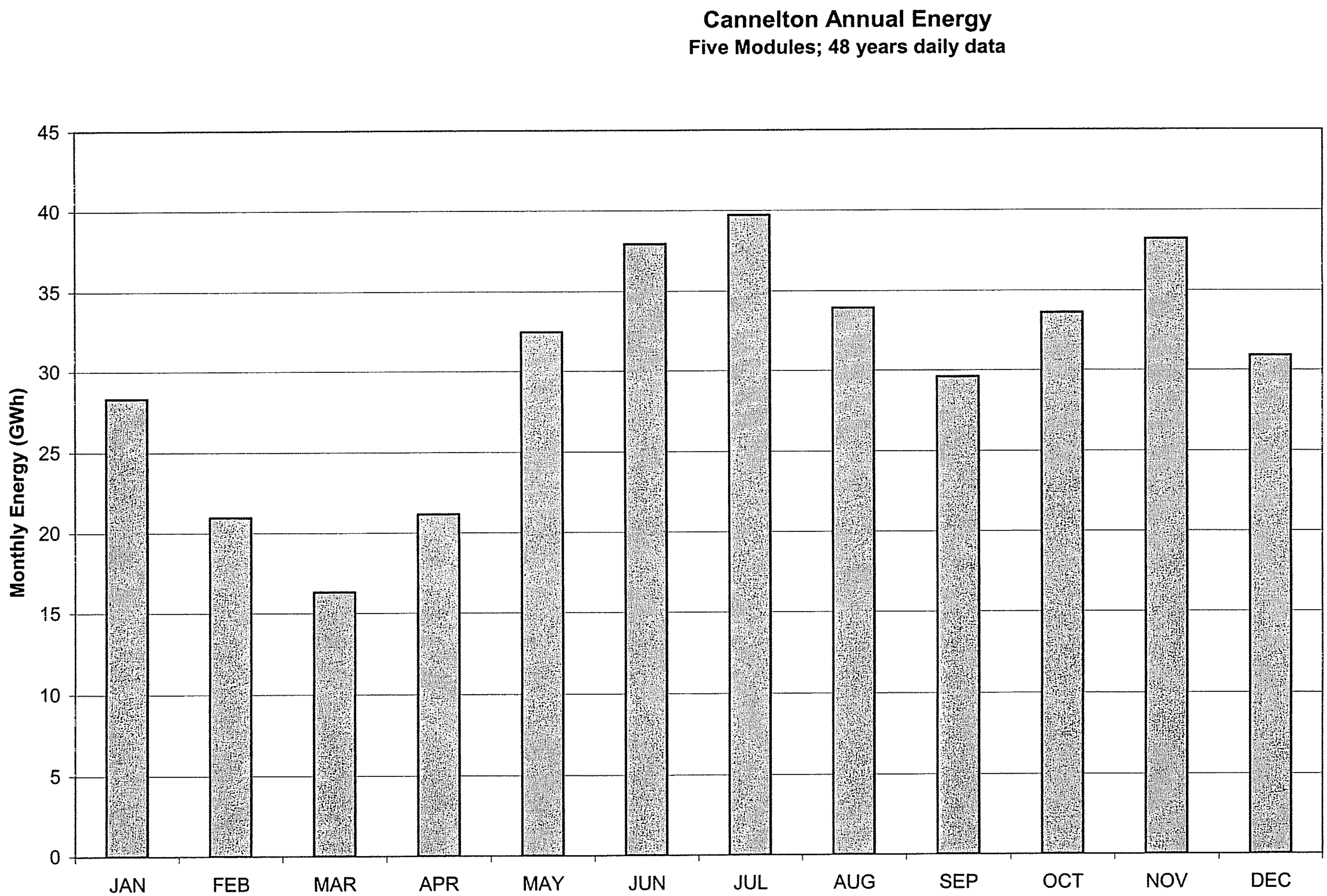

Cannelton Annual Energy
Five Modules; 48 years daily data
Monthly Energy (GWh)
45
40
35
30
25
20
15
10
5
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC

Figure 1 Total Annual Energy - Smithland & Cannelton

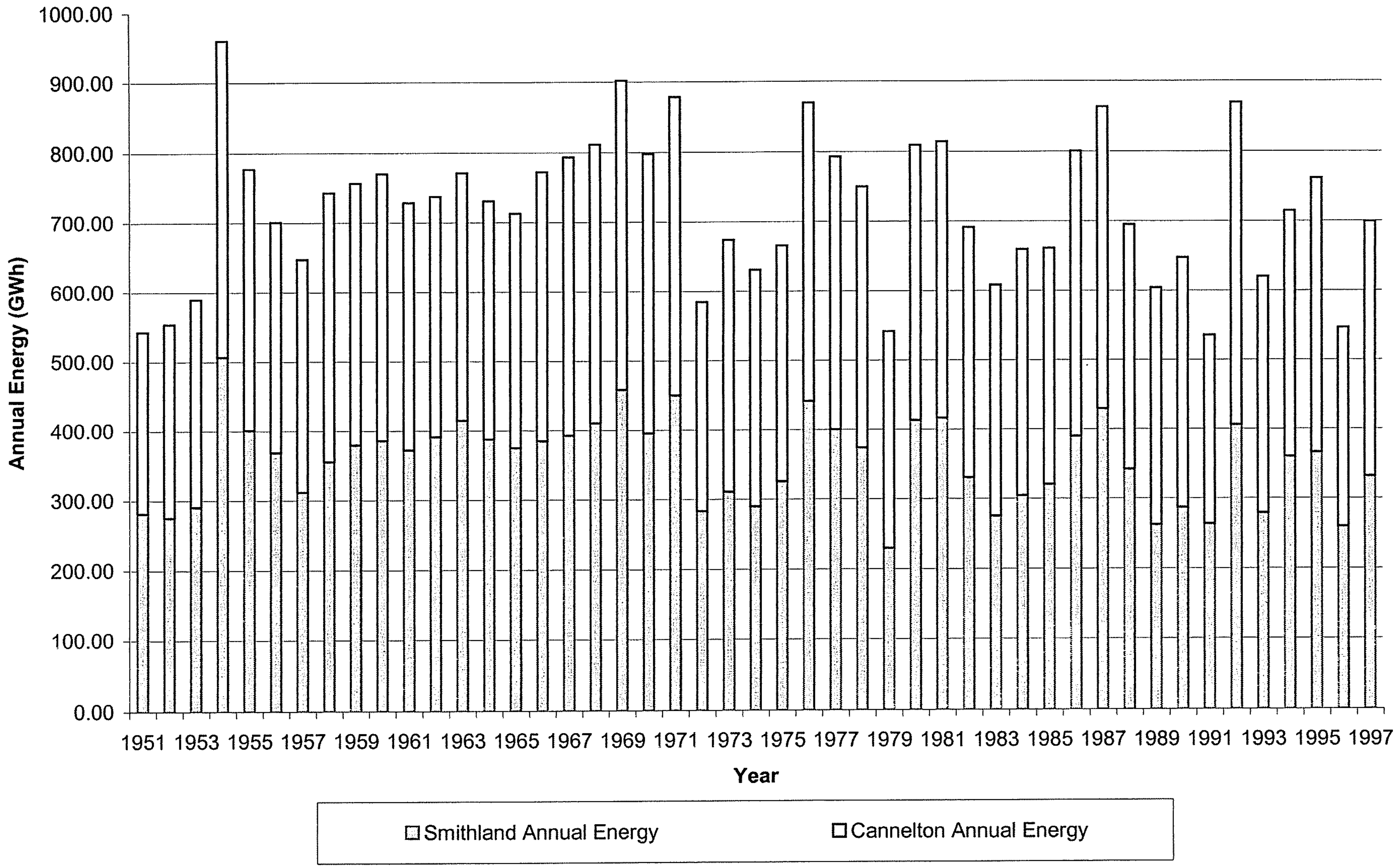
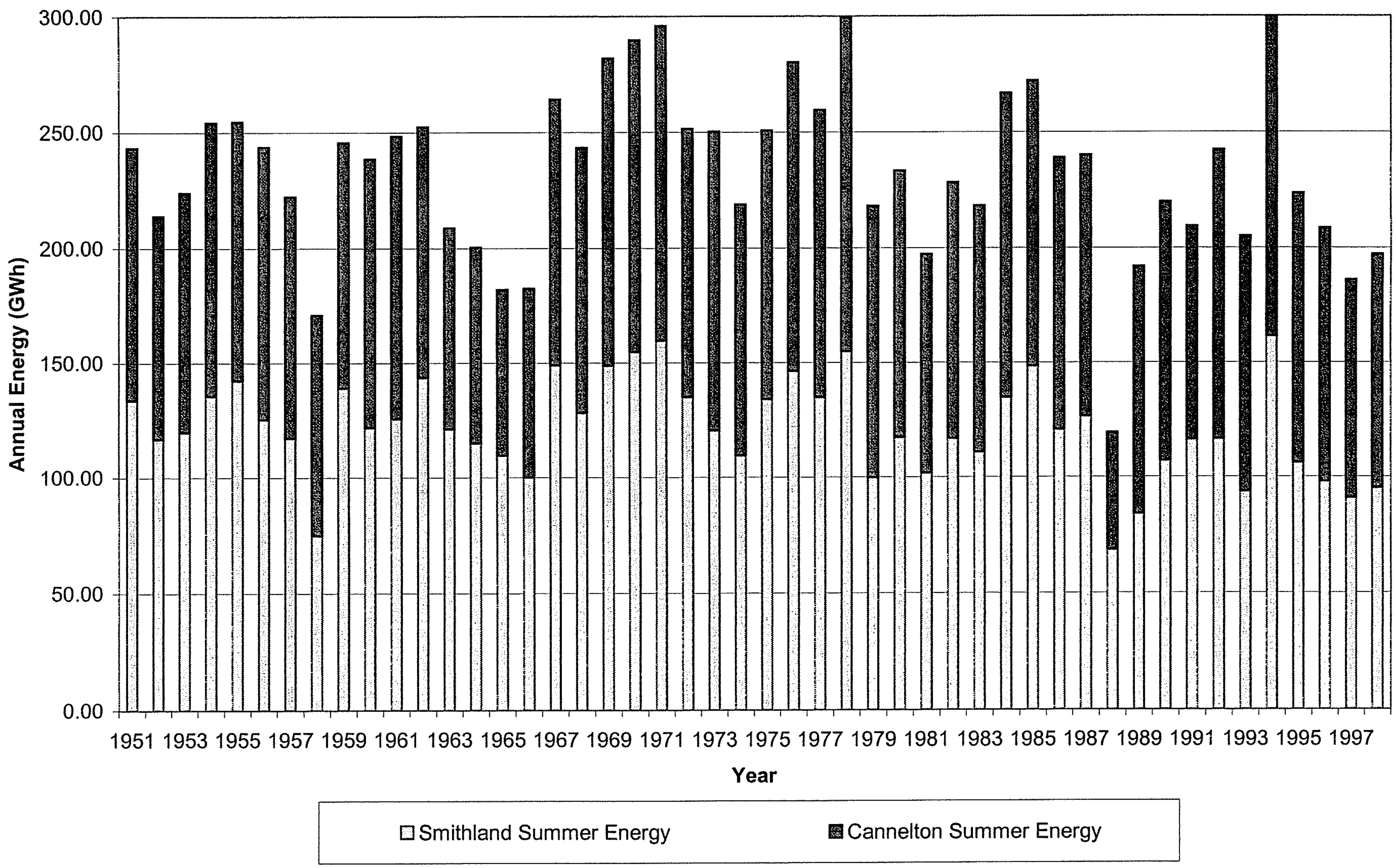


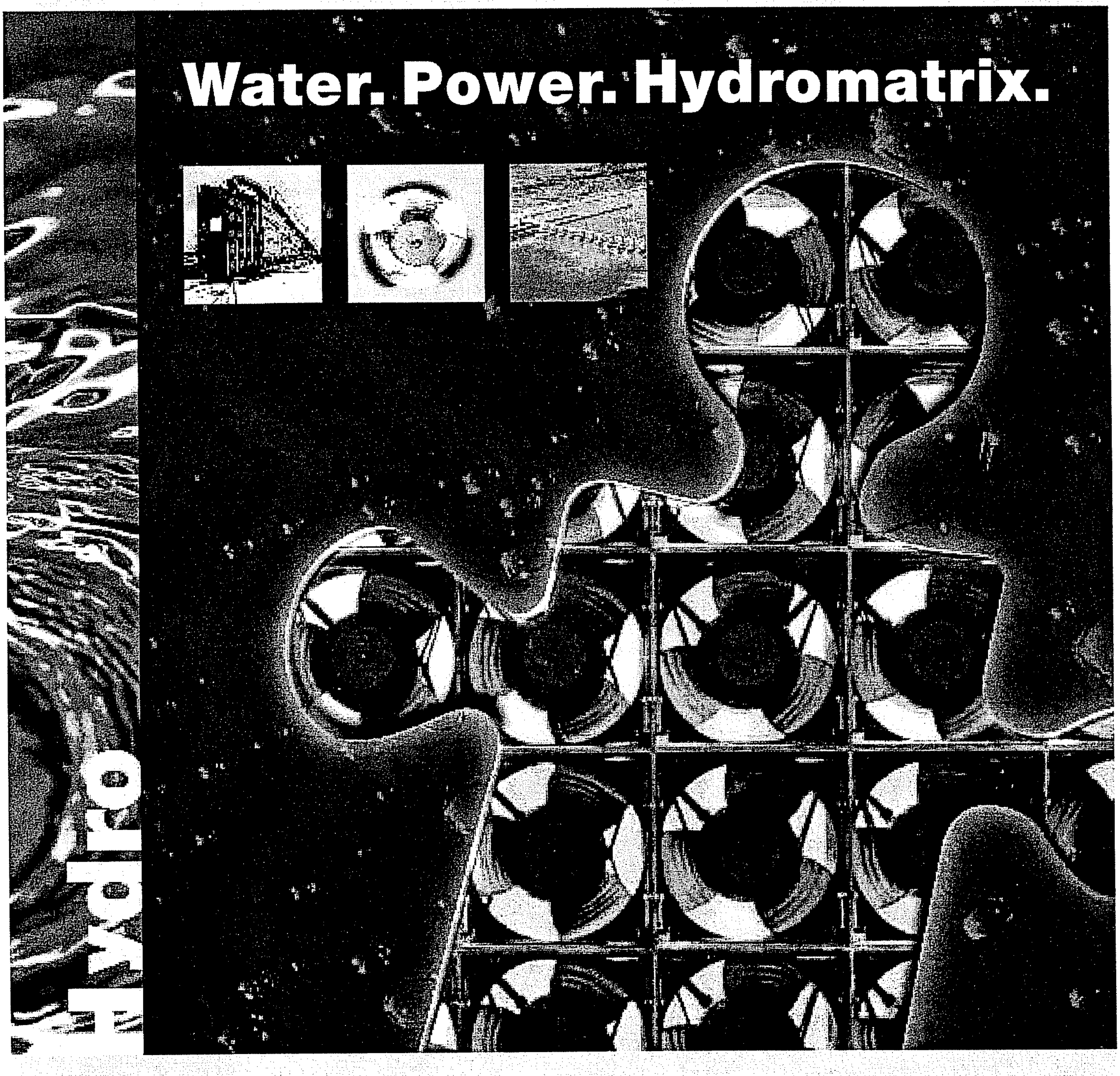
Figure 2 Total Summer Energy - Smithland & Cannelton



VATECH

VA TECH HYDRO

HYDROMATRIX®



www.hydromatrix.com

VOEST MCE

ELIN

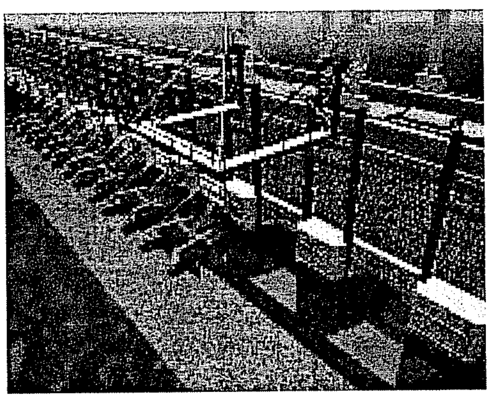
SAT AUTOMATION

HYDROMATRIX® SYSTEMS

General

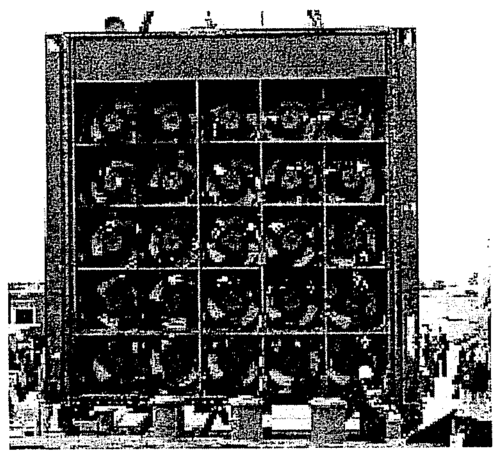
The HYDROMATRIX® turbine-generator system is a low cost solution for installation of hydropower at low head sites with existing dam and gate structures.

HYDROMATRIX® is a new concept of hydraulic energy generation advanced by VA TECH HYDRO, which combines the advantages of proven technology, low cost installation and is easily integrated into existing dam structures or weirs. Projects that cannot be developed in a feasible way by use of conventional turbine-generator



designs may now be developed profitably using the HYDROMATRIX® approach.
The HYDROMATRIX® design utilizes a factory assembled "grid" or module of small propeller turbine-generator units. The module is shipped to the site where it is installed into the existing water passage. When flows in excess of the module's capacity must be passed, the HYDROMATRIX® module may be raised or removed from its operating position like a gate.

Since no new, significant civil structures are needed, the HYDROMATRIX® technology enables customers to install hydroelectric powerplants at far more competitive costs and with less environmental impact when compared with conventional plants. In addition, by using the HYDROMATRIX® solution, construction and start-up schedules can

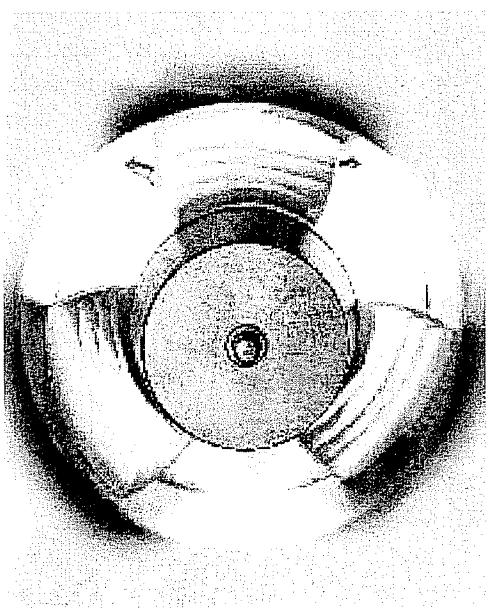


be shortened by years. The HYDROMATRIX® technology enables customers to tap the unused hydropower potential of intake towers, ship lock sluices, navigation and irrigation dams by using the existing civil structures to develop a valuable renewable energy resource.
Obermeyer Machinery Corp., the U.S. based originator of the HYDROMATRIX® concept, and VA TECH HYDRO, a world leader in the design and manufacture of hydroelectric turbine-generator equipment, have joined resources to market the HYDROMATRIX® concept - a patent protected approach for low head hydroprojects.

Advantages

The following advantages make HYDROMATRIX® an attractive solution:

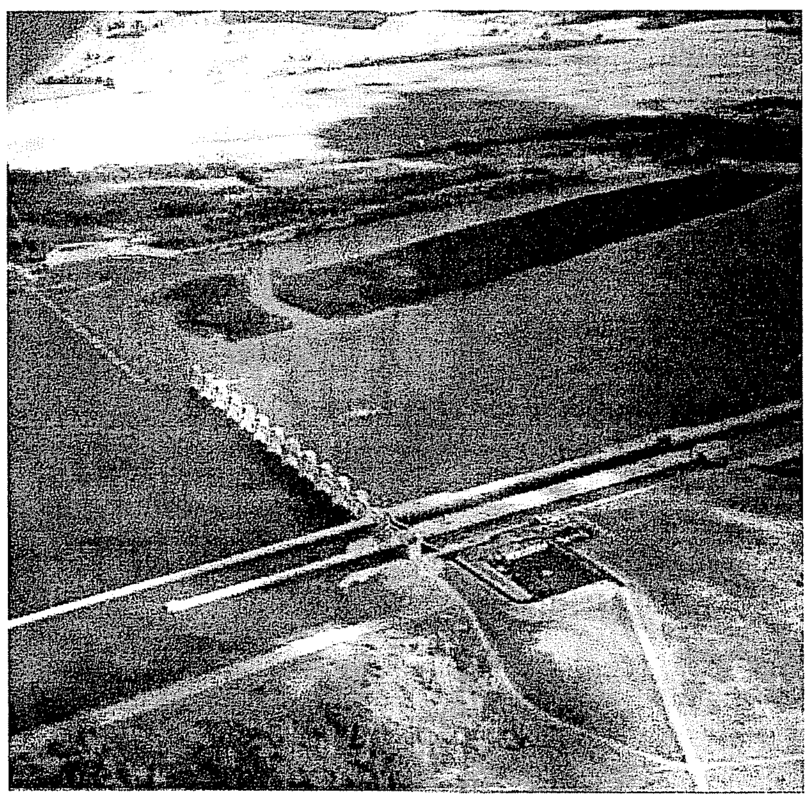
- Clean & environmentally friendly energy (KYOTO-protocol)
- Use of existing weir structures, no new civil construction
  - no geological risk
  - no additional land usage
- Standardized modular concept
- Short project schedule (1 – 1.5 years)
- High availability
- HYDROMATRIX® modules removable for flood conditions



Application Criteria

In order to achieve technically and economically feasible applications, the following criteria should be met:

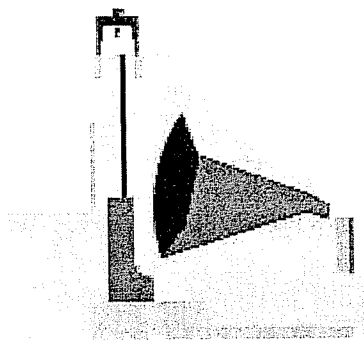
- Available plant discharge from ~100 m^3/s (3,500 cfs)
- Available head from 3 m up to 30 m (10-100 feet)
- Minimum submergence 1.5 m (5 feet) below tailwater
- Utility grid connection in close proximity
- Structure available and suitable for HYDROMATRIX® module



APPLICATION TYPES

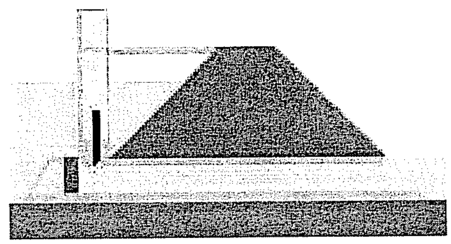
Navigation dams

Large lock and dam navigational structures along a number of major rivers represent an ideal application opportunity for HYDRO-MATRIX®. Adding power production to these sites can, in many cases, be very economical, when the existing structures allow implementation of HYDROMATRIX®.



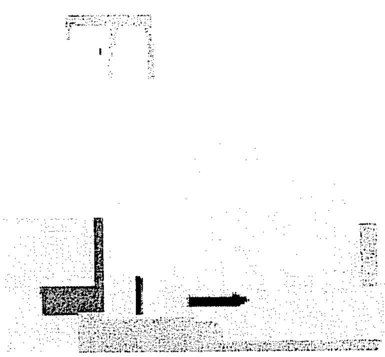
Intake towers

Water reservoirs for drinking water or other purposes having existing intake structures are also ideal opportunities for the use of the HYDROMATRIX® technology. In such applications operating heads of as much as 30 m can be developed.



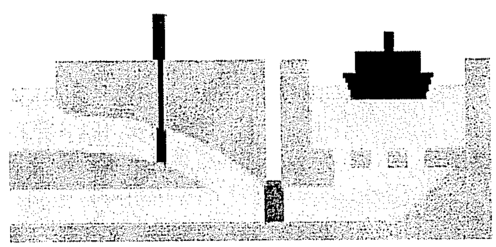
Irrigation dams

Worldwide, many structures have been built for irrigation purposes, spilling water to agricultural areas on a regular basis. In many cases these are also ideal candidates for the HYDROMATRIX® application.



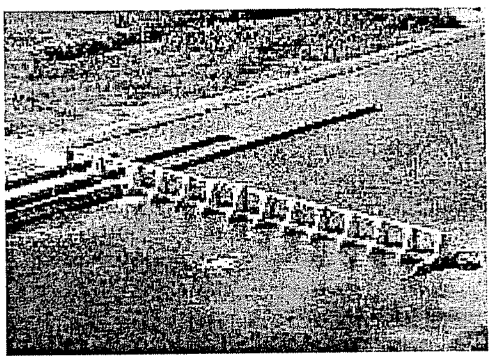
Sluice in shiplocks

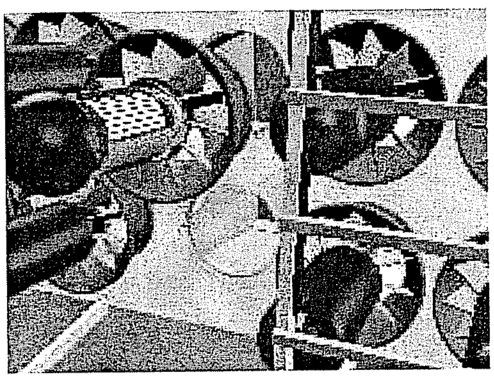
River navigation systems also include locks for ship transfer. These frequently have available an existing slot in which a HYDROMATRIX® module can be installed for power generation. The turbine-generator units can even be specifically designed to run in both flow directions if such is required to satisfy lock operations.



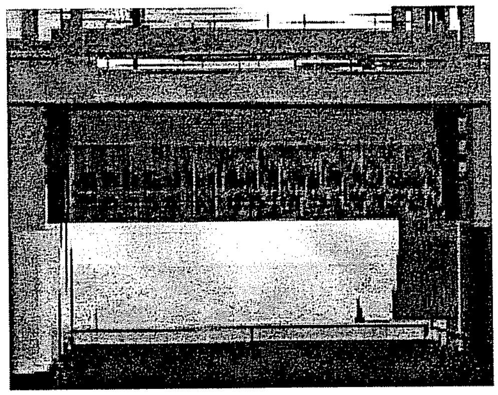
Navigation dams

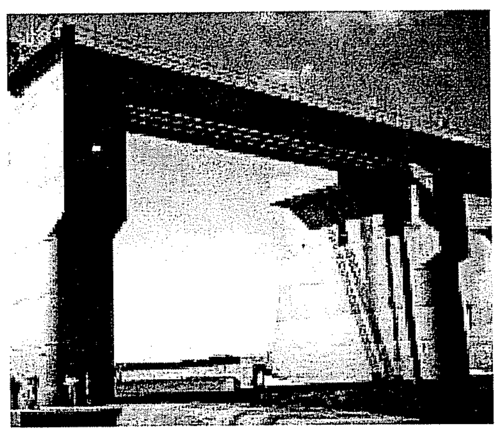
Smithland Lock and Dam is located on the Ohio River in Kentucky, USA and is operated by the US Army Corps of Engineers for ship navigation and flood control. Development of this site to generate electricity using the HYDROMATRIX® concept is a collaboration between PG & E National Energy Group (a private developer), the Corps of Engineers and VA TECH HYDRO.





This project forsees the installation of five HYDROMATRIX® modules having a total of 170 turbine / generator sets. The HYDROMATRIX® power modules would be installed in the existing taintor gate bays which are used for flood control. The scope of the contract for VA TECH HYDRO would be to deliver a fully operational HYDROMATRIX® power plant on a turnkey basis which includes all the mechanical and electrical systems. The first HYDROMATRIX® power module is planned to commence commercial operation in approximately two years.

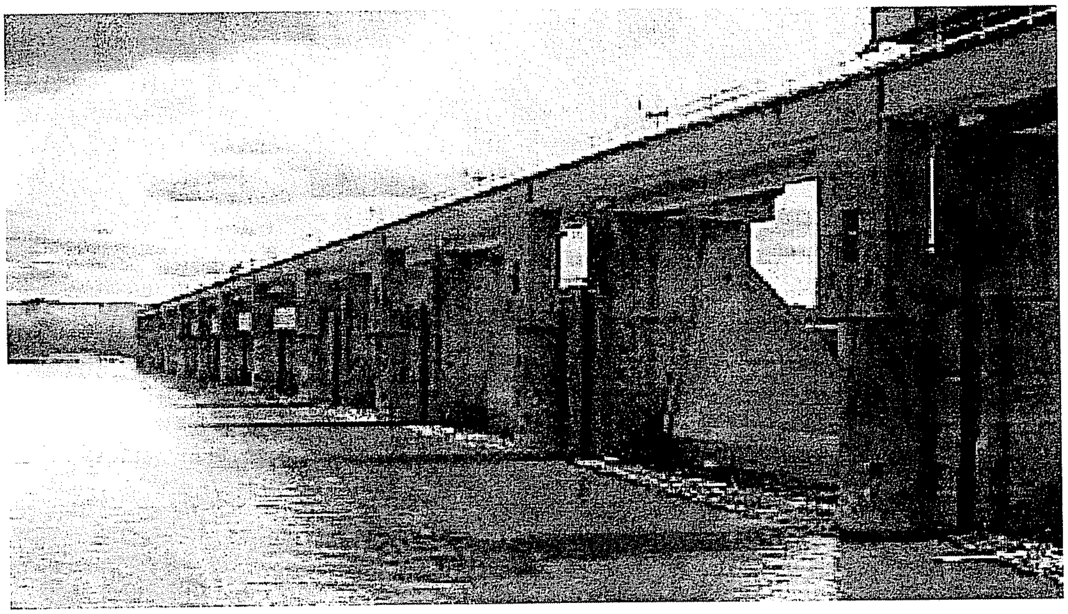




Technical data:	
Plant capacity:	85 MW
Head:	6.5 m (21.3 feet)
Speed:	360 rpm
Unit output:	500 kW
Runner diameter:	1,250 mm (49.2 inches)
Number of units:	170
Average yearly production:	352.5 GWh

REFERENCES:
CANNELTON - USA

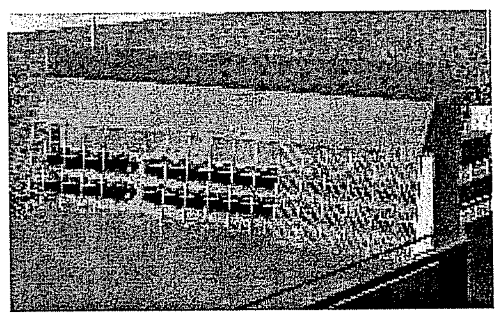
Navigation dams



Cannelton Lock and Dam is located on the Ohio River in Indiana, USA and is operated by the US Army Corps of Engineers for ship navigation and flood control. Development of this site to generate electricity using the HYDROMATRIX® concept is a collaboration between PG & E National Energy Group (a private developer), the Corps of Engineers and VA TECH HYDRO.

This project forsees the installation of five HYDROMATRIX® modules having a total of 140 turbine / generator sets.

The HYDROMATRIX® power modules would be installed in the existing taintor gate bays which are used for flood control. The scope of the contract for VA TECH HYDRO would be to deliver a fully operational HYDROMATRIX® power plant on a turnkey basis which includes all the mechanical and electrical systems. The first HYDROMATRIX® powermodule is planned to commence commercial operation in approximately three years.



Technical data:	
Plant capacity:	**88 MW**
Head:	**6.5 m (21.3 feet)**
Speed:	**360 rpm**
Unit output:	**627 kW**
Runner diameter:	**1,330 mm (52.4 inches)**
Number of units:	**140**
Average yearly production:	**366.7 GWh**

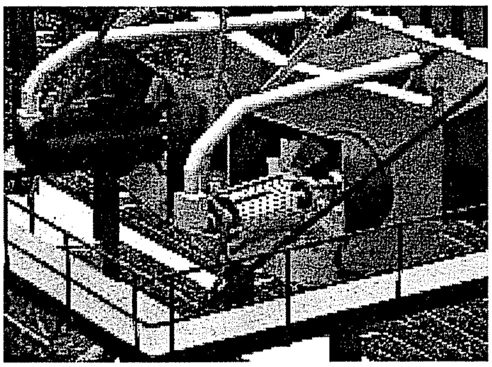
JEBEL AULIA - SUDAN

HYDROMATRIX®

Irrigation dams

The Jebel Aulia dam on the White Nile is located approximately 40 km south of the capital Khartoum. The dam serves for irrigation of the adjacent agricultural activities.

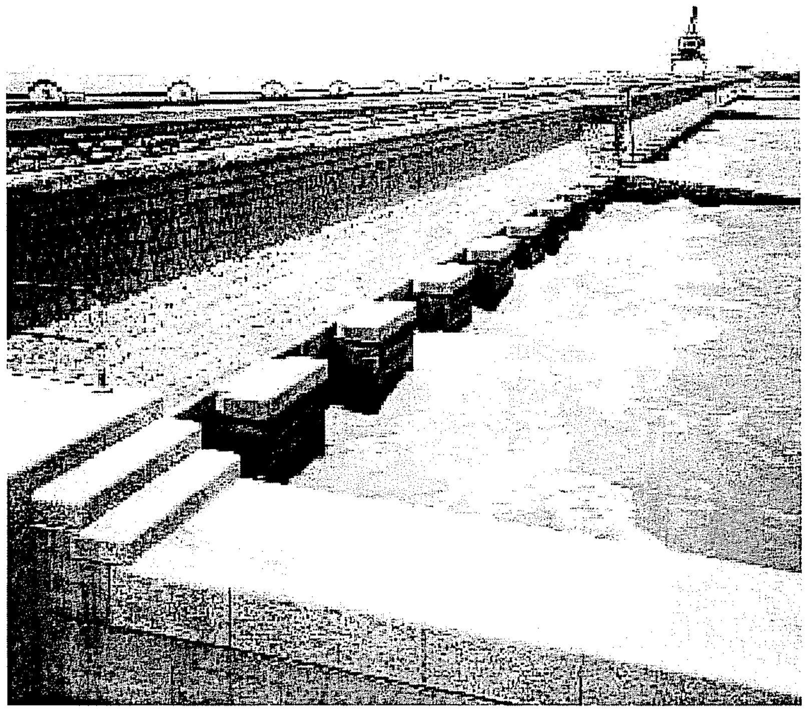
The HYDROMATRIX® powerplant consists of 40 modules having a total of 80 turbine-generator-sets. Of the 50 existing dam openings, 40 will be equipped with HYDROMATRIX® modules.



The scope of VA TECH HYDRO includes all mechanical and electrical auxiliaries. Locally contracted activities will be carried out by the customer, National Electricity Corporation of Sudan.

Since the HYDROMATRIX® concept makes use of the existing gate slot structures, little civil construction is necessary. This is one of the primary advantages of the HYDROMATRIX® technology.

The first HYDROMATRIX® module will commence commercial operation 16 months after contract signing and will be completed 7 months later.



The excellent business relationship between National Electricity Corporation and VA TECH HYDRO dates back to 1968, when the customer ordered the equipment for the Roseires hydropower plant.

Technical data:	
Plant capacity:	30.4 MW
Head:	5.5 m (18 feet)
Speed:	375 rpm
Unit output:	380 kW
Runner diameter:	1,120 mm (44.1 inches)
Number of units:	80
Average yearly production:	116.4 GWh

REFERENCES:
COLEBROOK - USA

Intake towers

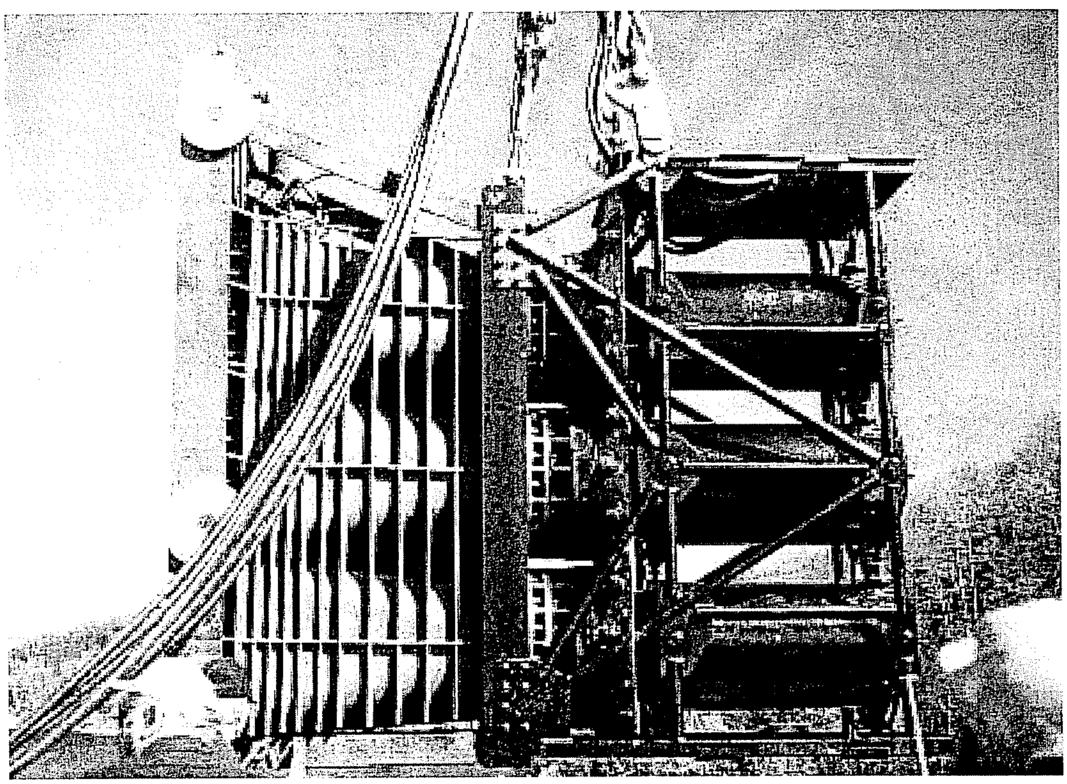
Located in Colebrook, Connecticut at an existing US Army Corps of Engineers flood control dam and reservoir, the first HYDRO-MATRIX® type units were installed in 1988. The plant annually averages 7,500 MWh (7.5 million kWh) of generation (with annual sales of nearly 13,000 MWh during "wet" years).

The inlet structure of the Colebrook Dam consists of a 77 m (250-foot) tall intake control tower with three separate gated passageways flowing to a single concrete-lined tunnel.

The dam has three upstream service bulkhead slots used during service of downstream gates. Two HYDROMATRIX® modules use two of the bulkhead slots. Each module contains three turbine-generator units.

Because of the wide head range of 7.6 m (25 feet) to 30.5 m (100 feet), flow through each module can be varied from 23 m³/s (75 cfs) to 107.7 m³/s (350 cfs).

Technical data:	
Plant capacity:	**3.0 MW**
Head:	**7.6-30.5 (25-100 feet)**
Speed:	**900 rpm**
Unit output:	**500 kW**
Runner diameter:	**660 mm (26 inches)**
Number of units:	**6**
Average yearly production:	**7.5 GWh**

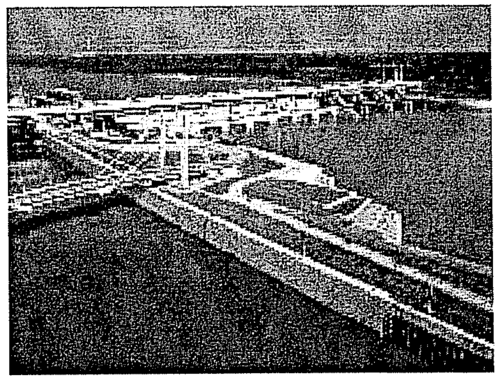


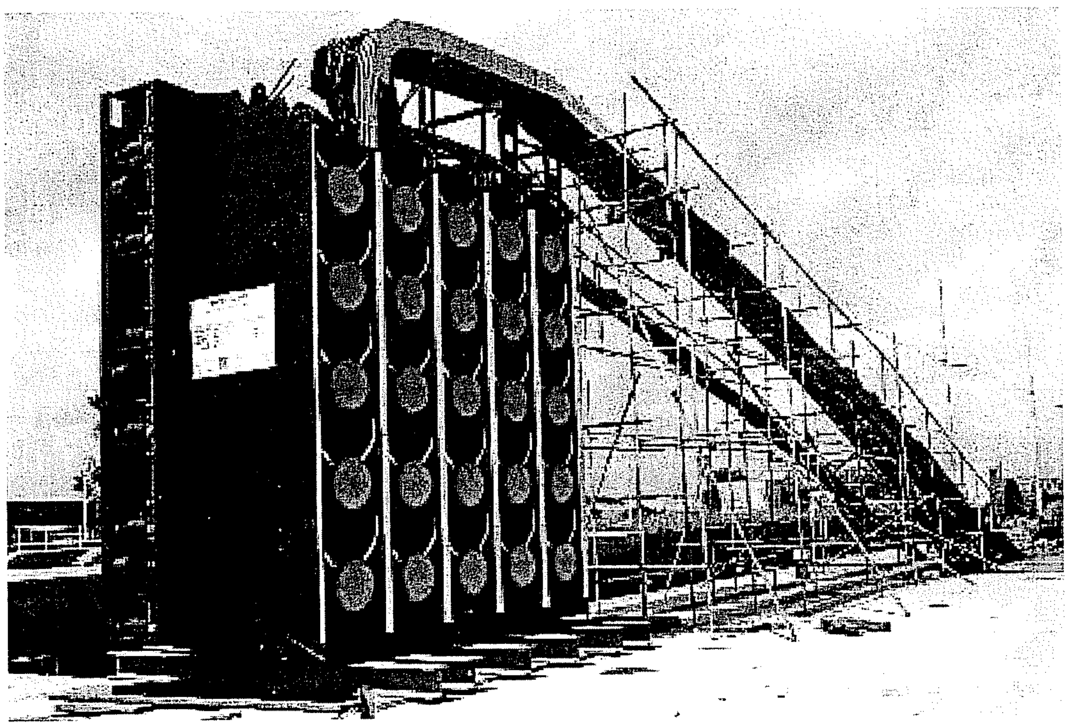
REFERENCES:
FREUDENAU - AUSTRIA

HYDROMATRIX®

Sluice in shiplocks

Located at an active navigation lock on the Danube River near Vienna, Austria, a 25-unit HYDROMATRIX® module was commissioned in early March, 2000. Development of this site to generate additional electricity using the HYDROMATRIX® concept was a collaboration between Donaukraft (the project owner), Verbundplan (the Consultant) and VA TECH HYDRO.





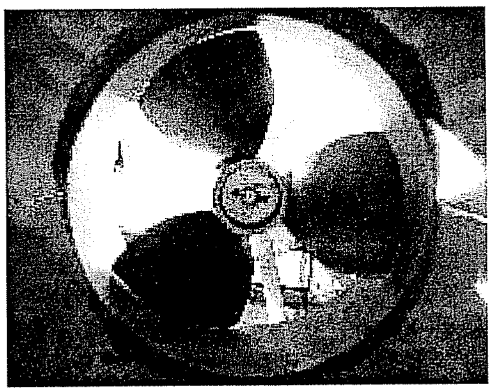
The module is designed to generate power during both the fill and drain periods of lock operation.This requires the turbine-generator units to operate in both flow directions. The module consists of 25 submerged horizontal propeller turbines driving induction type generators.

Technical data:	
Plant capacity:	**5 MW**
Head:	**10.3 m (33.8 feet)**
Speed:	**500 rpm**
Unit output:	**200 kW**
Runner diameter:	**910 mm (35.8 inches)**
Number of units:	**25**
Average yearly production:	**3.7 GWh**

ELECTROMECHANICAL EQUIPMENT

Turbine-generator units

A turbine-generator unit consists of a stay ring with fixed stay vanes, a fixed blade propeller type runner of aluminum-bronze and an induction type generator directly connected to the turbine runner. The stator forms a watertight steel fabricated housing and is mounted to the stay ring. Two bearings situated within the bulb support the generator rotor, shaft and runner rotating assembly. The shaft seal is of the mechanical face seal type and is located within the generating housing.

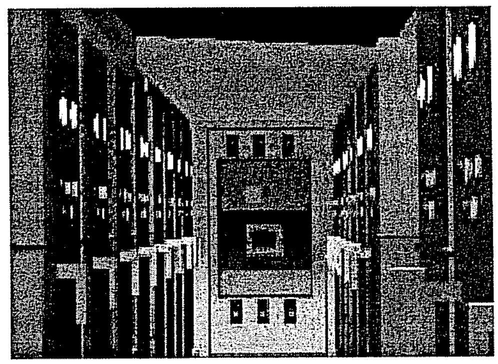


Module steel structure

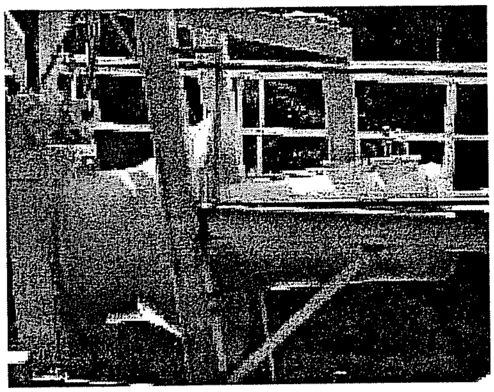
Each module consists of a stiff, steel fabricated structure, which supports the turbine-generator units. Rubber seals are provided at the bottom of the module as well as along the module sides to minimize bypass leakage. The module also includes steel fabricated draft tubes with integrated control gates. The draft tube shape and length are optimized to achieve high turbine efficiencies. Depending on the site conditions trash racks, bulkheads or roller gates can be incorporated into the module steel structure.

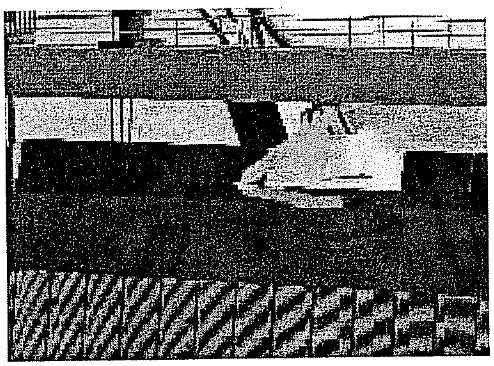
Electrical equipment

The electrical equipment is a standardized container type switchgear station, which includes the generator switchgear, the control and protection system as well as the reactive power compensation. For larger module sizes this electrical switchgear is placed inside the module. Standardized PLC systems are used for full automatic



operation of the entire power station. The system is completed with step-up transformers and high voltage switch gear equipment located on or close to the dam.





Auxiliaries

Few auxiliary systems are necessary to operate a HYDROMATRIX™ plant. Where the capacity of the existing crane is insufficient to lift the modules, a new crane with rails can be supplied and installed. Depending on the water quality, a trash rack cleaning machine can be supplied as part of the system as well. In order to ensure an independent power supply for the auxiliaries an emergency generator can also be provided.

QUESTIONNAIRE

Information needed for Budget Quotation

- Top view of the existing dam including main dimensions and available space for HYDROMATRIX®
- Cross section of the existing dam including main dimensions and elevations
- Hydrological data (as much historical data as possible):
  - Head water level
  - Tailwater level versus discharge
  - Discharge versus time

Content of Budget Quotation

Preliminary technical data of HYDROMATRIX® provided:

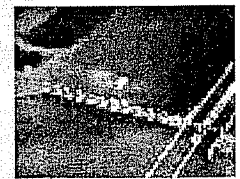
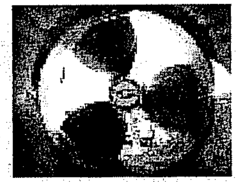
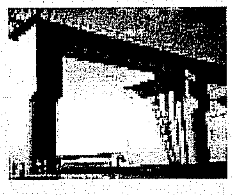
- Number of units
- Runner diameter
- Unit output
- Layout drawings
- Preliminary annual energy calculation
- Preliminary time schedule
- Budget price

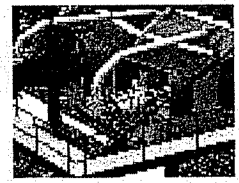
Contact: Worldwide

Harald G. Schmid
Product Coordinator HYDROMATRIX®
Tel. (++43/70) 6987 - 3343
Fax (++43/70) 6980 - 2554
E-Mail: harald.schmid@vatech-hydro.at

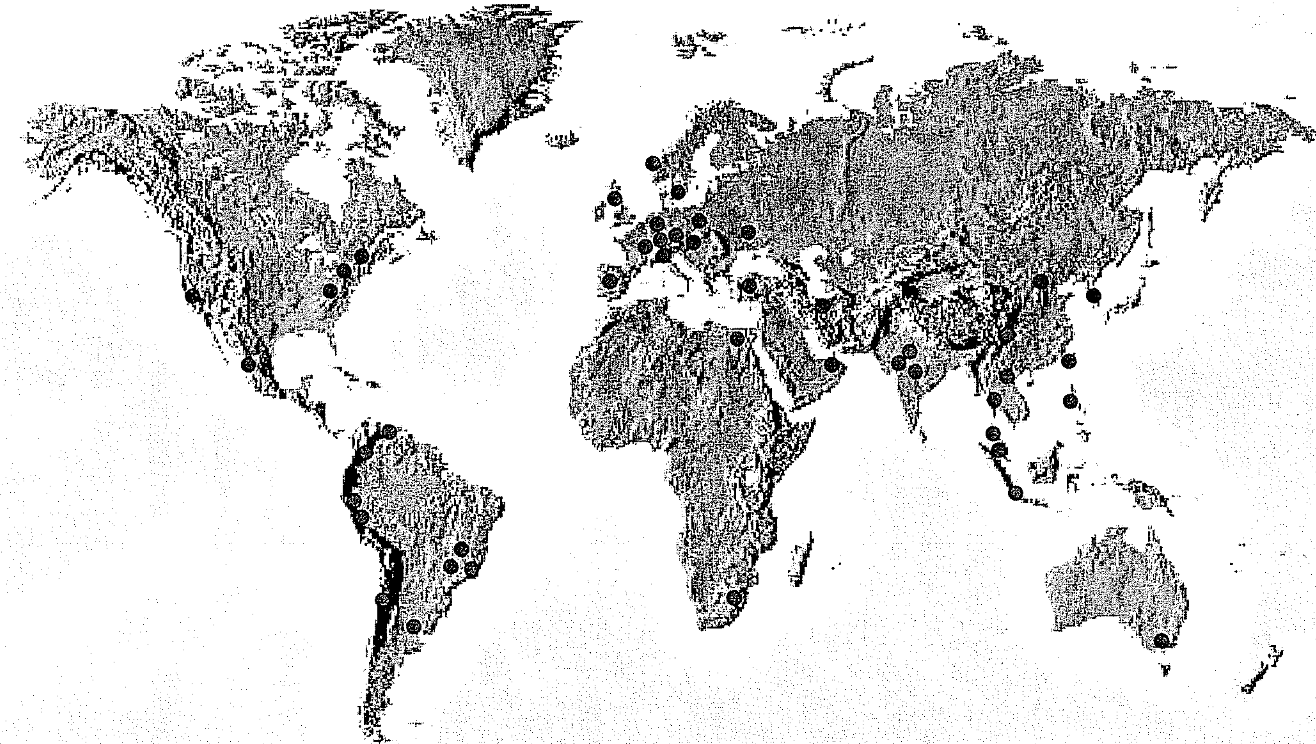
Contact: USA

Alexander Bihlmayer
Project Manager HYDROMATRIX®
Tel. (++1/704) 943 - 4343
Fax (++1/704) 943 - 0200
E-Mail: abihlmayer@vatechhydro.com



VA TECH HYDRO worldwide



Set ups in Argentina, Austria, Australia, Brazil, Canada, Chile, China, Columbia, Egypt, France, Germany, Hungary, India, Indonesia, Iran, Italy, Korea, Malaysia, Mexico, Norge, Peru, Philippines, Poland, South-Africa, Spain, Sweden, Switzerland, Taiwan, Thailand, Turkey, United Arab Emirates, United Kingdom, Ukraine, USA, Venezuela and Vietnam.

VA TECH HYDRO

e-mail: contact@vatech-hydro.com

Penzinger Strasse 76
A-1141 Vienna, Austria
Phone: (++43/1) 89 100 - 2963
Fax: (++43/1) 89 100 - 3821

Lunzer Strasse 78
A-4031 Linz, Austria
Phone: (++43/70) 6987 - 4231
Fax: (++43/70) 6980 - 2554

Escher-Wyss-Strasse 25
D-88212 Ravensburg, Germany
Phone: (++49/751) 83 - 2941
Fax: (++49/751) 83 - 3280

eHYD.LH.20.5000.L.D01

www.vatech-hydro.com

W.V. Hydro, Inc.

P.O. Box 5550
Aiken, SC 29804
E-mail: jimprice@atlantic.net
Phone: (865) 436-0402
Fax: (865) 436-0592
Cell: (803) 215-4165

October 14, 2004

Charles Freibert, Jr.
Director, Marketing
LG&E Energy Corp.
220 West Main Street
Louisville, KY 40202

Revision of Purchase Price for Three Ohio River Hydroelectric Projects

Dear Mr. Freibert:

This letter revises our previous pricing offer to LGEE for all delivered power from the Smithland, Cannelton and Meldahl Hydroelectric Projects (Projects). This offer modifies our previous offers made in response to LGEE's RFP on May 31, 2003 and amended later. The pricing has regrettably increased, because of material costs in the marketplace. We have priced two alternatives for the installation scheme of the Projects, which allows us to offer lower pricing and provides some benefits in terms of the operating experience on one alternative. Although we remain in contact with VA TECH and other vendors for a Hydromatrix installation, we have revised the pricing for conventional installation of hydropower at the three sites that would be built by Voith through a consortium. The current information that we have indicates that is the best choice in pricing, delivery of the plant and amount of generation. We continue to consider alternatives, as we believe you know; we are revising our options to provide the best price and generation choice to LGEE and its customers.

Summary

The present estimate of the average annual energy for the three projects is 1140 GWh (reduced for line losses); about one third of this is generated in the months of June through August. The schedule from Voith indicates about 20 MW would be on line in the summer (July) of 2008, 135 MW in the summer of 2009 and 230 MW in June, 2010, when all three plants are complete. This schedule assumes all regulatory approvals are received in late 2005 and a closing with release of the contractor occurs on January 2, 2006. License amendments will be necessary to revise the installation plan to a conventional layout, which existed in the license before the amendment for a Hydromatrix scheme. We consider these minor license amendments, because each license will be revised to its previous articles, and expect to obtain the amendments within the proposed schedule.

The proposed pricing is for all delivered power at the appropriate LGEE interconnection with a different price in each of the years beginning in 2008, as shown in the attached table and Excel file. We offer a five-year extension on the 30 years in the contract at $39 per MWh in each of those years (through 2042).

The proposed installation from the Voith consortium would use three or four large, vertical semi-Kaplan turbines with variable angle blades but no wicket gates. The installation of this conventional powerhouse would be beside the KY shore at each site. The capacity of each project is about 80 MW, as in the Hydromatrix installation. There is no necessity for any demonstration of equipment, because of the extensive experience with this type of equipment. This removes our concern regarding the letter of credit if the first Hydromatrix module did not perform sufficiently. We would be glad to bring the Voith engineers to Louisville to discuss the plant features. We are currently examining the energy calculations and will keep you informed of any changes. We expect to complete the energy studies for the present time in about a week. Please use the expected generation below until then.

Please call if there are any questions.

Yours truly,

James B. Price

James B. Price
President

A detailed construction schedule for the conventional plants is below and attached.

Time schedule SML & CAN & MEL

Prior to Issuing Notice to Proceed to Voith, contracts, financing and FERC and PSC approvals must be in place.

	Months after NTP	Estimated Dates
Notice to proceed (NTP)- Release Voith after EPC signed	0	Jan-06 **<—Specify this Date**
unit 1 becomes operational	31	Jul-08
Substantial completion M2 SML	33	Sep-08
Substantial completion M3 SML	35	Nov-08
Substantial completion M4 SML	37	Jan-09 Smithland Complete
Substantial completion M1 CAN	39	Apr-09
Substantial completion M2 CAN	41	Jun-09
Substantial completion M3 CAN	43	Jul-09
Substantial completion M4 CAN	45	Sep-09 Cannelton Complete
Substantial completion M1 MEL	47	Nov-09
Substantial completion M2 MEL	49	Jan-10
Substantial completion M3 MEL	51	Apr-10
Substantial completion M4 MEL	53	Jun-10 Meldahl Complete

M? = unit number at each site
Each plant would have 4 turbine/generator (7.5 - 8.4 m in diameter)

The following are the power sale prices during the 30-year term of the PPA.

Proposed Power Sale Prices from Three Hydro Projects

	Year	$/MWh
1	2008	34.1
2	2009	35.0
3	2010	37.4
4	2011	39.6
5	2012	41.8
6	2013	42.9
7	2014	44.0
8	2015	45.1
9	2016	48.4
10	2017	48.4
11	2018	49.5
12	2019	49.5
13	2020	51.7
14	2021	51.7
15	2022	51.7
16	2023	51.7
17	2024	51.7
18	2025	52.8
19	2026	52.8
20	2027	52.8
21	2028	52.8
22	2029	52.8
23	2030	52.8
24	2031	46.0
25	2032	46.0
26	2033	46.0
27	2034	46.0
28	2035	35.0
29	2036	35.0
30	2037	35.0

We offer a five year extension at $39/MWh, subject to regulatory approval.

Estimated Generation (GWh)

	Smithland	Cannelton	Meldahl
Annual	375	385	390
Summer	125	122	130

Questions for W. V. Hydro - Smithland & Cannelton Hydroelectric Projects

The following provides the Answers to LGEE's questions based on our discussion on Nov. 18; our answers are in bold italics.
Dec. 15, 2003

1. Do you wish to lower the price or improve any of the terms contained in your initial response to the Companies RFP? ***Yes, we wish to revise the power sale prices from year 24 through year 30; we wish to add any economic benefits associated with the green power attributes in the offered prices, and we also offer two ownership options to LGEE. We briefly discussed a longer contract, e.g. 50 years, and a lower levelized price at our meeting, but our impression was that a longer term was not interesting to LGEE. The revised (lower) prices after year 23 of the proposed contract are in an attached table; the levelized price for 30 years in 2006 dollars is $36.11/MWh. We are trying to give the advantage of the low-cost prices associated with a long-term contract for hydropower to LGEE.***

We realized at our meeting that LGEE was counting on the Green Power value, so we agree to include that in the offered pricing. The two ownership options are the right to become majority owner of the Projects initially and a Right of First Offer to LGEE exercisable between years 3 and 10 of the PSA. We believe the price should be at fair market value, possibly based on escalation from the initial price ($1200/kw) or some market-based price for a comparable hydro project to avoid undesirable tax consequences. These two ownership options are discussed at the end of this document.

2. The initial RFP indicated that the Companies had a capacity need beginning in 2007. If the Companies needs are delayed to 2009 or 2010, are you still interested in being considered as a supplier? If yes, please specify in detail the modifications to your initial proposal that would be required. ***We believe our discussions on Nov. 18 clarified our in-service dates. We have attached a schedule for the commissioning date (in-service) for each module, as promised at our meeting. The execution of the PSA and EPC contracts will determine the actual in-service date for each module. The two hydro projects are installed in modules; each module is a complete 16 MW power plant with its own step-up transformer. The first module should come on line in early 2006 (18 MW). The remaining nine modules would come on line at two month intervals from early 2008 through early 2009, depending on PSA execution date.***

3. Your initial response to the RFP did not provide adequate information for the Companies to evaluate the delivery risk associated with your proposal. Please review the Delivery section of the RFP and respond with the best available current information to all of the delivery questions. ***The Projects will be interconnected to LGEE's Cloverport SS in Breckenridge County, KY (Cannelton) and Livingston County SS in Livingston County (Smithland). The***

projects' partnerships have entered interconnection agreements with MISO and KU. There should be no delivery issues.

4. Please state your pricing, as required in the RFP, with the Delivery Point as the Companies' system assuming the Companies remain a member of MISO. How will your pricing change if the Companies are not a member of MISO? ***See answer to question 1 and attached table. The ownership option for LGEE to become the majority owner also affects the pricing dramatically, by making the cost of service to LGEE about $20/MWh (50% equity) before considering return on equity. The Projects would be interconnected with LGEE, so there is no difference if LGEE is not interconnected with MISO.***

5. Please provide financial statements for the proposed contracting entity. If the proposed entity is not investment grade, describe the credit enhancements that will be put in place to reduce the Companies credit risk in the transaction. ***There are two issues that are unique to this proposed contract. a) The operating entity for each project is a special purpose partnership that holds all the relevant rights for construction and operation of the plants; it does not have a credit rating at this time. These are specific projects that will be built to deliver to LGEE exclusively during the contract term; the power is not being generated from an unknown asset or a portfolio. A <u>subordinate security interest in these specific physical assets</u> could be provided to assure the Companies regarding continued operation. The failure of the sellers to properly maintain the plant could be prevented by Step-In Rights, subordinate to any rights the lender demands. In addtion, as stated below, the Partnerships will provide a Letter of Credit (LOC) for certain potential failures of the Projects.***

b) We discussed the Companies' credit risk in a take-and-pay contract; no capacity payments are proposed, which is consistent with a run-of-river hydroelectric such as these two projects, and similar to LGEE's Falls of the Ohio Hydroelectric Plant. So there is no credit risk of failure to deliver capacity when dispatched. The plants do provide capacity in a statistical manner with substantial summer generation, which is one of their major benefits. The viability of the seasonal capacity(summer generation) is only dependent on the plants being operated correctly; the river conditions demonstrate from historical (48 years) data that the capacity is available.

6. Confirm that the pricing in your initial offer allows your bid to be fully compliant with the requirements of the RFP. Do you wish to provide the Companies with any alternative proposals? If so, please describe the proposed alternate proposal and how it may benefit the Companies and their customers. In addition for any alternative proposal, specify the details of such proposal in a manner that is consistent with the requirements contained in the RFP and such that the proposal can adequately be evaluated. ***The only alternate proposals are the ownership options explained at the end of this document. There are no alternate supply options, because we will construct these two specific projects to sell to LGEE. We believe we are compliant with the RFP requirements to the extent that the***

Projects can be. The Projects also offer to use off-peak energy to generate hydrogen, if it is economical to do so. The decision on whether this use of off-peak power is economical would be made by the Partnerships.

7. Provide a development status report for the project. ***We discussed this in detail at our meeting on Nov. 18. The Projects are fully permitted; there are no outstanding regulatory issues. The Smithland Project is completely designed and almost completely approved by the Corps of Engineers (dam owner) and FERC. Upon signing a power purchase agreement with LGEE, we will enter EPC Contracts with VA TECH, similar to those executed in 2001, and arrange financing.***

8. List all necessary third party consents required and the status of those consents. This should include any MISO agreements, any interconnection and operating agreements, and any other agreements with a third party. ***There are none. As stated in answer 7, there are <u>no regulatory approvals necessary</u>. The interconnection agreement for each Project with MISO and KU is signed and filed with FERC. The Corps of Engineers and FERC must approve design and operation of the Projects relative to the operation of Locks and Dams, where they are located. This is similar to the interaction between the Corps and LG&E at Falls of the Ohio Hydroelectric Plant. These approvals cannot prevent generation occurring as planned.***

9. Does W.V. Hydro require any development milestone(s) be met before entering into a binding PSA with the Companies with at least the required $150/kw LOC guaranteeing performance? If so, please describe the development milestone(s) and their status.

We discussed the difficulty of relating a capacity supply penalty ($150/kw) to a take-and-pay (no capacity payments) contract, as planned for these projects. Based on our discussions, we offer the following resolutions. The Partnerships would provide a Letter of Credit (LOC) that could be drawn down for failure to meet agreed-upon construction deadlines, project completion and performance requirements. The LOC would not be provided until a binding PSA, EPC Contracts and project financing are in place. The detailed drawdown conditions and potential damage to the Companies must be determined during PSA completion.

As discussed, we believe the LOC amount and drawdown penalties should be related to specific losses that would determine when drawdown is allowed and what the penalty is. We agree to the amount set by LGEE ($150/kw) as noted in the following. Except for completion delays, completion failure, failure to demonstrate required performance and failure to generate when river conditions permit, we are not aware of any circumstances that would need to be secured by a Letter of Credit or any other security acceptable to LGEE. For instance, there would be no penalty for failure to deliver contacted capacity, because there is no contacted capacity. So

our plan is to provide an LOC that could be drawn down in the event of the following failures.

An LOC for meeting the construction schedule and performance requirements should be based on the expected loss to the Companies, but should not be greater than \$150/kw or \$15,900,000 (106 MW) for any and all drawdown events. For generator performance below guarantee, the LOC would be drawn down \$150 for each kW.

We do not consider an LOC the best protection for assuring proper operation of the plants. We discussed this issue with the Companies to see what benefits other security features would provide without reaching any conclusion. The Projects do not offer and are not paid for firm capacity, but there is seasonal capacity inherent in the generation. The Companies are only paying for power delivered, so within limits, a derated plant will automatically be paid less revenue, because it delivers less power. We do recognize the Companies are counting on this generation and suggest the security features named below as an alternative to an LOC, which adds cost to the Projects. Although the Projects cannot fail to deliver a capacity commitment, they could provide less power than expected if not properly maintained.

Because this is a take-and-pay contract, the loss to the Companies would be limited to the increased cost of power purchased or generated to supply power that is not delivered from the Projects because of an act of negligence (improper maintenance) by the Partnerships. The penalty or drawdown should be based on any experienced increase cost of power in such a situation. We propose that as a general condition any replacement power be assumed to cost \$2/MWh more than the power that would have been delivered by the Projects, so that amount could be combined with lost generation to determine the drawdown from the LOC as a penalty.

Rather than an LOC, we prefer alternate arrangements to deal with the potential problem of incompetent operation, such as improper mainteneance, trash rack cleaning, etc. The Partnerships could provide a subordinate (to the lender) security agreement in the two physical plants; we could provide Step-In Rights, subject to the lender's approval.

The generation from these two projects comes from physical generation sources that will be dedicated to delivering to LGEE; the contract should state that LGEE has first claim to receive and pay for any generation from the two plants. This is not an arbitrage or portfolio sale; when these plants generate, LGEE receives the power. If an ownership right is accepted by the Companies, the certainty of continued operation at the planned amount should be greater. These features should assure the Companies that during operation the plants will be operated as expected and the anticipated generation will be delivered.

Two Ownership Options

We offer LGEE two ownership options. The first is a majority ownership at the initial construction of the Projects, which is now. This is the most economical, because the Projects do not have to be financed twice: once before LGEE's involvement and secondly, upon LGEE's involvement. We emphasize that this option does not alter our offer to sell the power only as indicated above and in our RFP bid. The second offer is a Right of First Offer that LGEE may exercise during years 3 through 10 of the PSA.

Offer to LGEE of the Majority Ownership in the Projects

In addition to our offer to sell power only, we offer LGEE an opportunity to become the majority owner of the two projects. This is an alternative offer and does not displace the offer to sell power. We realize LGEE is probably too unfamiliar with these projects to respond positively at this time. If LGEE were interested in ownership based on the enclosed financial information, we would like to meet you again with our vendor, VA TECH, to explain the technical details and other features of the Projects. The Smithland Project is designed and 90% approved by the Corps of Engineers, dam owner, and the FERC; the Cannelton project will be very similar. The financial details for this alternative offer are outlined below and in the attached file, SmCanFinanceInfoLGEE.xls. For long-term debt (20 years) at 7.5% interest rate, the cost of service for all project features with power delivered to MISO is a levelized value of $20/MWh in 2006 dollars; this pricing assumes 50% equity. Perhaps LGEE could obtain a lower interest rate, which would improve the return. This alternative would allow LGEE to realize the full economic benefit of two hydroelectric that will continue to generate for as long as the dams are maintained for navigation, which will be a long time!

In this offer LGEE would become the majority owner of the Projects with our companies remaining as the minority partners. This is the arrangement we had with National Energy Group before their financial difficulties. The vendor, VA TECH, is willing to finance the first module. This first module would be commissioned 24 months after executing an EPC contract for the two projects. Upon completion of its performance and reliability test (about month 30), VA TECH would be paid for the module, about $25 M and would proceed with the remaining nine modules. Until this payment is made, the only costs to the Projects are the transmission line for Smithland, physical models, a letter of credit fee and review by the Corps; these costs total about $3.5 M. From month 30 until completion of both Projects in month 63, summer of 2009, progress payments will be made, so a construction loan should be arranged in month 30. The total cost for the two projects would be about $200 M ($1200/kw), which includes all costs for equipment, facilities, development, financing and construction interest.

After module 1 is commissioned in month 24, it begins generating 90 GWh per year on average. Each module is a self-contained power plant with its own step-up transformer. Operation would be done by a crew of about 7 at each project, trained by VA TECH. Maintenance is not prohibitive, because the equipment is simple and hardy. VA TECH is willing to do the major maintenance biannually and at 5 and 10 year intervals.

For 50% equity and 7.5% interest rate, the cost of service to LGEE is $20/MWh; for 80% debt and 7.5% interest rate, the cost of service is about $28/MWh. We have attached a file, SmCanFinanceInfoLGEE.xls, showing the annual operating cost and estimated debt cost for the 80% debt case, so that LGEE can do initial financial evaluations. As stated above, we need to discuss the details with LGEE, if the ownership option is appealing. Please advise us. We can share the detailed cash flow analysis and as much technical detail as is desired.

Offer to LGEE of a First Right of Offer in the Projects

This is a simple offer in which LGEE has the right to receive the first offer in the event that the Partnerships decide to sell the Projects, or if LGEE expresses a desire for such an offer during the applicable period. The applicable period is from years 3 through 10 of the PSA. In this case, LGEE would indicate its willingness to consider buying up to 50% of the Projects from the Partnerships, by purchasing partnership interests, or, if the Partners wished to sell they would offer their interests to LGEE. The price would be based on escalation in the initial price of the Projects, $1200/kw, or a fair market price for the Projects determined at the time of purchase using the purchase price for similar projects.

This offer would allow LGEE to enter the Projects as an owner after they are constructed but would be less economical than becoming majority partner at the time of construction, because LGEE can obtain more favorable financing.

Proposed Power Sale Prices from Hydro Projects - Revised Prices

Levelized Price

$36.11 for 30 years in 2006 $.

	Year	$/MWh	
1	2006	29.0	The price of the power decreases dramatically in 2029 to $23 per MWh.
2	2007	29.0	After that year, the price escalates at 1.5% p.a. for 6 years.
3	2008	32.0	
4	2009	33.0	
5	2010	34.0	
6	2011	35.5	
7	2012	36.5	
8	2013	36.5	The levelized price of the power in 2006 dollars is $36.11 per MWh at 10%
9	2014	39.0	discount for the 30 years of fixed prices. The Smithland plant begins
10	2015	39.0	operation in 2006 and is complete in 2008; the Cannelton plant is
11	2016	41.0	complete in late 2008 or early 2009. The first 23 years have the same
12	2017	41.0	prices as the offer of June 24, 2003, which is a revision of the bid.
13	2018	43.0	
14	2019	44.5	
15	2020	44.5	
16	2021	45.0	
17	2022	47.0	
18	2023	48.0	
19	2024	48.0	
20	2025	48.0	
21	2026	48.0	
22	2027	48.0	
23	2028	42.0	
24	2029	23.0	Escalation Rate
25	2030	23.3	1.5%
26	2031	23.7	
27	2032	24.1	
28	2033	24.4	
29	2034	24.8	
30	2035	25.1	

Time schedule SML & CAN Milestones

Time schedule **Rev. 06**

Milestones		Months after LNP	Cash Flow Analysis	Estimated Dates	
Limited Notice to proceed (LNP)			0	March 15, 2004	Specify this Date
Module 1 becomes operational		**25**	24	March 15, 2006	
=> Start of test period			24	March 15, 2006	
Substantial completion M1 SML	**FNP**	**30**	30	September 13, 2006	
=> Full Notice to proceed (FNP)		Months after FNP	30	September 13, 2006	
Substantial completion M2 SML		19	49	April 13, 2008	
Substantial completion M3 SML		20	50	May 13, 2008	
Substantial completion M4 SML		21	51	June 13, 2008	
Substantial completion M5 SML		**23**	53	August 13, 2008	
Substantial completion M1 CAN		25	55	October 12, 2008	
Substantial completion M2 CAN		27	57	December 12, 2008	
Substantial completion M3 CAN		29	59	February 11, 2009	
Substantial completion M4 CAN		31	61	April 13, 2009	
Substantial completion M5 CAN		**33**	63	June 13, 2009	

Estimated detailed design and review by Corps before final approval of Smithland design is 3 months.
Schedule can decrease if other actions proceed while Corps is reviewing for 3 months.

Begin Construction in Oct. 2003; MOD 10 commissioned in Dec. 2008 (mo. 63)

Cash Flow			>			1	2	3	4	5	6	7	8	9	10
Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Months	0	3	12	12	12	12	12	12	12	12	12	12	12	12	12
Modules Generating		1	1	1	7	10	10	10	10	10	10	10	10	10	10
Operating Expenses						<--All 10 Modules operating; both plants complete									
Total Operating Expenses	$0	$180	$386	$557	$1,449	$2,958	$4,250	$4,404	$4,458	$4,531	$4,602	$4,869	$4,953	$5,042	$5,130
Debt Service															
Interest	$0	$0	$1,316	$1,755	$1,755	$11,890	$11,831	$11,712	$11,539	$11,355	$11,129	$10,796	$10,440	$9,988	$9,500
Principal	$0	$0	$0	$0	$0	$793	$1,585	$2,299	$2,457	$3,012	$4,439	$4,756	$6,024	$6,500	$7,927
Total Debt Service	$0	$0	$1,316	$1,755	$1,755	$12,683	$13,416	$14,011	$13,997	$14,367	$15,568	$15,552	$16,464	$16,488	$17,427
$/mwh of operating expense	**6.55** levelized in 2009				4.76	3.34	3.98	5.79	6.00	6.08	6.18	6.28	6.65	6.77	6.89
Cost of Service (¢/kwh) levelized in 2009	**2.78**			1.98	1.98	0.74	2.20	2.48	2.60	2.61	2.71	2.89	2.92	3.07	3.08

Cost of Service Does not include any tax costs, such as depreciation. It is the debt, operating and other costs divided by average annual generation.

11	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**Totals**
2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	
12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	13	
10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	
$5,224	$5,169	$5,264	$5,356	$5,456	$5,554	$5,821	$5,926	$6,038	$6,148	$6,266	$6,234	$6,354	$6,471	$6,597	$6,721	$7,092	
$8,906	$8,216	$7,467	$6,754	$5,921	$5,030	$4,078	$3,127	$2,057	$868	$0	$0	$0	$0	$0	$0	$0	
$9,195	$9,988	$9,512	$11,098	$11,890	$12,683	$12,683	$14,268	$15,854	$11,573	$0	$0	$0	$0	$0	$0	$0	
$18,101	$18,204	$16,979	$17,851	$17,812	$17,713	$16,761	$17,395	$17,911	$12,441	$0	$0	$0	$0	$0	$0	$0	
7.01	7.15	7.07	7.20	7.33	7.47	7.61	7.85	7.99	8.15	8.30	8.47	8.42	8.59	8.75	8.93	9.10	
3.23	3.34	3.35	3.21	3.36	3.52	3.53	3.45	3.58	3.69	2.78	1.29	1.31	1.34	1.37	1.41	1.44	

THIS IS THE DEPRECIATION ON AN ANNUAL BASIS FOR THE LGEE OWNERSHIP CASE; PHASE I IS THE FIRST MODULE AT SMITHLAND; PHASE II IS THE OTHER 9 MODULES.

Depreciation / Amortization

Tax Depreciation/Am	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Costs to Depreciate:															
Phase I		27,633													
Phaes II		0	0	0	170,539										
Total Plant Costs To C	0	27,633	0	0	170,539	0	0								

Tax Depreciation	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Phase I	0	1,036	1,995	1,845	1,707	1,579	1,460	1,351	1,250	1,233	1,233	1,233	1,233	1,233	1,233
Phase II	0	0	0	0	6,395	12,311	11,387	10,534	9,743	9,013	8,336	7,712	7,609	7,608	7,609
Total Tax Depreciatoir	0	1,036	1,995	1,845	8,102	13,890	12,847	11,885	10,992	10,246	9,569	8,945	8,842	8,841	8,842

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Totals
																0
																27,633
																170,539
																198,171

2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Totals
1,233	1,233	1,233	1,233	1,233	1,233	616	0	0	0	0	0	0	0	0	0	27,633
7,608	7,609	7,608	7,609	7,608	7,609	7,608	7,609	7,608	3,805	0	0	0	0	0	0	170,539
8,841	8,842	8,841	8,842	8,841	8,842	8,224	7,609	7,608	3,805	0	0	0	0	0	0	198,171

Assumptions for Case with LGEE Ownership

Smithland & Cannelton Hydro Projects

Assumptions

Smithland & Cannelton Combined

Financing

Construction Loan Amount ($)

Blended Construction Interest Rate	
Construction Loan Amount ($	178,168
Total Construction Loan	178,168
Total IDC	20,003
Total Project Cost	198,171

Term Loan Amount ($)

Debt (%)	80.0%
Equity (%)	20.0%
Term Loan Amount ($)	158,538
Equity ($)	39,635
Total Funding	$ 198,173
Term of LT Debt (begin 2009)	20
Term Loan Interest Rate	7.50%
Avg DSCR	1.58

Schedule (Shift as necessary)

Sign EPC contract	8/15/2003
First Module Commissioned	9/15/2005
First Module Substantial Com	3/15/2006
Construction Loan incl VA TE	3/15/2006
Second Module Commissione	10/13/2007
Tenth Module Commissioned	12/15/2008
Term Loan with Equity Fundin	12/15/2008

These dates should be shifted to actual EPC date.

Escalators

GNP	3.00%
FERC Administrative Cha	2.50%
EPC Cost Escalation	2.00%
O&M Escalation	2.50%
Interest on Reserves	3.00%
Discount Rate	**10.0%**

Operations

		Smithland	Cannelton	Combined
		353	367	720
Base Annual Energy (GW	716	Forced Outage Not Included		
Nominal Capacity (MW)	163			
Dollars per KW	1198			

Other

Tax Rate (effective)	40.36%
Federal	35.00%
State - KY	8.25%
Book Depreciation - Years	21
KY Sales Tax	0.00%

FINANCING PLAN

VA TECH will finance the first module; after it meets its substantial completion in March 2006(month 30), a financial closing should occur with payout of VA TECH and financing for the rest of constuction. The construction loan will be converted to a term loan with equity funding at the end of construction in Dec. 2008. The energy generated during construction and interest accrued during construciton are included in the cash page.

Changes :

Spread Equity out to be funded during construction period. - assume $4 M paid in 2005 for development and T Line (Mod 1 complete); balance in early 2009 (both projects complete)

Phase II depreciation begins in 2007

BRING CONSTRUCTION LOAN IN AT MO. 30 TO TAKE OUT VA TECH; term loan begins in month 64

Use VA TECH financing for first module

Shortened LT debt to 20 years, beginning in Jan 2009

Depreciation starts when first module is operational in Sept 2005

Added KY B&O Tax for each County Sept. 3, 2003

Appendix A - Demand Costs ($000s), Energy Costs ($000s), and Total Costs ($000s)

RFP for Purchased Power

Assumptions

MW purchase assumed 500
NPV rate 7.91%

Options on Baseload Capacity

80% Capacity Factor
7,008 Total Annual Hours
1.23 Coal Fuel Cost ($/MMBTU) in 2007 $
5.00 Gas Cost ($/MMBTU) in 2007 $
1.50% Fuel esc

	Include SO2	Yes	150 $/ton
	Include NOx	Yes	4,000 $/ton
2010	Include CO2	No	10 $/ton
	Emission Esc Rate	1.0%	

CCN Application

Resource Assessment

	Year	[redacted]									WV Hydro	TC
Max MW Level (info only)											114	549
Demand ($000)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	35,460	40,500	96,000	114,300	88,800	-	74,602	-	108,420	-	85,544
	2008	35,460	40,500	96,000	114,300	90,780	-	75,625	-	110,588	-	85,724
	2009	35,460	40,500	96,000	114,300	99,120	-	76,674	-	112,800	-	85,907
	2010	35,460	40,500	96,000	114,300	101,220	-	77,750	-	115,056	-	86,095
	2011	35,460	40,500	96,000	114,300	103,380	-	78,854	-	117,357	-	86,286
	2012	35,460	40,500	96,000	114,300	105,600	-	79,987	-	119,704	-	86,482
	2013	35,460	40,500	96,000	114,300	107,820	-	81,149	-	122,099	-	86,681
	2014	35,460	40,500	96,000	114,300	110,160	-	82,342	-	124,541	-	86,885
	2015	35,460	40,500	96,000	114,300	112,500	-	83,565	-	127,031	-	87,093
	2016	35,460	40,500	96,000	114,300	114,900	-	84,820	-	129,572	-	87,305
	2017	35,460	40,500	96,000	114,300	117,360	-	86,108	-	132,163	-	87,522
	2018	35,460	40,500	96,000	114,300	119,880	-	87,430	-	134,807	-	87,744
	2019	35,460	40,500	96,000	117,188	122,460	-	88,786	-	137,503	-	87,970
	2020	35,460	40,500	96,000	120,154	125,100	-	90,177	-	140,253	-	88,200
	2021	35,460	40,500	96,000	123,203	127,740	-	91,604	-	143,058	-	88,436
	2022	35,460	40,500	96,000	126,335	130,500	-	93,068	-	145,919	-	88,677
	2023	35,460	40,500	96,000	129,554	133,320	-	94,571	-	148,837	-	88,922
	2024	35,460	40,500	96,000	132,861	136,200	-	96,112	-	151,814	-	89,173
	2025	35,460	40,500	96,000	136,259	139,140	-	97,694	-	154,850	-	89,429
	2026	35,460	40,500	96,000	139,750	142,140	-	99,317	-	157,947	-	89,690
	2027	35,460	40,500	96,000	143,337	145,200	-	100,981	-	161,106	-	89,957
	2028	35,460	40,500	96,000	147,023	148,320	-	102,690	-	164,329	-	90,230
	2029	35,460	40,500	96,000	150,811	151,560	-	104,442	-	167,615	-	90,508
	2030	35,460	40,500	96,000	154,702	154,860	-	106,240	-	170,967	-	90,792
	2031	35,460	40,500	96,000	158,701	158,220	-	108,085	-	174,387	-	91,082
	2032	35,460	40,500	96,000	162,809	161,640	-	109,978	-	177,875	-	91,378
Energy ($000)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	147,315	149,308	55,532	52,012	45,526	149,796	48,823	137,358	34,889	101,616	48,228
	2008	149,649	151,672	56,409	52,934	46,472	149,796	49,965	141,478	35,519	112,128	48,948
	2009	152,023	154,077	57,300	53,875	46,367	149,796	51,135	145,723	36,160	115,632	49,679
	2010	154,437	156,522	58,205	54,736	47,315	149,796	52,331	150,094	36,813	119,136	50,421
	2011	156,892	159,007	59,125	55,613	48,298	149,796	53,556	154,597	37,479	124,392	51,175
	2012	159,388	161,535	60,061	56,504	49,281	149,796	54,809	159,235	38,157	127,896	51,940
	2013	161,926	164,106	61,011	57,411	50,301	149,796	56,092	164,012	38,848	127,896	52,717
	2014	164,507	166,720	61,977	58,333	51,321	149,796	57,404	168,933	39,552	136,656	53,506
	2015	167,132	169,378	62,959	59,272	52,412	149,796	58,747	174,001	40,269	136,656	54,307
	2016	169,802	172,081	63,956	60,227	53,504	149,796	60,122	179,221	41,001	143,664	55,121
	2017	172,517	174,830	64,971	61,198	54,596	149,796	61,529	184,597	41,746	143,664	55,946

RFP for Purchased Power

Assumptions		Options on Baseload Capacity			CCN Application
MW purchase assumed	500	80% Capacity Factor	Include SO2 Yes	150 $/ton	Resource Assessment
NPV rate	7.91%	7,008 Total Annual Hours	Include NOx Yes	4,000 $/ton	
		1.23 Coal Fuel Cost ($/MMBTU) in 2007 $	2010 Include CO2 No	10 $/ton	
		5.00 Gas Cost ($/MMBTU) in 2007 $	Emission Esc Rate 1.0%		
		1.50% Fuel esc			

	Year	[redacted]									WV Hydro	TC
Max MW Level (info only)											114	549
	2018	175,278	177,626	66,001	62,187	55,724	149,796	62,969	190,135	42,505	150,672	56,785
	2019	178,087	180,470	67,049	63,192	56,889	149,796	64,442	195,839	43,278	155,928	57,636
	2020	180,943	183,362	68,113	64,216	58,089	149,796	65,950	201,714	44,067	155,928	58,501
	2021	183,848	186,304	69,195	65,257	59,289	149,796	67,493	207,766	44,870	157,680	59,378
	2022	186,803	189,296	70,295	66,317	60,526	149,796	69,073	213,999	45,689	164,688	60,270
	2023	189,809	192,339	71,413	67,395	61,798	149,796	70,689	220,419	46,523	168,192	61,174
	2024	192,867	195,434	72,549	68,493	63,072	149,796	72,343	227,031	47,373	168,192	62,093
	2025	195,977	198,583	73,704	69,609	64,381	149,796	74,036	233,842	48,239	168,192	63,026
	2026	199,142	201,787	74,878	70,746	65,726	149,796	75,768	240,858	49,122	168,192	63,974
	2027	202,360	205,045	76,071	71,903	67,106	149,796	77,541	248,083	50,021	168,192	64,936
	2028	205,635	208,360	77,284	73,080	68,523	149,796	79,356	255,526	50,938	147,168	65,913
	2029	208,967	211,732	78,517	74,278	69,976	149,796	81,213	263,192	51,872	105,120	66,904
	2030	212,356	215,163	88,246	75,498	71,429	149,796	83,113	271,087	52,824	108,274	67,912
	2031	215,804	218,654	89,604	76,739	72,919	149,796	85,058	279,220	53,795	111,427	68,934
	2032	219,313	222,205	90,985	78,003	74,444	149,796	87,048	287,597	54,784	114,931	69,973
Total Cost ($000)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	182,775	189,808	151,532	166,312	134,326	149,796	123,425	137,358	143,309	101,616	133,772
	2008	185,110	192,172	152,409	167,234	137,252	149,796	125,590	141,478	146,107	112,128	134,672
	2009	187,484	194,577	153,300	168,175	145,487	149,796	127,808	145,723	148,960	115,632	135,586
	2010	189,898	197,022	154,205	169,036	148,535	149,796	130,081	150,094	151,869	119,136	136,516
	2011	192,352	199,507	155,125	169,913	151,678	149,796	132,410	154,597	154,836	124,392	137,461
	2012	194,848	202,035	156,061	170,804	154,881	149,796	134,796	159,235	157,861	127,896	138,422
	2013	197,387	204,606	157,011	171,711	158,121	149,796	137,241	164,012	160,946	127,896	139,399
	2014	199,968	207,220	157,977	172,633	161,481	149,796	139,746	168,933	164,092	136,656	140,391
	2015	202,593	209,878	158,959	173,572	164,912	149,796	142,312	174,001	167,301	136,656	141,400
	2016	205,262	212,581	159,956	174,527	168,404	149,796	144,942	179,221	170,573	143,664	142,426
	2017	207,977	215,330	160,971	175,498	171,956	149,796	147,637	184,597	173,909	143,664	143,469
	2018	210,739	218,126	162,001	176,487	175,604	149,796	150,398	190,135	177,311	150,672	144,528
	2019	213,547	220,970	163,049	180,380	179,349	149,796	153,228	195,839	180,781	155,928	145,606
	2020	216,403	223,862	164,113	184,370	183,189	149,796	156,127	201,714	184,319	155,928	146,701
	2021	219,309	226,804	165,195	188,460	187,029	149,796	159,097	207,766	187,928	157,680	147,814
	2022	222,264	229,796	166,295	192,652	191,026	149,796	162,141	213,999	191,608	164,688	148,946
	2023	225,270	232,839	167,413	196,949	195,118	149,796	165,260	220,419	195,360	168,192	150,097
	2024	228,327	235,934	168,549	201,353	199,272	149,796	168,455	227,031	199,187	168,192	151,266
	2025	231,438	239,083	169,704	205,868	203,521	149,796	171,730	233,842	203,089	168,192	152,455
	2026	234,602	242,287	170,878	210,496	207,866	149,796	175,085	240,858	207,069	168,192	153,664
	2027	237,821	245,545	172,071	215,240	212,306	149,796	178,523	248,083	211,128	168,192	154,893
	2028	241,095	248,860	173,284	220,103	216,843	149,796	182,045	255,526	215,267	147,168	156,142
	2029	244,427	252,232	174,517	225,089	221,536	149,796	185,655	263,192	219,487	105,120	157,413
	2030	247,816	255,663	184,246	230,200	226,289	149,796	189,353	271,087	223,792	108,274	158,704
	2031	251,265	259,154	185,604	235,440	231,139	149,796	193,143	279,220	228,181	111,427	160,017
	2032	254,774	262,705	186,985	240,812	236,084	149,796	197,026	287,597	232,658	114,931	161,351

Exhibit JPM-1 - Resource Assessment

Appendix A - Demand Costs ($000s), Energy Costs ($000s), and Total Costs ($000s)

RFP for Purchased Power

Assumptions

MW purchase assumed 500
NPV rate 7.91%

Options on Baseload Capacity

80% Capacity Factor
7,008 Total Annual Hours
1.23 Coal Fuel Cost ($/MMBTU) in 2007 $
5.00 Gas Cost ($/MMBTU) in 2007 $
1.50% Fuel esc

Include SO2 Yes 150 $/ton
Include NOx Yes 4,000 $/ton
2010 Include CO2 No 10 $/ton
Emission Esc Rate 1.0%

CCN Application

Resource Assessment

	Year											
		[redacted]									WV Hydro	TC
Max MW Level (info only)											114	549
15-Year Operating NPV (2003$)		$1,347,734	$1,397,123	$1,073,806	$1,179,141	$1,071,299	$1,026,013	$937,051	$1,119,131	$1,097,746	$880,450	$953,137
20-Year Operating NPV (2003$)		$1,579,450	$1,636,567	$1,245,010	$1,383,279	$1,273,337	$1,178,309	$1,107,898	$1,349,117	$1,299,738	$1,050,624	$1,106,766
25-Year Operating NPV (2003$)		$1,748,971	$1,811,508	$1,368,254	$1,539,233	$1,426,831	$1,282,392	$1,236,573	$1,531,330	$1,451,853	$1,141,233	$1,216,021
Rank in Category (20-yr Op NPV)		10	11	5	9	6	4	3	8	7	1	2
Delivery Point		[redacted]									WV Hydro	LGE
Comments		Unit Ownership	Unit Contingent	200 MW unit contingent	Unit Contingent	Firm	Unit Firm	20.5% Ownership in OVEC (485 MW)	10.6 MW (net) summer rating	Up to 500 MW in 50 MW increments unit contingent	106 MW summer peak	

Sensitivity: Rankings at Varying RunTimes

Capacity Factor											
50%	7	9	6	11	8	2	4	3	10	1	5
60%	9	11	6	10	7	2	3	5	8	1	4
70%	10	11	6	9	7	2	3	5	8	1	4
80%	10	11	5	9	6	4	3	8	7	1	2
90%	10	11	4	8	5	6	2	9	7	3	1
100%	10	11	4	8	5	7	2	9	6	3	1

Exhibit JPM-1 - Resource Assessment

Appendix A - Demand Costs ($/kW-Year), Energy Costs ($/kW-Month), and Total Costs ($/MWh)

RFP for Purchased Power

Cost Summary

		Options on Baseload Capacity									WV Hydro	TC
		[redacted]										
Demand ($/kW-Year)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	70.92	81.00	192.00	228.60	177.60	-	149.20	-	216.84	-	171.09
	2008	70.92	81.00	192.00	228.60	181.56	-	151.25	-	221.18	-	171.45
	2009	70.92	81.00	192.00	228.60	198.24	-	153.35	-	225.60	-	171.81
	2010	70.92	81.00	192.00	228.60	202.44	-	155.50	-	230.11	-	172.19
	2011	70.92	81.00	192.00	228.60	206.76	-	157.71	-	234.71	-	172.57
	2012	70.92	81.00	192.00	228.60	211.20	-	159.97	-	239.41	-	172.96
	2013	70.92	81.00	192.00	228.60	215.64	-	162.30	-	244.20	-	173.36
	2014	70.92	81.00	192.00	228.60	220.32	-	164.68	-	249.08	-	173.77
	2015	70.92	81.00	192.00	228.60	225.00	-	167.13	-	254.06	-	174.19
	2016	70.92	81.00	192.00	228.60	229.80	-	169.64	-	259.14	-	174.61
	2017	70.92	81.00	192.00	228.60	234.72	-	172.22	-	264.33	-	175.04
	2018	70.92	81.00	192.00	228.60	239.76	-	174.86	-	269.61	-	175.49
	2019	70.92	81.00	192.00	234.38	244.92	-	177.57	-	275.01	-	175.94
	2020	70.92	81.00	192.00	240.31	250.20	-	180.35	-	280.51	-	176.40
	2021	70.92	81.00	192.00	246.41	255.48	-	183.21	-	286.12	-	176.87
	2022	70.92	81.00	192.00	252.67	261.00	-	186.14	-	291.84	-	177.35
	2023	70.92	81.00	192.00	259.11	266.64	-	189.14	-	297.67	-	177.84
	2024	70.92	81.00	192.00	265.72	272.40	-	192.22	-	303.63	-	178.35
	2025	70.92	81.00	192.00	272.52	278.28	-	195.39	-	309.70	-	178.86
	2026	70.92	81.00	192.00	279.50	284.28	-	198.63	-	315.89	-	179.38
	2027	70.92	81.00	192.00	286.67	290.40	-	201.96	-	322.21	-	179.91
	2028	70.92	81.00	192.00	294.05	296.64	-	205.38	-	328.66	-	180.46
	2029	70.92	81.00	192.00	301.62	303.12	-	208.88	-	335.23	-	181.02
	2030	70.92	81.00	192.00	309.40	309.72	-	212.48	-	341.93	-	181.58
	2031	70.92	81.00	192.00	317.40	316.44	-	216.17	-	348.77	-	182.16
	2032	70.92	81.00	192.00	325.62	323.28	-	219.96	-	355.75	-	182.76
Demand ($/kW-Month)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	5.91	6.75	16.00	19.05	14.80	-	12.43	-	18.07	-	14.26
	2008	5.91	6.75	16.00	19.05	15.13	-	12.60	-	18.43	-	14.29
	2009	5.91	6.75	16.00	19.05	16.52	-	12.78	-	18.80	-	14.32
	2010	5.91	6.75	16.00	19.05	16.87	-	12.96	-	19.18	-	14.35
	2011	5.91	6.75	16.00	19.05	17.23	-	13.14	-	19.56	-	14.38
	2012	5.91	6.75	16.00	19.05	17.60	-	13.33	-	19.95	-	14.41
	2013	5.91	6.75	16.00	19.05	17.97	-	13.52	-	20.35	-	14.45
	2014	5.91	6.75	16.00	19.05	18.36	-	13.72	-	20.76	-	14.48
	2015	5.91	6.75	16.00	19.05	18.75	-	13.93	-	21.17	-	14.52
	2016	5.91	6.75	16.00	19.05	19.15	-	14.14	-	21.60	-	14.55
	2017	5.91	6.75	16.00	19.05	19.56	-	14.35	-	22.03	-	14.59
	2018	5.91	6.75	16.00	19.05	19.98	-	14.57	-	22.47	-	14.62
	2019	5.91	6.75	16.00	19.53	20.41	-	14.80	-	22.92	-	14.66
	2020	5.91	6.75	16.00	20.03	20.85	-	15.03	-	23.38	-	14.70
	2021	5.91	6.75	16.00	20.53	21.29	-	15.27	-	23.84	-	14.74
	2022	5.91	6.75	16.00	21.06	21.75	-	15.51	-	24.32	-	14.78

RFP for Purchased Power

Cost Summary

		Options on Baseload Capacity									WV Hydro	TC
		[redacted]										
	2023	5.91	6.75	16.00	21.59	22.22	-	15.76	-	24.81	-	14.82
	2024	5.91	6.75	16.00	22.14	22.70	-	16.02	-	25.30	-	14.86
	2025	5.91	6.75	16.00	22.71	23.19	-	16.28	-	25.81	-	14.90
	2026	5.91	6.75	16.00	23.29	23.69	-	16.55	-	26.32	-	14.95
	2027	5.91	6.75	16.00	23.89	24.20	-	16.83	-	26.85	-	14.99
	2028	5.91	6.75	16.00	24.50	24.72	-	17.11	-	27.39	-	15.04
	2029	5.91	6.75	16.00	25.14	25.26	-	17.41	-	27.94	-	15.08
	2030	5.91	6.75	16.00	25.78	25.81	-	17.71	-	28.49	-	15.13
	2031	5.91	6.75	16.00	26.45	26.37	-	18.01	-	29.06	-	15.18
	2032	5.91	6.75	16.00	27.13	26.94	-	18.33	-	29.65	-	15.23
Energy ($/MWh)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	42.04	42.61	15.85	14.84	12.99	42.75	13.93	39.20	9.96	29.00	13.76
	2008	42.71	43.29	16.10	15.11	13.26	42.75	14.26	40.38	10.14	32.00	13.97
	2009	43.39	43.97	16.35	15.38	13.23	42.75	14.59	41.59	10.32	33.00	14.18
	2010	44.07	44.67	16.61	15.62	13.50	42.75	14.93	42.84	10.51	34.00	14.39
	2011	44.78	45.38	16.87	15.87	13.78	42.75	15.28	44.12	10.70	35.50	14.60
	2012	45.49	46.10	17.14	16.13	14.06	42.75	15.64	45.44	10.89	36.50	14.82
	2013	46.21	46.83	17.41	16.38	14.36	42.75	16.01	46.81	11.09	36.50	15.04
	2014	46.95	47.58	17.69	16.65	14.65	42.75	16.38	48.21	11.29	39.00	15.27
	2015	47.70	48.34	17.97	16.92	14.96	42.75	16.77	49.66	11.49	39.00	15.50
	2016	48.46	49.11	18.25	17.19	15.27	42.75	17.16	51.15	11.70	41.00	15.73
	2017	49.23	49.89	18.54	17.47	15.58	42.75	17.56	52.68	11.91	41.00	15.97
	2018	50.02	50.69	18.84	17.75	15.90	42.75	17.97	54.26	12.13	43.00	16.21
	2019	50.82	51.50	19.13	18.03	16.24	42.75	18.39	55.89	12.35	44.50	16.45
	2020	51.64	52.33	19.44	18.33	16.58	42.75	18.82	57.57	12.58	44.50	16.70
	2021	52.47	53.17	19.75	18.62	16.92	42.75	19.26	59.29	12.81	45.00	16.95
	2022	53.31	54.02	20.06	18.93	17.27	42.75	19.71	61.07	13.04	47.00	17.20
	2023	54.17	54.89	20.38	19.23	17.64	42.75	20.17	62.90	13.28	48.00	17.46
	2024	55.04	55.77	20.70	19.55	18.00	42.75	20.65	64.79	13.52	48.00	17.72
	2025	55.93	56.67	21.03	19.87	18.37	42.75	21.13	66.74	13.77	48.00	17.99
	2026	56.83	57.59	21.37	20.19	18.76	42.75	21.62	68.74	14.02	48.00	18.26
	2027	57.75	58.52	21.71	20.52	19.15	42.75	22.13	70.80	14.28	48.00	18.53
	2028	58.69	59.46	22.06	20.86	19.56	42.75	22.65	72.92	14.54	42.00	18.81
	2029	59.64	60.43	22.41	21.20	19.97	42.75	23.18	75.11	14.80	30.00	19.09
	2030	60.60	61.41	25.18	21.55	20.39	42.75	23.72	77.37	15.08	30.90	19.38
	2031	61.59	62.40	25.57	21.90	20.81	42.75	24.27	79.69	15.35	31.80	19.67
	2032	62.59	63.41	25.97	22.26	21.25	42.75	24.84	82.08	15.63	32.80	19.97
Total Cost ($/MWh)	2003	-	-	-	-	-	-	-	-	-	-	-
	2004	-	-	-	-	-	-	-	-	-	-	-
	2005	-	-	-	-	-	-	-	-	-	-	-
	2006	-	-	-	-	-	-	-	-	-	-	-
	2007	52.16	54.17	43.25	47.46	38.34	42.75	35.22	39.20	40.90	29.00	38.18
	2008	52.83	54.84	43.50	47.73	39.17	42.75	35.84	40.38	41.70	32.00	38.43
	2009	53.51	55.53	43.75	48.00	41.52	42.75	36.47	41.59	42.51	33.00	38.69
	2010	54.19	56.23	44.01	48.24	42.39	42.75	37.12	42.84	43.34	34.00	38.96
	2011	54.90	56.94	44.27	48.49	43.29	42.75	37.79	44.12	44.19	35.50	39.23
	2012	55.61	57.66	44.54	48.75	44.20	42.75	38.47	45.44	45.05	36.50	39.50

RFP for Purchased Power

Cost Summary

	Options on Baseload Capacity										
	[redacted]									WV Hydro	TC
2013	56.33	58.39	44.81	49.00	45.13	42.75	39.17	46.81	45.93	36.50	39.78
2014	57.07	59.14	45.08	49.27	46.08	42.75	39.88	48.21	46.83	39.00	40.07
2015	57.82	59.90	45.36	49.54	47.06	42.75	40.61	49.66	47.75	39.00	40.35
2016	58.58	60.67	45.65	49.81	48.06	42.75	41.36	51.15	48.68	41.00	40.65
2017	59.35	61.45	45.94	50.09	49.07	42.75	42.13	52.68	49.63	41.00	40.94
2018	60.14	62.25	46.23	50.37	50.12	42.75	42.92	54.26	50.60	43.00	41.25
2019	60.94	63.06	46.53	51.48	51.18	42.75	43.73	55.89	51.59	44.50	41.55
2020	61.76	63.89	46.84	52.62	52.28	42.75	44.56	57.57	52.60	44.50	41.87
2021	62.59	64.73	47.14	53.78	53.38	42.75	45.40	59.29	53.63	45.00	42.18
2022	63.43	65.58	47.46	54.98	54.52	42.75	46.27	61.07	54.68	47.00	42.51
2023	64.29	66.45	47.78	56.21	55.68	42.75	47.16	62.90	55.75	48.00	42.84
2024	65.16	67.33	48.10	57.46	56.87	42.75	48.08	64.79	56.85	48.00	43.17
2025	66.05	68.23	48.43	58.75	58.08	42.75	49.01	66.74	57.96	48.00	43.51
2026	66.95	69.15	48.77	60.07	59.32	42.75	49.97	68.74	59.10	48.00	43.85
2027	67.87	70.08	49.11	61.43	60.59	42.75	50.95	70.80	60.25	48.00	44.20
2028	68.81	71.02	49.45	62.81	61.88	42.75	51.95	72.92	61.43	42.00	44.56
2029	69.76	71.98	49.81	64.24	63.22	42.75	52.98	75.11	62.64	30.00	44.92
2030	70.72	72.96	52.58	65.70	64.58	42.75	54.04	77.37	63.87	30.90	45.29
2031	71.71	73.96	52.97	67.19	65.96	42.75	55.12	79.69	65.12	31.80	45.67
2032	72.71	74.97	53.36	68.72	67.38	42.75	56.23	82.08	66.40	32.80	46.05

Financial Data Items

Cost of Capital		
Combined Companies	7.14%	
Kentucky Utilities Company	7.26%	
Louisville Gas and Electric Company	7.04%	
Escalation Rates		
Capital Costs	1.9%	Coal
	2.0%	CT
Fixed and Variable O&M	2.0%	
Combined Federal and State Tax Rate	40.36%	

Marketer Identification

Marketer A	[redacted]
Marketer B	[redacted]
Marketer C	[redacted]
Marketer D	[redacted]
Marketer E	[redacted]
Marketer F	WV Hydro

Trimble County 2

Capital Costs ($000) in Nominal Years

2005	6,801
2006	37,500
2007	130,250
2008	355,050
2009	219,000
2010	49,500

Variable and Fixed O&M Costs (2004 $000)

Variable O&M Costs	4,000
Fixed O&M Costs	7,300

CCN Resource Assessment Scenarios

		TC #1			r E			Marketer E & F			All CTs		
		Case 1						Case 8			Case 9		
	Capacity Need MW		Installed MW	Accum. MW		lled N	Accum. MW		Installed MW	Accum. MW		Installed MW	Accum. MW
2004	-812			0			0			0			0
2005	-656			0			0			0			0
2006	-520			0			0			0			0
2007	-369			0			0			0			0
2008	-167			0			0			0			0
2009	37			0			0			0			0
2010	163	TC2	549	549	CT-2	296	296	Marketer E	549	730	CT-2	296	296
								Marketer F	181				
2011	360			549	TC2	549	845			730	CT-1	148	444
2012	477			549			845			730	CT-1	148	592
2013	702	CT-2	296	845			845			730	CT-1	148	740
2014	856	CT-1	148	993	CT-1	148	993	CT-1	148	878	CT-1	148	888
2015	1,046	CT-1	148	1,141	CT-1	148	1,141	CT-2	296	1,174	CT-2	296	1,184
2016	1,199	CT-1	148	1,289	CT-1	148	1,289	CT-1	148	1,322	CT-1	148	1,332
2017	1,357	CT-1	148	1,437	CT-1	148	1,437	CT-1	148	1,470	CT-1	148	1,480
2018	1,537	CT-1	148	1,585	CT-1	148	1,585	CT-1	148	1,618	CT-1	148	1,628
2019	1,774	CT-2	296	1,881	CT-2	296	1,881	CT-2	296	1,914	CT-1	148	1,776
2020	1,970	CT-1	148	2,029	CT-1	148	2,029	CT-1	148	2,062	CT-2	296	2,072
2021	2,110	CT-1	148	2,177	CT-1	148	2,177	CT-1	148	2,210	CT-1	148	2,220
2022	2,357	CT-2	296	2,473	CT-2	296	2,473	CT-2	296	2,506	CT-1	148	2,368
2023	2,522	CT-1	148	2,621	CT-1	148	2,621	CT-1	148	2,654	CT-2	296	2,664
2024	2,789	CT-2	296	2,917	CT-2	296	2,917	CT-1	148	2,802	CT-1	148	2,812
2025	2,969	CT-1	148	3,065	CT-1	148	3,065	CT-2	296	3,098	CT-2	296	3,108
2026	3,225	CT-2	296	3,361	CT-2	296	3,361	CT-1	148	3,246	CT-1	148	3,256
2027	3,405	CT-1	148	3,509	CT-1	148	3,509	CT-2	296	3,542	CT-2	296	3,552
2028	3,661	CCCT-1	474	3,983	CCCT-1	474	3,983	CCCT-1	474	4,016	CCCT-1	474	4,026
2029	3,899			3,983			3,983			4,016			4,026
2030	4,212	CCCT-1	474	4,457	CCCT-1	474	4,457	CCCT-1	474	4,490	CCCT-1	474	4,500
2031	4,442			4,457			4,457			4,490			4,500
2032	4,683	CCCT-1	474	4,931	CCCT-1	474	4,931	CCCT-1	474	4,964	CCCT-1	474	4,974
2033	5067	CT-1	148	5,079	CT-1	148	5,079	CT-1	148	5,112	CT-1	148	5,122

Summary of All Plans (Excluding Transmission) - TC2 CCN Evaluation
Native Load Only Scenario

			TC2 and Marketer F	TC2 and Marketer F	TC2 and Marketer F	Marketer E	Marketer E	Marketers E and F	
Case/ Exp Plan:	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010	1-TC2	2-148G	F & 1-TC2	F	1-TC2	1-PbyO	2-148G	E & F	2-148G
2011		1-TC2		1-TC2			E		1-148G
2012									1-148G
2013	2-148G				F	2-148G			1-148G
2014	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2015	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2016	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2017	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2018	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2019	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2020	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2021	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2022	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2023	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2024	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2025	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2026	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2027	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2028	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2029									
2030	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2031									
2032	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2033	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
30 Yr PVRR ($000)	16,443,935	16,450,735	16,399,793	16,377,517	16,370,555	16,508,339	16,512,364	16,462,347	16,850,301
Cost Delta	73,380	80,180	29,238	6,962	-	137,784	141,809	91,792	479,746
Plan Rank (Low to High)	4	5	3	2	1	7	8	6	9
Capital Cost PVRR	1,508,424	1,482,598	1,452,300	1,408,798	1,452,300	1,532,518	1,505,119	1,476,395	930,439
Variable Cost PVRR	13,746,614	13,776,494	13,778,486	13,804,999	13,749,248	13,773,792	13,803,346	13,803,815	14,735,763
Fixed Cost PVRR	1,188,897	1,191,644	1,169,007	1,163,720	1,169,007	1,202,028	1,203,899	1,182,138	1,184,099
Total PVRR	16,443,935	16,450,735	16,399,793	16,377,517	16,370,555	16,508,339	16,512,364	16,462,347	16,850,301
Capital Ranking	8	6	3	2	3	9	7	5	1
Variable Cost Ranking	1	4	5	8	2	3	6	7	9
Fixed Cost Ranking	6	7	2	1	3	8	9	4	5

Summary of All Plans (Excluding Transmission) - TC2 CCN Evaluation
+5% EFOR Sensitivity

			TC2 and Marketer F	TC2 and Marketer F	TC2 and Marketer F	Marketer E	Marketer E	Marketers E and F	
Case/ Exp Plan:	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010	1-TC2	2-148G	F & 1-TC2	F	1-TC2	1-PbyO	2-148G	E & F	2-148G
2011		1-TC2		1-TC2			E		1-148G
2012									1-148G
2013	2-148G				F	2-148G			1-148G
2014	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2015	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2016	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2017	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2018	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2019	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2020	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2021	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2022	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2023	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2024	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2025	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2026	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2027	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2028	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2029									
2030	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2031									
2032	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2033	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
30 Yr PVRR ($000)	17,047,026	17,069,188	16,960,982	16,948,057	16,936,923	17,110,027	17,128,324	17,024,245	17,597,924
Cost Delta	110,104	132,266	24,059	11,134	-	173,104	191,401	87,323	661,002
Plan Rank (Low to High)	5	6	3	2	1	7	8	4	9
Capital Cost PVRR	1,508,424	1,482,598	1,452,300	1,408,798	1,452,300	1,532,518	1,505,119	1,476,395	930,439
Variable Cost PVRR	14,349,706	14,394,947	14,339,675	14,375,539	14,315,616	14,375,481	14,419,306	14,365,713	15,483,386
Fixed Cost PVRR	1,188,897	1,191,644	1,169,007	1,163,720	1,169,007	1,202,028	1,203,899	1,182,138	1,184,099
Total PVRR	17,047,026	17,069,188	16,960,982	16,948,057	16,936,923	17,110,027	17,128,324	17,024,245	17,597,924
Capital Ranking	8	6	3	2	3	9	7	5	1
Variable Cost Ranking	3	7	2	6	1	5	8	4	9
Fixed Cost Ranking	6	7	2	1	3	8	9	4	5

Summary of All Plans (Excluding Transmission) - TC2 CCN Evaluation
+5% Load Sensitivity

Case/ Exp Plan:	Case 1	Case 2	TC2 and Marketer F Case 3	TC2 and Marketer F Case 4	TC2 and Marketer F Case 5	Marketer E Case 6	Marketer E Case 7	Marketers E and F Case 8	Case 9
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010	1-TC2	2-148G	F & 1-TC2	F	1-TC2	1-PbyO	2-148G	E & F	2-148G
2011		1-TC2		1-TC2			E		1-148G
2012									1-148G
2013	2-148G				F	2-148G			1-148G
2014	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2015	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2016	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2017	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2018	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2019	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2020	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2021	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2022	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2023	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2024	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2025	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2026	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2027	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2028	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2029									
2030	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2031									
2032	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2033	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
30 Yr PVRR ($000)	17,638,721	17,654,046	17,566,840	17,552,098	17,542,914	17,710,514	17,722,801	17,627,598	18,213,241
Cost Delta	95,807	111,132	23,926	9,184	-	167,600	179,887	84,684	670,327
Plan Rank (Low to High)	5	6	3	2	1	7	8	4	9
Capital Cost PVRR	1,508,424	1,482,598	1,452,300	1,408,798	1,452,300	1,532,518	1,505,119	1,476,395	930,439
Variable Cost PVRR	14,953,538	14,991,943	14,945,533	14,979,580	14,921,607	14,975,968	15,013,783	14,969,065	16,098,703
Fixed Cost PVRR	1,176,759	1,179,506	1,169,007	1,163,720	1,169,007	1,202,028	1,203,899	1,182,138	1,184,099
Total PVRR	17,638,721	17,654,046	17,566,840	17,552,098	17,542,914	17,710,514	17,722,801	17,627,598	18,213,241
Capital Ranking	8	6	3	2	3	9	7	5	1
Variable Cost Ranking	3	7	2	6	1	5	8	4	9
Fixed Cost Ranking	4	5	2	1	3	8	9	6	7

Summary of All Plans (Excluding Transmission) - TC2 CCN Evaluation
High Generation Sensitivity

Case/ Exp Plan:	Case 1	Case 2	TC2 and Marketer F Case 3	TC2 and Marketer F Case 4	TC2 and Marketer F Case 5	Marketer E Case 6	Marketer E Case 7	Marketers E and F Case 8	Case 9
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010	1-TC2	2-148G	F & 1-TC2	F	1-TC2	1-PbyO	2-148G	E & F	2-148G
2011		1-TC2		1-TC2			E		1-148G
2012									1-148G
2013	2-148G				F	2-148G			1-148G
2014	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2015	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2016	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2017	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2018	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2019	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2020	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2021	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
2022	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	2-148G	1-148G
2023	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	2-148G
2024	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2025	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2026	2-148G	2-148G	1-148G	1-148G	1-148G	2-148G	2-148G	1-148G	1-148G
2027	1-148G	1-148G	2-148G	2-148G	2-148G	1-148G	1-148G	2-148G	2-148G
2028	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2029									
2030	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2031									
2032	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2	1-CC#2
2033	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G	1-148G
30 Yr PVRR ($000)	15,866,661	15,900,199	15,749,192	15,754,520	15,740,710	15,924,041	15,954,885	15,805,322	16,491,472
Cost Delta	125,951	159,489	8,482	13,810	-	183,331	214,175	64,612	750,762
Plan Rank (Low to High)	5	6	2	3	1	7	8	4	9
Capital Cost PVRR	1,508,424	1,482,598	1,452,300	1,408,798	1,452,300	1,532,518	1,505,119	1,476,395	930,439
Variable Cost PVRR	13,169,340	13,225,957	13,127,885	13,182,002	13,119,403	13,189,495	13,245,867	13,146,790	14,376,934
Fixed Cost PVRR	1,188,897	1,191,644	1,169,007	1,163,720	1,169,007	1,202,028	1,203,899	1,182,138	1,184,099
Total PVRR	15,866,661	15,900,199	15,749,192	15,754,520	15,740,710	15,924,041	15,954,885	15,805,322	16,491,472
Capital Ranking	8	6	3	2	3	9	7	5	1
Variable Cost Ranking	4	7	2	5	1	6	8	3	9
Fixed Cost Ranking	6	7	2	1	3	8	9	4	5