SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

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PUBLIC SERVICE COMMISSION

November 29, 2005

Ms. Elizabeth O'Donnell
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Big Rivers Electric Corporation 2005 Integrated Resource Plan

Dear Ms. O'Donnell:

Case No. 2005-00485

Enclosed in connection with the 2005 Integrated Resource Plan of Big Rivers Electric Corporation are the following:

1. Petition of Big Rivers Electric Corporation for confidential treatment of portions of its 2005 Integrated Resource Plan;

2. One sealed and bound copy of the Integrated Resource Plan with the confidential material highlighted;

3. Ten copies of the Integrated Resource Plan with the confidential material redacted; and

4. One additional, unbound copy of the Integrated Resource Plan with the confidential material redacted.

Big Rivers' 2005 Integrated Resource Plan has been prepared to comply with the Commission's regulations and to serve as a guide for Big Rivers in planning its resources to meet its future system demands. We would point out that, as with Big Rivers' 2002 Integrated Resource Plan, the 2005 Big Rivers' Integrated Resource Plan is atypical of other integrated resource plans the Commission will review because Big Rivers no longer operates or controls its generating units.

I certify that a copy of the items listed in this letter, and attachments, have been served on each of the parties to the 2002 Big Rivers' Integrated Resource Plan proceeding, as shown on the attached service list. If you have any questions regarding this filing,

Telephone (270) 926-4000
Telecopier (270) 683-6694

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

please do not hesitate to contact David A. Spainhoward, Vice-President, Contract Administration and Regulatory Affairs at Big Rivers, or me.

Sincerely yours,

Tyson Kamuf

TAK/ej
Enclosures

cc; w/o enclosures: Michael H. Core
C. William Blackburn
David Spainhoward

cc; w/enclosures: Service List
Mark Bailey
Burns Mercer
Kelly Nuckols

RECEIVED
NOV 3 0 2005
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF) CASE NO. 2005-00485
BIG RIVERS ELECTRIC CORPORATION)

PETITION OF BIG RIVERS ELECTRIC CORPORATION FOR CONFIDENTIAL TREATMENT OF CERTAIN PORTIONS OF ITS 2005 INTEGRATED RESOURCE PLAN

Big Rivers Electric Corporation ("Big Rivers"), pursuant to 807 KAR 5:001(7), respectfully petitions the Kentucky Public Service Commission ("Commission") to classify and protect as confidential certain information contained in its 2005 Integrated Resource Plan ("IRP") filed with this petition on November 30, 2005. The IRP is filed pursuant to 807 KAR 5:058 to provide the Commission with information including Big Rivers' historical and projected demand, resource, and financial data, and other operating performance and system information, in addition to the facts, assumptions, and conclusions on which the plan is based and the actions that the plan proposes. 807 KAR 5:058 Section 1(2). In support of this petition, Big Rivers states as follows:

1. One (1) sealed copy of the IRP containing the confidential information, with that information highlighted, and ten (10) copies of the IRP with the confidential information redacted are filed with this petition. 807 KAR 5:001 Section 7(2)(a)(2) and 5:001 Section 7(2)(b). One (1) additional, unbound copy of the IRP, with the confidential information redacted, is also filed with this petition to assure compliance with the requirements of 807 KAR 5:058 Section 1(3).

2. As grounds for confidentiality pursuant to 807 KAR 5:001 Section 7(2)(a)(1), Big Rivers states that the information for which confidential treatment is requested is within the

category of commercial information "generally recognized as confidential or proprietary, which if openly disclosed would permit an unfair commercial advantage to the competitors of the entity that disclosed the records." KRS 61.878(1)(c)(1). The information that 807 KAR 5:058 requires the IRP to contain includes highly sensitive information on matters including strategic planning, finance, resources and operations. The public disclosure of such information would, in the current and changing electric utility industry, give an unfair advantage to the competitors of Big Rivers, and would adversely impact Big Rivers.

3. Public disclosure of the information designated as confidential by Big Rivers would also provide Big Rivers' competitors with an unfair advantage by injuring the ability of Big Rivers to buy power at the most competitive prices, and by disclosing proprietary information on the operations of Big Rivers. The information designated as confidential generally comes within the following two categories:

(i) Cost Summaries and Revenue Requirements. To maintain a competitive posture in wholesale power market and continued successful arbitrage efforts, Big Rivers' revenue requirements must be confidential. This information is not public. By letter dated May 5, 2005, the Commission granted confidential treatment to material in Big Rivers' Updated Financial Model filed by Big Rivers on April 29, 2005.

(ii) Power Supply Cost from LEM. Big Rivers acknowledges that the cost of the power that Big Rivers purchases from LEM has been disclosed in other forms, however, Big Rivers submits that the disclosure of such information as contained and presented in the IRP could adversely impact Big Rivers. The IRP is subject to request by marketers and competitors who could, if this information were made public in the IRP, access this information to the detriment of Big Rivers. This information is contained in various places in the IRP and IRP appendices.

4. The treatment of the information as confidential should not hinder the Commission or the parties in the presentation and consideration of this matter.

5. If and to the extent that any of the confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will notify the Commission and have its confidential status removed. 807 KAR 5:001 Section 7(9)(a).

6. The information for which Big Rivers seeks confidential treatment in this petition is substantially the same type of information that the Commission granted confidential treatment in connection with Big Rivers' 2002 IRP. *See* letter dated May 20, 2003, from Executive Director Thomas M. Dorman to James M. Miller in Case No. 2002-00428.

WHEREFORE, Big Rivers respectfully requests the Commission to classify and protect as confidential the information filed with this petition.

SULLIVAN, MOUNTJOY, STAINBACK
& MILLER, P.S.C.

James M. Miller
Tyson Kamuf
100 St. Ann Street, P. O. Box 727
Owensboro, Kentucky 42302-0727
(270) 926-4000
Counsel for Big Rivers Electric Corporation

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to 807 KAR 5:001 Section 7(2)(c), I have served a copy of this petition and a redacted copy of the IRP by regular mail, postage prepaid, to the following persons on this 29th day of November, 2005:

Elizabeth Blackford, Esq.
Assistant Attorney General
1024 Capital Center Drive
Suite 200
Frankfort, KY 40601

Office of the Attorney General of
the Commonwealth of Kentucky

John Stapleton
Director of Energy
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Hon. Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Counsel for Natural Resources and
Environmental Protection

Tyson Kamuf

Case No. 2005-00485

2005 Integrated Resource Plan

Big Rivers Electric Corporation

Henderson, Kentucky

November 2005

REDACTED
REPORT

GDS Associates, Inc.

Table of Contents

1. General Provisions

1.1. Jurisdiction

Big Rivers Electric Corporation falls under commission jurisdiction in the Commonwealth of Kentucky; therefore, the company files an Integrated Resource Plan triennially with the KPSC in accordance with 807 KAR 5:058.

1.2. Report Content

The plan presents historical and projected demand, resource, and financial data, and other operating performance and system information. In addition, the plan presents the facts, assumptions, and conclusions upon which the plan is based and the resulting actions proposed. Supporting documents include the "*2005 Load Forecast*", presented as Appendix A, and the "*The Maximum Achievable Cost Effective Potential for Electric Energy Efficiency in the Service Territory of the Big Rivers Electric Corporation*", presented as Appendix B, and which throughout the contents of this report, will be referenced as the "DSM" study.

1.3. Number of Plan Copies Filed

Ten (10) bound copies of the IRP report, plus one (1) unbound copy of the plan were filed with the KPSC on November 30, 2005, in accordance with 807 KAR 5:058 § 1(3).

1.4. Issues Raised in the Staff Report on Big River's 2002 IRP

In its report titled *Staff Report on the Integrated Resource Plan Report of Big Rivers Electric Corporation, Case No. 2002-00428, March 2004*, the KPSC staff made recommendations in four areas with respect to Big Rivers 2002 IRP, including load forecasting, demand-side planning, supply-side planning, and integration and plan optimization. Each of these recommendations has been addressed and is summarized as follows.

1.4.1. Load Forecast Issues

1.4.1.1. Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Big Rivers' 2002 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands

This report includes a comparison of actual and projected peak demands, by season, for years 2003-2004. Refer to Section 5.3.3 of this report.

1.4.1.2. Provide a comparison of the annual forecast of energy sales with actual results for the period following Big Rivers' 2002 IRP. Include a discussion of the reasons for the differences between forecasted and actual results

This report includes a comparison of actual and projected energy requirements for years 2003-2004. Refer to Section 5.3.3 of this report.

1.4.1.3. Big Rivers should, to the extent possible, report on and reflect in its forecasts the impacts of increasing wholesale and retail competition in the electric industry

Industry restructuring is addressed in Big Rivers' 2005 load forecast. At the time the forecast was prepared, the Commonwealth of Kentucky had not passed legislation implementing customer choice. One of the forecast assumptions was that the Commonwealth of Kentucky was not expected to deregulate within the foreseeable future; therefore, the load forecast did not include any impacts associated with customer choice or any other deregulation issues

With respect to wholesale competition, each of Big Rivers' members currently purchases wholesale power from Big Rivers under a full requirements contract, which does not expire until January 1, 2023. Those contracts allow the member cooperatives to purchase power only from Big Rivers, with one exception. That exception is with Kenergy, who can purchase power for two large industrial customers from any wholesale provider. Big Rivers' future load could increase or decrease depending upon Big Rivers' ability to compete in the wholesale market. However, considering its current contract with LEM, Big Rivers expects to be an extremely competitive wholesale provider in the market. The current load forecast does not include any impacts directly associated with wholesale competition. Big Rivers will continue to evaluate wholesale and retail competition in future load forecasts.

1.4.1.4. Big Rivers should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of environmental costs such as those associated with NOx reductions imposed on sources in the Eastern United States.

The NOx compliance effective date was May 31, 2004. In development of the 2005 load forecast, it was assumed that Big Rivers would not experience any reductions or increases in load from existing industrial or potential new industrial customers due to environmental factors. It is assumed that environmental regulations could potentially impact power costs and retail prices, which could impact energy consumption; however, such impacts have not been experienced over the last three years as Big Rivers spent approximately $30 million to reduce NOx emissions without impacting wholesale rates. In development of the 2005 Load Forecast, it was assumed that associated impacts would be insignificant, and projections included in the forecast do not include any environmental impacts.

1.4.2. Demand-Side Planning Issues

1.4.2.1. Staff agrees with the AG and KDOE in their arguments for proceeding with a net metering program before the LG&E and KU pilots are complete. Big Rivers stated in its response to a data request that it planned to conduct a study, which would include net metering. The study was expected to be available by the fall of 2003. Staff looks forward to receiving the Big Rivers study, hopefully in the near future.

Since the filing of Big Rivers' 2002 IRP, the Kentucky General Assembly passed statewide net metering legislation (SB 247) and the Governor signed into law on April 22, 2004, requiring all investor-owned utilities and rural electric cooperatives to offer net metering to customers with PV systems of 15 kW or less. Effective March 1 2005, a net metering tariff is available to Big Rivers' Members retail consumers who generate electricity in parallel to the cooperatives network and generate energy using solar energy (PV). Refer to Section 5.7.4 of the IRP report.

1.4.2.2. Big Rivers' future IRPs should evaluate DSM programs that provide increased efficiency for all customers, not just residential and commercial customers. Big Rivers should include an evaluation of programs related to improved manufacturing processes in its next IRP.

For this IRP filing, Big Rivers has conducted a thorough analysis of the maximum achievable cost effective potential for energy efficiency in all three major customer classes: residential, commercial, and industrial. For the industrial class, electric energy savings potential was evaluated for various energy efficiency measures. Refer to the report in Appendix B titled "*The Maximum Achievable Cost Effective Potential for Electric Energy Efficiency in the Service Territory of the Big Rivers Electric Corporation*".

1.4.2.3. Big Rivers had indicated that it would make a filing with the Commission by the end of 2003 for approval to include a Green Power project in its renewable energy portfolio. To date, such a filing has not been received. Big Rivers should communicate with Staff on the status of this filing and indicate whether it expects to make such a filing sometime in 2004. Staff looks forward to receiving Big Rivers' communication and reviewing its Green Power filing, hopefully in the near future.

Ongoing discussions between Big Rivers and Weyerhaeuser Company, an international forest products firm, have culminated in an agreement where Big Rivers will purchase from Weyerhaeuser over the course of one year 1MW per hour of power generated from a facility fueled by waste by-products and gases. An agreement with Weyerhaeuser for the purchase of renewable power was signed on November 1, 2005. A green power tariff will be developed and filed with the Commission before year end 2005. Refer to Section 5.1.3.1 of this report.

1.4.2.4. Big Rivers had indicated that it expected to have completed the design of its high efficiency heating incentive program in mid 2003 and that it would seek Commission approval after its Board of Directors approved the program. Staff recommends that Big Rivers inform Staff of the status of this program and explain whether it anticipates filing for such approval in 2004.

Big Rivers continues to evaluate and implement programs that positively impact the efficient use of energy while providing benefits to consumers. Since the 2002 IRP, Big Rivers has implemented three incentive programs: "Touchstone Energy Home", "Dual Fuel/Add-on Heat Pump" and "Electric for Gas Water Heating". Each of these programs was approved by the Big Rivers Board of Directors; however, Big Rivers did not prepare a filing of the programs for the Kentucky PSC. Refer to Section 5.7.1 of this report.

1.4.3. Supply-Side Resource Issues

1.4.3.1. Staff believes that Big Rivers should continue to consider alternatives such as the potential investment at the Weyerhaeuser facility which was an issue in this proceeding. Therefore, Staff will repeat its recommendation that Big Rivers file, in its next IRP if not sooner, its cost estimate and feasibility study regarding a possible capital investment in the Weyerhaeuser facility.

Big Rivers has continued to consider potential investment at the Weyerhaeuser facility. Discussions between Big Rivers and Weyerhaeuser management have been ongoing and have focused on the potential of Big Rivers securing and additional 20-30 MW of renewable power through Big Rivers' investment at the facility. The next meeting between the two parties is expected to be scheduled before the end of 2005. Refer to Section 5.2.1.1 of this report.

1.4.4. Integration and Plan Optimization

1.4.4.1. Given that Big Rivers did not undertake a traditional integration and optimization process in its IRP, Staff has no recommendations on Big Rivers' integration process. However, it is important for future IRPs, particularly if circumstances change to the point that Big Rivers forecasts a need for additional resources, that the process be robust and that it give equal weight to demand-side and supply-side resources.

Big Rivers agrees that the integration and optimization process in integrated resource planning should be robust and give equal weight to demand-side and supply-side resources, as evidenced by the information presented in association with this IRP filing.

1.5. Administrative Case No. 387

In Administrative Case No. 387, the Kentucky Public Service Commission ordered that the following information be addressed in utility IRPs:

1.5.1. Opportunities for joint ownership when planning new generation

Big Rivers currently purchases, and plans to purchase, all of its power requirements beyond the term of this current IRP; therefore, Big Rivers management has not initiated any new generation plans, nor has the Cooperative investigated opportunities for joint ownership in a generation resource.

1.5.2. An assessment of the availability of shared maintenance schedules

Since Big Rivers does not currently operate or maintain any generation facilities, an assessment of the availability of shared maintenance does not apply.

1.5.3. A description of capacity additions and reserve margins

Refer to section 5.4 of this report, Resource Acquisitions and System Improvements.

1.5.4. Consideration of the purchase of merchant power and consideration of TVA wholesale customers

Big Rivers' will be able to meet all projected energy and demand requirements (including the high range forecast) through 2019 and beyond through its existing power supply contracts. As a result, Big Rivers has not considered the purchase of merchant power during the course of the 2005 IRP. Big Rivers has no plans to provide power to TVA wholesale customers.

1.6. Administrative Case No. 2005-00090

In Administrative Case No. 2005-00090, the Kentucky Public Service Commission ordered that Big Rivers, which no longer operates its generation, provide a summary overview of scheduled and unscheduled outages for all of the generation operated by Western Kentucky Energy (WKE) for the three most recent calendar years, along with a summary of all environmental equipment that has been installed on each unit. Refer to Appendix G of this report.

2. Filing Schedule

Big Rivers plans to provide copies of the 2005 IRP to those parties intervening in the 2005 IRP. Big Rivers understands that the commission will establish a schedule for reviewing the IRP.

3. Waiver

Big Rivers has not filed any motion requesting a waiver of specific provisions of the IRP administrative regulation.

4. Report Format

4.1. Organization of Report

In efforts to present the plan in a clear and concise manner, the structure of Big Rivers' IRP report is based on the specific items identified in 807 KAR 5:058.[1]

4.2. Project Team

The 2005 Integrated Resource Plan was prepared for Big Rivers Electric Corporation ("Big Rivers") by GDS Associates, Inc. ("GDS"). The study was completed in October 2005, approved by Big Rivers' Board of Directors in October 2005, and filed with the KPSC on or before November 30, 2005. A number of people from Big Rivers, Meade County Rural Electric Cooperative Corporation, Kenergy Corp., Jackson Purchase Energy Corporation, and GDS Associates contributed considerable time and effort during the course of the study. These individuals, and their area of expertise, are presented as follows:

Name	Company	Area of Expertise
Bill Yeary	Big Rivers Electric Corporation	Project Management
Bill Blackburn		
Mike Core, President		Review
Richard Beck		Marketing
Travis Housley		System Operations
James Haner		Finance
David Spainhoward		Regulatory Affairs
Burns Mercer, President	Meade County Rural Electric Cooperative Corporation	Review
Kelly Nuckols, President	Jackson Purchase Energy Corporation	Review
Mark Bailey	Kenergy Corp.	Review
Brian Smith	GDS Associates, Inc.	Power Supply and Resource Planning
Jacob Thomas		
Dick Spellman		Demand Side

[1] http://www.lrc.state.ky.us/kar/807/005/058.htm.

Amber Roberts		Planning
John Hutts		Load Forecasting

The following individuals are available to respond to inquiries during the commission's review of the plan.

Name	Company	Phone
Bill Yeary,	Big Rivers Electric Corp	270-827-2561
Bill Blackburn		
Mike Core, President		
Richard Beck		
Travis Housley		
James Haner		
David Spainhoward		
John Hutts	GDS Associates, Inc.	770-425-8100
Dick Spellman		
Brian Smith		

5. Plan Summary

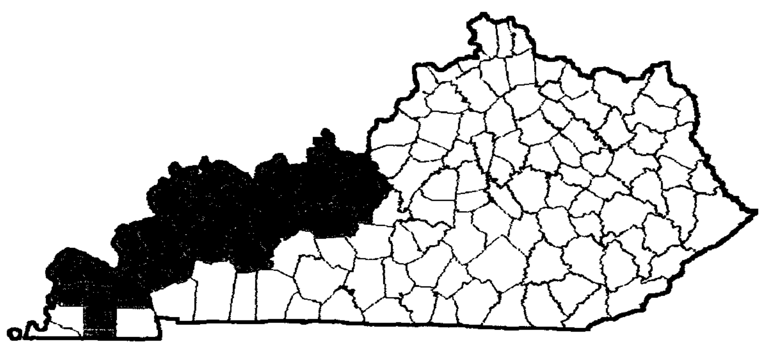
5.1. Utility Description, Current Facilities, and Plan Results

5.1.1. Utility Description

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky, and provides wholesale power to three member cooperatives: Kenergy Corp. (Kenergy), Jackson Purchase Energy Corporation (JPEC), and Meade County Rural Electric Cooperative Corporation (MCRECC), all of which provide retail electric service to consumers located in western Kentucky. With the exception of two aluminum smelters, Alcan Aluminum and Century Aluminum, which are served by Kenergy, Big Rivers provides all of the power requirements of its three member cooperatives. Big Rivers' wholesale rate, approved by the KPSC, is presented in its tariff, PSC KY No. 22, Big Rivers Electric Corporation of Henderson, Kentucky Rates, Rules and Regulations for Furnishing Electric Service. Approximately 90% of the accounts served by the member cooperatives are residential.

Big Rivers' member cooperatives provide electric service in 22 counties located in western Kentucky, which are presented in Figure 5.1.

Figure 5.1
Service Area Counties



The topography of Big Rivers' member cooperatives' service areas ranges from rolling, sandy embayment areas to flat plateau areas with low relief and subterranean drainage. Typical elevations range from approximately 340 to 1000 feet above sea level. The climate in the area is humid, temperate and continental.

Big Rivers' annual peak demand for 2004, 604 MW, occurred on July 13, 2004, at hour ending 6 p.m. The winter peak, 562 MW, occurred on December 22, 2004, at hour ending 7 p.m. Figures 5.2 and 5.3 on the following page present the annual load characteristics for year 2004.

Figure 5.2
Annual Load Shape - 2004

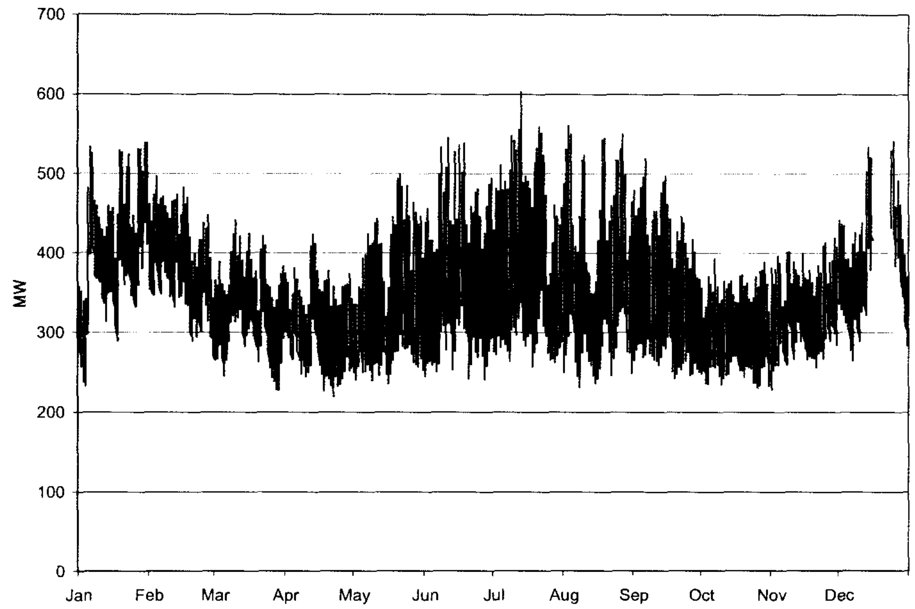
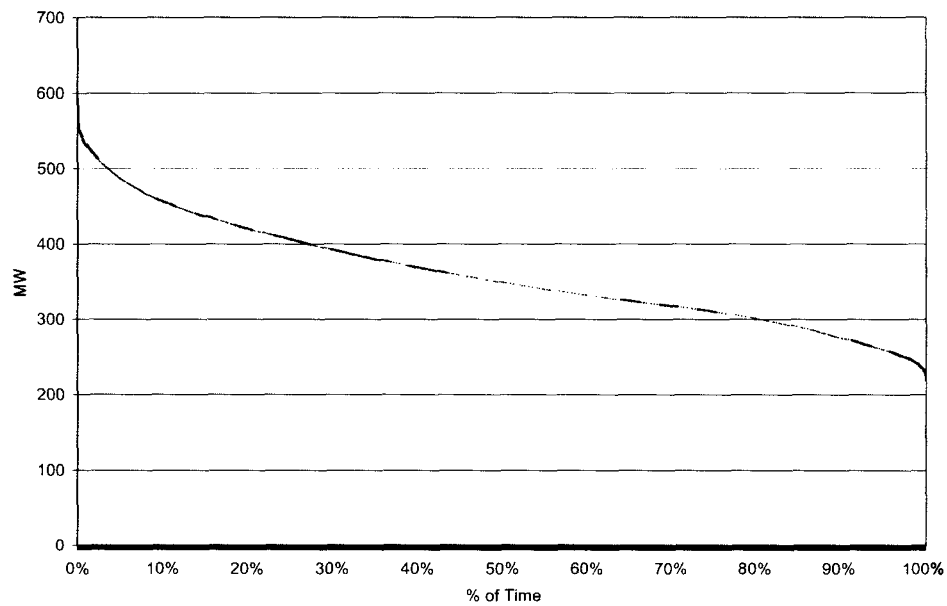


Figure 5.3
Annual Load Duration Curve – 2004



5.1.2. Current Facilities

Big Rivers currently owns but does not operate any generation facilities. On July 15, 1998, Big Rivers entered into a 25-year lease arrangement with LG&E Energy Corp (now LG&E Energy LLC) and four of its wholly owned subsidiaries: Western Kentucky Energy Corp. ("WKEC"), WKE Station Two, Inc. ("Station Two Subsidiary"), WKE Corp., and LG&E Energy Marketing, Inc. ("LEM"), the "LG&E Parties".

Big Rivers owns the 455 MW three unit coal-fired Coleman Plant, the 454 MW two unit coal-fired Green Plant, the Reid Plant, which consists of a 65 MW coal and natural gas-fired unit as well as a 65 MW natural gas or oil-fired combustion turbine, and the 420 MW coal-fired Wilson unit. Big Rivers also has contractual rights to a portion of 312 MW at Henderson Municipal Power and Light's ("HMP&L's") Station Two facility.

WKEC currently leases Big Rivers' generating facilities, and Station Two Subsidiary has become the assignee of Big Rivers' Station Two contractual rights and obligations. WKEC, as lessee of Big Rivers' facilities, and Station Two Subsidiary, as the assignee of Big Rivers' rights and obligations to the output of Station Two not allocated to the City of Henderson, will own the output of the generating facilities. Each of WKEC and Station Two Subsidiary sells its respective output entitlement to LEM.

LEM is obligated to sell to Big Rivers, (1) "Base Power," which is a quantity of power specified by contract and subject to certain limitation, and (2) certain generation-based ancillary services. In addition to power received from LEM, Big Rivers' member cooperatives can receive power under the contract with Southeastern Power Administration (SEPA). LEM acts as Big Rivers' agent for scheduling power under the SEPA contract, but Big Rivers receives the power to its maximum benefit on a monthly basis. Big Rivers' current SEPA contract terminates at the end of 2016. For purposes of analyses presented in this report, however, it was assumed that the contract will be extended.

The power supply arrangement with LEM is documented in four agreements: (1) Power Purchase Agreement between Big Rivers and LG&E Parties; (2) Lease and Operating Agreement between Big Rivers and the LG&E Parties; (3) Transmission Services and Interconnection Agreement between Big Rivers and LG&E Parties; and (4) Agreement and Amendments to Agreements by and among City of Henderson, Kentucky, et. al. Big Rivers, and LG&E Parties.

To serve its member requirements, Big Rivers' purchases power from LEM under a Power Purchase Agreement ("PPA") that runs through 2023. Base Power purchases from LEM are priced on an annually variable basis; no demand payments are associated with the purchases.

Purchases from LEM are financially firm in that Big Rivers has the contractual right to invoice LEM for damages arising from LEM's failure to deliver. Damages are defined in the PPA as reasonably incurred replacement power costs. Delivery points for LEM power are Big Rivers' generating facilities and points of interchange between Big Rivers and the Tennessee Valley Authority, Southern Illinois Power Cooperative, Louisville Gas and Electric Company, Kentucky Utilities Company, and Southern Indiana Gas and Electric Company, and Hoosier Energy Rural Electric Cooperative.

Big Rivers also purchases 190 MW of dependable capacity from SEPA. Of this 190 MW, 12 MW is delivered to the City of Henderson, Kentucky. The remaining 178 MW is used to serve Big Rivers' native load.

Big Rivers has contracted with Weyerhaeuser for the purchase of 1 MW per hour of power generated from a local facility fueled by waste by-products and gases. An agreement with Weyerhaeuser for the purchase of renewable power was signed on November 1, 2005.

5.1.3. IRP Plan Results

As shown below in Table 5.1, Big Rivers will be able to meet all of its demand and energy requirements through 2020 through the SEPA and LEM contracts. In year 2010, the high range forecast reaches 729 MW, which is only 46 MW below total capacity; however, the increase in the LEM contract beginning in 2011 keeps Big Rivers in a surplus mode throughout year 2019. In addition to its existing contracts, Big Rivers also has access to the wholesale power markets to buy and sell power as needed subject to market availability.

Table 5.1
Load Forecast, Capacity, Peak Demand, and Energy Requirements

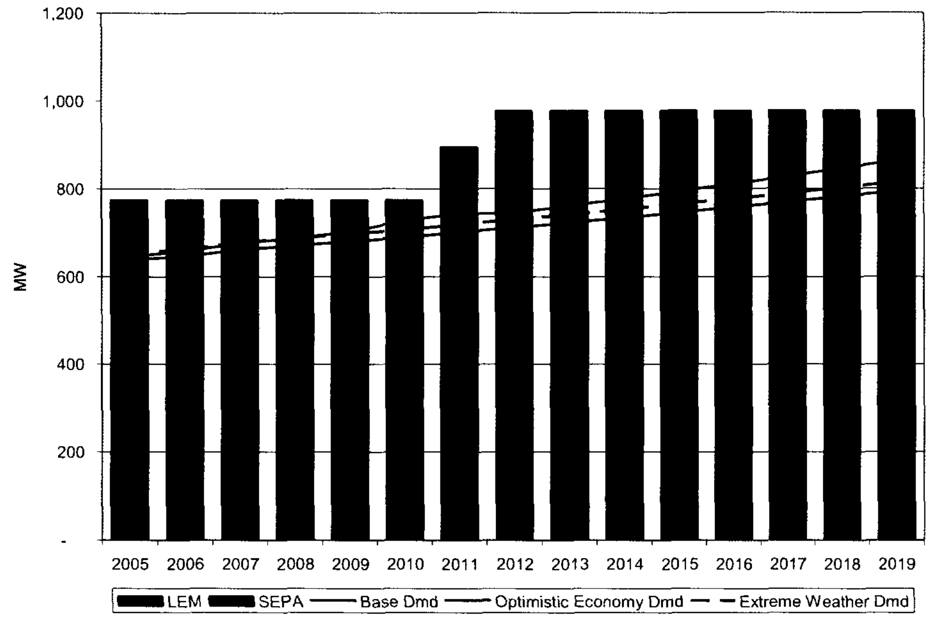
Year	System Peak Demand (MW)[2]	Total Energy Requirements for Generation Service (MWh)[3]	LEM Contract Maximum Capacity (MW)	LEM Contract Maximum Energy (MWh)	SEPA Contract Maximum Capacity (MW)	SEPA Contract Maximum Energy (MWh)	Total Capacity (MW)	Capacity Surplus (MW)
2005	634	3,306,259	597	5,327,285	178	267,000	775	141
2006	641	3,378,253	597	5,327,285	178	267,000	775	134
2007	657	3,431,620	597	5,327,285	178	267,000	775	118
2008	666	3,473,882	597	5,327,285	178	267,000	775	109
2009	675	3,519,951	597	5,327,285	178	267,000	775	100
2010	685	3,564,196	597	5,327,285	178	267,000	775	90
2011	696	3,616,207	717	6,321,741	178	267,000	895	199
2012	706	3,664,368	800	7,008,000	178	267,000	978	272
2013	718	3,717,197	800	7,008,000	178	267,000	978	260
2014	728	3,767,931	800	7,008,000	178	267,000	978	250
2015	741	3,825,636	800	7,008,000	178	267,000	978	237
2016	752	3,878,697	800	7,008,000	178	267,000	978	226
2017	764	3,936,470	800	7,008,000	178	267,000	978	214
2018	776	3,991,983	800	7,008,000	178	267,000	978	202
2019	789	4,054,080	800	7,008,000	178	267,000	978	189

Figure 5.4 on page 12 compares Big Rivers' demand forecast, under three scenarios, to capacity purchased from LEM and SEPA. The graph illustrates that Big Rivers does not have an incremental need for power during the 2005 through 2019 period under (1) Base Case, (2) Optimistic Economy, and (3) Extreme

[2] System peak demand represents the sum of rural system coincident peak demand plus all non-rural demand, net of smelters, plus transmission losses.
[3] Total energy requirements include transmission losses of 0.81 percent.

Weather forecasts. Big Rivers' purchases from SEPA and LEM are firm contracts, and the LEM contract includes liquidated damages for non-delivery (LD Firm); therefore, Big Rivers has no need for a planning reserve margin as is the case with generating utilities.

Figure 5.4
Capacity and Peak Demand Requirements



5.1.3.1. Non-Utility Generation

During 2001, an 85 MW generator was installed by Willamette Industries, since purchased by Weyerhaeuser Company, and a customer of Kenergy Corp. Due to operating restraints, Weyerhaeuser generated during 2001 at a 50 MW level. This effectively reduced Big Rivers' demand requirement obligations by 50 MW and energy requirement obligations by 438,000 MWh. The generation at Weyerhaeuser, plus the increases in the capacity from the LEM contract beginning in 2011, contributes to Big Rivers' position of capacity surplus throughout the next fifteen years. Big Rivers is evaluating the feasibility of making a capital investment at the Weyerhaeuser facility that will enable excess steam to be recycled and used for generation of up to an additional 20-30 MW of capacity. The next round of discussions between Big Rivers and Weyerhaeuser management to discuss related issues is expected to take place before the end of 2005.

Electricity generated at the Weyerhaeuser site is renewable energy, as the plant is fueled by waste by-products and gases. Big Rivers has recently reached agreement to contract with Weyerhaeuser for the purchase of 1 MW per hour over the course of one year. An agreement for the purchase of renewable power was signed on November 1, 2005. Outside of any potential arrangements made with Weyerhaeuser, Big Rivers currently has no formal plans for the addition of new power generation resources or new power supply contracts.

5.1.3.2. Voluntary Load Curtailment Rider

Since the summer of 1999, Big Rivers has worked with its members and their larger industrial customers to reduce load during times of peak demand. This program has been well received by the members' customers and has been mutually beneficial to Big Rivers, the member cooperatives, and their retail customers through the sharing of cost savings. Big Rivers filed a Voluntary Curtailment Rider with the KPSC, which was approved on April 6, 2000. Table 5.2 below shows the actual results of voluntary curtailment periods. Load reduction ranged from 17 MW to a high of 28 MW, and voluntary curtailment involved 4 industrial customers of Big Rivers' members.

Table 5.2
1999-2005 Voluntary Industrial Curtailment Results

Year	Hour	Load Actual (MW)	Load Reduction (MW)	Load Resultant (MW)
1999	14 (2 p.m)	644	16	660
1999	15	645	22	667
1999	16	646	24	670
1999	17	644	27	671
1999	18	639	27	666
1999	19	629	22	651
2000	n/a	n/a	n/a	n/a
2001	n/a	n/a	n/a	n/a
2002	n/a	n/a	n/a	n/a
2003	n/a	n/a	n/a	n/a
2004	n/a	n/a	n/a	n/a
2005 ytd	n/a	n/a	n/a	n/a

Although no load curtailments under this tariff have occurred since 1999, Big Rivers continues to contact qualifying industrial customers regarding the voluntary rider and currently has the capability of curtailing 35 MW.

5.2. Description of models, methods, data, and key assumptions used to develop the results contained in the plan

5.2.1. Model Description

Although Big Rivers does not have a need for additional sources of power during the study period to meet native load requirements, costs of alternative sources of power were calculated and compared to costs contained in the PPA to demonstrate that Big Rivers' current power supply arrangements are economically favorable.

5.2.1.1. Supply-Side Evaluation Model

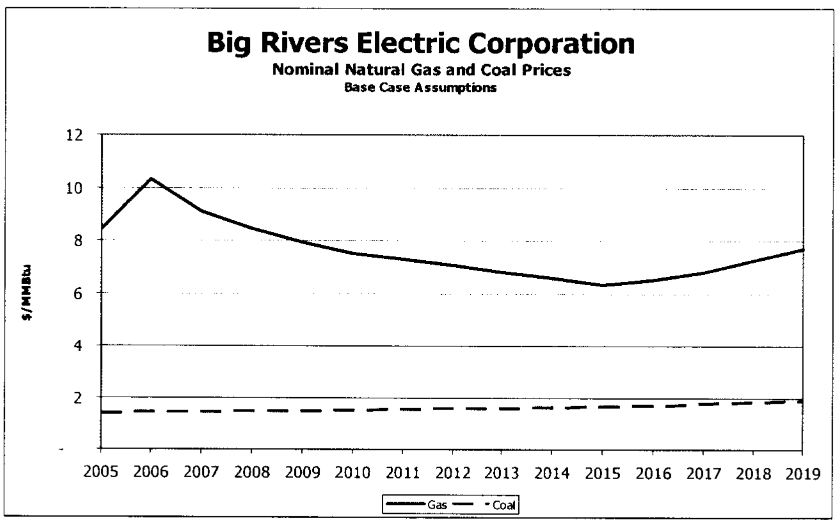
An Excel spreadsheet model was developed to compare costs of alternative power sources to costs associated with Big Rivers' contract with LEM. The model quantifies fixed and variable costs of power supply resources. Fixed costs include interest, depreciation, and fixed O&M expenses. Variable costs include fuel expenses and non-fuel variable operating expenses.

The evaluation model simulates the construction period of each resource and calculates the total installed cost including interest during construction. Service life interest expenses are based on an amortization schedule defined by total installed cost, service life, and Big Rivers' embedded cost of debt, 5.35%. Interest during construction is also calculated using that rate. Annual straight-line depreciation expense is calculated as the total installed cost divided by service life.

For the Base Case cost comparison, resource parameters were taken from the Energy Information Administration's ("EIA's") 2005 Annual Energy Outlook for all resource options. These parameters include length of construction period, overnight capital cost, non-fuel operating costs, heat rates and inflation. The parameters associated with each alternative are shown in Appendices C, D, and E, where there are individual pricing sheets for each alternative resource. Big Rivers' cost of capital and cost of debt are based on an internal analysis.

The Base Case coal price forecast was also taken from the EIA's Annual Energy Outlook. A nominal coal price forecast was developed using the EIA's constant year forecast for the East South Central energy demand region, and annual changes in the EIA's estimate of the Gross Domestic Product Index. A natural gas price forecast was developed using a similar process for years after 2014. For years 2006 through 2010, NYMEX Henry Hub gas futures prices published on September 12, 2005 were used. Values for 2011-2014 were calculated to smooth the transition between the 2010 futures price and the 2015 EIA price. Figure 5.5 below shows annual nominal costs for both coal and natural gas.

Figure 5.5
Nominal Natural Gas and Coal Prices



The evaluation of alternative resources was performed under Base Case assumptions and two sensitivity cases. Base Case annual fuel prices were reduced by 20% in the Reduced Fuel Price scenario; Base Case capital costs were reduced by 25% in the Reduced Capital Cost scenario.

The following alternatives were analyzed using the evaluation model.

1) Pulverized Coal
2) Coal Gasification
3) Conventional Combined Cycle Combustion Turbine
4) Advanced Combined Cycle Combustion Turbine
5) Conventional Simple Cycle Combustion Turbine
6) Advanced Simple Cycle Combustion Turbine
7) Fuel Cells
8) Distributed Generation – Base Load
9) Distributed Generation – Peak Load
10) Biomass
11) Landfill Gas
12) Geothermal
13) Wind
14) Solar Thermal
15) Photovoltaic
16) Hydroelectric

While it is unlikely that all of these alternatives would be available to Big Rivers due to geographical or other constraints, the comparison of alternative costs to LEM contract costs shows that, if available, each alternative would be more expensive than costs associated with the PPA. This finding holds true under all three scenarios: (1) Base Case fuel price and Capital Cost assumptions, (2) Reduced Fuel Prices, and (3) Reduced Capital Costs.

Because costs associated with many resources are site specific and could vary from generic estimates used in alternative resource cost comparisons, Big Rivers calculated the capital cost that would be required for an alternative power option to compare favorably with purchases from LEM. An installed cost of approximately [REDACTED] would be required, along with zero operating costs and a capacity factor of 50%, for an alternative to cost roughly the same as power purchased from LEM. This value is a target capital cost, primarily for renewable resource options that in some instances have near zero operating costs, that Big Rivers will use as a benchmark to evaluate new generating options.

Appendices D and E present similar graphical cost comparisons for the Reduced Fuel Price and Reduced Capital Cost scenarios. Appendices C, D and E show numerical information for each alternative under Base Case, Reduced Fuel Price, and Reduced Capital Cost scenarios, respectively.

Figures 5.6a, 5.6b, and 5.6c graphically compare annual costs of each alternative, under base case assumptions, to the annual costs associated with the PPA.

Figure 5.6a
LEM Costs vs. Total Costs of Power Supply Options

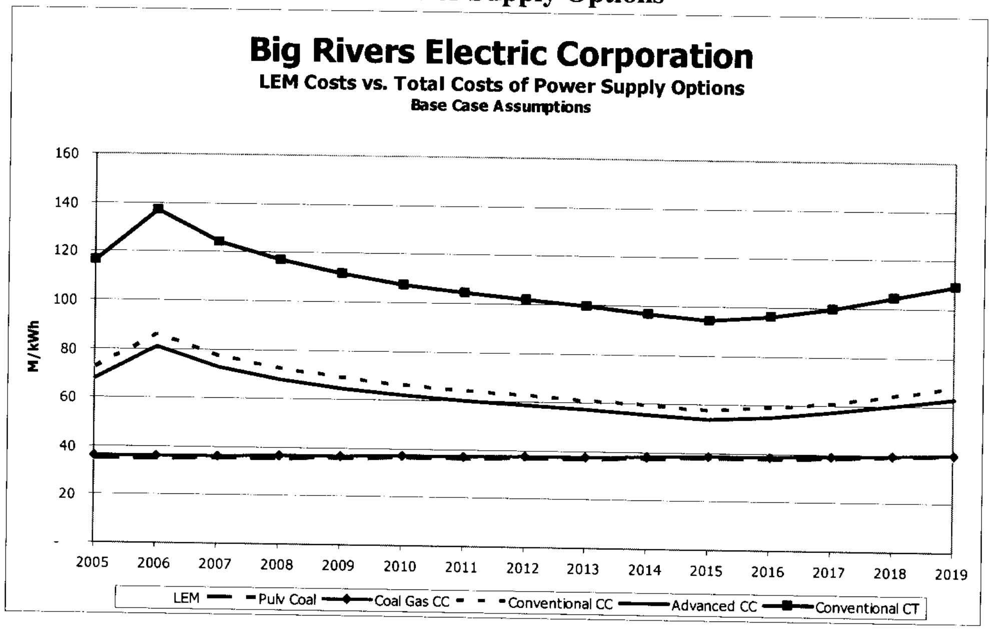


Figure 5.6b
LEM Costs vs. Total Costs of Power Supply Options

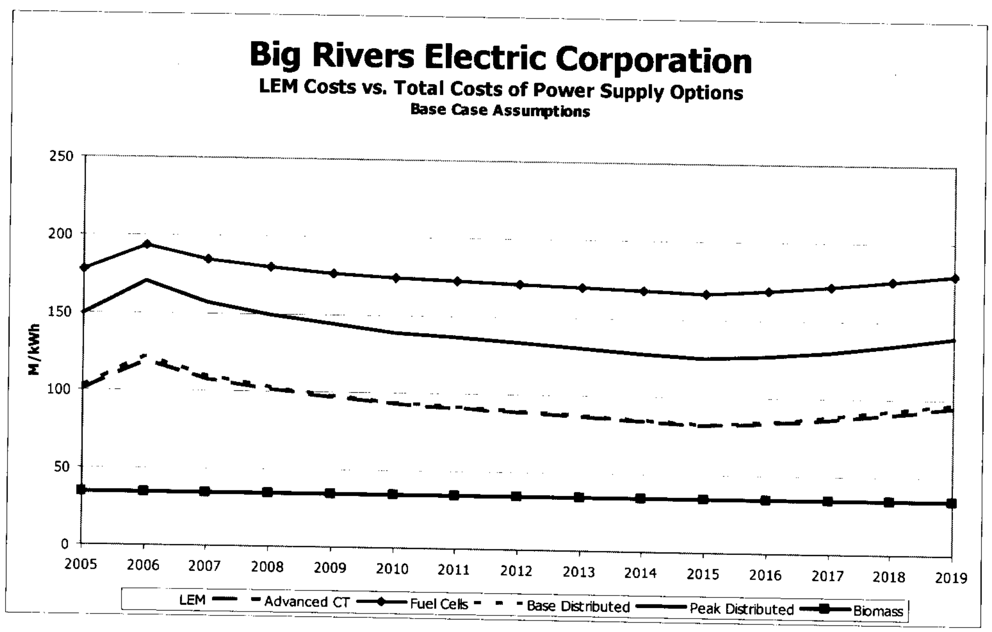
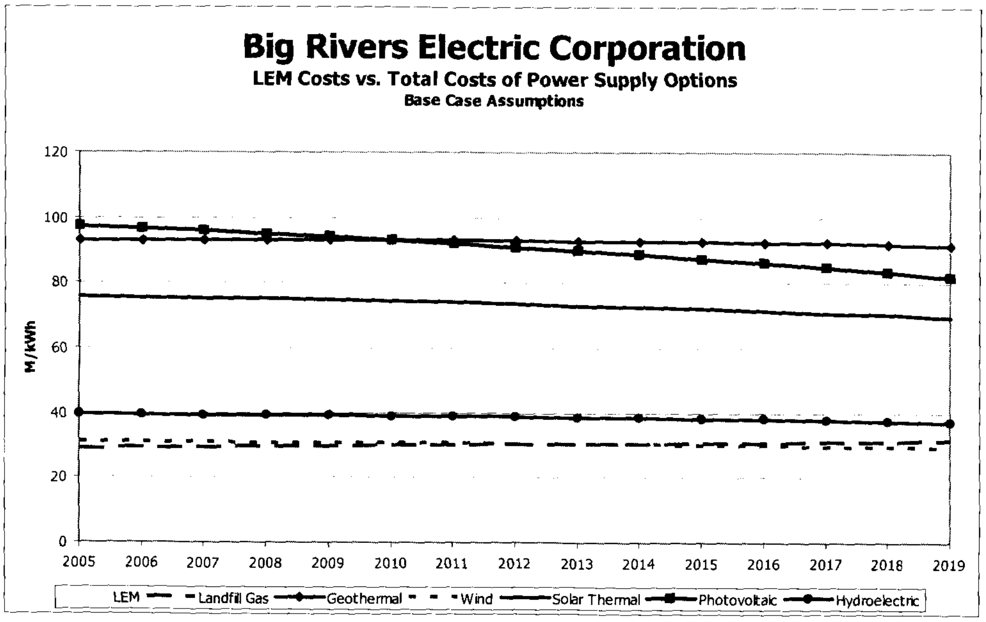


Figure 5.6c
LEM Costs vs. Total Costs of Power Supply Options



5.2.2. Data and Key Assumptions

Table 5.3 below presents the values assumed for the key variables included in the supply-side evaluation model.

Table 5.3
Key Inputs in Supply-Side Screening Model

Technology	Capital Cost	Regional Multiplier	Adjusted Capital Cost	Construction Period	Service Life
Pulverized Coal	1,213.00	1.004	1,217.85	4	30
Coal Gasification CC	1,402.00	1.004	1,407.61	4	30
Conventional CC	567.00	1.004	569.27	3	30
Advanced CC	558.00	1.004	560.23	3	30
Conventional CT	395.00	1.004	396.58	2	30
Advanced CT	374.00	1.004	375.50	2	30
Fuel Cess	4,250.00	1.004	4,267.00	3	30
Base Distributed	807.00	1.004	810.23	3	30
Peak Distributed	970.00	1.004	973.88	2	30
Biomass	1,757.00	1.004	1,764.03	4	30
Landfill Gas	1,500.00	1.004	1,506.00	3	30
Geothermal	3,108.00	1.004	3,120.43	4	30
Wind	1,134.00	1.004	1,138.54	3	30
Solar Thermal	2,960.00	1.004	2,971.84	3	30
Photovoltaic	4,467.00	1.004	4,484.87	2	30
Hydroelectric	1,451.00	1.004	1,456.80	4	30

Technology	Primary Fuel	Variable O&M mill/kWh	Fixed O&M $/kW	Capacity Factor	Heat Rate
Pulverized Coal	Coal	4.06	24.36	90.00%	8.844
Coal Gasification CC	Coal	2.58	34.21	90.00%	8.309
Conventional CC	Gas	1.83	11.04	80.00%	7.196
Advanced CC	Gas	1.77	10.35	80.00%	6.752
Conventional CT	Gas	3.16	10.72	25.00%	10.817
Advanced CT	Gas	2.80	9.31	25.00%	9.183
Fuel Cess	Gas	42.40	5.00	70.00%	7.930
Base Distributed	Gas	6.30	14.18	90.00%	9.950
Peak Distributed	Gas	6.30	14.18	25.00%	11.200
Biomass	None	2.96	47.18	80.00%	N/A
Landfill Gas	None	0.01	101.07	98.00%	N/A
Geothermal	None	0.00	104.98	50.00%	N/A
Wind	None	0.00	26.81	50.00%	N/A
Solar Thermal	None	0.00	50.23	50.00%	N/A
Photovoltaic	None	0.00	10.34	50.00%	N/A
Hydroelectric	None	4.60	12.35	50.00%	N/A

5.3. Load Forecast Summary

Big Rivers' 2005 Load Forecast was completed in July 2005 and updated the most recent forecast that was completed in July 2003. The forecast contains projections of energy and demand requirements for the 2005-2019 forecast horizon. High and low range forecast scenarios were developed to address uncertainties regarding the factors expected to influence energy consumption in the future. In addition to the energy and demand projections, the forecast presents the assumptions upon which the forecast was based and the methodologies employed in development of the forecast. The 2005 Load Forecast report is presented in the IRP as Appendix A.

5.3.1. Forecast Results

Total system energy and peak demand requirements are projected to increase at average compound rates of 1.6% and 1.5%, respectively, from 2004 through 2019[4]. Growth in energy sales is projected to be similar to the 1994-2004 period with the exception of the large commercial class, sales for which are projected to be level throughout the forecast period for existing consumers. Rural system energy and peak demand requirements, which are represented as total system requirements less those associated with direct-serve customers, are projected to increase at average rates of 2.2% and 2.1%, respectively, over the same period.

The primary influence on growth in system requirements over the forecast period will continue to be growth in rural system requirements, which is primarily a function of growth in number of customers and changes in small industrial activity. The forecast is summarized below in Tables 5.4 and 5.5.

[4] Based on weather normalized values for 2005 and 2019.

Table 5.4
Load Forecast Summary

		Total System		Rural System	
Year	Consumers	Energy Requirements (MWH)	Peak Demand (NCP)	Energy Requirements (MWH)	Peak Demand (NCP)
1994	87,256	7,721,677	1,189,000	1,571,482	352,635
1999	98,168	3,532,841	663,890	1,921,792	475,416
2004	106,414	3,158,698	604,155	2,133,190	476,409
2009	114,383	3,519,951	675,440	2,485,739	536,630
2014	123,516	3,767,931	728,343	2,737,034	589,533
2019	133,462	4,054,080	789,356	3,027,093	650,546

Table 5.5
Load Forecast – Average Annual Growth Rates

Description	2000-2005	2000-2015
Total Native System Energy Requirements	1.8%	1.6%
Total Native System Peak Demand (CP)	1.3%	1.5%
Rural System Energy Requirements	2.6%	2.2%
Rural System Peak Demand (CP)	2.4%	2.1%
Residential Energy Sales	2.1%	2.2%
Residential Consumers	1.3%	1.4%
Small Commercial & Industrial Energy Sales	3.2%	2.1%
Small Commercial & Industrial Energy Consumers	2.4%	2.2%
Large Industrial – Direct Serve Energy Sales	0.3%	0.1%
Large Industrial – Direct Serve Consumers	0.0%	0.0%
Irrigation Sales	0.0%	0.0%
Public Street Lighting Sales	2.0%	1.8%

5.3.2. Forecast Assumptions

The forecast was based upon a number of assumptions regarding factors that impact energy consumption, including: demographics, economic activity, price of electricity and competing fuels, electric market share, and weather conditions. The assumptions were developed by GDS Associates and discussed with cooperative management prior to development of the final forecast. The economic outlook for the base case forecast was formulated using information collected from Woods & Poole Economics, Inc., NPA Data Services, and the University of Louisville.

- Population will increase at an average rate of 0.5% per year from 2004-2019.
- Employment will increase at an average rate of 1.0% per year from 2004-2019.

- Real personal income will increase at an average rate of 1.8% per year from 2004-2019.
- Real retail sales will increase at an average rate of 1.5% per year from 2004-2019.
- Inflation, as measured by the Personal Consumption Expenditure Index, will increase at an average compound rate of 2.5%.
- Over the long-term the real (deflated) price of electricity to retail customers is projected to decrease slightly and is not expected to significantly impact current energy consumption patterns.
- Weather conditions, as measured by heating and cooling degree days for the Evansville, Indiana and Paducah, Kentucky stations, will be equal to average amounts computed using data from 1985 through 2004 for Evansville, Indiana and Paducah, Kentucky.
- It is assumed that service to the two largest Kenergy industrial customers, Alcan Primary Products Corporation and Century Aluminum of Kentucky, LLC, will continue throughout the forecast period.
- No new demand-side management programs are currently planned that will impact system energy and demand requirements.
- The electric industry in Kentucky is not expected to be deregulated in the near future; therefore, no impacts associated with customer choice are included in the forecast.

5.3.3. Comparison of Actual vs. Projected Load and Energy

A comparison of actual and forecasted peak demands is presented below in Table 5.6. Amounts are presented on an annual basis for the summer and winter seasons for years 2003 and 2004.

Table 5.6
Actual Weather Normalized vs. Forecasted Peak Demand

Summer Peak (MW)

Year	Actual (Normal)	2003 Forecast	% Error
2003	612	612	0.0%
2004	632	623	-1.4%

Winter Peak (MW)

Year	Actual (Normal)	2003 Forecast	% Error
2003	584	563	-3.6%
2004	547	573	4.8%

A comparison of actual and forecasted energy sales is presented below in Table 5.7. Amounts are presented on an annual basis for years 2003 and 2004.

Table 5.7
Actual Weather Normalized vs. Forecasted Energy Sales

	Annual Energy Sales (MWH)		
Year	**Actual (Normal)**	**2003 Forecast**	**% Error**
2003	3,161,430	3,117,936	-1.4%
2004	3,189,428	3,167,095	-0.7%

Modeling error and factors that cannot be quantified are the primary reasons that the projections in the 2003 load forecast are lower than actual amounts in years 2003-2004.

5.4. Resource Acquisitions and System Improvements

5.4.1. Resource Acquisitions

Big Rivers has no plans to acquire new resources during the 15 year IRP horizon with the exception of possible aforementioned renewable power from Weyerhaeuser, including the recent 1 MW negotiated agreement and the potential 20-30 MW purchase. Planned purchases from SEPA and from LEM are sufficient to meet both base case and high case load and energy requirements. Although no economic analysis has been completed to date, Big Rivers has considered installing distributed generation at points in its transmission system in lieu of making capital additions. To date, no distributed generation has been installed, and none is planned for the immediate future; however, Big Rivers will continue to evaluate distributed generation as an alternative to capital improvements in maintaining current reliability standards.

5.4.2. Transmission System

The Big Rivers transmission planning process includes coordination with the distribution cooperative planning processes. The intent of this coordination is to ensure that proper transmission costs are included in the evaluation of distribution system enhancements. Additionally, information that will allow the inclusion of proposed distribution system delivery points in the Big Rivers planning model is provided through this coordination.

Three year construction work plans and 15 year long-range plans are prepared as part of the Big Rivers planning process. The long-range plan is reviewed and updated as necessary every three years. This coincides with the preparation of each new construction work plan. The study models used in the preparation of these plans utilize a total load level equivalent to the approved Big Rivers load forecast. This load level is distributed across the system based on historic load growth at each individual delivery point. Transmission system improvements planned for years 2005-2007, plus those planned for the next ten years, are identified by year in Appendix F.

When the work plan studies indicate system constraints resulting from normal or single contingency outage scenarios, Big Rivers will ensure that the transmission system is being efficiently utilized by evaluating alternative switching configurations. If these alternative configurations fail to alleviate the system problems, system enhancements (new transmission circuits, transformers, interconnections, etc.) will be evaluated. The system enhancements could also include distributed generation as a potential solution to system constraints. The evaluation of any enhancement will consider the effectiveness of the enhancement as well as economic comparisons of the proposed alternatives. An evaluation of the effectiveness of an enhancement should consider, at minimum, how quickly the proposed facilities can be called upon and how well they alleviate system constraints.

Evaluations regarding the ability to transfer energy into or out of Big Rivers control area are typically done at the request of those in the power marketing area (internal or external to Big Rivers). These studies are completed according to procedures outlined in the Big Rivers Open Access Transmission Tariff as well as FERC Orders 888 and 889.

5.5. IRP Plan Implementation

No additional capacity is required over the 15-year forecast horizon; therefore, the 2005 IRP includes no supply-side implementation plan. From a demand-side perspective, Big Rivers has developed a three-year action plan that focuses on programs promoting energy conservation and efficiency.

5.6. Supply-Side Plan

Capacity and energy purchased under existing contracts economically satisfy Big Rivers' power needs. No supply-side implementation is required over the next three years.

5.7. Demand-Side Plan

Demand-side planning at Big Rivers is a joint planning process among Big Rivers and its three member cooperatives. Big Rivers completed a comprehensive demand-side management study in October 2005, the results of which are presented in the 2005 IRP.

5.7.1. Existing Big Rivers Demand-Side Programs

Big Rivers publishes a quarterly magazine on behalf of its three distribution electric cooperatives called the "Commercial and Industrial News." Since January 1999 the publication has covered energy related topics focusing on energy efficiency and management. Big Rivers is in the process of evaluating a dual fuel home incentive, but such an incentive program has not been approved. Big Rivers has developed information for its three member distribution cooperatives that compares annual operating costs for various types of heating systems (fossil fuel versus electric systems), and each cooperative chooses how and when they use that information. Big Rivers is also reviewing the provisions of the new Federal Energy legislation enacted in July 2005 to monitor new appliance energy efficiency standards that go into effect on January 1, 2006. Big Rivers is in the process of evaluating a dual fuel heating system incentive, but such an incentive program has not been approved.

Big Rivers remains a strong proponent for the efficient use of Kentucky's energy resources and is committed to helping members educate their member-consumers about the importance of efficient energy usage. Big Rivers continues to work with its members to develop energy efficiency programs designed to communicate to member-consumers the energy savings associated with energy efficient construction techniques and equipment. The programs are communicated through an assortment of collateral materials, and training is available for architects, builders and energy managers and employees of the distribution cooperative.

In addition, Big Rivers continues to provide direct support to its members and their commercial and industrial customers to promote efficient and cost effective energy use. Documents will be developed to inform members of benefits outlined in the new energy bill. Big Rivers will continue to support the incentive programs both financially and through the development of promotional material.

Additional education is provided to commercial and industrial accounts through on-site visits and the Commercial & Industrial News, a quarterly Big Rivers' publication. Big Rivers also provides the following commercial and industrial services through JPEC, Kenergy and MCRECC:

5.7.1.1. Energy Efficiency Workshop.

JPEC, MCRECC and Kenergy provide educational workshops for customers on energy saving devices and techniques. The workshops are educational seminars designed to present information on energy savings devices and techniques to the employees of the three distribution cooperatives. The employees who attend the seminar are persons who work for commercial businesses that buy power from the distribution cooperatives. Electrical safety workshops are also available.

5.7.1.2. Energy-Use Assessment.

This assessment or audit assists customers to improve energy efficiency by using the utilities expertise in energy delivery and use combined with a customer's knowledge to identify opportunities to lower energy costs and improve efficiency. The cooperatives have been working with customers for years to improve facility and process efficiency.

5.7.1.3. Operation Assessment

This service evaluates when and how energy is used in a customer's facility. Many facilities have the ability to adjust operations and/or equipment controls to save energy and money.

5.7.1.4. Customer Billing Review

Customer service staff from Kenergy, MCRECC and JPEC visit a customer's facility to explain and answer questions about billing documents and rate structures.

5.7.1.5. Commercial Lighting Evaluation

Cooperative staff can evaluate the necessary facility and security lighting to provide productive and safe light levels. MCRECC, JPEC and Kenergy can also provide leased lighting options.

5.7.1.6. Power Factor Correction Assistance

JPEC, MCRECC and Kenergy provide technical support to commercial and industrial customers to correct low power factor, resulting in significant savings those customers each year. Low power factor results in higher electricity costs. The cooperatives provide engineering assistance and will work with a customer's electric contractor to ensure proper correction levels.

5.7.1.7. Power Quality Assessment

Customers who experience equipment damage or productivity losses as a result of power quality problems may call their distribution cooperative commercial and industrial service representative. Cooperative staff will assist any customer to identify the source of the problem whether it is inside the facility, on the power system or a result of a neighboring customer.

5.7.1.8. Power Quality Correction

Engineering and customer service staff members assist commercial and industrial customers to correctly identified the source of power quality problems and provide technical support to correct the problem.

5.7.1.9. Energy Use Summary

MCRECC, Kenergy and JPEC all provide energy use summaries on their associated web sites. Three to four years of energy use and billing data is displayed in graphical and tabular form along with weather data for the previous two years. Information from the most recent bill is necessary to access the website for security reasons.

5.7.1.10. Remote Meter Data Collection

Technology has made it possible for customers to view hourly data from the meter. The information can be securely displayed on the Internet for use by customers to manage their energy use.

5.7.1.11. Customized Billing Services

Recent changes in bill printing have made available to cooperative customers the ability to receive multiple bills in the same mailing.

5.7.1.12. Residential Energy Auditing

At the cooperatives request, Big Rivers' staff will provide telephone and onsite residential energy audits.

5.7.2. Existing Member Cooperative Demand-Side

5.7.2.1. Kenergy

Kenergy offers educational and informative brochures, magazine articles, and television and radio commercials relating to energy efficiency topics. The ground source heat pump continues to be the central HVAC technology promoted. Energy Resource Conservation Loans at 5 percent interest are available from Kenergy to qualifying customers installing a geothermal system in their existing homes. This offer is not available for new construction. The loans may finance up to 100 percent of the installation cost and may be amortized for up to 60 months. Kenergy publishes advertisements in newspapers and magazines that describe their 5% financing for installations in existing homes for geothermal energy systems. Informative pamphlets and magazine articles are used by Kenergy to educate customers on the energy savings gained by installing a geothermal system.

Kenergy's web site provides operating cost information such as the following annual cost estimates and efficiencies for different types of heating and cooling equipment in an average-size home (approximately 1,500 sq. ft). Resistance heat includes baseboards, ceiling cable and electric furnace. Propane based on $1.20 per gallon + $40 yearly tank rental. Natural gas based on $.80 per CCF.

ANNUAL HEATING & COOLING OPERATING COSTS	
Resistance Heat	$816.05
Propane Heat 80% Efficient	$967.52
Natural Gas	$605.16
10 SEER Heat Pump	$594.58
12 SEER Heat Pump	$506.03
14 SEER Heat Pump	$440.62
Geothermal	$322.56

Kenergy is not currently conducting any load management programs.

5.7.2.2. Jackson Purchase Energy Corporation

JPEC provides similar informational articles and brochures for their members. One publication that they distribute is USDOE's "Energy Savers Tips on Saving Energy & Money at Home", a 33 page booklet which is a brochure that compiles ideas and measures that will help reduce energy usage and save money for members. Magazine articles are also posted on the cooperative's web site with ideas on how to save energy (for example, by providing shade trees around a home to reduce peak air-conditioning loads). The JPEC web site provides the following additional links:

- A link to the electronic copy of the Energy Savers pamphlet.
- The JPEC web site provides a link to the Department of Energy's Home Energy Saver Web Site. A cooperative member can go to that web site

and obtain detailed information on energy use for their home and how to reduce their energy usage. A cooperative member can even customize the information for their specific type of home.

JPEC provides cash incentives for high efficiency heat pumps in new and existing residential homes. JPEC is not currently conducting any load management programs. JPEC provides free caulk to its member consumers in efforts to help consumers maintain adequate insulation of their homes.

5.7.2.3. Meade County Rural Electric Cooperative Corporation

MCRECC provides energy efficiency informational brochures on geothermal heating and cooling systems, and also publishes articles relating to energy efficiency tips in Kentucky Living magazine. The articles suggest ways to save on cooling costs during the summer and save on heating costs during the winter. Radio advertisements are also used to educate their consumers about energy efficiency topics. Advertisements increase awareness of water and energy conservation issues such as leaking faucets and to increase awareness of energy efficiency measures that can be used to save money on heating and cooling bills while still making the home comfortable.

MCRECC offers the "All Seasons Comfort Home" program to a cooperative member that is building a new home. The program provides recommended, proven standards for insulation, energy-saving features, and assistance in the selection and installation of high efficiency heat pumps and geothermal heating and cooling systems. MCRECC provides information to members on the most efficient and economical heating and cooling system equipment. MCRECC is not currently conducting any load management programs.

The energy efficiency initiatives offered by Big Rivers' member system distribution cooperatives are summarized below in Table 5.8.

5.7.2.4. Summary of Existing Energy Efficiency Initiatives

The energy efficiency initiatives offered by Big Rivers' member system cooperatives are summarized below in Table 5.8.

Table 5.8
Summary of Existing Energy Efficiency Initiatives Offered by Big Rivers Electric Corporation and Its Distribution Cooperative Members

Kenergy

- Kentucky Living Magazine – Monthly magazine to all customers - focus articles on energy efficiency for the home and business and 4 page insert from local cooperative detailing programs, safety and customer service.
- DOE Pamphlet "Energy Savers - Tips on Saving Energy & Money at Home"
- Heat Pump Programs – Incentives Programs - 5% financing for Ground Source Heat Pumps for up to 5 years
- C/I News – Quarterly magazine to commercial and industrial customers – focus on energy related topics including conservation and efficiency improvements.

- Energy Efficiency Informational Brochures "Geothermal Heating and Cooling – The Answer to Comfortable and Affordable Living"
- Distribution of compact fluorescent bulbs at annual meeting
- Incentives Programs:
  - Touchstone Energy Home
  - Water Heater Replacement
  - Add-on Heat Pump
- Heat Loss / Gain analysis for HVAC contractors
- Web Site Information and Links
  - Geothermal Heat Pump Systems
  - USDOE – Energy Saving Tips for Consumers
  - USDOE – Home Energy Audit
  - Commercial Building Energy Checklist
- Energy Audits As Needed
  - Commercial / Industrial
  - Residential
- News Paper Advertising
  - Safety
  - Energy Efficiency

Jackson Purchase Energy

- DOE Pamphlet "Energy Savers - Tips on Saving Energy & Money at Home"
- Customer Newsletter – "Plugged In" Focus articles include energy efficiency, safety information and customer service
- C/I News – Quarterly magazine to commercial and industrial customers – focus on energy related topics including conservation and efficiency improvements.
- Pamphlet - "Keep An Eye On That Thermostat"
- Pamphlet - "How much will this light bulb save you?"
- Distribution of compact fluorescent bulbs at annual meeting
- Incentives Programs:
  - Touchstone Energy Home
  - Water Heater Replacement
  - Add-on Heat Pump
- Web Site Information and Links
  - USDOE – Energy Saving Tips for Consumers
  - USDOE – Home Energy Audit
- Energy Audits As Needed
  - Commercial / Industrial
  - Residential
- News Paper Advertising
  - Safety
  - Energy Efficiency
- Energy Efficiency Training for Employees
  - Basic – Employees with limited customer contact receive training in energy cost and efficiencies
  - Advanced – Employees with extensive customer contact receive in addition to the basic course. Training includes additional training in

HVAC, water heating, lighting, building envelope and construction techniques who in turn will provide that guidance to customers.

Meade County RECC

- DOE Pamphlet "Energy Savers - Tips on Saving Energy & Money at Home"
- C/I News – Quarterly magazine to commercial and industrial customers – focus on energy related topics including conservation and efficiency improvements.
- Kentucky Living Magazine – Monthly magazine to all customers - focus articles on energy efficiency for the home and business and 4 page insert from local cooperative detailing programs, safety and customer service.
- Brochure – "Planting Trees to Save Money"
- Distribution of compact fluorescent bulbs at annual meeting
- Web Site Information and Links
  - Geothermal Heat Pump Systems
  - USDOE – Energy Saving Tips for Consumers
  - USDOE – Home Energy Audit
  - Commercial Building Energy Checklist
- Energy Audits As Needed
  - Commercial / Industrial
  - Residential
- News Paper Advertising
  - Safety
  - Energy Efficiency
- Energy Efficiency Training for Employees
  - Basic – Employees with limited customer contact receive training in energy cost and efficiencies

5.7.3. Demand-Side Action Plan

The results of the economic screening of the energy efficiency measures and programs indicate that several energy efficiency measures are cost effective even after the inclusion of administrative, marketing, evaluation and incentive costs. The maximum achievable cost effective potential for electric energy efficiency measures/programs by 2015 in the Big Rivers member cooperative service areas is estimated to be approximately 12% of 2015 annual kWh sales. Big Rivers has reviewed a considerable range of technical reports and market research analyses to prepare this assessment of electric energy efficiency measures, and finds that barriers to the adoption of energy efficiency measures and practices remain in the energy marketplace. Given that many energy efficiency measures can be cost effective for homes and businesses (according to the Participant Benefit/Cost Test and the Total Resource Cost Test), and given that barriers to energy efficiency remain, Big Rivers has updated its three-year energy efficiency action plan to help its members save energy and money, and to take advantage of the environmental and other benefits of energy efficiency programs. Listed in Table 5.9 on the following page is a summary of the key actions included in the three-year plan, along with a proposed budget.

Table 5.9
Summary of Three-Year Energy Efficiency Action Plan

Action	Description	Market Barrier Addressed	Proposed Annual Budget
1	Web based information improvements will be made to the Big Rivers web site. Upgrade links to the USDOE consumer information and energy efficiency web sites. Update and continue to provide on line access to account information to customers of the distribution cooperatives through their websites. This information allows customers easy access to account/billing information and links to energy efficiency information at various state and federal websites.		$15,000
2	Continued financial support of distribution cooperative's incentive programs. The incentive programs include: "Touchstone Energy Home Program", "Add-On Heat Pump" and "Electric Water Heater Exchange". The "Dual Fuel Touchstone Energy Home Program" is currently in development.		$59,500
3	Enerpath Energy Auditing Software. Web based auditing system for commercial and industrial to support on-site audits performed by Big Rivers and distribution cooperative staff.		$4,500
4	Energy efficiency services including: Energy efficiency and education material to distribution cooperatives; Energy Star related material; Energy efficient workshops for cooperative employees; Pamphlet, flyer and insert publication for cooperative members; Incentive program support. Purchase of energy efficiency publications from USDOE such as "Energy Savers, Tips on Saving Energy and Money at Home".		$32,000
5	Purchase of Compact Fluorescent lamps for distribution cooperative members. Up to 12,000 lamps will be delivered to distribution cooperatives for annual meetings and other events.		$8,900
6	Promotion and development of		$28,000

Action	Description	Market Barrier Addressed	Proposed Annual Budget
	collateral material for the introduction of the renewable "green" power starting in 2006.		
7	Purchase of the Questline online energy efficiency support publication. Includes online energy efficiency website with energy expert and a monthly email newsletter for Kenergy commercial and industrial members.		$3,600
8	Public presentation of energy efficiency presentation by Doug Rye for the MCRECC service territory.		$3,500
9	Development and publication of the Commercial and Industrial News, a quarterly publication for the commercial and industrial member of the distribution cooperative. The C/I News presents articles on energy related issues pertinent to the market sectors. Energy efficiency articles include motors, lights, HVAC, compressors, power factor and a number of other subjects.		$36,000
	TOTAL ANNUAL BUDGET		$191,000

5.7.4. Net Metering

Effective March 1 2005, a net metering tariff is available to Big Rivers' Members retail customers who generate electricity in parallel to the cooperatives network and generate energy using solar energy (PV).

5.7.5. Local Integrated Resource Planning

With respect to local integrated resource planning, Big Rivers has taken positive steps since 2001 as evidenced by the 85 MW cogeneration unit brought on-line in 2001 by the Weyerhaeuser Company. Big Rivers has been negotiating with Weyerhaeuser and evaluating the feasibility of making a capital investment at the site, which would potentially provide for the generation of an additional 20-30 MW. More details regarding the status of the additional capacity will be available after the meeting expected to take place before the end of 2005.

In recent years, Big Rivers has evaluated the purchase of renewable resource power from neighboring utilities. Since the 2002 IRP, Big Rivers' management has discussed potential green power purchases with representatives from Weyerhaeuser, Wabash Valley Power Association, and East Kentucky Power Cooperative. After consideration of options from the three entities, Big Rivers narrowed its search to Weyerhaeuser, and has since agreed to terms for the purchase of 1 MW per hour for a one-year contract, which begins November 1,

2005. Outside of the agreement with Weyerhaeuser, Big Rivers is not currently seeking additional power from other sources.

5.8. Key Issues and Uncertainties

Big Rivers' supply-side plan is in place at this time. Load and energy growth beyond that contemplated in the Base Case, Optimistic Economy, and Extreme Weather forecasts might require power resources that are not planned for at this time. Big Rivers prepares forecasts on a biannual cycle and can assess capacity reserve projections on the same basis.

6. Significant Changes Since the 2002 IRP

Big Rivers' 2002 IRP identified no capacity deficiency throughout the 15-year planning horizon. Big Rivers' purchases from SEPA and LEM are expected to continue to adequately serve the revised load and energy forecast during the 2005 through 2019 period.

Since completion of the 2002 IRP, Big Rivers completed a new demand-side planning study in 2005. The study focused on the feasibility and need for alternative demand-side options and addressed issues and concerns raised by the KPSC staff during its evaluation of the 2002 IRP. Big Rivers has expanded the assessment of electric energy efficiency potential savings in this new study to include additional energy efficiency equipment and building practices, and to include a detailed assessment of the maximum achievable cost effective savings potential associated with aggressive energy efficiency measure/program implementation over the next decade in the Big Rivers member cooperative service areas. While the prior DSM study examined the cost effectiveness of many energy efficiency measures, this new energy efficiency potential assessment goes further to examine the potential savings that could be achieved throughout the Big Rivers member cooperative service areas assuming aggressive implementation of programs over a ten-year period and assuming unlimited funding. The purpose of this analysis was to determine the maximum achievable kWh and dollar savings that cold be achieved under such a scenario. The new energy efficiency analysis provides a calculation of the net present value savings to Big Rivers' members for the maximum achievable cost effective energy efficiency potential savings scenario.

7. Load Forecast

Big Rivers' 2005 Load Forecast was completed in July 2005[5]. The study contains projected load and energy requirements for years 2005-2019 and addresses the filing requirements of both the Rural Utilities Service (RUS) and the KPSC. The complete 2005 Load Forecast is included in this report as Appendix A.

Forecasted load growth for Big Rivers is provided below in Table 7.1. Total system native energy and peak demand requirements are projected to grow at annual average annual rates of 1.6 percent and 1.5 percent, respectively, from 2004 to 2019. Growth in system requirements is projected to be conservative, as

[5] Big Rivers contracted GDS Associates, Inc. to develop the 2005 Load Forecast.

requirements for direct serve customers, which comprise approximately 32% of total system energy sales, have been held constant throughout the forecast period. Rural system energy and peak demand requirements, which are represented as total system requirements less those associated with direct-serve customers, are projected to increase at an average rate of 2.2% and 2.1%, respectively, over the same period..

Table 7.1
2005 Load Forecast Summary

Year	Total Member Cooperative Retail Consumers	Total Energy Sales to Member Cooperatives (MWh)	Generation & Transmission Losses	Total Energy Requirements for Generation Service (MWh)	System Peak Demand (kW)	Annual Load Factor
2005	108,000	3,279,478	0.81%	3,306,259	633,622	59.6%
2006	109,541	3,350,889	0.81%	3,378,253	641,362	60.1%
2007	111,139	3,403,824	0.81%	3,431,620	656,658	59.7%
2008	112,768	3,445,744	0.81%	3,473,882	665,642	59.6%
2009	114,383	3,491,439	0.81%	3,519,951	675,440	59.5%
2010	116,052	3,535,326	0.81%	3,564,196	684,845	59.4%
2011	117,843	3,586,916	0.81%	3,616,207	695,958	59.3%
2012	119,691	3,634,687	0.81%	3,664,368	706,235	59.2%
2013	121,596	3,687,087	0.81%	3,717,197	717,515	59.1%
2014	123,516	3,737,410	0.81%	3,767,931	728,343	59.1%
2015	125,472	3,794,649	0.81%	3,825,636	740,670	59.0%
2016	127,428	3,847,280	0.81%	3,878,697	751,973	58.9%
2017	129,422	3,904,585	0.81%	3,936,470	764,286	58.8%
2018	131,431	3,959,648	0.81%	3,991,983	776,107	58.7%
2019	133,462	4,021,242	0.81%	4,054,080	789,356	58.6%

Big Rivers is not obligated to provide for generation requirements for Alcan and Century (formerly NSA), two aluminum smelters that purchase power through Kenergy; however, Big Rivers does provide for transmission service to these two customers. When the electric loads for the two aluminum smelters are included, system peak demand for transmission service provided by Big Rivers increases by 857,174 kW in each year. Big Rivers' system peak demand, including the smelters, is projected to grow at an average annual rate of 0.8 percent per year, and the corresponding energy is projected to grow at an average annual rate of 0.5 percent per year from 2005 to 2019.

7.1. Projections at Total System and by Customer Classification

Refer to Big Rivers' 2005 Load Forecast, Appendix B, Tables – Long-Term Forecast, for tables listing projected energy and peak demand. Peak demand is not available by customer classification.

7.2. System Data for the Historical Period

Refer to Big Rivers' 2005 Load Forecast, Appendix B, Tables – Long-Term Forecast, for historical information for the base year, 2004, and the four preceding years. Weather normalized energy and peak demand are presented in the 2005 Load Forecast, Appendix E, Weather Normalization.

Currently, there are no demand-side programs in place for which estimates of energy sales and peak demand impacts are measurable.

7.3. Projections for the Fifteen (15) Years Succeeding the Base Year

Refer to Big Rivers' 2005 Load Forecast, Appendix B, Tables – Long-Term Forecast, for projections of energy sales and peak demand for the fifteen (15) years succeeding the base year 2004. Projections are presented at the total system and customer class levels.

7.4. Additional Projections and Information

Refer to Big Rivers' 2005 Load Forecast, Appendix B, Tables – Long-Term Forecast, for projections of annual energy sales for the system and sales disaggregated by customer class, and summer and winter peak demand.

Refer to Big Rivers' 2005 Load Forecast, Appendix A, Tables – Short-Term Forecast, for projections of monthly energy sales for the system, monthly energy sales disaggregated by customer class, and monthly system peak demand.

The impacts of existing demand-side programs were not explicitly quantified in the load forecast. The impacts of such programs are, however, reflected in the historical data upon which the forecasting models were based. Therefore, impacts of demand-side programs are captured implicitly, to a certain extent, in the econometric models.

7.5. Information for the Multi-State Integrated Utility System

Big Rivers is not part of a multi-state integrated utility system.

7.6. Load Forecast Updates

The current load forecast was completed in July 2005. No updates to the 2005 forecast have been completed. Big Rivers plans to develop a 2007 Load Forecast, which is planned for completion during the summer of 2007.

7.7. Description of Load Forecast Procedures, Assumptions, and Methodologies

The 2005 Load Forecast is included in this report as Appendix A. Refer to the Big Rivers' 2005 Load Forecast for a description of the data sets used in the forecast, the key assumptions made, and the procedures and methodologies employed. At the time of this IRP, Big Rivers has not made plans to conduct any load research or detailed end-use load studies other than those identified in Table

5.9 on page 25. Big Rivers conducts consumer surveys quarterly to collect consumer attitudes and opinions, which provide a source of information for formulating load forecast assumptions.

8. Resource Assessment and Acquisition Plan

8.1. Resource Assessment and Acquisition Plan

Big Rivers' current assessment and acquisition plan for providing adequate and reliable supply of electricity is based on the continuation of power purchases from SEPA and from LEM. Big Rivers' existing owned generating resources are leased to Western Kentucky Energy Corporation (WKEC), which operates these resources. Big Rivers has no plans for improvements to existing facilities or expansion of existing facilities other than that described in section 5.4.1 herein. There are no plans for future resources to meet demand at this time.

8.2. Resource Assessment and Acquisition Plan Options

8.2.1. Improvements to Generation, Transmission, and Distribution Facilities

8.2.1.1. Improvements to Generation Facilities

WKEC currently leases and operates generation owned by Big Rivers. SO2 scrubbers are being installed at plant Coleman and are expected to be operational by the first quarter of 2006.

8.2.1.2. Improvements to Transmission Facilities

With respect to the improvement and more efficient utilization of existing transmission facilities in the period from 2003 through the end of 2005, Big Rivers constructed and placed in service approximately 8 miles of new 69kV transmission line to connect to five new delivery point substations of its member systems. An additional 14 miles of new 69kV line was constructed to strengthen the sub-transmission network and thus improve reliability. In 2004, one new 20 MVA 161-69kV transmission substation was constructed and one 50 MVA transformer was added at another 161-69kV station to further improve system reliability. That same year, a new 69kV interconnection with the Kentucky Utilities system was added in the Kenergy Centertown station area for emergency or back-up supply service to four distribution stations.

Big Rivers upgraded its communications infrastructure with the replacement of its analog microwave system equipment with new digital equipment. During this period, Big Rivers also completed a replacement of its Energy Management System (EMS) hardware and software as well. Big Rivers has designed and is nearing completion of an emergency or back-up control center including a second complete EMS installation at Kenergy's South Hanson office site.

Big Rivers has continued to study with the member systems the feasibility of value sharing through the application of technologies common to the four companies. Big Rivers and its members are each currently working toward the completion of database development and integration of Geospatial Information

System (GIS) software into the engineering, operations, maintenance, and customer accounting areas of service provided to the consumers. Possible other areas of interest are in commonality of two-way radio systems, a microwave system expansion interconnecting all four companies, joint dispatch center operation, etc.

Work toward completion of other transmission system improvements is a continuous process. A list of planned improvements to the Big Rivers system for the 2005-2014 time period is included in Appendix F.

8.2.1.3. Improvements to Distribution Facilities

Big Rivers' three member cooperatives, Kenergy, JPEC, and MCRECC, are responsible for improvements to their respective distribution facilities.

8.2.2. Demand-Side Programs

Big Rivers completed a comprehensive demand-side management study in October 2005. Results of the study are summarized in section 5.7 of this report. The complete study is included as Appendix B to the IRP. As a result of the study, Big Rivers has developed a three-year action plan that will focus on programs designed to promote energy conservation and efficiency.

8.2.3. Expansion of Generation Facilities

Big Rivers existing capacity exceeds projected demand for at least the next 15 years. There are currently no plans to expand existing generation facilities to meet load other than as described in section 5.4.1 herein. Likewise, Big Rivers has no plans to for joint construction and ownership of new units.

8.2.4. Assessment of Non-Utility Generation

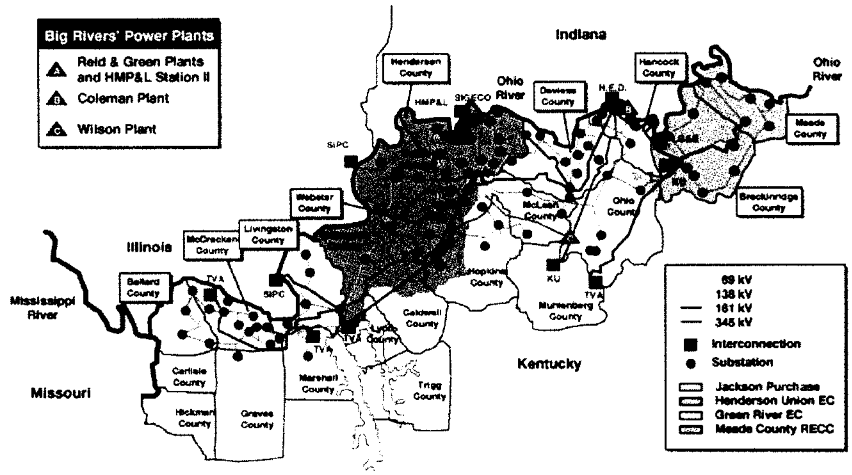
While Big Rivers' capacity exceeds projected load beyond the current 15-year planning horizon, Big Rivers is actively assessing non-utility generation. Section 5.1.3.1 describes efforts recently taken by Big Rivers to assess non-utility generation potential associated with cogeneration at an industrial location. Big Rivers has actively encouraged non-utility generation to locate at its Wilson site as opportunities present themselves.

8.3. Existing and Planned Resources

8.3.1. Map of Generation and Transmission Facilities

Big Rivers owns an extensive transmission system for the delivery of power to its member cooperatives. The system is interconnected with the LG&E, the TVA, Kentucky Utilities, Southern Illinois Power Cooperative, Hoosier Energy Rural Electric Cooperative, Henderson Municipal Power & Light, and Southern Indiana Gas and Electric Company. Based on the transfer capacity of the electrical interconnections and the forecasted load growth, it is expected that the local interconnections can import the total needs of the Big Rivers system without major modification over the next 15 years. A map of the system is presented below as Figure 8.1.

Figure 8.1
Big Rivers Electric Corporation Transmission System



8.3.2. Existing Generation Facilities

Big Rivers owns or has contractual rights to the electric generation facilities listed below in Table 8.1. As discussed in section 5.1.2, these facilities are currently leased by WKEC.

Table 8.1
Generation Facilities

	Reid Plant	Green Plant	HMP&L Station II	Coleman Plant	Wilson Plant
Number of Units	2	2	2	3	1
Location	Robards, KY	Robards, KY	Robards, KY	Hawesville, KY	Centertown, KY
Status	Existing	Existing	Existing	Existing	Existing
Operation Date(s)	1966,1976	1979, 1981	1973,1974	1969,1970, 1972	1986
Type of Facility	Steam, CT	Steam	Steam	Steam	Steam
Net Capability	130 MW	454 MW	312 MW	455 MW	420 MW
Fuel Type	Coal, NG/Oil	Coal	Coal	Coal	Coal
Fuel Storage *	N/A	N/A	N/A	N/A	N/A
Scheduled Upgrades, deratings, retirement *	N/A	N/A	N/A	N/A	N/A
Actual and Projected Operating Cost *	N/A	N/A	N/A	N/A	N/A
* Big Rivers does not operate or maintain these units					

8.3.3. Description of Purchases, Sales, and Exchanges of Electricity

Big Rivers plans to purchase all energy and peak demand requirements for the next 15 years through contracts with SEPA and LEM. The specifics of these contracts are described in section 5.1 of this report. The projected power requirements and capacity resources are summarized in Table 5.1 on page 11.

8.3.4. Description of Existing and Projected Energy and Generating Capacity from Renewable Resources

Big Rivers currently purchases 178 MW of hydro power from SEPA. This allocation is contracted through 2016 and is expected to be renewed once the current contract expires. In addition to the SEPA power, Big Rivers is currently evaluating a capital investment at Weyerhaeuser Company, where at its cogeneration facility, power is generated by the burning of waste products. Refer to section 5.1.3.1 of this report for a more detailed description.

8.3.4.1. Run-of-River Hydro

In addition to the recent agreement to purchase green power from the Weyerhaeuser Company, Big Rivers has evaluated the feasibility of run-of-river hydro facilities, which are a type of hydroelectric project in which the amount of electricity generated is controlled mainly by the volume of water flowing in the stream above the project. Hydro projects which cannot store significant quantities of water at or above the site must be operated as run-of-river facilities.

The primary advantage of run-of-river facilities is that the flow of water is not restricted; therefore, there are minimal, if any, negative environmental impacts. The primary disadvantage of run-of-river generating stations is that they cannot store water, thus electric output varies with seasonal flows of water in a river, and availability could be limited in times of need. In addition, these type plants produce relatively small amounts of electricity.

In the most recent study sponsored by the U.S. Department of Energy, it was concluded that there were 51 sites in Kentucky that had undeveloped hydropower potential[6]. These 51 sites are located within three major river basins and several small river basins. There are 17 underdeveloped sites in the Ohio Main Stream River basin, which account for 52 percent of the underdeveloped hydro capacity. The analysis conducted indicated that the individual site capacities ranged from 35 kW to 180 MW and that 65 percent of the sites were small hydropower sites, which were less the 10 MW.

Considering Big Rivers power supply arrangements currently and for the next fifteen years, development of run-of-river hydro facilities is not an economically feasible option for Big Rivers. The cost to develop such facilities is estimated at $1,700-$2,300 per kW. The levelized total cost over a 30 year life is estimated to be 45 mills/kWh, which is significantly more than the cost Big Rivers currently pays through its contract with LEM. Although the development of run-of-river hydro facilities is not feasible at this time, Big Rivers will continue to evaluate this technology, as well as other renewable resources, in the future.

[6] *U.S. Hydropower Resource Assessment Final Report*, Idaho National Engineering and Environmental Laboratory, prepared for the U.S. Department of Energy, December 1998.

8.3.5. Demand-Side Planning Programs

Big Rivers completed a Demand-Side Management study in October 2005. The key results of the study are presented in section 5.7 of this report, and the complete study is included as Appendix B to the IRP. The programs currently in place, plus those new programs identified in the three-year action plan, are educational programs and efforts designed to help consumers conserve energy by being more efficient users; therefore, no energy and peak demand savings estimates have been developed at this time.

8.4. Base Year and Forecasted Power Requirements and Resources

Big Rivers' resource assessment and acquisition plan for the adequate and reliable means to meet annual and seasonal peak demands and total energy requirements at the lowest possible cost is currently based on the purchase of all peak demand and energy requirements through the SEPA and LEM contracts discussed in section 5.1.2 of this report.

8.4.1. Resource Capacity

Big Rivers' peak demand forecast for years 2005-2019, as well as the resources required to meet the projected peaks, are presented in Table 5.1 on page 11. The current forecast shows no reductions in peak demand requirements due to DSM programs.

8.4.2. Generation

Big Rivers' energy forecast for years 2005-2019, as well as the resources required to meet energy requirements, are presented in Table 5.1 on page 11. The current forecast shows no reductions in energy requirements due to DSM programs.

8.4.3. Total Energy Input by Fuel Type

Big Rivers currently purchases, and will continue to purchase through at least year 2019, all of its power requirements through its contract with LG&E. Big Rivers does not operate any power plants; therefore, a current breakdown of total energy input by primary fuel is not available.

8.5. Resource Assessment and Acquisition Plan Methodology

The methodology, models, key assumptions, and screening criteria associated with resource assessment and acquisition plan are described in section 5.2 of this report. The model outputs are presented in Appendices C, D, and E. Future planning and research will include periodic updates to demand-side planning options and evaluations directed towards increased utilization of renewable resources. Big Rivers currently purchases, and will continue to purchase through at least year 2019, all power requirements through LG&E. and does not operate or perform maintenance on any units; however, Big Rivers has obtained from Western Kentucky Energy information regarding environmental equipment installed at the respective Coleman, Henderson, Green, Wilson, and Reid units and is presented in Table 8.2.

Table 8.2
Environmental Equipment

Unit	Firing System	NO_x Reduction	SO_2 Reduction	Particulate Reduction
Coleman 1	Front Wall Fired	low-Nox burners & advanced over-fire air	wet limestone FGD, forced oxidation	ESP
Coleman 2	Front Wall Fired	low-Nox burners & advanced over-fire air	wet limestone FGD, forced oxidation	ESP
Coleman 3	Rear Wall Fired	low-Nox burners & advanced over-fire air	wet limestone FGD, forced oxidation	ESP
Henderson 1	Rear Wall Fired	low-Nox burners & selective catalytic reduction	wet mag-lime FGD, natural oxidation	ESP
Henderson 2	Rear Wall Fired	low-Nox burners & selective catalytic reduction	wet mag-lime FGD, natural oxidation	ESP
Green 1	Opposed Wall Fired	low-Nox burners & coal Re-burn	wet mag-lime FGD, natural oxidation	ESP
Green 2	Opposed Wall Fired	low-Nox burners & coal Re-burn	wet mag-lime FGD, natural oxidation	ESP
Wilson 1	Opposed Wall Fired	low-Nox burners & selective catalytic reduction	wet limestone FGD, inhibited oxidation	ESP
Reid 1	Front Wall Fired	convert to 50% Gas-Fired		ESP
Reid CT	Oil Fired	convert to natural gas or fuel oil		

9. Financial Information

Big Rivers' projections of member system revenues, expressed in both nominal and real terms, are presented on the following page in Table 9.1. The table also lists the 2005 net present value of revenue requirements, calculated using a discount rate of 5.35%. This rate represents Big Rivers' embedded cost of debt. Also shown are annual average system rates calculated as annual member revenues divided by annual member energy sales.

Table 9.1
Member Revenue Projections

Year	Nominal Member Revenue ($000)	2005 PV Member Revenues ($000)	Member Sales (MWh)	Member Revenues / Sales (M/kWh)	Inflation (%)	Cumulative Inflation Impact	2005 $ Member Revenues ($000)
2005	109,239	1,345,953	3,279,478	33.31		1.0000	111,461
2006	112,826		3,350,889	33.67	2.45%	1.0245	113,653
2007	117,349		3,403,824	34.48	2.56%	1.0508	112,629
2008	119,028		3,445,744	34.54	2.82%	1.0804	110,950
2009	120,765		3,491,439	34.59	2.98%	1.1125	109,250
2010	122,460		3,535,326	34.64	3.04%	1.1464	107,437
2011	124,319		3,586,916	34.66	3.03%	1.1810	105,877
2012	138,716		3,634,687	38.16	3.15%	1.2183	104,079
2013	140,783		3,687,087	38.18	3.13%	1.2563	102,452
2014	142,806		3,737,410	38.21	3.16%	1.2961	100,729
2015	145,122		3,794,649	38.24	3.20%	1.3376	106,112
2016	162,064		3,847,280	42.12	3.16%	1.3799	104,353
2017	164,605		3,904,585	42.16	3.25%	1.4247	102,639
2018	167,114		3,959,648	42.20	3.21%	1.4704	100,931
2019	169,784		4,021,242	42.22	3.16%	1.5169	106,532

10. Notice

Big Rivers will provide notice of its 2005 IRP filing as required by 807 KAR 5:058.

Appendix A
2005 Load Forecast

Big Rivers Electric Corporation

Henderson, Kentucky

2005 Load Forecast

July 2005

GDS Associates, Inc.

Table of Contents

APPENDICES

1. Executive Summary

Big Rivers Electric Corporation (Big Rivers) is an electric generation and transmission cooperative headquartered in Henderson, Kentucky. This 2005 Load Forecast was completed in July 2005 and updates the most recent forecast that was completed in July 2003. The forecast contains projections of energy and demand requirements for the 2005-2019 forecast horizon. High and low range forecast scenarios were developed to address uncertainties regarding the factors expected to influence energy consumption in the future. In addition to the energy and demand projections, this report presents the assumptions upon which the forecast is based and the methodologies employed in development of the forecast.

1.1 Forecast Results

Total system native energy and peak demand requirements are projected to increase at average compound rates of 1.6% and 1.5%, respectively, from 2004 through 2019[1]. Growth in system requirements is projected to be conservative, as requirements for direct serve customers, which comprise approximately 32% of total system energy sales, have been held constant throughout the forecast period. Rural system energy and peak demand requirements, which are represented as total system requirements less those associated with direct-serve customers, are projected to increase at an average rate of 2.2% and 2.1%, respectively, over the same period.

The forecast is summarized in Tables 1.1 and 1.2 on the following page. The primary influences on long-term growth in system requirements over the forecast period will continue to be growth in rural system requirements, which is primarily a function of growth in number of customers and changes in industrial activity. Industrial sales have declined in recent years due to economic conditions and the development of a cogeneration site by Weyerhauser. When combined with rural system sales, which have increased over the same period, total system sales growth has been low. Over the forecast horizon, industrial sales are projected to stay relatively level, and residential

[1] Based on weather normalized values for 2005 and 2019.

sales are expected to grow at 2.2% annually, resulting in overall system growth of 1.6% per year.

Table 1.1
Load Forecast Summary

		Total System		Rural System	
Year	Consumers	Energy Requirements (MWH)	Peak Demand (CP kW)	Energy Requirements (MWH)	Peak Demand (CP kW)
1994	87,256	7,721,677	1,189,000	1,571,482	352,635
1999	98,168	3,532,841	663,890	1,921,792	475,416
2004	106,414	3,158,698	604,155	2,133,190	476,409
2009	114,383	3,519,951	675,440	2,485,739	536,630
2014	123,516	3,767,931	728,343	2,737,034	589,533
2019	133,462	4,054,080	789,356	3,027,093	650,546

Table 1.2
Load Forecast – Average Annual Growth Rates

Description	2004-2009	2004-2019
Total Native System Energy Requirements	1.8%	1.6%
Total Native System Peak Demand (CP)	1.3%	1.5%
Rural System Energy Requirements	2.6%	2.2%
Rural System Peak Demand (CP)	2.4%	2.1%
Residential Energy Sales	2.1%	2.2%
Residential Consumers	1.3%	1.4%
Small Commercial & Industrial Energy Sales	3.2%	2.1%
Small Commercial & Industrial Energy Consumers	2.4%	2.2%
Large Industrial – Direct Serve Energy Sales	0.3%	0.1%
Large Industrial – Direct Serve Consumers	0.0%	0.0%
Irrigation Sales	0.0%	0.0%
Public Street Lighting Sales	2.0%	1.8%

Section 2 of the report presents a brief summary of the cooperative background and service area characteristics. Section 3 describes the load forecast database. Section 4 presents the assumptions made during the forecasting process. Section 5 presents the short-term forecast, which contains monthly projections of energy sales and peak demand for years 2005 to 2008. Section 6 presents the long-term forecast, which contains projections for the 2005 to 2019 period. Section 7 presents the forecast scenarios, and Section 8 describes the forecasting methodologies employed in developing the forecast.

1.2 Forecast Assumptions

The forecast is based upon a number of assumptions regarding factors that impact energy consumption, including: demographics, economic activity, price of electricity and competing fuels, electric market share, and weather conditions. The assumptions were developed by GDS Associates and discussed with cooperative management prior to development of the final forecast. The economic outlook for the base case forecast was formulated using information collected from Woods & Poole Economics, Inc., NPA Data Services, and the University of Louisville.

- Population will increase at an average rate of 0.5% per year from 2004-2019.
- Employment will increase at an average rate of 1.0% per year from 2004-2019.
- Real personal income will increase at an average rate of 1.8% per year from 2004-2019.
- Real retail sales will increase at an average rate of 1.5% per year from 2004-2019.
- Inflation, as measured by the Personal Consumption Expenditure Index, will increase at an average compound rate of 2.5%.
- Over the long-term the real (deflated) price of electricity to retail customers is projected to decrease slightly and is not expected to significantly impact current energy consumption patterns.
- Weather conditions, as measured by heating and cooling degree days for the Evansville, Indiana and Paducah, Kentucky stations, will be equal to average amounts computed using data from 1985 through 2004 for Evansville, Indiana and Paducah, Kentucky.

- It is assumed that service to the two largest Kenergy industrial customers, Alcan Primary Products Corporation and Century Aluminum of Kentucky, LLC, will continue throughout the forecast period.
- No new demand-side management programs are currently planned that will impact system energy and demand requirements.
- The electric industry in Kentucky is not expected to be deregulated in the near future; therefore, no impacts associated with customer choice are included in the forecast.

1.3 Industry Restructuring

At the time this forecast was completed, legislation had been introduced in Congress to deregulate and/or restructure the nation's electric utility industry. Currently 19 states, excluding Kentucky, have deregulated or restructured their electric utilities, allowing customers to choose the generation source of their electric power. California, however, has suspended retail access. Five other states have delayed the restructuring process or the implementation of retail access.

In Kentucky, a 1998 bill providing for retail choice in 2000 was introduced, but the legislature instead passed legislation establishing the Electricity Restructuring Task Force, which released a study concluding that the average rate level in Kentucky would be similar under either a regulated or retail choice environment, and that customers would see higher prices in periods of tight capacity. The task force's final report, issued December 1999, recommended no restructuring action in the legislature for 2000, and monitoring of states in which retail choice has been enacted. During the 2000 legislative session, the task force was reauthorized, and HB 897, which addresses cost allocation and affiliate transactions was enacted. In April 2002 the governor signed SB 257, which creates a plant siting board that must approve all merchant power plants. In March 2004 the governor signed SB 118, which allows cooperate utilities, upon public service commission approval, to sell wholesale power to municipal utilities. In April the governor signed SB 246, which requires utilities to obtain PSC approval for transmission projects 138 KV or greater in capacity and a mile or more in length.

1.4 Forecasting Process

The forecast was developed using methods recognized in the industry today as the standards, including econometrics, informed judgment, exponential smoothing, and historical trends. The residential class accounts for the majority of rural system requirements; therefore, considerable time and effort were devoted to development of econometric models to forecast the number of consumers and energy sales for the class. Similarly, econometric models were developed to project commercial energy sales. Large commercial direct serve customer demand and energy projections were developed using information provided by cooperative management regarding local industrial operations. Energy sales projections for all other classifications were based on linear trends. An econometric model was developed to project rural system peak demand. Projections of rural system non-coincident peak demand were computed by summing the member cooperative forecasts. Projections of direct-serve peak demand were developed by member cooperative staff and based on informed judgment. Total system CP projections were computed as the sum of rural system CP and direct-serve CP.

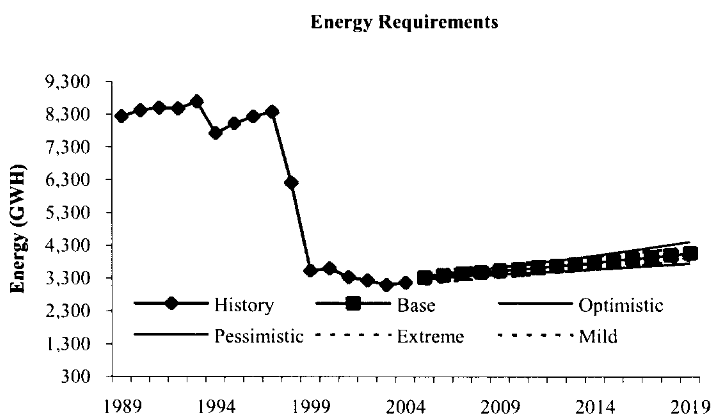
The forecast is based on a bottom-up approach. Projections were developed at the customer class level and aggregated to the total system level. Projections of peak demand were developed at the rural system, total native system, and total native system plus smelter levels. The forecast is based on an analysis of data and information for a historical period covering the 1989 to 2004 period, and the forecast period covers years 2005-2019. The base case forecast assumes normal weather conditions for each year, the averages being computed using heating and cooling degree days for the twenty years beginning 1985 and ending 2004.

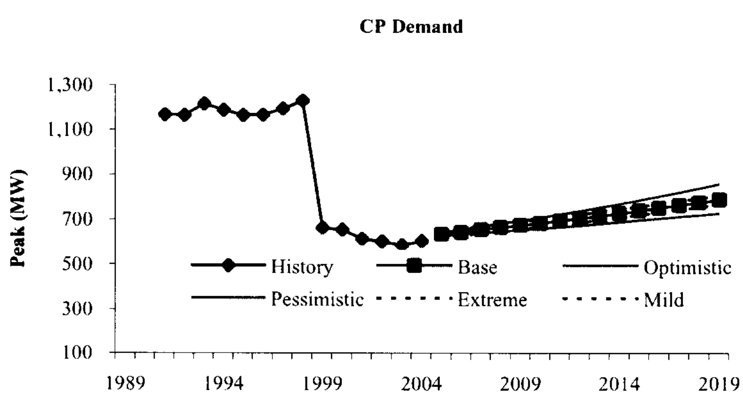
1.5 Forecast Scenarios

The base case forecast was developed using the expected economic outlook and average weather conditions. Since there is uncertainty associated with all load forecasts, four forecast scenarios were generated to evaluate varying economic and weather impacts from those used in development of the base case forecast. Although these scenarios have lower probabilities of occurring than the base case forecast, they provide valuable information for system planning. Results from the four scenarios are presented graphically in Figure 1.1 and presented in detail in Section 7.

Figure 1.1

Total Native System Forecast Scenarios





1.6 Comparison to Regional and National Forecasts

Table 1.3 compares Big Rivers' forecast to regional and national forecasts developed by the following entities.

Table 1.3
Comparison to Regional and National Forecasts

	Average Annual Growth Rates		
	Total Energy Consumption	**Residential Energy**	**Commercial Energy**
AEO2005	2.0%	1.8%	2.6%
GII	1.7%	1.7%	1.9%
GRI	2.1%	2.2%	2.1%
ECAR	1.7%	N/A	N/A
Big Rivers	2.2%	2.2%	2.1%

Source: AEO2005: Annual Energy Outlook 2005.
GII: DRI-WEFA (now Global Insight, Inc.), U.S. Energy Outlook (Summer 2004).
GRI: Gas Research Institute, GRI Baseline Projection of U.S. Energy Supply and Demand, 2001 Edition.
ECAR: East Central Area Reliability Council (10 Year Projection).

Note: Cooperative values reflect rural system data.

2. Introduction

The 2005 Load Forecast was conducted by representatives from Big Rivers, the member cooperatives of Big Rivers, and GDS Associates, Inc.

2.1 Purpose

The purpose of the long-term load forecast is to provide reliable load projections for the Cooperative's resource, transmission, and financial planning functions. This forecast of system requirements includes the following:

- Number of consumers by customer classification
- Energy sales by customer classification
- Generation and transmission losses
- Total native system energy requirements
- Total native system seasonal peak demand
- Rural system energy sales
- Rural system seasonal peak demand

Five forecast scenarios were developed in the forecast: a base case which focuses on expected economic conditions and normal weather, and two sets of high-range and low-range projections, both of which consider deviations from expected economic conditions and deviations from normal weather conditions.

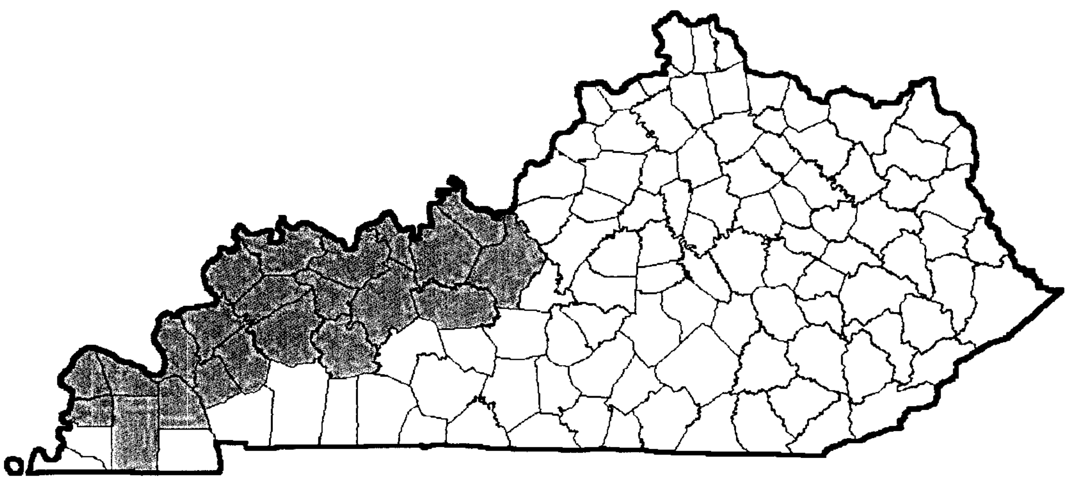
2.2 Cooperative Background

Big Rivers is headquartered in Henderson, Kentucky, and provides wholesale power to three member cooperatives: Kenergy Corp. ("Kenergy"), Jackson Purchase Energy Corporation ("JPEC"), and Meade County RECC ("MCRECC"), all of which provide retail electric service to consumers located in western Kentucky. Approximately 89% of the accounts the member cooperatives serve are residential. The data used in the modeling process was weighted based on the percentage of residential customers in each county that the cooperative services. This weighting system was used to better represent the growth in population, employment, and income of the cooperative's service area.

2.3 Service Area

Big Rivers' member cooperatives provide electric service in 22 counties located in western Kentucky, which are presented in Figure 2.1.

Figure 2.1
Service Area Counties



2.3.1 Geography

The topography of Big Rivers' member cooperatives' service areas ranges from rolling, sandy embayment areas to flat plateau areas with low relief and subterranean drainage. Typical elevations range from approximately 340 to 1000 feet above sea level. The climate in the area is humid, temperate and continental.

2.3.2 Climate

Weather conditions are similar to those of Evansville, Indiana and Paducah, Kentucky. The climate in the area is humid, temperate and continental. Daily and seasonal changes in temperature, cloudiness, wind and precipitation may be sudden and extreme. The seasons are well defined, but changes between the seasons are gradual. Winters are harsh with sustained periods of very low temperatures. Snowfall provides minimal precipitation, averaging 10 inches per year. The frequent thunderstorms that occur in the spring bring rainfall, which is beneficial to area crops. Annual rainfall averages 46 to 50 inches. The summer season is long, humid and hot.

Heating and cooling degree days for Evansville, Indiana and Paducah, Kentucky were used in the forecasting models to quantify the impacts of weather on energy consumption. A degree day represents the difference between the average temperature for a given day and a base temperature. Positive differences represent cooling degree days, and negative differences represent heating degree days. For example, if the average temperature for a day is 80 degrees, and the base temperature used is 65 degrees[2], there would be 15 cooling degree days for that day. Cooling and heating degree days are presented in Table 2.1.

Table 2.1
Degree Days

	Evansville			**Paducah**		
Year	Heating Degree Days	Cooling Degree Days	Total Degree Days	Heating Degree Days	Cooling Degree Days	Total Degree Days
1985	4785	1445	6230	4479	1439	5918
1986	4386	1576	5962	3946	1734	5680
1987	4290	1623	5913	3868	1831	5699
1988	4822	1500	6322	4398	1658	6056
1989	4830	1396	6226	4443	1492	5935
1990	3856	1380	5236	3460	1557	5017
1991	4253	1757	6010	3713	1965	5678
1992	4217	1240	5457	3724	1382	5106
1993	4652	1613	6265	4531	1686	6217
1994	4180	1489	5669	3911	1409	5320
1995	4314	1773	6087	4129	1615	5744
1996	5068	1224	6292	4573	1390	5963
1997	4901	1119	6020	4445	1271	5716
1998	3863	1629	5492	3535	1798	5333
1999	4149	1284	5433	3650	1531	5181
2000	4710	1289	5999	4273	1566	5839
2001	4233	1377	5610	3921	1540	5461
2002	4410	1737	6147	4099	1877	5976
2003	4529	1143	5672	4150	1289	5439
2004	4253	1269	5522	3885	1394	5279
Average	4435	1443	5878	4057	1571	5628

[2] The National Oceanic and Atmospheric Administration computes degree days using a base of 65 degrees.

2.4 Power Supply

Big Rivers provides wholesale power to three member cooperatives: Kenergy, JPEC, and MCRECC, all of which provide retail electric service to consumers located in western Kentucky. With the exception of two aluminum smelters, Alcan Primary Products Corporation ("Alcan") and Century Aluminum of Kentucky, LLC ("Century"), which are served by Kenergy, Big Rivers provides all of the power requirements of its three member cooperatives. Big Rivers' wholesale rate, approved by the Kentucky Public Service Commission (KPSC) on July 18, 1998, is presented in its tariff, PSC KY No. 22, Big Rivers Electric Corporation of Henderson, Kentucky Rates, Rules and Regulations for Furnishing Electric Service. Big Rivers has prepared a draft of its proposed Renewable Resource Tariff, which is now in the in-house review process. Big Rivers is scheduled to submit the Renewable Resource Tariff to the KPSC in the Fall of 2005.

Big Rivers currently owns but does not operate any generation facilities. On July 15, 1998, Big Rivers entered into a 25-year lease arrangement with LG&E Energy Corp and four of LG&E's wholly owned subsidiaries: Western Kentucky Energy Corp. ("WKEC"), WKE Station Two, Inc. ("Station Two Subsidiary"), WKE Corp. ("LG&E Parties"), and LG&E Energy Marketing, Inc. ("LEM").

Big Rivers owns the 455 MW three unit coal-fired Coleman Plant, the 454 MW two unit coal-fired Green Plant, the Reid Plant, which consists of a 65 MW coal and natural gas-fired unit as well as a 65 MW natural gas or oil-fired combustion turbine, and the 420 MW coal-fired Wilson unit. Big Rivers also has contractual rights to a portion of 312 MW at Henderson Municipal Power and Light's ("HMP&L's") Station Two facility. In addition, Big Rivers has contractual rights to 178 MW up to 267,000 MWh per year from SEPA.

2.5 Alternative Fuels

Electricity, natural gas, and propane are the primary heating fuels available within the service area. Wood is used by many consumers as a supplemental heating source as timber is readily available in western Kentucky. The use of wood stoves as a heating source is not expected to have significant impact on usage levels or peak demand as use of wood stoves has decreased in recent years.

2.6 Economic Conditions

Energy consumption is influenced significantly over the long-term by economic conditions. As the local economy expands, population and employment increase, which translate into new cooperative consumers and additional energy sales and peak demand. The economy of western Kentucky depends primarily upon agriculture, manufacturing, services, and wholesale and retail trade. Coal mining and related operations are located throughout the state. Data used to represent economic activity for the service area was computed using county level information.

Population in the counties served by Big Rivers' members increased at an average compound rate of 0.5% per year from 1994 through 2004, reaching just over 244,000 in 2004. This rate of growth is slightly lower than that of the entire state over the same period. Employment in the member cooperative service areas increased at an average compound rate of 1.2% per year from 1994 through 2004, which is lower than that of the entire state over the same period. Per capita income increased at a rate of 1.9% over the 1994 through 2004 period and retail sales increased at an average rate of 2.9% over the same period. Refer to Table 2.2 for a summary of historical economic growth in the service area.

Table 2.2
Summary of Economic Data

Area	Period	Population (x1,000)	Households (x1,000)	Employment (x1,000)	Personal Income (x1,000,000)	Per Capita Income (x1)	Retail Sales (x1,000,000)
United States	1984	235,826	85,202	121,091	$4,750,479	$20,144	$1,878,828
	1994	263,126	97,168	145,572	$6,142,296	$23,344	$2,285,264
	2004	294,197	111,629	173,952	$8,442,046	$28,695	$3,232,204
Southeast	1984	55,515	20,116	27,394	$975,552	$17,573	$425,419
	1994	63,574	24,035	34,464	$1,347,858	$21,201	$551,633
	2004	72,992	28,562	41,898	$1,874,207	$25,677	$808,361
Kentucky	1984	3,695	1,316	1,683	$59,566	$16,121	$24,992
	1994	3,849	1,468	2,053	$73,959	$19,215	$30,674
	2004	4,153	1,658	2,401	$97,871	$23,566	$42,443
Big Rivers	1984	228	82	96	$3,723	$47,930	$1,447
	1994	232	89	111	$4,321	$55,190	$1,638
	2004	244	98	125	$5,448	$66,507	$2,188
Average Growth Per Year							
United States	1984-1994	1.1%	1.3%	1.9%	2.6%	1.5%	2.0%
	1994-2004	1.1%	1.4%	1.8%	3.2%	2.1%	3.5%
Southeast	1984-1994	1.4%	1.8%	2.3%	3.3%	1.9%	2.6%
	1994-2004	1.4%	1.7%	2.0%	3.4%	1.9%	3.9%
Kentucky	1984-1994	0.4%	1.1%	2.0%	2.2%	1.8%	2.1%
	1994-2004	0.8%	1.2%	1.6%	2.8%	2.1%	3.3%
Big Rivers	1984-1994	0.2%	0.9%	1.4%	1.5%	1.4%	1.2%
	1994-2004	0.5%	1.0%	1.2%	2.3%	1.9%	2.9%

3. Load Forecast Database

A load forecast database was created to house all the data used in development of the load forecast. This section identifies the data collected and used in the study, sources from which the data were collected, and computations that were conducted. Four classes of data were collected for this study: (i) system data, (ii) price data, (iii) economic and demographic data, and (iv) meteorological data. The data elements collected under each category, as well as the source and time period, are presented in Table 3.1.

Table 3.1
Load Forecast Database

Class of Data	Source	Data Element	Units	Time Period
System	RUS Form 7	Number of Consumers by RUS Classification	Meters	1970 – 2004
		Energy Sales by RUS Classification	KWh	1970 – 2004
		Revenue by RUS Classification	$	1970 – 2004
		Purchases	KWh	1970 – 2004
		Power Cost	$	1970 – 2004
		Peak Demand	NCP and CP	1970 – 2004
		System Own Use	kWh	1970 – 2004
		Miles of Line	Miles	1970 – 2004
Price	Bureau of Labor Statistics	Producer Price Index 1982=100, Not Seasonally Adjusted	Index	1970.01 – 2004.12
		Consumer Price Index 1982-1984 avg.=100, Seasonally Adjusted	Index	1970.01 – 2004.12
		Personal Consumption Expenditures Index 1992=1, Seasonally Adjusted	Index	1970 – 2025

Class of Data	Source	Data Element	Units	Time Period
Economic and Demographic	Woods & Poole Economics, Inc.	Total Personal Income	Real $ (1,000,000)	1970 – 2025
		Retail Sales	Real $ (1,000,000)	1970 – 2025
Economic and Demographic	Woods & Poole Economics, Inc.	Farm Earnings	Real $ (1,000,000)	1970 – 2025
		Mining Earnings	Real $ (1,000,000)	1970 – 2025
		Service Earnings	Real $ (1,000,000)	1970 – 2025
		Total Earnings	Real $ (1,000,000)	1970 – 2025
		Total Population	(x100)	1970 – 2025
		Households	(x100)	1970 – 2025
		Total Employment	(x100)	1970 – 2025
	NPA Data Services, Inc.	Total Personal Income	Real $ (millions)	1970 – 2025
		Earnings/Job	Real $	1970 – 2025
		Population	(x1,000)	1970 – 2025
		Number of Households	(x1,000)	1970 – 2025
		Total Employment	(x1,000)	1970 – 2025
	University of Louisville	Total Population	(actual/proj)	1970 – 2025
Natural Gas Prices	Gas Research Institute	Real Price of Residential and Commercial Gas	($/million BTU)	1990-1993, 1995, 2000, 2010
	Energy Inform. Administration			1992, 1993, 2000, 2005, 2010
Meteorological	National Oceanic and Atmospheric Administration	Heating and Cooling Degree Days	Base of 65°F	1970.01 – 2004.12
		Average High and Low Temperatures	Degrees F	1970.01 – 2004.12
		Extreme High and Low Temperatures	Degrees F	1970.01 – 2004.12

3.1 Weighting Factors

Economic and demographic data were collected for each county in which Big Rivers' member cooperatives provide electric service. In most instances, a member cooperative provides electric service in only portions of each county served, and the remaining portions are served by other electric systems. Weighting factors were developed to estimate the cooperatives' market share of county population, employment, income, and retail sales.

The number of residential customers served by county and the total number of households located within each county were used to develop county weighting factors. These weighting factors represent the member cooperatives' market shares for each county served. County weights were computed using the formula presented in Equation 3.1.

$$CTYWGT_{it} = RCON_{it} \times HHOLD_{it} \qquad (3.1)$$

$CTYWGT_{it}$ = weight for $county_i$ in $year_t$

$RCON_{it}$ = number of residential consumers in $county_i$ in $year_t$

$HHOLD_{it}$ = number of households in $county_i$ in $year_t$

3.2 Historical Data Estimates

The historical values for population, total employment, and total personal income used in the modeling process were collected from Woods & Poole Economics, Inc. Per capita income was computed from personal income and population values. Population is based on census data for 1970, 1980, 1990, and 2000 with all interim years and years 2001-2004 based on estimates developed by the Department of Commerce, Bureau of Economic Analysis (BEA). Employment and total personal income amounts for 1970 through 2000 are final estimated values based upon quarterly surveys conducted by BEA. Data values for years 2001-2004 are projections based on Woods & Poole's forecasting models.

4. Forecast Assumptions

4.1 Forecast Methodology

Econometrics was the forecasting methodology employed in developing the energy sales forecasting models for the residential and small commercial classifications. When using econometric techniques to forecast energy sales, it is assumed that the relationships between energy consumption and those influential factors included in the models remain the same in both the historical and forecast periods.

4.2 Economic Outlook

It is assumed that growth in Big Rivers peak demand and energy requirements over time has been strongly influenced by economic conditions, including population, employment, total personal income, and retail sales. It is assumed that the influences of these factors will continue over the next fifteen years. Projections of the economic time series used in developing the base case load forecast were formulated using information obtained from Woods & Poole Economics, Inc., NPA Data Services, and the University of Louisville. Projections for key economic data used in this forecast are presented in Table 4.1.

4.2.1 Population

Population is an excellent measure of growth in residential consumers over time and captures the impacts of migration, birth rates, and mortality levels in the local area. Population growth in the member cooperative areas has been slightly lower than the state as a whole over the past ten years. Population in the counties served by the member cooperatives is projected to increase at an average compound rate of 0.5% from 2004 through 2019, which is equal to growth experienced over the previous ten years.

4.2.2 Employment

Employment is a measure of economic activity and, with respect to this forecast, captures growth in the number of commercial accounts over time. Employment is projected to increase at an average compound rate of 1.0% per year over the 15 year forecast horizon, which is lower than growth over the most recent ten years.

4.2.3 Total Personal Income

Total personal income, expressed in real dollars (adjusted for inflation using the personal consumption expenditures index), represents income received from all persons and from all sources. In conjunction with total population, total personal income provides a measure of consumer spending potential, including electricity. Based on the information obtained from the sources identified in Section 3 of this report, total personal income is projected to increase at an average rate of 1.8% per year from 2004 through 2019. This rate of growth is lower than the previous ten years.

4.2.4 Retail Sales

Retail sales represent all sales dollars (adjusted for inflation using the personal consumption expenditures index), for all business establishments, including mail order and on-line sales. Retail sales provide a measure of commercial activity in the service area. Retail sales are projected to increase at an average rate of 1.5% over the forecast period. This rate is lower than that of the most recent ten years.

4.3 Weather Conditions

It is assumed that the weather conditions measured at Evansville and Paducah are representative of western Kentucky. Heating and cooling degree days were used to represent weather conditions, and values for each year of the forecast period are based on the average amounts computed for the 20 year periods ending in 2004. For Evansville, normal cooling degree days are assumed constant at 1,443 per year, and heating degree days are assumed constant at 4,435 per year. For Paducah, normal cooling degree days are assumed constant at 1,571 per year, and heating degree days are assumed constant at 4,057 per year.

4.4 Wholesale and Retail Electricity Prices

It is assumed that Big Rivers' average wholesale price to its member cooperatives will remain constant over the forecast period. When factoring in the effects of inflation, real prices are expected to show declines throughout the next fifteen years. Table 4.2 presents average historical and projected wholesale prices in terms of mills/kWh.

4.5 Alternative Fuel Prices

Natural gas and liquid propane are the two primary alternative heating fuels in the service area. Real prices for both are expected to increase over the short-term and then level over the long-term, which may cause some switching to electricity for heating. However, this load forecast contains no direct impacts of changes in alternative fuel prices as it was assumed that the changes in alternative fuel prices would not be significant enough over the long term to impact electricity consumption.

4.6 Industry Restructuring

At the time this forecast was completed, no legislation had been passed regarding deregulation of the electric industry in Kentucky; as a result, the forecast includes no explicit impacts associated with industry restructuring.

Table 4.1
Key Economic Variables

	Total Population (x1,000)			Households (x1,000)		Employment (x1,000)	
Year	W&P	NPA	UofL	W&P	NPA	W&P	NPA
1984	228.37	228.37	228.37	81.77	82.91	96.04	96.04
1985	228.21	228.23	228.21	82.18	83.63	95.41	95.43
1986	227.61	227.61	227.61	82.84	84.08	96.30	96.30
1987	226.74	226.75	226.74	83.45	84.43	96.81	96.81
1988	225.45	225.46	225.45	84.25	84.90	98.52	98.51
1989	225.74	225.76	225.74	85.38	85.68	101.58	101.58
1990	226.43	226.43	226.43	86.04	86.25	103.63	103.63
1991	226.53	226.53	226.53	86.60	86.63	103.11	103.10
1992	228.15	228.14	228.15	87.85	87.63	104.85	104.85
1993	230.37	230.38	230.37	88.66	88.80	107.79	107.79
1994	231.93	231.93	231.93	89.12	89.75	110.71	110.70
1995	234.11	234.13	234.11	90.59	90.91	114.95	115.06
1996	235.60	235.60	235.60	92.07	91.87	116.66	116.78
1997	237.36	237.38	237.36	93.03	92.89	119.49	119.60
1998	238.40	238.43	238.40	93.71	93.65	121.28	121.20
1999	239.30	239.26	239.30	94.59	94.41	122.67	122.63
2000	240.64	240.60	240.64	95.39	95.39	123.59	123.53
2001	240.89	240.70	240.89	95.77	95.84	121.29	121.24
2002	241.78	241.52	241.78	96.32	97.03	122.57	119.78
2003	243.10	242.32	243.10	97.21	98.18	123.89	119.71
2004	244.18	246.66	244.18	97.99	98.86	125.19	120.42
2005	245.44	248.34	245.02	98.83	99.72	126.47	122.70
2006	246.62	249.95	246.00	99.62	100.59	127.72	124.56
2007	247.92	251.56	246.97	100.43	101.47	129.00	126.50
2008	249.23	253.17	247.95	101.24	102.36	130.28	128.19
2009	250.50	254.78	248.93	102.01	103.16	131.56	129.67
2010	251.84	256.39	249.91	102.78	103.97	132.87	131.11
2011	253.17	257.98	251.18	103.55	104.81	134.18	132.45
2012	254.55	259.56	252.46	104.33	105.64	135.52	133.61
2013	256.02	261.14	253.73	105.11	106.48	136.86	134.80
2014	257.44	262.72	255.01	105.83	107.35	138.22	135.99
2015	258.91	264.31	256.28	106.57	108.27	139.59	137.27
2016	260.42	266.07	257.35	107.28	109.17	140.98	138.29
2017	261.96	267.83	258.41	107.97	110.10	142.39	139.30
2018	263.51	269.59	259.48	108.63	111.03	143.81	139.99
2019	265.02	271.35	260.54	109.24	112.00	145.24	140.91
Average Annual Compound Growth Rates							
1984-1994	0.2%	0.2%	0.2%	0.9%	0.8%	1.4%	1.4%
1994-2004	0.5%	0.6%	0.5%	1.0%	1.0%	1.2%	0.8%
2004-2009	0.5%	0.7%	0.4%	0.8%	0.9%	1.0%	1.5%
2009-2014	0.5%	0.6%	0.5%	0.7%	0.8%	1.0%	1.0%
2014-2019	0.6%	0.6%	0.4%	0.6%	0.9%	1.0%	0.7%
2004-2019	0.5%	0.6%	0.4%	0.7%	0.8%	1.0%	1.1%

Table 4.1
Key Economic Variables (cont.)

	Personal Income (x1,000)		Per Capita Income		Retail Sales (x1,000,000)
Year	W&P	NPA	W&P	NPA	W&P
1984	$3,723	$3,980	$16,303	$17,426	1,447.00
1985	$3,684	$3,938	$16,143	$17,256	1,425.00
1986	$3,700	$3,955	$16,255	$17,376	1,426.00
1987	$3,759	$4,019	$16,579	$17,723	1,407.00
1988	$3,796	$4,058	$16,839	$17,999	1,446.00
1989	$3,919	$4,189	$17,361	$18,557	1,472.00
1990	$3,960	$4,233	$17,489	$18,695	1,479.00
1991	$3,982	$4,256	$17,578	$18,789	1,434.00
1992	$4,167	$4,454	$18,263	$19,525	1,472.00
1993	$4,195	$4,484	$18,209	$19,465	1,541.00
1994	$4,321	$4,619	$18,629	$19,914	1,638.00
1995	$4,371	$4,673	$18,671	$19,958	1,686.00
1996	$4,522	$4,834	$19,192	$20,516	1,756.00
1997	$4,671	$4,993	$19,677	$21,033	1,799.00
1998	$4,832	$5,165	$20,268	$21,664	1,854.00
1999	$4,891	$5,228	$20,436	$21,849	1,970.00
2000	$5,154	$5,509	$21,417	$22,898	2,063.00
2001	$5,228	$5,588	$21,701	$23,216	2,054.00
2002	$5,259	$5,573	$21,752	$23,075	2,126.00
2003	$5,353	$5,736	$22,021	$23,672	2,158.00
2004	$5,448	$6,024	$22,311	$24,424	2,188.00
2005	$5,543	$6,256	$22,583	$25,190	2,218.00
2006	$5,640	$6,480	$22,868	$25,923	2,250.00
2007	$5,739	$6,707	$23,147	$26,663	2,281.00
2008	$5,839	$6,922	$23,428	$27,343	2,314.00
2009	$5,941	$7,124	$23,719	$27,961	2,347.00
2010	$6,046	$7,327	$24,007	$28,579	2,382.00
2011	$6,152	$7,519	$24,301	$29,147	2,416.00
2012	$6,261	$7,705	$24,596	$29,684	2,451.00
2013	$6,372	$7,897	$24,886	$30,240	2,488.00
2014	$6,484	$8,096	$25,188	$30,815	2,526.00
2015	$6,599	$8,300	$25,489	$31,404	2,564.00
2016	$6,717	$8,498	$25,791	$31,939	2,602.00
2017	$6,836	$8,688	$26,096	$32,439	2,643.00
2018	$6,958	$8,870	$26,406	$32,903	2,684.00
2019	$7,083	$9,071	$26,725	$33,431	2,725.00
Average Annual Compound Growth Rates					
1984-1994	1.5%	1.5%	1.3%	1.3%	1.2%
1994-2004	2.3%	2.7%	1.8%	2.1%	2.9%
2004-2009	1.7%	3.4%	1.2%	2.7%	1.4%
2009-2014	1.8%	2.6%	1.2%	2.0%	1.5%
2014-2019	1.8%	2.3%	1.2%	1.6%	1.5%
2004-2019	1.8%	2.8%	1.2%	2.1%	1.5%

Table 4.2
Price Projections

Year	PCE Implicit Price Deflator	Nominal Average Wholesale Price (mills/kWh)
1989	70.91	52.67
1990	74.11	46.53
1991	76.97	48.42
1992	79.31	47.47
1993	81.21	50.47
1994	82.86	55.10
1995	84.76	53.99
1996	86.58	54.29
1997	88.23	29.68
1998	89.18	28.46
1999	90.65	28.00
2000	92.99	27.65
2001	94.89	28.63
2002	95.93	28.66
2003	97.84	27.87
2004	100.00	27.88
2005	102.34	27.88
2006	104.85	27.88
2007	107.53	27.88
2008	110.56	27.88
2009	113.85	27.88
2010	117.32	27.88
2011	120.87	27.88
2012	124.68	27.88
2013	128.57	27.88
2014	132.64	27.88
2015	136.88	27.88
2016	141.21	27.88
2017	145.80	27.88
2018	150.48	27.88
2019	155.24	27.88

5. Short-Term Energy Sales and Peak Demand Forecast

The short-term forecast contains energy and demand projections by month for years 2005 through 2008. The short-term forecast includes projections of energy sales by class, rural system energy sales, rural system coincident peak demand, total system energy sales, and total system coincident peak demand. A summary of projected growth rates is presented in Table 5.1. Projected energy sales and peak demand requirements are presented by month in Appendix A, Tables – Short-Term Forecast.

Table 5.1
Short-Term Forecast

Description	2005	2006	2007	2008
Residential Sales	2.4%	1.9%	2.1%	2.1%
Small Commercial & Industrial Sales	5.7%	6.0%	1.4%	1.2%
Large Industrial – Direct Serve Sales	0.6%	0.0%	1.0%	0.0%
Irrigation Sales	0.1%	0.0%	0.0%	0.0%
Street Lighting Sales	2.1%	2.0%	2.0%	1.9%
Rural System Sales	4.2%	3.2%	1.8%	1.8%
Rural System CP	4.3%	1.6%	2.7%	1.7%
Total Energy Requirements	2.7%	2.2%	1.6%	1.2%

5.1 Short-Term Energy Sales Forecast

Econometric models were developed to project monthly energy sales for the residential and small commercial classifications for the three member cooperatives. Energy sales projections for the large commercial direct serve customers were developed individually for consumer by member cooperative management based on historic trends, operating characteristics, or any information made available to the cooperative by individual consumers. Public street lighting energy sales projections were developed using historic trends. Projections of rural system energy sales were computed as total system sales less sales to direct-serve consumers.

5.2 Short-Term Peak Demand Forecast

Projections of rural system coincident peak demand were computed as the sum of the member cooperatives' projections of rural system coincident demand times a coincidence factor of 98 percent. The rural system demand projections were based on econometric models. Projections of non-rural peak demand (direct-serve consumers) were developed by member cooperative management and based on historic trends and information made available by individual direct-serve consumers.

6. Long-Term Energy Sales and Peak Demand Forecast

The load and energy projections presented in this section indicate that energy sales and peak demand requirements are expected to increase at average compound rates of 1.6% and 1.5%, respectively, from 2004 through 2019. Rural system energy sales and peak demand are projected to increase at average compound rates of 2.2% and 2.1%, respectively. The primary impact on growth in rural system sales will be the result of increases in the number of residential consumers, which are expected to increase at a rate of 1.4% per year. A summary of projected growth rates is presented below in Table 6.1. Tables presenting the long-term energy sales and peak demand forecast by year are included in Appendix B, Tables - Long-Term Forecast.

Table 6.1
Load Forecast – Average Annual Growth Rates

Description	2004-2009	2004-2019
Total Native System Energy Requirements	1.8%	1.6%
Total Native System Peak Demand (CP)	1.3%	1.5%
Rural System Energy Requirements	2.6%	2.2%
Rural System Peak Demand (CP)	2.4%	2.1%
Residential Energy Sales	2.1%	2.2%
Residential Consumers	1.3%	1.4%
Small Commercial & Industrial Energy Sales	3.2%	2.1%
Small Commercial & Industrial Energy Consumers	2.4%	2.2%
Large Industrial – Direct Serve Energy Sales	0.3%	0.1%
Large Industrial – Direct Serve Consumers	0.0%	0.0%
Irrigation Sales	0.0%	0.0%
Public Street Lighting Sales	2.0%	1.8%

6.1 Forecast Methodology

The forecast was developed using methods recognized in the industry today as the standards, including econometrics, informed judgment, and historical trends. The method selected to project energy sales for each customer classification was determined primarily on the level of class sales relative to the total system.

Econometric models were developed to project total system coincident peak demand by member cooperative. Demand was projected on a summer and winter seasonal basis for each year of the forecast period. The summer season includes months May through October, and the winter season includes months November through April.

The forecast is based on a bottom-up approach. Projections were developed at the member cooperative customer class level and aggregated to the total system level. Projections of energy sales were developed by customer classification, while projections of peak demand were developed at the total system and rural system levels.

A more detailed discussion of the alternative forecasting techniques and processes employed in this forecast is presented in Section 8, Forecast Methodology.

6.2 Forecast Results

6.2.1 Residential

The residential class accounts for 89% of all accounts, therefore, considerable time and effort were devoted to development of econometric models to forecast the number of consumers and energy sales for the class. Class sales over the past five years have increased at an average rate of 2.3% per year. Sales are projected to increase at a slightly lower rate of 2.2% per year, or just over 35,688 MWh per year from 2004 through 2019. Customer growth is projected to average 1,503 consumers per year over the forecast period. This growth is slightly higher than growth over the most recent five years of 1,335 consumers per year and reflects the assumption that population and consumer growth over the forecast period is expected to be similar to that of recent years.

Average monthly energy consumption per customer is projected to increase at 0.7% per year from 2004 through 2019. This is slightly lower to the rate of 0.8% experienced over the most recent five years. Impacts influencing lower growth in household energy consumption include increased efficiencies in new electric appliances, regulatory energy standards, and energy conservation. Impacts contributing to continued growth in average use per consumer include larger homes, which result in larger HVAC units, growth in income levels, which increase disposable income available to purchase electric goods, and lower real energy prices, which influence increases in energy consumption.

Projections of total residential sales were computed as the product of projected energy consumption per consumer and projected number of consumers. The econometric models for average energy consumption and number of consumers for each member cooperative are presented in the appendix. The energy models quantify relationships between monthly energy consumption, per capita income, price of electricity, heating degree days, and cooling degree days. The consumer models quantify relationships between consumer growth and population. Autoregressive parameters were included in the consumer models to address the non-random nature of the model residuals.

6.2.2 Small Commercial & Industrial

The Small Commercial & Industrial classification contains all commercial and industrial customers that are not direct serve customers of Big Rivers. The class represented about 21% of total system energy sales in 2004 and consists of a wide variety of customers, from small establishments with demands less than 10 kW to larger industrial operations with demands above 1,000 kW. Growth in both the number of customers and energy sales has been relatively high over the last five years at 3.2% and 2.2% respectively. Growth in class sales through 2019 is projected to be 2.1% per year. Consumers are projected to increase at an average rate of 2.2%.

The models developed for each member cooperative to project small commercial energy sales are presented in the appendix. While the models differ in specification, they address the impacts of retail sales, total personal income, heating degree days, and cooling degree days. The models developed to project small commercial consumers specify relationships between number of consumers and service area employment.

6.2.3 Large Industrial – Direct Serve

The Large Industrial classification contains commercial and industrial customers that are directly served customers of Big Rivers. These customers are usually large industrial operations, and there are few customers in the class. The 20 customers in 2004 represented just under 32% of total system energy sales. Projections of energy sales and peak demand were developed by cooperative management on an individual basis for each account. The number of consumers for the class is expected to remain level at 20 from 2005 through 2019. Energy sales are projected to remain nearly constant throughout the forecast period.

6.2.4 All Other Classifications

The public street lighting classification represents less than 1% of total system sales. Energy sales have steadily increased over the past ten years, and are projected to continue their increase at a rate of 1.8% per year from 2004 through 2019. This equates to an average of approximately 62 MWh per year. Irrigation sales also account for less than 1% of total system sales. Energy sales projections for the class have been held constant at 164 MWH per year.

6.3 System Losses

Distribution losses were projected for each member cooperative and added to member system energy sales to compute member system energy purchases. The sum of member system purchases, excluding smelter requirements, is equal to Big Rivers' native sales. Transmission losses are projected to be 0.81% per year throughout the forecast period. Total native system requirements are equal to Big Rivers' energy sales plus transmission losses.

6.4 Peak Demand

This forecast contains projections of rural system coincident (Rural CP) demand and total system coincident (CP) peak demand. Big Rivers' rural system coincident demand is the sum of the member cooperatives' rural coincident demand amounts times a coincidence factor of 98%. Direct serve coincident demand is the sum of the member cooperatives' direct serve non-coincident demand amounts times a coincidence factor of 95%. Total system coincident peak demand is equal to the sum of rural CP and direct-served customer CP.

Rural system CP demand is projected to increase at an average rate of 2.1% over the forecast period, reaching 651 MW by 2019. Peak demand is expected to occur during the summer season. Total system CP is projected to increase at an average rate of 1.5% per year and reach 789 MW by 2019.

Regression models were developed to project rural system peak demand at the member cooperative level. The models quantify relationships between peak demand and energy requirements. This specification captures the relationship between total energy requirements, heating and cooling degree days, and peak demand and provides a tool for capturing historical trends in system load factor.

6.5 Evaluation of 2003 Load Forecast

Table 6.2 compares the current 2005 load forecast to the previous forecast, which was completed in 2003.

Table 6.2
Load Forecast Comparison – Historical Years

2003	Actual	Weather Normalized	2003 Forecast	% Difference From Actual	% Difference From Normal
Native Energy Req. (MWh)	3,087,548	3,197,877	3,153,252	-2.13%	-1.40%
CP Demand (kW)	583,906	611,587	612,422	4.88%	0.14%

2004	Actual	Weather Normalized	2003 Forecast	% Difference From Actual	% Difference From Normal
Native Energy Req. (MWh)	3,158,698	3,218,668	3,202,968	-1.40%	-0.49%
CP Demand (kW)	604,155	631,837	623,309	-3.17%	4.58%

The amounts listed in Table 6.2 show that the 2003 load forecast was relatively accurate for years 2003 and 2004. Table 6.3 compares the projected growth in both the 2005 and 2003 Load Forecasts. On average, energy requirements in the current forecast are 2% higher than in the 2003 forecast, and peak demand requirements in the current forecast are approximately 1% lower than in the 2003 forecast.

Table 6.3
Load Forecast Comparison – Forecast Years

	2005 Load Forecast		2003 Load Forecast	
Year	Total Native Energy (MWh)	CP Demand (kW)	Total Native Energy (MWh)	CP Demand (kW)
2003			3,153,252	612,422
2004			3,202,968	623,309
2005	3,306,259	633,622	3,251,501	633,615
2006	3,378,253	641,362	3,299,141	644,050
2007	3,431,620	656,658	3,353,697	656,002
2008	3,473,882	665,642	3,403,453	666,898
2009	3,519,951	675,440	3,458,300	678,912
2010	3,564,196	684,845	3,509,389	690,098
2011	3,616,207	695,958	3,568,081	702,958
2012	3,664,368	706,235	3,621,561	714,670
2013	3,717,197	717,515	3,680,594	727,605
2014	3,767,931	728,343	3,736,078	739,758
2015	3,825,636	740,670	3,799,364	753,629
2016	3,878,697	751,973	3,857,653	766,399
2017	3,936,470	764,286	3,921,771	780,451
2018	3,991,983	776,107		
2019	4,054,080	789,356		

7. Range Forecasts

The base case projections reflect expected economic activity for the area as well as average weather conditions. To address the inherent uncertainty related to these factors, long-term high and low range projections were developed. The range forecasts reflect the energy and demand requirements that would correspond to (1) more optimistic or pessimistic economic activity, and (2) more mild or extreme weather conditions. Such forecast scenarios are useful for various planning functions. Four scenarios were generated: (i) base case economics and mild weather, (ii) base case economics and extreme weather, (iii) optimistic economics and normal weather, and (iv) pessimistic economics and normal weather. The range forecasts are presented in table and graphical form in Appendix C, Range Forecasts.

7.1 Weather Scenarios

7.1.1 Extreme Weather

The extreme weather forecast for energy is based on the aggregated results of the scenarios prepared for each member cooperative, which were developed by inputting extreme degree days into the residential energy sales per consumer models and the small commercial energy sales models. Energy sales for the large commercial, public street and highway lighting, and irrigation classes were assumed to be non-weather sensitive. Based on severe weather conditions, total system energy requirements are projected to reach 4,255,111 MWh by 2019, which would result in average growth of 2.0% per year over the forecast period. Rural system energy requirements would reach 3,231,099 MWh in 2019, resulting in an average growth rate of 2.8% per year.

To develop the extreme weather native system coincident peak demand scenario, an extreme load factor based on actual points from 1989 through 2004, was applied to the base case energy requirements forecast. This forecast indicates that native system coincident peak demand would reach 810 MW by 2019, resulting in an average growth rate of 2.0% over the forecast period. Rural system coincident peak demand is projected to reach 678 MW by 2019 under extreme weather conditions, resulting in an average growth rate of 2.4% per year from 2004 through 2019.

7.1.2 Mild Weather

The mild weather scenario for energy sales is based on the aggregated results of the scenarios prepared for each member cooperative, which were developed by inputting mild degree days into the residential energy sales per consumer models and the small commercial energy sales models. Based on mild weather conditions, total system energy requirements are projected to reach 3,853,049 MWh by 2019, which would result in average growth of 1.3% per year over the forecast period. Rural system requirements would grow at a rate of 1.9% per year, reaching 2,823,088 MWh in 2019.

To develop the mild weather native system coincident peak demand scenario, an extreme load factor based on data from 1981 through 2004, was applied to the base case energy requirements forecast. This forecast indicates that native system coincident peak demand will reach 770 MW by 2019, resulting in an average growth rate of 1.6% over the forecast period. Rural system coincident peak demand is projected to reach 625 MW by 2019 under mild weather conditions, resulting in an average growth rate of 1.8% per year from 2004 through 2019.

7.2 Economy Scenarios

High and low scenarios for energy requirements and peak demand were developed based on optimistic and pessimistic macroeconomic assumptions. Economic uncertainty was addressed for the economic factors specified in the econometric models, including population, employment, and income.

7.2.1 Optimistic Outlook

The optimistic economy energy forecast scenario is represented as the aggregate member cooperative energy forecast for the same scenario. The scenario was developed by applying the coefficients for population, employment, and total personal income from the econometric models to the optimistic forecasts of each economic factor. The assumptions made for each member cooperative regarding those factors are presented in each member cooperative's load forecast.

Based on the assumptions made in the optimistic economic outlook scenario, system energy requirements are projected to reach 4,411,758 MWh by 2019, resulting in an average annual growth rate 2.3% per year. Rural system energy requirements under this scenario would grow at an average rate of 3.1% per year, reaching 3,384,977 MWh in 2019.

To develop the corresponding native system coincident peak demand forecast, the base case system load factor was applied to the rural energy requirements forecast based on the optimistic economic outlook. This forecast indicates that native system coincident peak demand will reach 859 MW by 2019, resulting in an average annual growth rate of 2.4% per year. Rural system coincident peak demand will grow at an average rate of 2.9% per year over the forecast period, reaching 727 MW by 2019.

7.2.2 Pessimistic Outlook

The pessimistic economy energy forecast scenario is represented as the aggregate member cooperative energy forecast for the same scenario. The scenario was developed by applying the coefficients for population, employment, and total personal income from the econometric models to the pessimistic forecasts of each economic factor. The assumptions made for each member cooperative regarding those factors are presented in each member cooperative's load forecast.

Based on the assumptions made in the pessimistic economic outlook scenario, system energy requirements will reach 3,744,490 MWh by 2019, resulting in an average annual growth rate 1.1% per year. Rural system energy requirements under this scenario would increase by 1.6% per year from 2004 through 2019 and would reach 2,717,891 MWh in 2019.

To develop the corresponding native system coincident peak demand forecast, the base case system load factor was applied to the energy requirements forecast based on the pessimistic economic outlook. This forecast indicates native system coincident peak demand would reach 729 MW by 2019, resulting in an average annual growth rate of 1.3% per year. Rural system coincident peak demand would grow at an average rate of 1.4% per year over the forecast period, reaching 584 MW by 2019.

8. Forecast Methodology

A bottom-up approach was followed in developing the forecast for Big Rivers. Number of consumers and energy sales were projected at the customer class level and aggregated to produce the total system forecast. Econometrics was employed in forecasts developed for the residential and small commercial classifications. Energy sales and peak demand for large commercial customers were developed by cooperative staff using historical trends and information made available by the individual customers. Energy sales and number of consumers for all other classifications were based on trend models. Total system energy requirements were projected by applying an average line loss factor to projections of total system energy sales. Peak demand forecasts were developed at the rural system and total system levels using econometric models.

8.1 Forecasting Process

The primary methodologies employed in developing the load forecast included econometrics, linear trend, neural networks, exponential smoothing, and expert opinion. Each of these forecasting techniques is described briefly below, and in more detail in the sections that follow.

Econometric models have the advantage of explicitly tracking the underlying causes of trends and patterns in historical data. They provide information that allows Cooperative management to estimate the impacts of certain factors on energy consumption. The methodology has proven very useful for simulation and "what-if" study. In addition, econometric models can be used to identify sources of forecasting error. On the other hand, econometric models require considerable amounts of data, and when used for forecasting, force the assumption that relationships developed during the historical period will remain the same throughout the forecast horizon. Econometric models have been developed to project residential and small commercial requirements as these two consumer classifications account for the overwhelming majority of total system energy sales.

Linear regression applies the same mathematical concepts as econometrics; however, in the context of this study refers to a relationship between only two variables. An advantage of linear regression is that forecasts can be quickly generated and the process requires considerably less data than econometrics. The disadvantage to linear regression is that one or more influential factors are omitted from the analysis. Linear regression is used to project load and energy requirements for those consumer classifications that (i) account for a small portion of the total system or (ii) have exhibited inconsistent growth patterns for reasons that cannot be adequately explained.

Neural networks are flexible, nonlinear models that are similar to econometrics in that they typically include economic variables. Given copious amounts of historical data, they can be trained to predict with great accuracy changes and patterns in historical data. However, the information provided in the output of a neural network tends to be harder to interpret than the outputs of an econometric model. Neural network models have been used in predicting commercial energy sales for various commercial classes.

Exponential smoothing is a univariate mathematical procedure in which the forecast from one period is taken into consideration for the forecast for the next. In this way, the information contained in historical data is continually captured in the forecast. Exponential smoothing requires collection of less data, as only the variable of interest is used in developing the forecast. However, this is also its weakness as no explanatory variables are included in the model specification. Therefore, no conclusions can be drawn as to the causes of variability in the item being forecasted. For this reason, the exponential smoothing method is primarily only considered for forecasts of number of customers and not for energy requirements.

Expert opinion is used when other techniques are ineffective. This approach is utilized to project industrial requirements. Projections are made individually for each account and are based upon information collected from the account's management. The advantages of this method include simplicity and expert input. The major disadvantage is that forecasts based on expert opinion can be biased by one person's opinion.

8.2 Econometrics

Econometrics is a forecasting technique in which the relationship between a variable of interest and one or more influential factors is quantified. Econometrics is based on an area of statistical theory known as regression analysis. Regression analysis is a statistical technique for modeling and testing the relationship between two or more variables. The general form of an econometric model can be expressed as:

$$y_t = \beta_0 + \beta_1(x_{t1}) + \beta_2(x_{t2}) + \beta_3(x_{t3}) + \ldots\beta_k(x_{tn}) + \varepsilon_t$$

where:

t	= time element
y_t	= the dependent variable
$x_1, x_2, \ldots x_n$	= the set of independent variables
$\beta_0, \beta_1, \ldots \beta_k$	= the set of parameter coefficients
ε_t	= modeling error

8.2.1 Model Specification

In the context of this report, model specification refers to the process of defining: (i) the explanatory variables to incorporate in the model and (ii) the form of the model. Explanatory variables, also referred to as independent or exogenous variables, represent factors which are hypothesized to influence a change in the dependent, or endogenous variables. Definition of the explanatory variables should be based upon sound economic principles and assumptions. For example, it is reasonable to assume that local economic conditions produce significant impacts on energy consumption. Variables such as a gross state product and per capita income are often used as explanatory variables to represent, or indicate, the level of economic activity.

In the utility industry, an econometric model is usually developed using some combination of economic, demographic, price, and meteorological variables. It is desirable to also include specific information in the econometric model concerning the end-users, or consumers, of electricity; this information may be in the form of appliance saturation levels or indicators of consumer attitudes toward conservation. Inclusion of these types of explanatory variables in a model enables the forecaster to identify the major factors influencing periodic changes in a variable such as peak demand or energy sales. Inclusion of these variables also makes possible a better estimation of the impact these factors have on changes in consumption.

Models sometime include as an independent variable the lag of the dependent variable. Such models are commonly referred to as adaptive expectation or Koyck distributed lag models. L.M. Koyck demonstrated in 1954 that this specification is equivalent to an infinite geometric lag model. Under such a specification, the assumption is made that the impacts of the explanatory variables included in the model are significant over a period of years, with the current year weighted the heaviest, the previous year weighted less, and so on until the earliest year has no impact.

Econometric models can be specified in linear or log-linear form. When the model is specified in linear form, the assumption is made that elasticities are not constant, and that a unit change in a given explanatory variable will influence a change in the dependent variable equal to the unit change in the explanatory variable times the corresponding coefficient.

When the model variables are expressed in natural log form, it is assumed that elasticities are constant and that a percentage change in a given explanatory variable influences a constant percentage change in the dependent variable based upon the coefficient of the given explanatory variable. A second assumption made when specifying a log-linear model is that changes in the dependent variable are greater at lower levels of the explanatory variables than at higher levels. With respect to energy consumption, this assumption applies primarily to increases in income. Consumption increases rapidly when income increases from lower levels as consumers purchase electric goods and services; however, once income reaches a certain level, most high use electric end-uses have been purchased. As a result, additional increases in income tend to have less impact on consumption than the same level of increase from a lower level of income.

8.2.2 Model Estimation

Once a hypothesized relationship or model is specified, historical data are used to estimate the model parameters, β_0, β_1, β_2,... β_k and quantify the empirical relationship that exists between the variable of interest and the chosen set of explanatory variables. Investigation of the relationship between the dependent variable, y, and an independent variable, x, leads to one of three conclusions: (i) a change in variable x impacts no change in variable y, and a change in variable y impacts no change in variable x, (ii) a change in variable x impacts a change in variable y, while a change in variable y impacts no change in variable x, and (iii) a change in variable x impacts a change in variable y, and a change in variable y impacts a change in variable x. Under conclusion (i), no relationship exits and the explanatory variable should be omitted from further analysis. Under conclusion (ii) variable x is said to be exogenous; its value is determined outside of the marketplace. Under conclusion (iii), both variables x and y are said to be endogenous; both are determined within the marketplace.

The appropriate regression technique to employ in estimating the model depends upon the relationship between the dependent and independent variables. When all explanatory variables are exogenous, ordinary least squares is appropriate. When one or more of the explanatory variables are endogenous, two-stage least squares is appropriate.

8.2.3 Ordinary Least Squares (OLS)

Regression analysis is a statistical procedure that quantifies the relationship between two or more variables. Based upon available input data, a regression equation provides a means of estimating values of a dependent variable. The difference between the actual value of the dependent variables and its regression based estimated value is the error term, generally referred to as the residual. Ordinary least squares is the technique employed which minimizes the sum of the squared errors. A tentative least square model, for example, for residential usage, might be expressed as:

$$RUSE_t = \beta_0 + \beta_1(PCAP_t) - \beta_2(RRPE_t) + \beta_3(CDD_t) + \beta_4(HDD_t) + \varepsilon_t$$

$RUSE_t$	=	residential energy use in year t
$PCAP_t$	=	per capita income in year t
$RRPE_t$	=	price of electricity in year t
CDD_t	=	number of cooling degree days in year t
HDD_t	=	number of heating degree days in year t
ε_t	=	represents the unexplained error in year t

8.2.4 Two Stage Least Squares (TSLS)

The purpose of two stage least squares, as opposed to ordinary least squares, is to estimate two or more equations simultaneously. This technique is used when there are two or more endogenous variables contained in the modeling process. When such a condition exits, use of ordinary least squares to estimate each equation independently results in a biased set of model coefficients. The two stage least squares technique allows each equation to be estimated independently; however, the equations are solved simultaneously to estimate values of each endogenous variable.

The first stage of the TSLS estimation process involves estimating values of the endogenous variables by regressing each endogenous variable on all exogenous variables included in the model. The second stage of the TSLS estimation process involves regressing the dependent variables on the estimated endogenous variables generated in the first stage and all exogenous variables.

8.2.5 Model Validation

In this study, the model validation process involved evaluation of the models for theoretical consistency, statistical validity, and estimating accuracy. From a theoretical standpoint, the model should be consistent with economic theory and specify a relationship that addresses those factors known to influence energy usage. For models that address customer growth, it is appropriate to include a demographic variable such as population, number of households, or employment to explain growth in the number of consumers. For models that address changes in energy sales, more types of variables are needed. An economic variable such as income explains customers' ability to purchase electric goods and services. Weather variables explain changes in consumption due to weather conditions. Price of electricity and price of electricity substitutes measure consumer conservation. Appliance saturation levels measure change in consumption due to changes in end-use equipment. Lagged dependent variables account for the lagged effect of all explanatory variables from previous periods.

The coefficients for each parameter included in the models were tested to insure the proper sign (+ or -). The number of customers increases with population or some other demographic variable; therefore, the sign of demographic variables in the customer model should be positive. There is a direct relationship between energy consumption and income; as income increases, consumption will increase as well. The sign on the income variable in the energy consumption model should be positive. The sign on the price of natural gas, or some other electricity substitute should be positive. Energy consumption increases as weather conditions, as measured by degree days, become more extreme; the sign of both the heating and cooling degree day variables should be positive. There is an indirect relationship between energy consumption and price of electricity. As price increases, consumers tend to conserve energy, and consumption decreases.

The statistical validity of each model is based on two criteria. One, each model was examined to determine the statistical significance of each explanatory variable. Two, tests were performed to identify problems resulting from autocorrelation and/or multicollinearity. An analysis of the models' residuals were performed to determine whether mathematical transformations of the independent variables were required.

Each model was evaluated with respect to its estimating accuracy. The standard error of regression, a statistic generated during the regression analysis, was used to measure accuracy. Tentative models that initially had low degrees of accuracy were tested using alternative specifications.

8.2.6 Model Building Process

The development of forecasts using econometric modeling is a multi-step process. A substantial portion of the effort involved in effective model building is the collection of reliable data for both the historical and projected periods. It is critical, in building models which explain changes in load growth, that the appropriate influential factors be considered, and that the correct explanatory variables be collected to quantify those influential factors.

There are many factors that influence consumers to change their usage levels of electricity. A partial list would include changes in the economy, new industry in an area, key industry leaving an area, population shifts, temperature, unemployment levels, attitudes toward conservation, precipitation amounts, improved appliance efficiencies, political events, inflation, and increases in the price of electricity. The relationship between these factors and energy usage is further complicated since most of these factors are interrelated; for example, when inflation is rampant, increases in the price of electricity may not significantly lower usage by the consumer.

After all necessary data are collected, the model building process begins. During this process, numerous models containing various combinations of candidate explanatory variables are estimated and tested. Each tentative model is examined to see if the explanatory variables included in that particular model specification contribute significantly to the "explanation" of the variable of interest. For those models that pass this preliminary examination, the appropriate regression diagnostic tools are used to test the validity of the underlying statistical assumptions. Included in this examination are tests for autocorrelation and multicollinearity.

The tentative models are tested, not only for statistical reliability, but also for reasonableness of practical interpretation. For example, the model should not show that the effect of extremely cold winter weather has been a reduction in usage. The potential performance of a tentative model for forecasting purposes is also investigated. A model that contained only one explanatory variable (one which measured only weather effects, for example) might not be a good predictive model.

If a tentative model is found to have significant statistical problems, or if the model is simply found to be misspecified, the model is discarded, and a new tentative model is specified. Analysis of the residuals (actual minus estimated values) from the discarded model are helpful in the reformulation of the model and might indicate whether some mathematical transformation of the existing set of explanatory variables is required. This process of specification, estimating, and reformulation continues until a model is found which is statistically sound and which has a sound practical interpretation as well.

8.2.7 Final Model Selection

If a model is found to be a good representation of the proposed relationship, and if it is also determined to be statistically sound, it can be used to estimate values of the variable of interest in future time periods. It is important to note that the forecaster makes the assumption that the modeled relationship between the response and explanatory variables remains the same in the forecast period as it was measured in the historical period. Forecasts are calculated by inserting projected values of the explanatory variables into the estimated model equation. Different forecast scenarios can also be considered by incorporating different values of forecasted explanatory variables. Managerial judgment, based on practical estimations of future trends, can then be used to select the most appropriate and reasonable forecast.

8.3 Linear Regression

Linear regression analysis considers a simple regression model which specifies the relationship between a dependent variable, y, and, in the context of this report, one explanatory variable, x. The assumption regarding linear regression with respect to load forecasting is that a given variable of interest can be forecasted based on its relationship to one variable. Linear regression analysis is very useful for forecasting purposes when the variable of interest has demonstrated consistent growth in the measured period and is expected to continue the same growth in the forecast period.

Linear regression is commonly used to trend variables over time. Incorporating time as the explanatory variable in a simple linear regression equation is the simplest means of developing a time series equation. Using this approach as a means of forecasting, one assumes that time is an adequate measure of the factors which influence change, and that time will continue to represent those factors that impact the response variable in future years. This approach is commonly used when explanatory data series are not available.

8.4 Exponential Smoothing

The Triple Exponential Smoothing model is a univariate forecasting technique that includes trend and seasonal components. The model makes use of current time-period data and the previous period forecast to develop the forecast for the next period. The model specification consists of three parameters: a deseasonalized expected value, a trend variable, and a seasonal multiplier. The forecast equation is as follows:

$$Y_t = (L_{t-1} + T_{t-1}) \times F_{t-s}$$

Where:

Y_t = Forecast for period t

L_{t-1} = Deseasonalized expected value for period t-1

T_{t-1} = Trend variable of period t-1

F_{t-s} = Seasonal multiplier for period t-s, where s is the number of periods per year

Each of the three parameters listed above, L, T, and F, are determined by using weighted current period and lagged variables. This inclusion of previous forecast parameters makes exponential smoothing extremely sensitive to shifts in the independent variable. However, a drawback to this model is that it does not employ the use of explanatory variables such as weather conditions and economic activity. Therefore, exponential smoothing was not employed in this forecast for models other than number of consumers, where economic and weather conditions do not have as great an impact as in energy consumption.

Appendix A
Tables – Short-Term Forecast

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

TOTAL NATIVE ENERGY SALES

Year	Month	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual CP (MW)	Normal CP (MW)	Percent Growth	Actual Load Factor	Normal Load Factor
2004	Jan	298,081	294,435		539	500		75.7%	80.7%
2004	Feb	266,607	268,315	-8.9%	497	504	0.8%	73.4%	72.9%
2004	Mar	241,839	247,756	-7.7%	442	459	-8.9%	74.9%	73.9%
2004	Apr	221,731	230,800	-6.8%	424	418	-9.0%	71.6%	75.6%
2004	May	257,334	248,396	7.6%	499	502	20.0%	70.6%	67.8%
2004	Jun	268,465	262,031	5.5%	546	575	14.7%	67.4%	62.4%
2004	Jul	289,834	304,660	16.3%	604	632	9.8%	65.7%	66.1%
2004	Aug	275,803	290,890	-4.5%	561	602	-4.8%	67.3%	66.2%
2004	Sep	253,441	275,884	-5.2%	520	565	-6.1%	66.8%	66.9%
2004	Oct	226,065	236,694	-14.2%	395	410	-27.4%	78.5%	79.0%
2004	Nov	234,962	241,297	1.9%	420	474	15.6%	76.6%	69.7%
2004	Dec	295,843	288,270	19.5%	562	480	1.2%	72.1%	82.3%
2005	Jan		292,581	1.5%		570	18.6%		70.4%
2005	Feb		278,317	-4.9%		524	-8.0%		72.8%
2005	Mar		270,142	-2.9%		490	-6.6%		75.6%
2005	Apr		250,864	-7.1%		438	-10.5%		78.4%
2005	May		252,310	0.6%		512	16.8%		67.5%
2005	Jun		267,062	5.8%		599	17.0%		61.1%
2005	Jul		298,020	11.6%		633	5.6%		64.5%
2005	Aug		303,638	1.9%		634	0.1%		65.6%
2005	Sep		278,941	-8.1%		584	-7.8%		65.4%
2005	Oct		257,362	-7.7%		459	-21.5%		76.8%
2005	Nov		255,296	-0.8%		466	1.6%		75.0%
2005	Dec		274,944	7.7%		534	14.6%		70.5%
2006	Jan		296,682	7.9%		585	9.6%		69.4%
2006	Feb		284,248	-4.2%		539	-8.0%		72.3%
2006	Mar		276,084	-2.9%		503	-6.6%		75.2%
2006	Apr		256,467	-7.1%		451	-10.5%		78.0%
2006	May		258,013	0.6%		518	15.1%		68.2%
2006	Jun		272,904	5.8%		606	17.0%		61.6%
2006	Jul		304,620	11.6%		641	5.6%		65.1%
2006	Aug		310,296	1.9%		641	0.1%		66.3%
2006	Sep		285,350	-8.0%		591	-7.8%		66.1%
2006	Oct		263,545	-7.6%		465	-21.5%		77.7%
2006	Nov		261,350	-0.8%		479	3.1%		74.7%
2006	Dec		281,331	7.6%		549	14.6%		70.2%
2007	Jan		301,480	7.2%		595	8.4%		69.4%
2007	Feb		288,897	-4.2%		547	-8.0%		72.3%
2007	Mar		280,630	-2.9%		512	-6.6%		75.2%
2007	Apr		260,777	-7.1%		458	-10.5%		78.0%
2007	May		262,232	0.6%		531	15.9%		67.7%
2007	Jun		277,271	5.7%		621	17.0%		61.2%
2007	Jul		309,114	11.5%		656	5.6%		64.6%
2007	Aug		314,915	1.9%		657	0.1%		65.7%
2007	Sep		289,705	-8.0%		606	-7.8%		65.5%
2007	Oct		267,638	-7.6%		476	-21.5%		77.1%
2007	Nov		265,436	-0.8%		487	2.4%		74.7%
2007	Dec		285,729	7.6%		558	14.6%		70.2%
2008	Jan		305,230	6.8%		608	8.9%		68.8%
2008	Feb		292,586	-4.1%		559	-8.0%		71.7%
2008	Mar		284,125	-2.9%		522	-6.6%		74.5%
2008	Apr		264,058	-7.1%		468	-10.5%		77.3%
2008	May		265,390	0.5%		538	15.0%		67.6%
2008	Jun		280,609	5.7%		629	17.0%		61.1%
2008	Jul		312,807	11.5%		665	5.6%		64.5%
2008	Aug		318,730	1.9%		666	0.1%		65.6%
2008	Sep		293,274	-8.0%		614	-7.8%		65.4%
2008	Oct		270,909	-7.6%		482	-21.5%		77.0%
2008	Nov		268,726	-0.8%		497	3.2%		74.0%
2008	Dec		289,302	7.7%		570	14.6%		69.6%

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Month	Actual Energy (MWh)	Normal Energy (MWh)	Percent Growth	CP (MW)	Percent Growth	Load Factor
2004	Jan	217,135	214,211		435		67.5%
2004	Feb	189,622	191,045	-10.8%	379	-12.9%	69.0%
2004	Mar	157,641	163,123	-14.6%	319	-15.7%	69.9%
2004	Apr	138,274	146,007	-10.5%	302	-5.4%	66.1%
2004	May	168,536	158,116	8.3%	375	24.1%	57.7%
2004	Jun	184,791	178,158	12.7%	425	13.3%	57.4%
2004	Jul	204,832	216,299	21.4%	476	12.1%	62.2%
2004	Aug	190,165	211,043	-2.4%	444	-6.9%	65.2%
2004	Sep	169,841	189,837	-10.0%	412	-7.2%	63.2%
2004	Oct	140,605	150,299	-20.8%	269	-34.8%	76.6%
2004	Nov	154,409	159,747	6.3%	315	17.2%	69.5%
2004	Dec	217,339	208,874	30.8%	448	42.4%	63.8%
2005	Jan		210,383	0.7%	441	-1.7%	65.4%
2005	Feb		200,899	-4.5%	389	-11.7%	70.7%
2005	Mar		185,597	-7.6%	354	-9.0%	71.8%
2005	Apr		167,143	-9.9%	303	-14.4%	75.5%
2005	May		162,996	-2.5%	365	20.6%	61.1%
2005	Jun		183,449	12.5%	453	23.9%	55.5%
2005	Jul		213,454	16.4%	497	9.7%	58.9%
2005	Aug		218,538	2.4%	494	-0.4%	60.5%
2005	Sep		195,593	-10.5%	450	-8.9%	59.5%
2005	Oct		171,383	-12.4%	314	-30.3%	74.8%
2005	Nov		174,116	1.6%	344	9.6%	69.3%
2005	Dec		196,091	12.6%	419	21.5%	64.2%
2006	Jan		214,605	9.4%	457	9.1%	64.4%
2006	Feb		206,982	-3.6%	403	-11.7%	70.4%
2006	Mar		191,697	-7.4%	367	-9.0%	71.6%
2006	Apr		172,893	-9.8%	314	-14.4%	75.5%
2006	May		168,852	-2.3%	371	18.2%	62.3%
2006	Jun		189,448	12.2%	460	23.9%	56.5%
2006	Jul		220,224	16.2%	504	9.7%	59.8%
2006	Aug		225,364	2.3%	502	-0.4%	61.5%
2006	Sep		202,166	-10.3%	458	-8.9%	60.5%
2006	Oct		177,728	-12.1%	319	-30.3%	76.3%
2006	Nov		180,325	1.5%	357	11.8%	69.3%
2006	Dec		202,641	12.4%	433	21.5%	64.0%
2007	Jan		218,582	7.9%	464	7.1%	64.5%
2007	Feb		210,895	-3.5%	410	-11.7%	70.5%
2007	Mar		195,417	-7.3%	373	-9.0%	71.7%
2007	Apr		176,403	-9.7%	319	-14.4%	75.7%
2007	May		172,241	-2.4%	381	19.3%	61.9%
2007	Jun		193,016	12.1%	472	23.9%	56.0%
2007	Jul		223,897	16.0%	518	9.7%	59.2%
2007	Aug		229,165	2.4%	516	-0.4%	60.9%
2007	Sep		205,727	-10.2%	470	-8.9%	60.0%
2007	Oct		180,992	-12.0%	327	-30.3%	75.7%
2007	Nov		183,612	1.4%	363	10.8%	69.3%
2007	Dec		206,215	12.3%	441	21.5%	64.1%
2008	Jan		222,410	7.9%	477	8.2%	63.9%
2008	Feb		214,662	-3.5%	421	-11.7%	69.8%
2008	Mar		198,986	-7.3%	383	-9.0%	71.1%
2008	Apr		179,755	-9.7%	328	-14.4%	75.1%
2008	May		175,467	-2.4%	388	18.2%	62.0%
2008	Jun		196,427	11.9%	480	23.9%	56.0%
2008	Jul		227,670	15.9%	527	9.7%	59.2%
2008	Aug		233,062	2.4%	524	-0.4%	60.9%
2008	Sep		209,373	-10.2%	478	-8.9%	60.0%
2008	Oct		184,335	-12.0%	333	-30.3%	75.8%
2008	Nov		186,973	1.4%	373	11.9%	68.7%
2008	Dec		209,865	12.2%	453	21.5%	63.5%

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION

Year	Month	Consumers	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
2004	Jan	94,280		145,423	146,436		1,542	1,553	
2004	Feb	94,455	0.2%	135,557	131,366	-10.3%	1,435	1,391	-10.5%
2004	Mar	94,487	0.0%	108,427	109,110	-16.9%	1,148	1,155	-17.0%
2004	Apr	94,559	0.1%	90,902	94,441	-13.4%	961	999	-13.5%
2004	May	94,567	0.0%	101,190	96,365	2.0%	1,070	1,019	2.0%
2004	Jun	94,627	0.1%	113,739	107,571	11.6%	1,202	1,137	11.6%
2004	Jul	94,710	0.1%	133,763	143,352	33.3%	1,412	1,514	33.1%
2004	Aug	94,823	0.1%	115,245	133,056	-7.2%	1,215	1,403	-7.3%
2004	Sep	94,950	0.1%	110,133	124,916	-6.1%	1,160	1,316	-6.2%
2004	Oct	95,152	0.2%	85,489	91,062	-27.1%	898	957	-27.3%
2004	Nov	95,210	0.1%	89,876	96,748	6.2%	944	1,016	6.2%
2004	Dec	95,394	0.2%	132,922	134,687	39.2%	1,393	1,412	38.9%
2005	Jan	95,531	0.1%		140,618	4.4%		1,472	4.3%
2005	Feb	95,685	0.2%		134,708	-4.2%		1,408	-4.4%
2005	Mar	95,785	0.1%		120,911	-10.2%		1,262	-10.3%
2005	Apr	95,879	0.1%		105,728	-12.6%		1,103	-12.6%
2005	May	95,924	0.0%		96,748	-8.5%		1,009	-8.5%
2005	Jun	95,982	0.1%		109,309	13.0%		1,139	12.9%
2005	Jul	96,054	0.1%		133,694	22.3%		1,392	22.2%
2005	Aug	96,151	0.1%		142,042	6.2%		1,477	6.1%
2005	Sep	96,266	0.1%		124,726	-12.2%		1,296	-12.3%
2005	Oct	96,441	0.2%		104,365	-16.3%		1,082	-16.5%
2005	Nov	96,526	0.1%		104,948	0.6%		1,087	0.5%
2005	Dec	96,683	0.2%		125,335	19.4%		1,296	19.2%
2006	Jan	96,741	0.1%		141,213	12.7%		1,460	12.6%
2006	Feb	96,892	0.2%		137,275	-2.8%		1,417	-2.9%
2006	Mar	97,000	0.1%		123,315	-10.2%		1,271	-10.3%
2006	Apr	97,102	0.1%		107,951	-12.5%		1,112	-12.6%
2006	May	97,167	0.1%		98,874	-8.4%		1,018	-8.5%
2006	Jun	97,243	0.1%		111,608	12.9%		1,148	12.8%
2006	Jul	97,329	0.1%		136,325	22.1%		1,401	22.0%
2006	Aug	97,432	0.1%		144,789	6.2%		1,486	6.1%
2006	Sep	97,548	0.1%		127,252	-12.1%		1,305	-12.2%
2006	Oct	97,712	0.2%		106,614	-16.2%		1,091	-16.4%
2006	Nov	97,806	0.1%		107,216	0.6%		1,096	0.5%
2006	Dec	97,955	0.2%		127,860	19.3%		1,305	19.1%
2007	Jan	98,028	0.1%		143,970	12.6%		1,469	12.5%
2007	Feb	98,173	0.1%		139,971	-2.8%		1,426	-2.9%
2007	Mar	98,284	0.1%		125,828	-10.1%		1,280	-10.2%
2007	Apr	98,391	0.1%		110,265	-12.4%		1,121	-12.5%
2007	May	98,469	0.1%		101,074	-8.3%		1,026	-8.4%
2007	Jun	98,555	0.1%		113,978	12.8%		1,156	12.7%
2007	Jul	98,650	0.1%		139,026	22.0%		1,409	21.9%
2007	Aug	98,757	0.1%		147,610	6.2%		1,495	6.1%
2007	Sep	98,875	0.1%		129,845	-12.0%		1,313	-12.1%
2007	Oct	99,030	0.2%		108,925	-16.1%		1,100	-16.2%
2007	Nov	99,130	0.1%		109,547	0.6%		1,105	0.5%
2007	Dec	99,274	0.1%		130,461	19.1%		1,314	18.9%
2008	Jan	99,358	0.1%		146,806	12.5%		1,478	12.4%
2008	Feb	99,498	0.1%		142,747	-2.8%		1,435	-2.9%
2008	Mar	99,611	0.1%		128,417	-10.0%		1,289	-10.1%
2008	Apr	99,722	0.1%		112,647	-12.3%		1,130	-12.4%
2008	May	99,810	0.1%		103,337	-8.3%		1,035	-8.3%
2008	Jun	99,904	0.1%		116,415	12.7%		1,165	12.5%
2008	Jul	100,005	0.1%		141,804	21.8%		1,418	21.7%
2008	Aug	100,111	0.1%		150,504	6.1%		1,503	6.0%
2008	Sep	100,224	0.1%		132,501	-12.0%		1,322	-12.1%
2008	Oct	100,367	0.1%		111,294	-16.0%		1,109	-16.1%
2008	Nov	100,467	0.1%		111,932	0.6%		1,114	0.5%
2008	Dec	100,601	0.1%		133,116	18.9%		1,323	18.8%

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

SMALL COMMERCIAL & INDUSTRIAL CLASSIFICATION

Year	Month	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2004	Jan	11,441		57,183		4,998	
2004	Feb	11,463	0.2%	50,689	-11.4%	4,422	-11.5%
2004	Mar	11,464	0.0%	44,683	-11.8%	3,898	-11.9%
2004	Apr	11,474	0.1%	44,360	-0.7%	3,866	-0.8%
2004	May	11,541	0.6%	56,934	28.3%	4,933	27.6%
2004	Jun	11,566	0.2%	60,647	6.5%	5,244	6.3%
2004	Jul	11,564	0.0%	63,029	3.9%	5,450	3.9%
2004	Aug	11,580	0.1%	58,711	-6.9%	5,070	-7.0%
2004	Sep	11,589	0.1%	57,161	-2.6%	4,932	-2.7%
2004	Oct	11,562	-0.2%	50,666	-11.4%	4,382	-11.2%
2004	Nov	11,611	0.4%	52,354	3.3%	4,509	2.9%
2004	Dec	11,660	0.4%	63,316	20.9%	5,430	20.4%
2005	Jan	11,687	0.2%	57,581	-9.1%	4,927	-9.3%
2005	Feb	11,711	0.2%	54,530	-5.3%	4,656	-5.5%
2005	Mar	11,735	0.2%	53,863	-1.2%	4,590	-1.4%
2005	Apr	11,759	0.2%	51,558	-4.3%	4,385	-4.5%
2005	May	11,782	0.2%	56,667	9.9%	4,809	9.7%
2005	Jun	11,806	0.2%	63,513	12.1%	5,380	11.9%
2005	Jul	11,830	0.2%	67,535	6.3%	5,709	6.1%
2005	Aug	11,854	0.2%	63,825	-5.5%	5,384	-5.7%
2005	Sep	11,877	0.2%	59,669	-6.5%	5,024	-6.7%
2005	Oct	11,901	0.2%	57,031	-4.4%	4,792	-4.6%
2005	Nov	11,925	0.2%	58,971	3.4%	4,945	3.2%
2005	Dec	11,948	0.2%	59,356	0.7%	4,968	0.5%
2006	Jan	11,975	0.2%	60,992	2.8%	5,093	2.5%
2006	Feb	11,999	0.2%	57,727	-5.4%	4,811	-5.5%
2006	Mar	12,022	0.2%	57,241	-0.8%	4,761	-1.0%
2006	Apr	12,046	0.2%	54,786	-4.3%	4,548	-4.5%
2006	May	12,070	0.2%	60,094	9.7%	4,979	9.5%
2006	Jun	12,093	0.2%	66,901	11.3%	5,532	11.1%
2006	Jul	12,118	0.2%	71,323	6.6%	5,886	6.4%
2006	Aug	12,142	0.2%	67,549	-5.3%	5,563	-5.5%
2006	Sep	12,166	0.2%	63,376	-6.2%	5,209	-6.4%
2006	Oct	12,190	0.2%	60,799	-4.1%	4,988	-4.3%
2006	Nov	12,214	0.2%	62,590	2.9%	5,125	2.7%
2006	Dec	12,238	0.2%	63,039	0.7%	5,151	0.5%
2007	Jan	12,263	0.2%	61,992	-1.7%	5,055	-1.9%
2007	Feb	12,287	0.2%	58,727	-5.3%	4,780	-5.5%
2007	Mar	12,310	0.2%	58,241	-0.8%	4,731	-1.0%
2007	Apr	12,334	0.2%	55,787	-4.2%	4,523	-4.4%
2007	May	12,358	0.2%	61,096	9.5%	4,944	9.3%
2007	Jun	12,382	0.2%	67,904	11.1%	5,484	10.9%
2007	Jul	12,406	0.2%	72,091	6.2%	5,811	6.0%
2007	Aug	12,430	0.2%	68,319	-5.2%	5,496	-5.4%
2007	Sep	12,454	0.2%	64,147	-6.1%	5,151	-6.3%
2007	Oct	12,478	0.2%	61,571	-4.0%	4,934	-4.2%
2007	Nov	12,502	0.2%	63,363	2.9%	5,068	2.7%
2007	Dec	12,526	0.2%	63,814	0.7%	5,094	0.5%
2008	Jan	12,550	0.2%	62,770	-1.6%	5,001	-1.8%
2008	Feb	12,574	0.2%	59,507	-5.2%	4,732	-5.4%
2008	Mar	12,598	0.2%	59,023	-0.8%	4,685	-1.0%
2008	Apr	12,622	0.2%	56,570	-4.2%	4,482	-4.3%
2008	May	12,646	0.2%	61,880	9.4%	4,893	9.2%
2008	Jun	12,670	0.2%	68,689	11.0%	5,421	10.8%
2008	Jul	12,694	0.2%	72,878	6.1%	5,741	5.9%
2008	Aug	12,719	0.2%	69,106	-5.2%	5,433	-5.4%
2008	Sep	12,743	0.2%	64,935	-6.0%	5,096	-6.2%
2008	Oct	12,767	0.2%	62,360	-4.0%	4,885	-4.1%
2008	Nov	12,791	0.2%	64,153	2.9%	5,016	2.7%
2008	Dec	12,815	0.2%	64,605	0.7%	5,041	0.5%

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

LARGE INDUSTRIAL - DIRECT SERVE CUSTOMERS

Year	Month	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2004	Jan	20		80,988		4,049,422	
2004	Feb	20	0.0%	77,087	-4.8%	3,854,327	-4.8%
2004	Mar	20	0.0%	84,176	9.2%	4,208,801	9.2%
2004	Apr	20	0.0%	83,421	-0.9%	4,171,041	-0.9%
2004	May	20	0.0%	88,804	6.5%	4,440,201	6.5%
2004	Jun	20	0.0%	83,702	-5.7%	4,185,090	-5.7%
2004	Jul	20	0.0%	85,115	1.7%	4,255,734	1.7%
2004	Aug	20	0.0%	85,663	0.6%	4,283,125	0.6%
2004	Sep	20	0.0%	83,659	-2.3%	4,182,973	-2.3%
2004	Oct	20	0.0%	85,675	2.4%	4,283,766	2.4%
2004	Nov	20	0.0%	82,716	-3.5%	4,135,820	-3.5%
2004	Dec	20	0.0%	80,785	-2.3%	4,039,250	-2.3%
2005	Jan	20	0.0%	83,233	3.0%	4,161,634	3.0%
2005	Feb	20	0.0%	78,454	-5.7%	3,922,709	-5.7%
2005	Mar	20	0.0%	85,034	8.4%	4,251,685	8.4%
2005	Apr	20	0.0%	83,925	-1.3%	4,196,230	-1.3%
2005	May	20	0.0%	89,346	6.5%	4,467,277	6.5%
2005	Jun	20	0.0%	84,277	-5.7%	4,213,858	-5.7%
2005	Jul	20	0.0%	85,740	1.7%	4,287,015	1.7%
2005	Aug	20	0.0%	86,281	0.6%	4,314,031	0.6%
2005	Sep	20	0.0%	84,185	-2.4%	4,209,246	-2.4%
2005	Oct	20	0.0%	86,239	2.4%	4,311,974	2.4%
2005	Nov	20	0.0%	81,672	-5.3%	4,083,592	-5.3%
2005	Dec	20	0.0%	79,682	-2.4%	3,984,124	-2.4%
2006	Jan	20	0.0%	83,233	4.5%	4,161,634	4.5%
2006	Feb	20	0.0%	78,454	-5.7%	3,922,709	-5.7%
2006	Mar	20	0.0%	85,034	8.4%	4,251,685	8.4%
2006	Apr	20	0.0%	83,925	-1.3%	4,196,230	-1.3%
2006	May	20	0.0%	89,346	6.5%	4,467,277	6.5%
2006	Jun	20	0.0%	84,277	-5.7%	4,213,858	-5.7%
2006	Jul	20	0.0%	85,740	1.7%	4,287,015	1.7%
2006	Aug	20	0.0%	86,281	0.6%	4,314,031	0.6%
2006	Sep	20	0.0%	84,185	-2.4%	4,209,246	-2.4%
2006	Oct	20	0.0%	86,239	2.4%	4,311,974	2.4%
2006	Nov	20	0.0%	81,672	-5.3%	4,083,592	-5.3%
2006	Dec	20	0.0%	79,682	-2.4%	3,984,124	-2.4%
2007	Jan	20	0.0%	84,125	5.6%	4,206,274	5.6%
2007	Feb	20	0.0%	79,261	-5.8%	3,963,029	-5.8%
2007	Mar	20	0.0%	85,927	8.4%	4,296,325	8.4%
2007	Apr	20	0.0%	84,789	-1.3%	4,239,430	-1.3%
2007	May	20	0.0%	90,238	6.4%	4,511,917	6.4%
2007	Jun	20	0.0%	85,141	-5.6%	4,257,058	-5.6%
2007	Jul	20	0.0%	86,633	1.8%	4,331,655	1.8%
2007	Aug	20	0.0%	87,173	0.6%	4,358,671	0.6%
2007	Sep	20	0.0%	85,049	-2.4%	4,252,446	-2.4%
2007	Oct	20	0.0%	87,132	2.4%	4,356,614	2.4%
2007	Nov	20	0.0%	82,536	-5.3%	4,126,792	-5.3%
2007	Dec	20	0.0%	80,575	-2.4%	4,028,764	-2.4%
2008	Jan	20	0.0%	84,125	4.4%	4,206,274	4.4%
2008	Feb	20	0.0%	79,261	-5.8%	3,963,029	-5.8%
2008	Mar	20	0.0%	85,927	8.4%	4,296,325	8.4%
2008	Apr	20	0.0%	84,789	-1.3%	4,239,430	-1.3%
2008	May	20	0.0%	90,238	6.4%	4,511,917	6.4%
2008	Jun	20	0.0%	85,141	-5.6%	4,257,058	-5.6%
2008	Jul	20	0.0%	86,633	1.8%	4,331,655	1.8%
2008	Aug	20	0.0%	87,173	0.6%	4,358,671	0.6%
2008	Sep	20	0.0%	85,049	-2.4%	4,252,446	-2.4%
2008	Oct	20	0.0%	87,132	2.4%	4,356,614	2.4%
2008	Nov	20	0.0%	82,536	-5.3%	4,126,792	-5.3%
2008	Dec	20	0.0%	80,575	-2.4%	4,028,764	-2.4%

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

STREET LIGHTING CLASSIFICATION

Year	Month	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2004	Jan	76		259		3,407	
2004	Feb	77	1.3%	237	-8.6%	3,075	-9.8%
2004	Mar	77	0.0%	217	-8.5%	2,813	-8.5%
2004	Apr	78	1.3%	230	6.4%	2,955	5.1%
2004	May	78	0.0%	264	14.5%	3,383	14.5%
2004	Jun	80	2.6%	275	4.3%	3,441	1.7%
2004	Jul	80	0.0%	261	-5.0%	3,268	-5.0%
2004	Aug	80	0.0%	247	-5.4%	3,091	-5.4%
2004	Sep	80	0.0%	236	-4.4%	2,954	-4.4%
2004	Oct	81	1.3%	219	-7.4%	2,700	-8.6%
2004	Nov	81	0.0%	252	15.1%	3,108	15.1%
2004	Dec	81	0.0%	300	19.0%	3,700	19.0%
2005	Jan	81	0.4%	267	-10.8%	3,285	-11.2%
2005	Feb	81	0.2%	245	-8.4%	3,003	-8.6%
2005	Mar	82	0.2%	246	0.4%	3,009	0.2%
2005	Apr	82	0.2%	243	-0.9%	2,976	-1.1%
2005	May	82	0.2%	261	7.2%	3,183	7.0%
2005	Jun	82	0.2%	282	8.2%	3,438	8.0%
2005	Jul	82	0.2%	276	-2.2%	3,356	-2.4%
2005	Aug	82	0.2%	241	-12.8%	2,922	-12.9%
2005	Sep	83	0.2%	226	-6.3%	2,732	-6.5%
2005	Oct	83	0.2%	230	2.1%	2,784	1.9%
2005	Nov	83	0.2%	270	17.2%	3,256	16.9%
2005	Dec	83	0.2%	271	0.5%	3,265	0.3%
2006	Jan	83	0.2%	272	0.4%	3,272	0.2%
2006	Feb	83	0.2%	250	-8.3%	2,996	-8.4%
2006	Mar	84	0.2%	251	0.4%	3,003	0.2%
2006	Apr	84	0.2%	249	-0.9%	2,970	-1.1%
2006	May	84	0.2%	266	7.0%	3,173	6.8%
2006	Jun	84	0.2%	287	8.0%	3,421	7.8%
2006	Jul	84	0.2%	281	-2.1%	3,342	-2.3%
2006	Aug	84	0.2%	246	-12.5%	2,918	-12.7%
2006	Sep	84	0.2%	231	-6.2%	2,732	-6.4%
2006	Oct	85	0.2%	236	2.1%	2,783	1.9%
2006	Nov	85	0.2%	275	16.8%	3,244	16.6%
2006	Dec	85	0.2%	276	0.5%	3,253	0.3%
2007	Jan	85	0.2%	277	0.4%	3,260	0.2%
2007	Feb	85	0.2%	255	-8.1%	2,990	-8.3%
2007	Mar	85	0.2%	256	0.4%	2,997	0.2%
2007	Apr	86	0.2%	254	-0.9%	2,965	-1.1%
2007	May	86	0.2%	271	6.9%	3,163	6.7%
2007	Jun	86	0.2%	293	7.9%	3,406	7.7%
2007	Jul	86	0.2%	286	-2.1%	3,329	-2.3%
2007	Aug	86	0.2%	251	-12.3%	2,914	-12.5%
2007	Sep	86	0.2%	236	-6.1%	2,732	-6.2%
2007	Oct	87	0.2%	241	2.0%	2,781	1.8%
2007	Nov	87	0.2%	280	16.4%	3,232	16.2%
2007	Dec	87	0.2%	281	0.5%	3,242	0.3%
2008	Jan	87	0.2%	283	0.4%	3,248	0.2%
2008	Feb	87	0.2%	260	-8.0%	2,985	-8.1%
2008	Mar	87	0.2%	261	0.4%	2,991	0.2%
2008	Apr	87	0.2%	259	-0.9%	2,959	-1.0%
2008	May	88	0.2%	276	6.7%	3,153	6.6%
2008	Jun	88	0.2%	298	7.7%	3,391	7.5%
2008	Jul	88	0.2%	292	-2.1%	3,316	-2.2%
2008	Aug	88	0.2%	256	-12.1%	2,910	-12.2%
2008	Sep	88	0.2%	241	-6.0%	2,731	-6.1%
2008	Oct	88	0.2%	246	2.0%	2,780	1.8%
2008	Nov	89	0.2%	285	16.1%	3,222	15.9%
2008	Dec	89	0.2%	287	0.5%	3,231	0.3%

BIG RIVERS ELECTRIC CORPORATION

2005 SHORT-TERM LOAD FORECAST - BASE CASE

IRRIGATION CLASSIFICATION

Year	Month	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2004	Jan	4		0		0	
2004	Feb	4	0.0%	0	0.0%	0	0.0%
2004	Mar	4	0.0%	0	0.0%	0	0.0%
2004	Apr	4	0.0%	0	0.0%	0	0.0%
2004	May	4	0.0%	0	0.0%	0	0.0%
2004	Jun	4	0.0%	0	0.0%	0	0.0%
2004	Jul	4	0.0%	0	0.0%	0	0.0%
2004	Aug	4	0.0%	164	0.0%	40,939	0.0%
2004	Sep	4	0.0%	0	-100.0%	0	-100.0%
2004	Oct	4	0.0%	0	0.0%	0	0.0%
2004	Nov	4	0.0%	0	0.0%	0	0.0%
2004	Dec	4	0.0%	0	0.0%	0	0.0%
2005	Jan	4	0.0%	0	0.0%	0	0.0%
2005	Feb	4	0.0%	0	0.0%	0	0.0%
2005	Mar	4	0.0%	0	0.0%	0	0.0%
2005	Apr	4	0.0%	0	0.0%	0	0.0%
2005	May	4	0.0%	0	0.0%	0	0.0%
2005	Jun	4	0.0%	0	0.0%	0	0.0%
2005	Jul	4	0.0%	0	0.0%	0	0.0%
2005	Aug	4	0.0%	164	0.0%	41,000	0.0%
2005	Sep	4	0.0%	0	-100.0%	0	-100.0%
2005	Oct	4	0.0%	0	0.0%	0	0.0%
2005	Nov	4	0.0%	0	0.0%	0	0.0%
2005	Dec	4	0.0%	0	0.0%	0	0.0%
2006	Jan	4	0.0%	0	0.0%	0	0.0%
2006	Feb	4	0.0%	0	0.0%	0	0.0%
2006	Mar	4	0.0%	0	0.0%	0	0.0%
2006	Apr	4	0.0%	0	0.0%	0	0.0%
2006	May	4	0.0%	0	0.0%	0	0.0%
2006	Jun	4	0.0%	0	0.0%	0	0.0%
2006	Jul	4	0.0%	0	0.0%	0	0.0%
2006	Aug	4	0.0%	164	0.0%	41,000	0.0%
2006	Sep	4	0.0%	0	-100.0%	0	-100.0%
2006	Oct	4	0.0%	0	0.0%	0	0.0%
2006	Nov	4	0.0%	0	0.0%	0	0.0%
2006	Dec	4	0.0%	0	0.0%	0	0.0%
2007	Jan	4	0.0%	0	0.0%	0	0.0%
2007	Feb	4	0.0%	0	0.0%	0	0.0%
2007	Mar	4	0.0%	0	0.0%	0	0.0%
2007	Apr	4	0.0%	0	0.0%	0	0.0%
2007	May	4	0.0%	0	0.0%	0	0.0%
2007	Jun	4	0.0%	0	0.0%	0	0.0%
2007	Jul	4	0.0%	0	0.0%	0	0.0%
2007	Aug	4	0.0%	164	0.0%	41,000	0.0%
2007	Sep	4	0.0%	0	-100.0%	0	-100.0%
2007	Oct	4	0.0%	0	0.0%	0	0.0%
2007	Nov	4	0.0%	0	0.0%	0	0.0%
2007	Dec	4	0.0%	0	0.0%	0	0.0%
2008	Jan	4	0.0%	0	0.0%	0	0.0%
2008	Feb	4	0.0%	0	0.0%	0	0.0%
2008	Mar	4	0.0%	0	0.0%	0	0.0%
2008	Apr	4	0.0%	0	0.0%	0	0.0%
2008	May	4	0.0%	0	0.0%	0	0.0%
2008	Jun	4	0.0%	0	0.0%	0	0.0%
2008	Jul	4	0.0%	0	0.0%	0	0.0%
2008	Aug	4	0.0%	164	0.0%	41,000	0.0%
2008	Sep	4	0.0%	0	-100.0%	0	-100.0%
2008	Oct	4	0.0%	0	0.0%	0	0.0%
2008	Nov	4	0.0%	0	0.0%	0	0.0%
2008	Dec	4	0.0%	0	0.0%	0	0.0%

Appendix B
Tables – Long-Term Forecast

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL NATIVE REQUIREMENTS

Year	Consumers	Percent Growth	Native Energy Sales (MWh)	Normal Sales (MWh)	Percent Growth	Gen. & Trans. Losses	Native Requirements (MWh)	Normal Requirements (MWh)	Percent Growth
1989	79,851		8,072,761	8,064,940		2.10%	8,246,176	8,238,186	
1990	81,050	1.5%	8,191,465	8,223,545	2.0%	2.81%	8,428,685	8,461,694	2.7%
1991	82,199	1.4%	8,314,440	8,271,953	0.6%	2.22%	8,503,057	8,459,606	0.0%
1992	83,735	1.9%	8,326,337	8,378,301	1.3%	1.76%	8,475,933	8,528,831	0.8%
1993	85,500	2.1%	8,445,131	8,400,645	0.3%	2.81%	8,688,975	8,643,204	1.3%
1994	87,256	2.1%	7,454,220	7,468,126	-11.1%	3.46%	7,721,677	7,736,082	-10.5%
1995	89,393	2.4%	7,961,435	7,929,880	6.2%	0.81%	8,026,476	7,994,663	3.3%
1996	91,544	2.4%	8,045,962	8,037,526	1.4%	2.30%	8,235,361	8,226,726	2.9%
1997	93,842	2.5%	8,127,361	8,155,543	1.5%	3.02%	8,380,094	8,409,153	2.2%
1998	96,152	2.5%	6,063,704	6,064,811	-25.6%	2.33%	6,208,552	6,209,685	-26.2%
1999	98,168	2.1%	3,468,648	3,514,440	-42.1%	1.82%	3,532,841	3,579,480	-42.4%
2000	100,270	2.1%	3,540,880	3,556,620	1.2%	1.57%	3,597,500	3,613,491	1.0%
2001	101,987	1.7%	3,284,322	3,308,744	-7.0%	1.41%	3,331,207	3,355,977	-7.1%
2002	103,481	1.5%	3,192,013	3,179,639	-3.9%	1.25%	3,232,553	3,220,021	-4.1%
2003	104,763	1.2%	3,052,358	3,161,430	-0.6%	1.14%	3,087,548	3,197,877	-0.7%
2004	106,414	1.6%	3,130,003	3,189,428	0.9%	0.91%	3,158,698	3,218,668	0.7%
2005	108,000	1.5%		3,279,478	2.8%	0.81%		3,306,259	2.7%
2006	109,541	1.4%		3,350,889	2.2%	0.81%		3,378,253	2.2%
2007	111,139	1.5%		3,403,824	1.6%	0.81%		3,431,620	1.6%
2008	112,768	1.5%		3,445,744	1.2%	0.81%		3,473,882	1.2%
2009	114,383	1.4%		3,491,439	1.3%	0.81%		3,519,951	1.3%
2010	116,052	1.5%		3,535,326	1.3%	0.81%		3,564,196	1.3%
2011	117,843	1.5%		3,586,916	1.5%	0.81%		3,616,207	1.5%
2012	119,691	1.6%		3,634,687	1.3%	0.81%		3,664,368	1.3%
2013	121,596	1.6%		3,687,087	1.4%	0.81%		3,717,197	1.4%
2014	123,516	1.6%		3,737,410	1.4%	0.81%		3,767,931	1.4%
2015	125,472	1.6%		3,794,649	1.5%	0.81%		3,825,636	1.5%
2016	127,428	1.6%		3,847,280	1.4%	0.81%		3,878,697	1.4%
2017	129,422	1.6%		3,904,585	1.5%	0.81%		3,936,470	1.5%
2018	131,431	1.6%		3,959,648	1.4%	0.81%		3,991,983	1.4%
2019	133,462	1.5%		4,021,242	1.6%	0.81%		4,054,080	1.6%

ANNUAL GROWTH RATES

1989-1994	1.8%		-1.6%	-1.5%		10.5%	-1.3%	-1.2%	
1994-1999	2.4%		-14.2%	-14.0%		-12.1%	-14.5%	-14.3%	
1999-2004	1.6%		-2.0%	-1.9%		-12.9%	-2.2%	-2.1%	
2004-2009	1.5%			1.8%		-2.3%		1.8%	
2009-2014	1.5%			1.4%		0.0%		1.4%	
2014-2019	1.6%			1.5%		0.0%		1.5%	
2004-2019	1.5%			1.6%		-0.8%		1.6%	

Appendix D - Database of Data Sources - Relevant Commercial Sector Studies and Reports

Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
33	How to Buy an Energy Efficient Commercial Refrigerator and Freezer	4-Jan	3	Federal Emergency Management Program	Federal Emergency Management Program	Commercial	Online Brochure	National	Yes/PDF
34	How to Buy an Energy Efficient Water Cooled Electric Chiller	Nov-00	4	Federal Emergency Management Program	Federal Emergency Management Program	Commercial	Online Brochure	National	Yes/PDF
35	California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study Study ID #SW061	May-03	208	Mike Rufo and Fred Coito	KEMA-XENERGY Inc	Commercial	Technical Potential	California	Yes/PDF
38	How to Buy an Energy-Efficient Family-Sized Commercial Clothes Washer	Nov-00	2	Federal Emergency Management Program	Federal Emergency Management Program	Commercial	Online Brochure	National	Yes/PDF
39	Massachusetts Market Transformation Scoping Study	1997	198	Arthur D. Little	Mass Gas DSM/Market Transformation Collarborative		Report	Massachusetts	No (Hard Copy)
40	Assessment of Energy and Capacity Savings Potential in Iowa	Jul-02			Global Energy Partners and Quantec, LLC			Iowa	

Appendix D - Database of Data Sources - Relevant Industrial Sector Studies and Reports

Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
1	MN Master Tech Assumptions	2003	10	MN Dept of Commerce	MN Dept of Commerce	C/I	B/C Assumptions	MN LG C/I	Yes
2	California Industrial Energy Efficiency Market Characterization Study	2001		Xenergy	PG & E	Industrial	Market Research Study	California	
3	The Compressed Air Systems Market Assessment and Baseline Study for New England.	2003	71	Aspen Systems	Compressed Air Study Group	Industrial	Baseline	New England	No
4	Energy Management in Industry	1995	89	Caffel, C.	Centre for the Analysis and Dissemination of Demonstrated Energy Technologies (CADDET)	Industrial	Report	National	Yes/PDF
5	Saving Energy with Efficient Compressed Air Systems	1997		CADDET	CADDET		Brochure	National	
6	Saving Energy with Daylighting Systems	2001		CADDET	CADDET		Brochure	National	
7	Cooling, Heating and Power for Buildings (http://www.bchp.org/index.html - original broken link) (htt://www.chpcentermw.org/home.html - updated link)	2002	not applicable	Midwest CHP Application Center	DOE/ORNL		website	National	Yes
8	Guidelines for Selecting a Compressed Air System Service Provider and Levels of Analysis of Compressed Air Systems	2002	4	Compressed Air Challenge	Compressed Air Challenge			National	Yes/PDF
9	Energy Efficiency Opportunities in the Solid Wood Industries	1996	44	Carrol-Hatch Ltd.	Council of Forest Industries	Industrial	Report	National	Yes/PDF
10	ICARUS-3: The Potential of Energy Efficiency Improvement in the Netherlands up to 2000 and 2015	1994		De Beer, J.G., van Wees, M.T., Worrell, E., and Blok, K			Tech. Potential	Netherlands	
11	Industries of the Future Program for Metal Casting (http://www.eere.energy.gov/industry/metalcasting)	2003	not applicable	Office of Industrial Technologies, Energy Efficiency and Renewable Energy	DOE	Industrial	website	National	Yes
12	Electricity Consumption and the Potential for Electric Energy Savings in the Manufacturing Sector	1994	60	N.R. Elliot	ACEEE	Industrial	Tech. Potential	National	
13	Manufacturing Energy Consumption Survey 1994	1997	541	Energy Information Administration	Energy Information Administration (DOE)	Industrial	Survey	National	Yes/PDF
14	Energy Efficiency Improvement and Cost Saving Opportunities for the Vehicle Assembly Industry - A Guide for Energy and Plant Managers	Jan-03	78	Galitsky, C. and E. Worrell	LBNL	Industrial	Report	National	Yes/PDF
15	Energy Efficiency Opportunities for United States Breweries	2001	11	Galitsky, Christina, Nathan Martin, and Ernst Worrell	MBAA Technical Quarterly	Industrial	Article	National	Yes/PDF

Appendix D - Database of Data Sources - Relevant Industrial Sector Studies and Reports

Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
16	Pump Life Cycle Costs: A Guide to LCC Analysis for Pumping Systems	2001	19	Hydraulic Institute and Europump	Hydraulic Institute and Europump	Industrial		National	Yes/PDF
17	Efficiency Prediction Method for Centrifugal Pumps	1994		Hydraulic Institute	Hydraulic Institute	Industrial			
18	Pumps and Standards Since 1917- The Hydraulic Institute (http://www.pumps.org/)	2002	not applicable	Hydraulic Institute	Hydraulic Institute	Industrial	website	National	Yes
19	Industrial Assessment Center Database. (http://oipea-www.rutgers.edu/site_docs/dbase.html - original broken link) (http://iac.rutgers.edu/database - new link)		not applicable	Industrial Assessment Center	Industrial Assessment Center	Industrial	website	National	Yes
20	Information Plastic Processing Industry	1996			InfoMil	Industrial			
21	Information for Bread and Bread-and Pastry-Bakeries for energy use in the Environmental Permitting	1997			InfoMil	Industrial			
22	Group-Compressed Air Systems Energy Reduction Basics. (http://www.air.ingersoll-rand.com/NEW/pedwards.htm)	2001	not applicable	Ingersoll Rand	Air Solutions	Industrial	website	National	Yes
23	Scenarios for a Clean Energy Future	2000	371	Interlaboratory Working Group (ORNL & LBNL)	Office of Energy Efficiency and Renewable Energy	All		National	Yes/PDF
24	Industrial Electric Motor Drive Systems	1998	204	Jallouk, P., and C.D. Liles	CADDET	Industrial		National	Yes/PDF
25	Improving Compressed Air System Performance, a Sourcebook for Industry	1998	128	Lawrence Berkeley National Laboratory (LBNL) and Resource Dynamics Corporation	DOE Motor Callenge Program	Industrial		National	Yes/PDF
26	Improving Pumping System Performance: A Sourcebook for Industry	1999		Lawrence Berkeley National Laboratory (LBNL) and Resource Dynamics Corporation	DOE Motor Callenge Program	Industrial	Sourcebook	National	
27	Commercial and Industrial O&M Market Segment Baseline Study (Final Report)	Jul-99	158	Ledyard, T., L. Barbagallo and E. Lionberger	NE/NJ Utility Consortium	C/I	Baseline Study	NE/NJ	Yes/PDF
28	Opportunities to Improve Energy Efficiency and Reduce Greenhouse Gas Emissions in the U.S. Pulp and Paper Industry	Jul-00	58	Martin, N., N. Anglani, D. Einstein, M. Khrushch, E. Worrell, L.K. Price	Lawrence Berkeley National Laboratory	Industrial	Report	National	Yes/PDF
29	Emerging Energy-Efficient Industrial Technologies	2000	195	Martin, N., E. Worrell, M. Ruth, L. Price, R.N. Elliott, A.M. Shipley, J. Thorne	PG&E	Industrial	Report	National	Yes/PDF

Appendix D - Database of Data Sources - Relevant Industrial Sector Studies and Reports

Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
30	Learning from Experiences with Industrial Drying Technologies	1994		Mercer, A.C	CADDET	Industrial	Report		
31	Energy Efficiency in the Metals Fabrication Industries	1995	3	Michaelson, D. A. and F. T. Sparrow	ACCEEE	Industrial	Report		
32	Guide to Energy-Efficiency Opportunities in the Dairy Processing Industry	1997	36	Wardrop Engineering, Inc.	National Dairy Council of Canada	Industrial	Report		Yes/PDF
33	1999 O&M Services Program Impact and Process Evaluation - Final Report	2001	70	RLW Analytics, Inc.	Northeast Utilities System	C/I	Report		No
34	New Construction Program Report on 2000 Measure Installations	2002	33	RLW Analytics, Inc.	Northeast Utilities System	C/I	Report		No
35	Energy Cost Reduction in the Pulp and Paper Industry	1999	30	Francis, DW et al.	Paprican	Industrial	Report		Yes/PDF
36	Compressed Air Systems in the European Union, Energy, Emissions, Savings Potential and Policy Actions	2001	10	Radgen, P. and E. Blaustein (eds.)	European Commission	Industrial	Report		Yes/PDF
37	California's Secret Energy Surplus; The Potential for Energy Efficiency	2002	137	Rufo, Mike and Fred Coito	The Energy Foundation	All	Report	California	Yes/PDF
38	Evaluation of Advanced Technologies for Residential Appliances and Residential and Commercial Lighting	1995		Turiel, I., B. Atkinson, s. Boghosian, P. Chan, J. Jennings, J. Lutz, J. McMahon, and G. Rosenquist	LBNL	R/C	Report		
39	Energy Efficiency in Pumping Systems: Experience and Trends in the Pulp and Paper Industry	1999	11	Tutterow, V	ACEEE	Industrial	Report		
40	Profiting from your Pumping System	2000	8	Tutterow, V., D. Casada and A. McKane	Pump & Systems Magazine	Industrial	Report		Yes/PDF
41	Energy Use and Energy Intensity of the U.S. Chemical Industry	Apr-00	40	Worrell, E., Dian Phylipsen, Dan Einstein, Nathan Martin	LBNL	Industrial	Report		Yes/PDF
42	Opportunities to Improve Energy Efficiency in the U.S. Pulp and Paper Industry	Feb-01		Worrell, Ernst, Nathan Martin, Norma Anglani, Dan Einstein, Marta Khrushch, Lynn Price		Industrial	Report		
43	United States Industrial Electric Motor Systems Market Opportunities Assessment	Dec-98	93	Xenergy, Inc.	DOE: Office of Industrial Technology and ORNL	Industrial	Market Assessment	National	Yes/PDF
44	Motorup Evaluation and Market Assessment	2001	93	Xenergy, Inc.	Motorup Corp.	C/I	Market Assessment	National	Yes/PDF
45	Energy-Efficient Motor Systems: A Handbook on Technology, Program and Policy Opportunities (2nd Edition)	2002	520	Nadel, S., N. Elliott, M. Shepard, S. Greenberg, G. Katz and A.T. de Almeida	ACEEE	Industrial	Handbook	National	

Appendix D - Database of Data Sources - Documents Supplied by Big Rivers Electric Corporation

File #	Title of Document	Date of Publication	Number of Pages/Tabs in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format?
1	Big Rivers Electric Corporation Load Forecast	June-05	113 pgs	GDS Associates	BREC	All	Load Forecast	All Sectors	Yes
2	Big Rivers Electric Corporation web site	October-05	NA	BREC	BREC	All	Web site	All Sectors	Yes

Appendix D - Database of Data Sources - Other Documents Reviewed by GDS

File #	Title of Document	Date of Publication	Number of Pages/Tabs in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format?
1	2003 Gas Facts	2004	124	American Gas Association (AGA)	AGA	All	Reference Fact Book	All	No
2	NJ Clean Energy Annual Report	July-02	20	New Jersey Board of Public Utilities	NJ BPU	All	Annual Report	n/a	PDF
3	2001 DEER	August-01	309	Xenergy, Inc	Calif Energy Commission	All	Database of Energy Efficiency Measures	Varies	PDF
4	America's Best: Profiles of America's Leading Energy Efficiency Programs	December-03	47 (plus 63 Indiv Prog Descriptions)	Dan York and Marti Kushler	ACEEE	All	Program Descriptions	Varies	PDF
5	A Framework for Planning and Assessing Publicly Funded Energy Efficiency	March-01	220	Frederick Sebold and Alan Fields (RER); Lisa Skumatz; Shel Feldman; Miriam Goldberg; Ken Keating; Jane Peters	PG&E	All	Program Design, Theory and Policy	Varies	PDF
6	Increasing Energy Efficiency in New Buildings in the Southwest: Energy Codes and Best Practices	August-02	115	Kinney, Larry; Geller, Howard; Ruzzin, Mark	Southwest Energy Efficiency Project (SWEEP)	Res and Comm	Program Planning and Best Practices	Varies	PDF
7	Selecting Targets for Market Transformation Programs: A National Analysis	August-98	174	Suozzo, Margaret; Nadel, Steven	ACEEE	Res and Comm	Market Transformation Programs: Measures Analysis	Varies	PDF
8	Performance Guidelines for Instantaneous Water Heaters to Meet the Comfort Needs of the American Consumer	May-03	38 slides	Darrell, Paul, PhD	Battelle	Residential	Presentation	Water Heating	No

Appendix D - Database of Data Sources - Other Documents Reviewed by GDS

File #	Title of Document	Date of Publication	Number of Pages/Tabs in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format?
9	California Standard Practice Manual	Oct-01	37	California Public Utilities Company	CA PUC	All	Economic Analysis of Demand-Side Management Programs and Projects		Yes/PDF
10	Attachment V-Developing Greenhouse Mitigation Supply Curves for In-State Sources, Climate Change Research Development and Demonstration Plan	Apr-03	85	Guido, Franco et al.	CA Energy Commission		Public Interest Energy Research Program		Yes/PDF
11	The Elements of Sustainability. Efficiency and Sustainability	2000		David C. Hewitt	ACEEE		Research Study	Buildings	
12	Demand-Side Management Market Penetration: Modeling and Resource Planning Perspectives from Central Maine Power Company	Apr-89	10	Richard F. Spellman	Electric Power Research Institute	All	Market Research	Maine	Yes/PDF
13	Market Transformation: Substantial Progress from a Decade of Work	Apr-03	60	Nadel, Thorne, Sachs, Prindle, Elliott	ACEEE		Market Research		Yes/PDF
14	Focus on Energy Public Benefits Statewide Evaluation, Quarterly Summary Report	Mar-03	24	Focus Evaluation Team	State of WI Department of Administration Division of Energy		Statewide Evaluation		Yes/PDF

Appendix D - Database of Data Sources - Other Documents Reviewed by GDS

File #	Title of Document	Date of Publication	Number of Pages/Tabs in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format?
15	Focus on Energy Statewide Evaluation, Non-Energy Benefits Cross-Cutting Report	Jan-03	93	Nick Hall, TecMarket Works, PA Consulting	State of WI Department of Administration Division of Energy		Statewide Evaluation		
16	Beyond Energy Savings: A Review of the Non-Energy Benefits Estimated for Three Low-Income Programs	2002	14	Nick Hall & Jeff Riggert, TecMarket Works	ACEEE		Program Evaluation		
17	Energy Efficiency and Renewable Sources: A Primer	Oct-01	56	National Assoc. of State Energy Officials	Global Environment & Technology Foundation		Research Study		Yes/PDF
18	Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies	Dec-03	98	Elliott, R. Neal et al.	ACEEE		Report		Yes/PDF
19	Population Size of Various Cities in the Big Rivers Service Area	Summer 2005	not applicable	U.S Censu Bureau	U.S. Census Bureau	Residential	website		Yes
20	Annual Heating and Cooling Operating Costs for Various Equipment in a Average-Size Home http://www.kenergy.corp/Geothermal_Heating_and_Cooling.php)	Summer 2005	not applicable	Kenergy Corporation	Kenergy Corporation	Residental	website		Yes
21	America's Best Natural Gas Energy Efficiency Programs	3-Dec	50	Kushler, M, D. York, and P Witte	ACEEE		Report		Yes/PDF
22	Methodology and Forecasts of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Programs	Oct-04	290	Energy and Environmental Economics, Inc.	California Public Utilities Commission	All	Forecast	California	Yes/PDF
23	Proportion of Single-Family and Multi-Family Homes in the Big River Service Area			ESRI	ESRI	Residental			

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE
TOTAL NATIVE ENERGY REQUIREMENTS
PLUS SMELTERS & FIRM OFF-SYSTEM CONTRACTS

Year	Native Energy Sales (MWh)	Smelters Energy Sales (MWh)	Native + Smelters (MWh)	Off-System Firm Sales (MWh)	Total Sales (MWh)
1989	2,210,746	5,862,015	8,072,761		8,072,761
1990	2,274,687	5,916,778	8,191,465		8,191,465
1991	2,345,228	5,969,212	8,314,440		8,314,440
1992	2,325,059	6,001,278	8,326,337		8,326,337
1993	2,478,362	5,966,768	8,445,131		8,445,131
1994	2,511,359	4,942,862	7,454,220		7,454,220
1995	3,153,395	4,808,040	7,961,435		7,961,435
1996	3,017,864	5,028,098	8,045,962		8,045,962
1997	3,094,475	5,032,885	8,127,361		8,127,361
1998	3,288,843	5,142,775	8,431,618		8,431,618
1999	3,468,648	5,606,178	9,074,826		9,074,826
2000	3,540,880	6,306,888	9,847,768		9,847,768
2001	3,284,322	6,983,985	10,268,307		10,268,307
2002	3,192,013	7,169,801	10,361,814		10,361,814
2003	3,052,358	7,306,866	10,359,224		10,359,224
2004	3,130,003	7,331,341	10,461,344		10,461,344
2005	3,279,478	7,331,341	10,610,819	700,800	11,311,619
2006	3,350,889	7,331,341	10,682,230	306,600	10,988,830
2007	3,403,824	7,331,341	10,735,165		10,735,165
2008	3,445,744	7,331,341	10,777,085		10,777,085
2009	3,491,439	7,331,341	10,822,781		10,822,781
2010	3,535,326	7,331,341	10,866,667		10,866,667
2011	3,586,916	7,331,341	10,918,257		10,918,257
2012	3,634,687	7,331,341	10,966,028		10,966,028
2013	3,687,087	7,331,341	11,018,429		11,018,429
2014	3,737,410	7,331,341	11,068,752		11,068,752
2015	3,794,649	7,331,341	11,125,990		11,125,990
2016	3,847,280	7,331,341	11,178,621		11,178,621
2017	3,904,585	7,331,341	11,235,926		11,235,926
2018	3,959,648	7,331,341	11,290,989		11,290,989
2019	4,021,242	7,331,341	11,352,583		11,352,583

ANNUAL GROWTH RATES

1989-1994					
1994-1999					
1999-2004	-2.0%	5.5%	2.9%		2.9%
2004-2009	2.2%	0.0%	0.7%		0.7%
2009-2014	1.4%	0.0%	0.5%		0.5%
2014-2019	1.5%	0.0%	0.5%		0.5%
2004-2019	1.7%	0.0%	0.5%		0.5%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE
TOTAL NATIVE DEMAND REQUIREMENTS
PLUS SMELTERS & FIRM OFF-SYSTEM CONTRACTS

Year	Native Demand (kW)	Smelters NCP (kW)	Native + Smelters (kW)	Off-System Firm Load (kW)	Total Demand (kW)
1989	480,994	696,006	1,177,000		1,177,000
1990	478,437	695,563	1,174,000		1,174,000
1991	477,490	690,510	1,168,000		1,168,000
1992	460,988	705,012	1,166,000		1,166,000
1993	516,721	700,279	1,217,000		1,217,000
1994	485,092	703,908	1,189,000		1,189,000
1995	578,221	587,779	1,166,000		1,166,000
1996	570,093	596,907	1,167,000		1,167,000
1997	596,198	598,802	1,195,000		1,195,000
1998	624,931	605,069	1,230,000		1,230,000
1999	663,890	703,354	1,367,244		1,367,244
2000	655,248	799,949	1,455,197		1,455,197
2001	614,496	824,256	1,438,752		1,438,752
2002	602,623	843,206	1,445,829		1,445,829
2003	585,549	856,713	1,442,262		1,442,262
2004	604,155	857,174	1,461,329		1,461,329
2005	633,622	857,174	1,490,796	80,000	1,570,796
2006	641,362	857,174	1,498,536	35,000	1,533,536
2007	656,658	857,174	1,513,832		1,513,832
2008	665,642	857,174	1,522,816		1,522,816
2009	675,440	857,174	1,532,614		1,532,614
2010	684,845	857,174	1,542,019		1,542,019
2011	695,958	857,174	1,553,132		1,553,132
2012	706,235	857,174	1,563,409		1,563,409
2013	717,515	857,174	1,574,689		1,574,689
2014	728,343	857,174	1,585,517		1,585,517
2015	740,670	857,174	1,597,844		1,597,844
2016	751,973	857,174	1,609,147		1,609,147
2017	764,286	857,174	1,621,460		1,621,460
2018	776,107	857,174	1,633,281		1,633,281
2019	789,356	857,174	1,646,530		1,646,530

ANNUAL GROWTH RATES

1989-1994					
1994-1999					
1999-2004	-1.9%	4.0%	1.3%		1.3%
2004-2009	2.3%	0.0%	1.0%		1.0%
2009-2014	1.5%	0.0%	0.7%		0.7%
2014-2019	1.6%	0.0%	0.8%		0.8%
2004-2019	1.8%	0.0%	0.8%		0.8%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL SYSTEM REQUIREMENTS

Year	Summer Actual CP (kW)	Summer Normal CP (kW)	Percent Growth	Normal Load Factor	Winter Actual CP (kW)	Winter Normal CP (kW)	Percent Growth	Normal Load Factor
1989								
1990								
1991	1,168,000	1,184,609			1,140,000	1,171,917		
1992	1,166,000	1,204,754			1,149,000	1,165,897		
1993	1,217,000	1,200,391			1,137,000	1,138,877		86.6%
1994	1,055,000	1,049,464	-12.6%	84.1%	1,189,000	1,123,289	-1.4%	78.6%
1995	1,166,000	1,138,318	8.5%	80.2%	1,080,000	1,100,652	-2.0%	82.9%
1996	1,167,000	1,194,682	5.0%	78.6%	1,154,000	1,125,838	2.3%	83.4%
1997	1,195,000	1,189,464	-0.4%	80.7%	1,156,000	1,142,858	1.5%	84.0%
1998	1,230,000	1,257,682	5.7%	56.4%	1,123,000	1,162,427	1.7%	61.0%
1999	663,890	658,354	-47.7%	62.1%	577,320	582,953	-49.9%	70.1%
2000	655,248	671,857	2.1%	61.4%	576,843	597,495	2.5%	69.0%
2001	596,310	646,137	-3.8%	59.3%	614,496	612,619	2.5%	62.5%
2002	602,623	608,160	-5.9%	60.4%	530,467	588,669	-3.9%	62.4%
2003	583,906	611,587	0.6%	59.7%	585,549	583,672	-0.8%	62.5%
2004	604,155	631,837	3.3%	58.2%	539,476	547,042	-6.3%	67.2%
2005		633,622	0.3%	59.6%		569,524	4.1%	66.3%
2006		641,362	1.2%	60.1%		585,253	2.8%	65.9%
2007		656,658	2.4%	59.7%		595,002	1.7%	65.8%
2008		665,642	1.4%	59.6%		607,564	2.1%	65.3%
2009		675,440	1.5%	59.5%		616,200	1.4%	65.2%
2010		684,845	1.4%	59.4%		625,716	1.5%	65.0%
2011		695,958	1.6%	59.3%		635,069	1.5%	65.0%
2012		706,235	1.5%	59.2%		645,699	1.7%	64.8%
2013		717,515	1.6%	59.1%		655,578	1.5%	64.7%
2014		728,343	1.5%	59.1%		666,309	1.6%	64.6%
2015		740,670	1.7%	59.0%		676,791	1.6%	64.5%
2016		751,973	1.5%	58.9%		688,446	1.7%	64.3%
2017		764,286	1.6%	58.8%		699,312	1.6%	64.3%
2018		776,107	1.5%	58.7%		711,091	1.7%	64.1%
2019		789,356	1.7%	58.6%		722,483	1.6%	64.1%

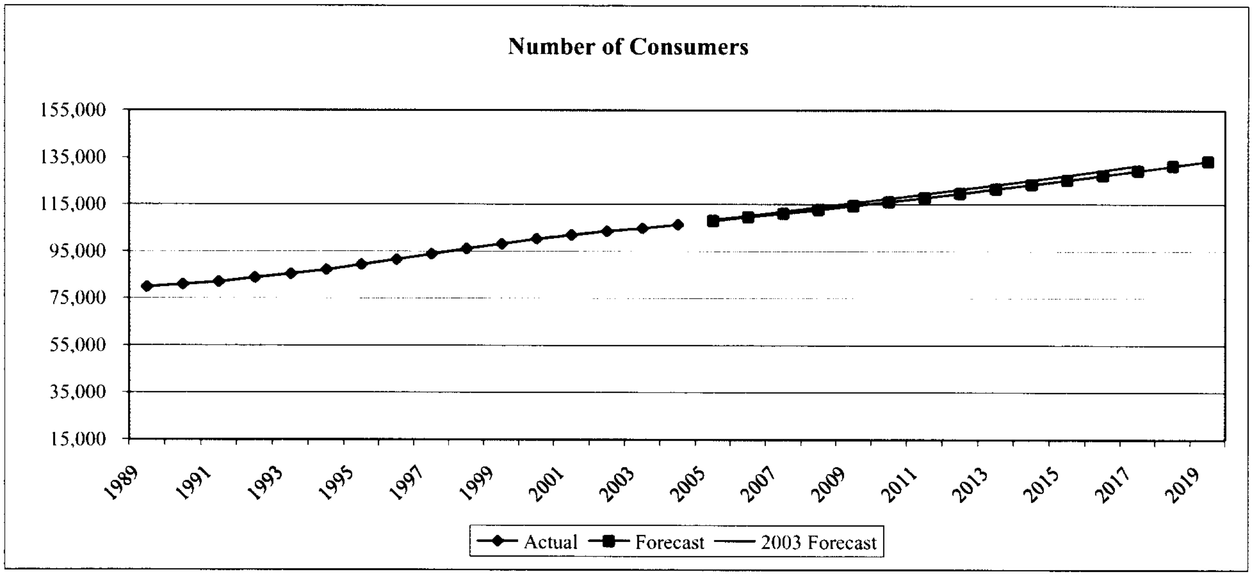
ANNUAL GROWTH RATES

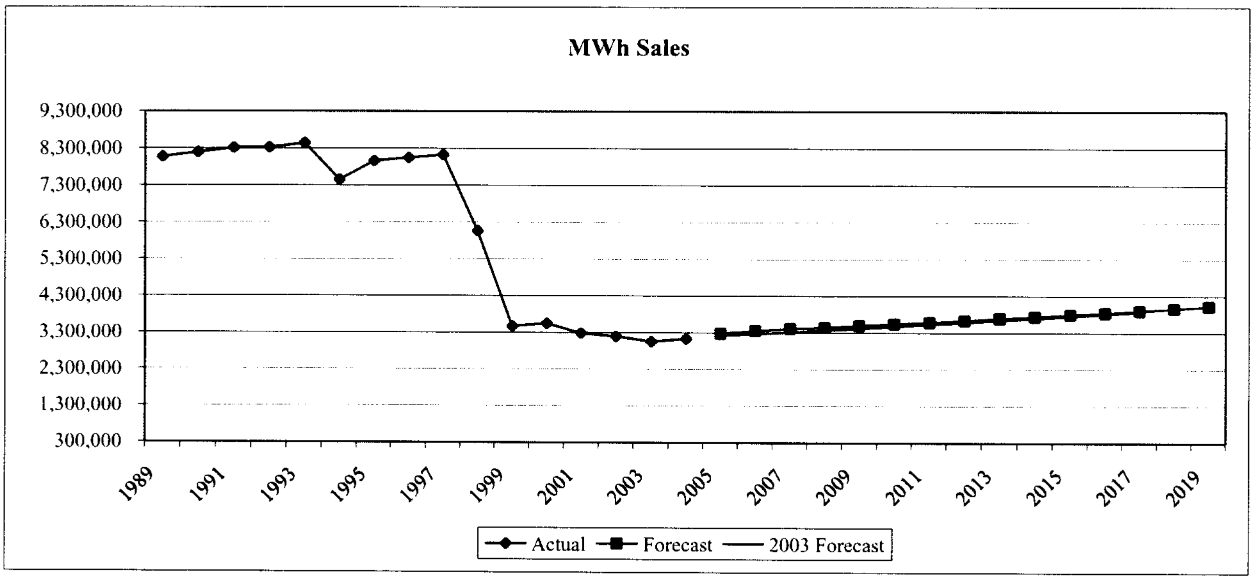
1989-1994								
1994-1999								
1999-2004	-1.9%	-0.8%		-1.3%	-1.3%	-1.3%		-0.8%
2004-2009		1.3%		0.5%		2.4%		-0.6%
2009-2014		1.5%		-0.1%		1.6%		-0.2%
2014-2019		1.6%		-0.1%		1.6%		-0.2%
2004-2019		1.5%		0.1%		1.9%		-0.3%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL NATIVE REQUIREMENTS

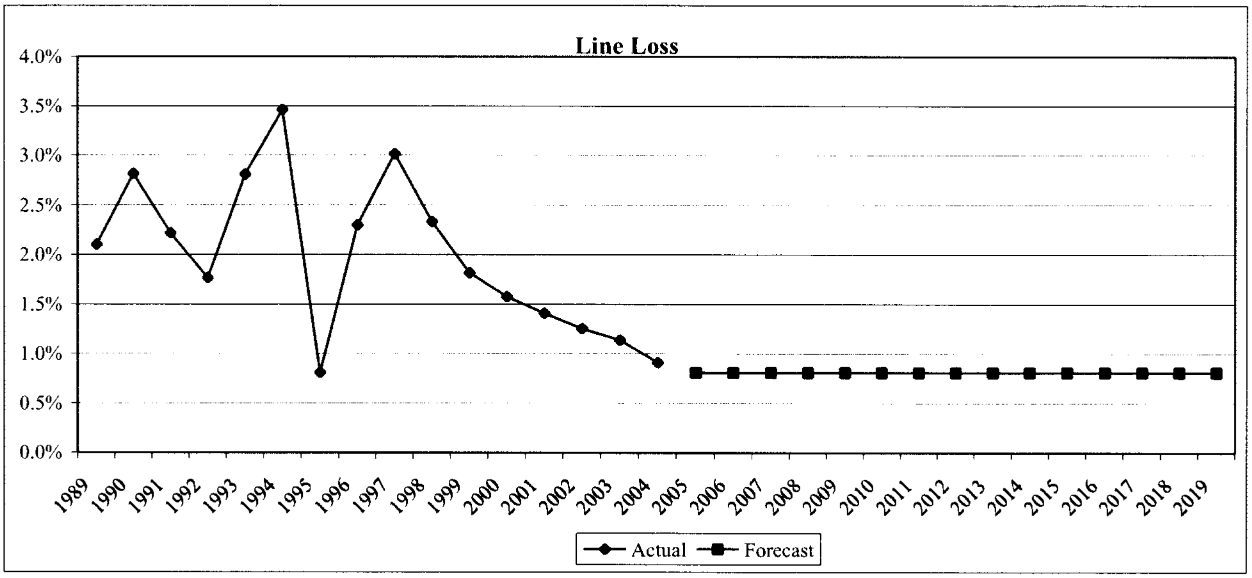




BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

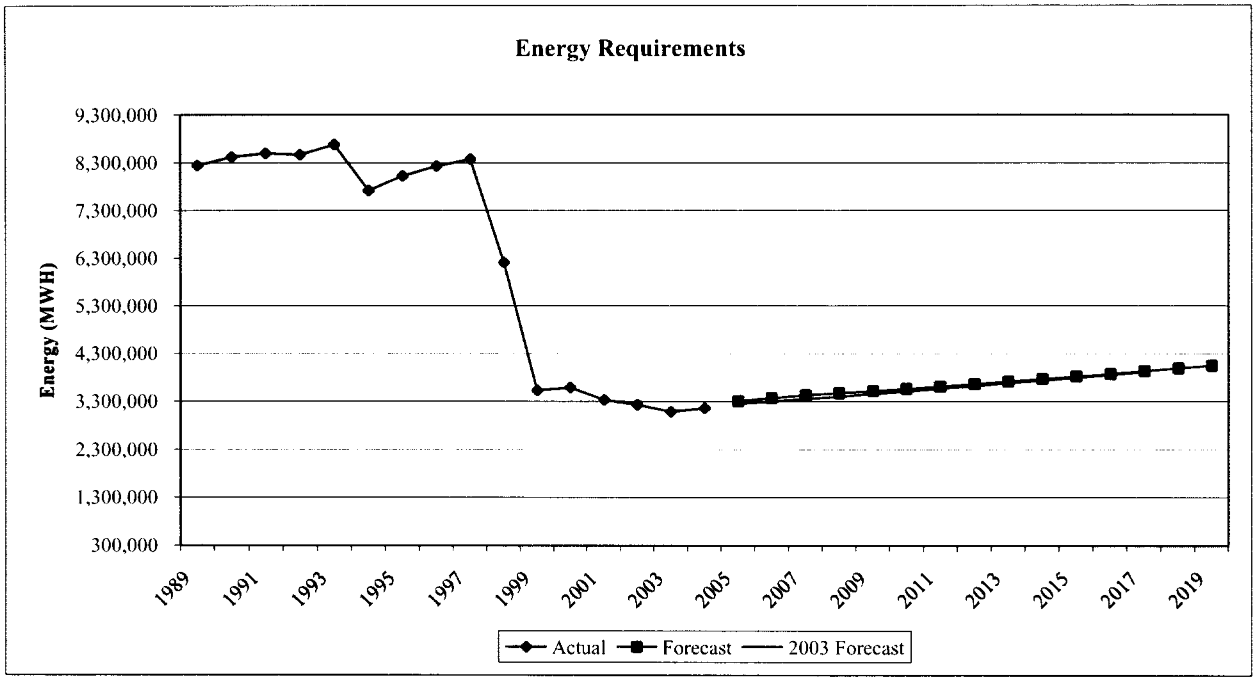
TOTAL NATIVE REQUIREMENTS

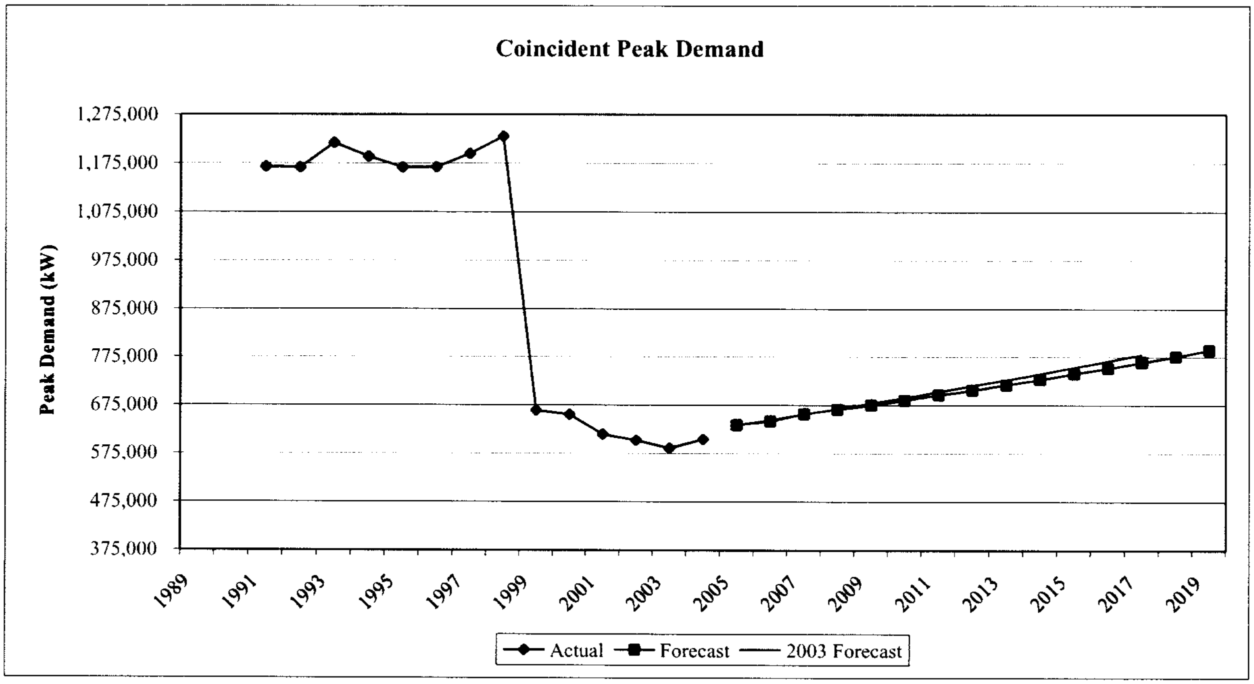


BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL NATIVE REQUIREMENTS

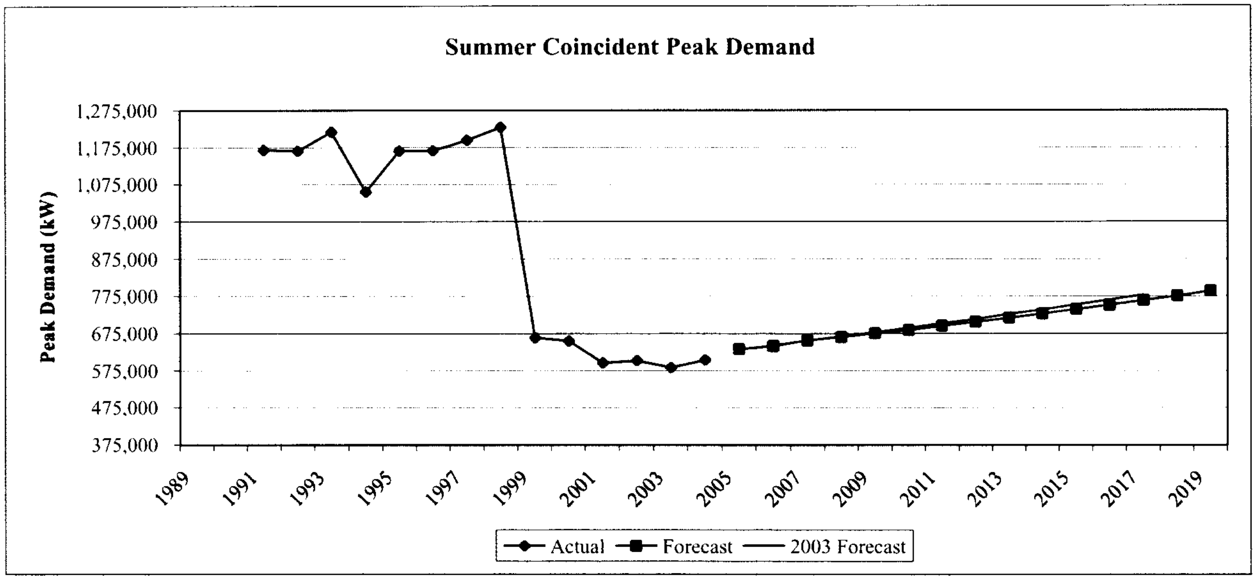


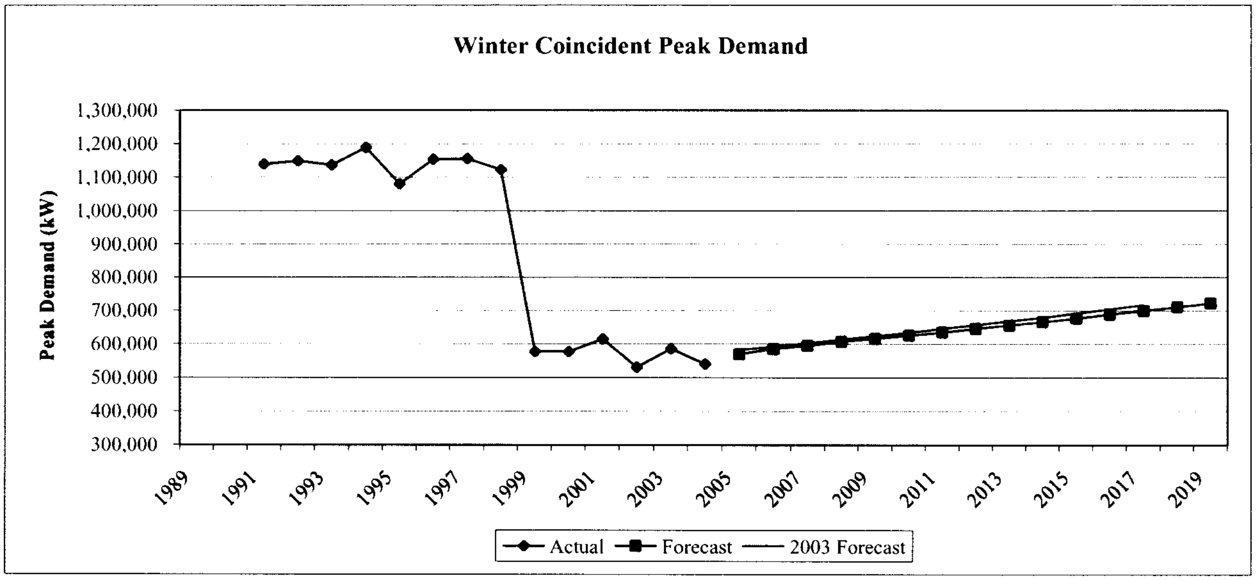


BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

TOTAL NATIVE REQUIREMENTS





BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Actual Energy (MWh)	Normal Energy (MWh)	Percent Growth	Summer NCP (kW)	Percent Growth	Load Factor	Winter NCP (kW)	Percent Growth	Load Factor
1989									
1990									
1991	1,488,403	1,446,974		339,855		48.6%	291,436		56.7%
1992	1,439,260	1,490,045	3.0%	331,489	-2.5%	51.3%	310,047	6.4%	54.9%
1993	1,580,290	1,536,760	3.1%	370,687	11.8%	47.3%	318,252	2.6%	55.1%
1994	1,571,482	1,584,881	3.1%	355,124	-4.2%	50.9%	359,832	13.1%	50.3%
1995	1,665,313	1,634,065	3.1%	387,914	9.2%	48.1%	335,672	-6.7%	55.6%
1996	1,728,686	1,720,265	5.3%	380,236	-2.0%	51.6%	382,214	13.9%	51.4%
1997	1,758,397	1,785,899	3.8%	409,524	7.7%	49.8%	376,231	-1.6%	54.2%
1998	1,828,160	1,829,448	2.4%	425,035	3.8%	49.1%	339,860	-9.7%	61.4%
1999	1,921,792	1,969,184	7.6%	485,118	14.1%	46.3%	405,295	19.3%	55.5%
2000	2,001,539	2,017,183	2.4%	472,464	-2.6%	48.7%	393,249	-3.0%	58.6%
2001	2,000,877	2,007,985	-0.5%	456,533	-3.4%	50.2%	438,627	11.5%	52.3%
2002	2,114,841	2,062,482	2.7%	477,039	4.5%	49.4%	393,369	-10.3%	59.9%
2003	2,089,678	2,137,729	3.6%	472,692	-0.9%	51.6%	476,072	21.0%	51.3%
2004	2,133,190	2,186,760	2.3%	486,132	2.8%	51.4%	443,873	-6.8%	56.2%
2005		2,279,642	4.2%	506,848	4.3%	51.3%	449,792	1.3%	57.9%
2006		2,352,923	3.2%	514,747	1.6%	52.2%	465,842	3.6%	57.7%
2007		2,396,163	1.8%	528,416	2.7%	51.8%	473,851	1.7%	57.7%
2008		2,438,985	1.8%	537,584	1.7%	51.8%	486,669	2.7%	57.2%
2009		2,485,739	1.9%	547,582	1.9%	51.8%	495,482	1.8%	57.3%
2010		2,530,572	1.8%	557,179	1.8%	51.8%	505,192	2.0%	57.2%
2011		2,583,349	2.1%	568,519	2.0%	51.9%	514,736	1.9%	57.3%
2012		2,632,109	1.9%	579,005	1.8%	51.9%	525,582	2.1%	57.2%
2013		2,685,665	2.0%	590,515	2.0%	51.9%	535,664	1.9%	57.2%
2014		2,737,034	1.9%	601,564	1.9%	51.9%	546,614	2.0%	57.2%
2015		2,795,566	2.1%	614,142	2.1%	52.0%	557,309	2.0%	57.3%
2016		2,849,293	1.9%	625,676	1.9%	52.0%	569,203	2.1%	57.1%
2017		2,907,872	2.1%	638,240	2.0%	52.0%	580,290	1.9%	57.2%
2018		2,964,093	1.9%	650,303	1.9%	52.0%	592,310	2.1%	57.1%
2019		3,027,093	2.1%	663,823	2.1%	52.1%	603,934	2.0%	57.2%

ANNUAL GROWTH RATES						
1994-1999	3.6%	4.8%	5.7%	-0.9%	4.8%	0.0%
1999-2004	2.1%	2.1%	0.0%	2.1%	1.8%	0.3%
2004-2009		2.6%	2.4%	0.2%	2.2%	0.4%
2009-2014		1.9%	1.9%	0.0%	2.0%	0.0%
2014-2019		2.0%	2.0%	0.0%	2.0%	0.0%
2004-2019		2.2%	2.1%	0.1%	2.1%	0.1%

Summer season is May to October. Winter season is November of the prior year through April of the reported year. For instance, the Winter CP for 2000 is the CP recorded between November 1999 and April 2000.

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS

Year	Actual Energy (MWh)	Normal Energy (MWh)	Percent Growth	Summer CP (kW)	Percent Growth	Load Factor	Winter CP (kW)	Percent Growth	Load Factor
1989									
1990									
1991	1,488,403	1,446,974		333,058		49.6%	285,607		57.8%
1992	1,439,260	1,490,045	3.0%	324,859	-2.5%	52.4%	303,846	6.4%	56.0%
1993	1,580,290	1,536,760	3.1%	363,273	11.8%	48.3%	311,887	2.6%	56.2%
1994	1,571,482	1,584,881	3.1%	348,022	-4.2%	52.0%	352,635	13.1%	51.3%
1995	1,665,313	1,634,065	3.1%	380,156	9.2%	49.1%	328,959	-6.7%	56.7%
1996	1,728,686	1,720,265	5.3%	372,631	-2.0%	52.7%	374,570	13.9%	52.4%
1997	1,758,397	1,785,899	3.8%	401,334	7.7%	50.8%	368,706	-1.6%	55.3%
1998	1,828,160	1,829,448	2.4%	416,534	3.8%	50.1%	333,063	-9.7%	62.7%
1999	1,921,792	1,969,184	7.6%	475,416	14.1%	47.3%	397,189	19.3%	56.6%
2000	2,001,539	2,017,183	2.4%	463,015	-2.6%	49.7%	385,384	-3.0%	59.8%
2001	2,000,877	2,007,985	-0.5%	447,402	-3.4%	51.2%	429,854	11.5%	53.3%
2002	2,114,841	2,062,482	2.7%	467,498	4.5%	50.4%	385,501	-10.3%	61.1%
2003	2,089,678	2,137,729	3.6%	463,238	-0.9%	52.7%	466,551	21.0%	52.3%
2004	2,133,190	2,186,760	2.3%	476,409	2.8%	52.4%	434,995	-6.8%	57.4%
2005		2,279,642	4.2%	496,711	4.3%	52.4%	440,796	1.3%	59.0%
2006		2,352,923	3.2%	504,452	1.6%	53.2%	456,525	3.6%	58.8%
2007		2,396,163	1.8%	517,848	2.7%	52.8%	464,374	1.7%	58.9%
2008		2,438,985	1.8%	526,832	1.7%	52.8%	476,936	2.7%	58.4%
2009		2,485,739	1.9%	536,630	1.9%	52.9%	485,572	1.8%	58.4%
2010		2,530,572	1.8%	546,035	1.8%	52.9%	495,088	2.0%	58.3%
2011		2,583,349	2.1%	557,148	2.0%	52.9%	504,441	1.9%	58.5%
2012		2,632,109	1.9%	567,425	1.8%	53.0%	515,071	2.1%	58.3%
2013		2,685,665	2.0%	578,705	2.0%	53.0%	524,950	1.9%	58.4%
2014		2,737,034	1.9%	589,533	1.9%	53.0%	535,682	2.0%	58.3%
2015		2,795,566	2.1%	601,860	2.1%	53.0%	546,163	2.0%	58.4%
2016		2,849,293	1.9%	613,163	1.9%	53.0%	557,818	2.1%	58.3%
2017		2,907,872	2.1%	625,475	2.0%	53.1%	568,684	1.9%	58.4%
2018		2,964,093	1.9%	637,297	1.9%	53.1%	580,464	2.1%	58.3%
2019		3,027,093	2.1%	650,546	2.1%	53.1%	591,855	2.0%	58.4%

ANNUAL GROWTH RATES

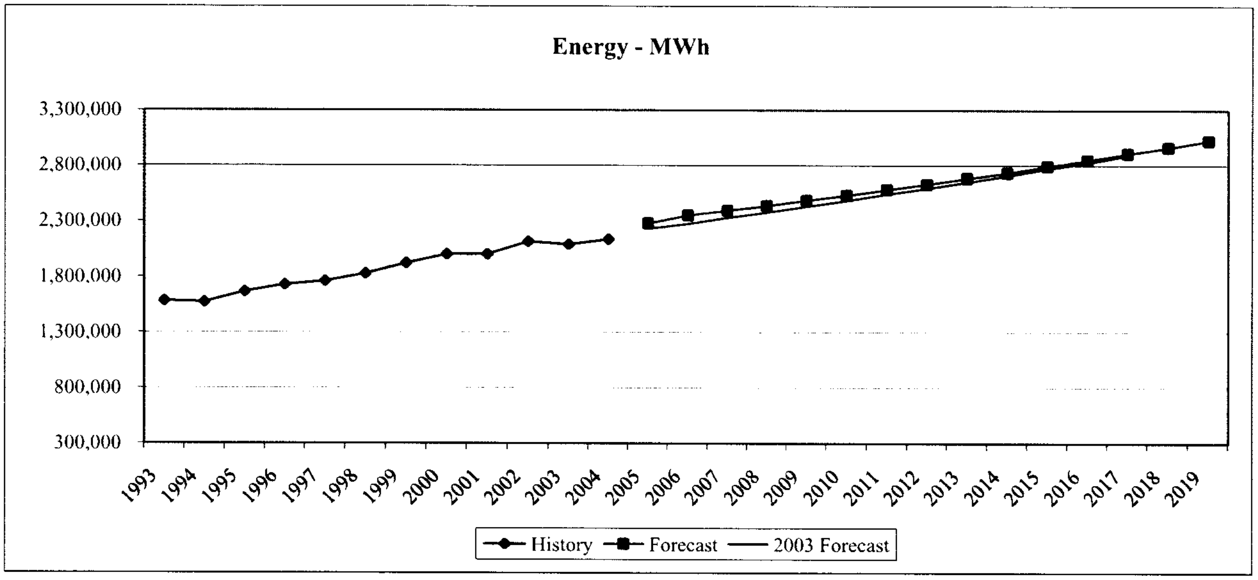
1994-1999	3.6%	4.8%	5.7%	-0.9%	4.8%	0.0%
1999-2004	2.1%	2.1%	0.0%	2.1%	1.8%	0.3%
2004-2009		2.6%	2.4%	0.2%	2.2%	0.4%
2009-2014		1.9%	1.9%	0.0%	2.0%	0.0%
2014-2019		2.0%	2.0%	0.0%	2.0%	0.0%
2004-2019		2.2%	2.1%	0.1%	2.1%	0.1%

Summer season is May to October. Winter season is November of the prior year through April of the reported year.
For instance, the Winter CP for 2000 is the CP recorded between November 1999 and April 2000.

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

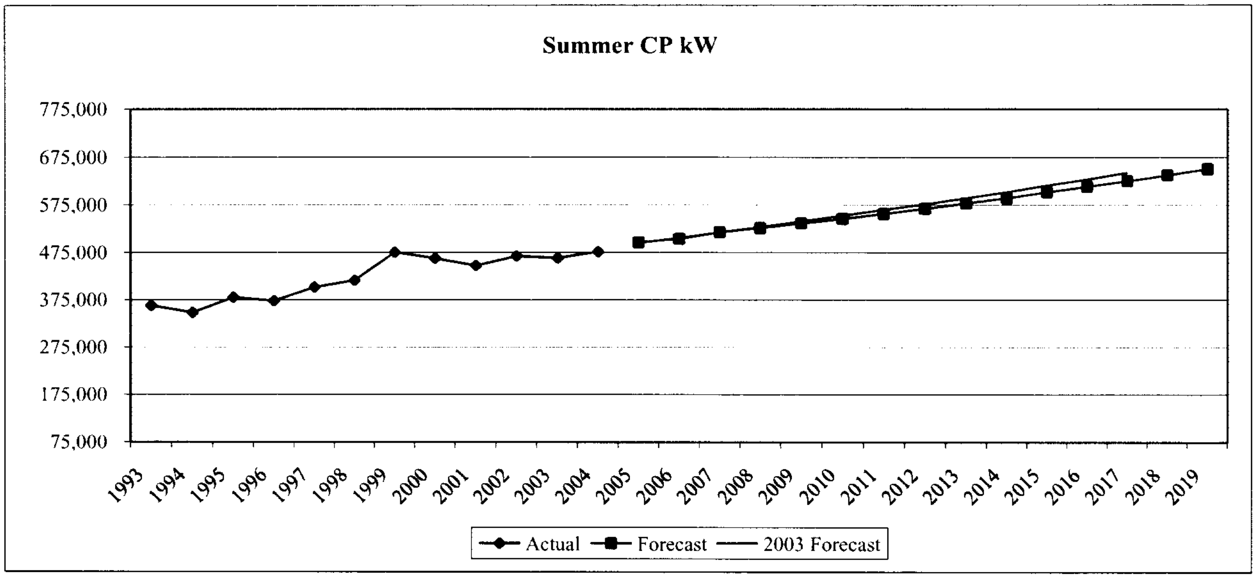
RURAL SYSTEM REQUIREMENTS

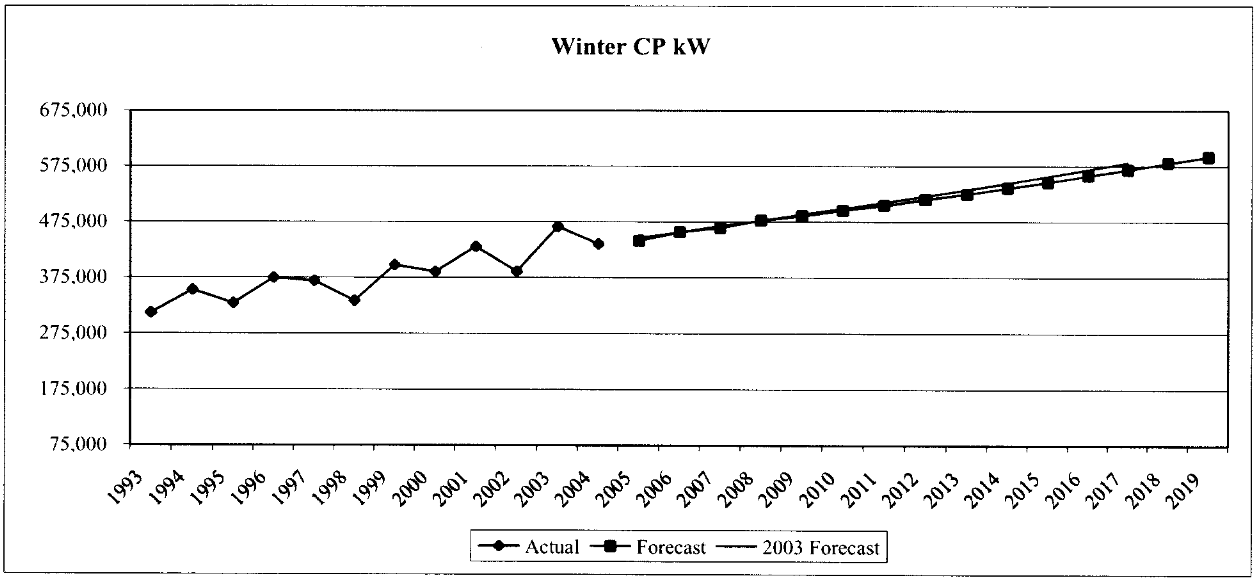


BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

RURAL SYSTEM REQUIREMENTS





BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION

Year	Consumers	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
1989	72,170		925,721	920,027		1,069	1,062	
1990	73,156	1.4%	930,785	955,778	3.9%	1,060	1,089	2.5%
1991	74,176	1.4%	991,459	958,020	0.2%	1,114	1,076	-1.1%
1992	75,667	2.0%	945,487	987,953	3.1%	1,041	1,088	1.1%
1993	77,266	2.1%	1,052,301	1,015,770	2.8%	1,135	1,096	0.7%
1994	78,879	2.1%	1,040,652	1,050,206	3.4%	1,099	1,110	1.3%
1995	80,808	2.4%	1,101,490	1,074,976	2.4%	1,136	1,109	-0.1%
1996	82,658	2.3%	1,144,623	1,136,625	5.7%	1,154	1,146	3.4%
1997	84,622	2.4%	1,137,995	1,160,931	2.1%	1,121	1,143	-0.2%
1998	86,615	2.4%	1,199,476	1,201,058	3.5%	1,154	1,156	1.1%
1999	88,092	1.7%	1,215,474	1,256,431	4.6%	1,150	1,189	2.9%
2000	89,860	2.0%	1,264,194	1,279,781	1.9%	1,172	1,187	-0.1%
2001	91,276	1.6%	1,286,139	1,290,263	0.8%	1,174	1,178	-0.7%
2002	92,355	1.2%	1,371,067	1,327,325	2.9%	1,237	1,198	1.7%
2003	93,405	1.1%	1,340,451	1,380,924	4.0%	1,196	1,232	2.9%
2004	94,768	1.5%	1,362,667	1,409,111	2.0%	1,198	1,239	0.6%
2005	96,076	1.4%		1,443,131	2.4%		1,252	1.0%
2006	97,327	1.3%		1,470,294	1.9%		1,259	0.6%
2007	98,635	1.3%		1,500,499	2.1%		1,268	0.7%
2008	99,973	1.4%		1,531,519	2.1%		1,277	0.7%
2009	101,296	1.3%		1,562,965	2.1%		1,286	0.7%
2010	102,670	1.4%		1,595,467	2.1%		1,295	0.7%
2011	104,164	1.5%		1,630,195	2.2%		1,304	0.7%
2012	105,712	1.5%		1,666,143	2.2%		1,313	0.7%
2013	107,313	1.5%		1,703,202	2.2%		1,323	0.7%
2014	108,930	1.5%		1,741,243	2.2%		1,332	0.7%
2015	110,577	1.5%		1,780,266	2.2%		1,342	0.7%
2016	112,222	1.5%		1,819,809	2.2%		1,351	0.7%
2017	113,902	1.5%		1,860,346	2.2%		1,361	0.7%
2018	115,596	1.5%		1,901,856	2.2%		1,371	0.7%
2019	117,307	1.5%		1,944,439	2.2%		1,381	0.7%

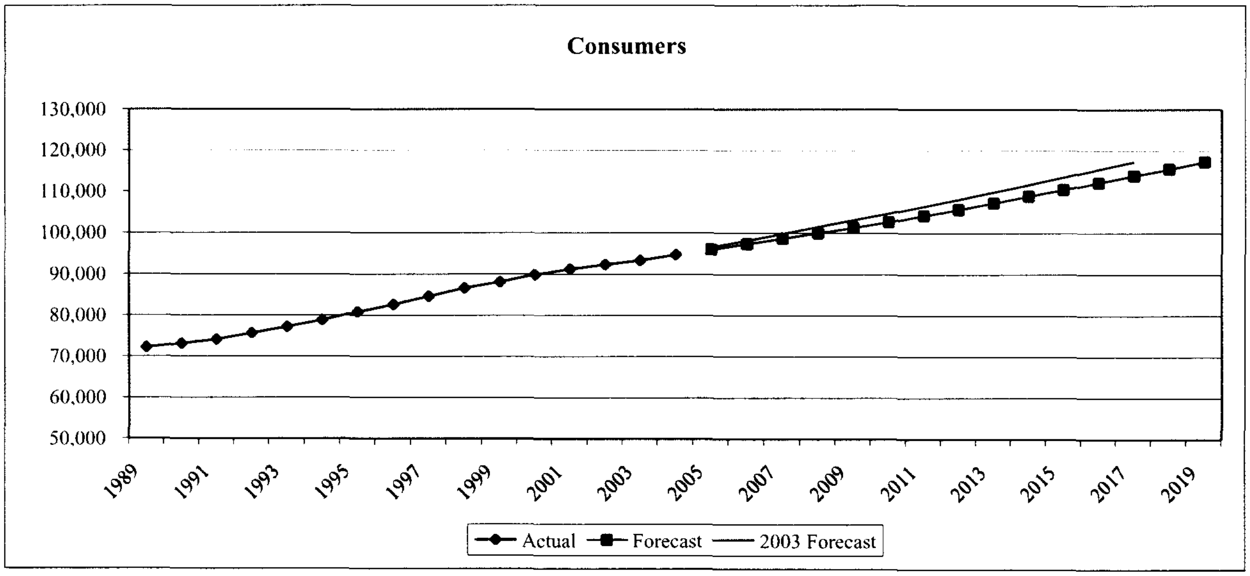
ANNUAL GROWTH RATES

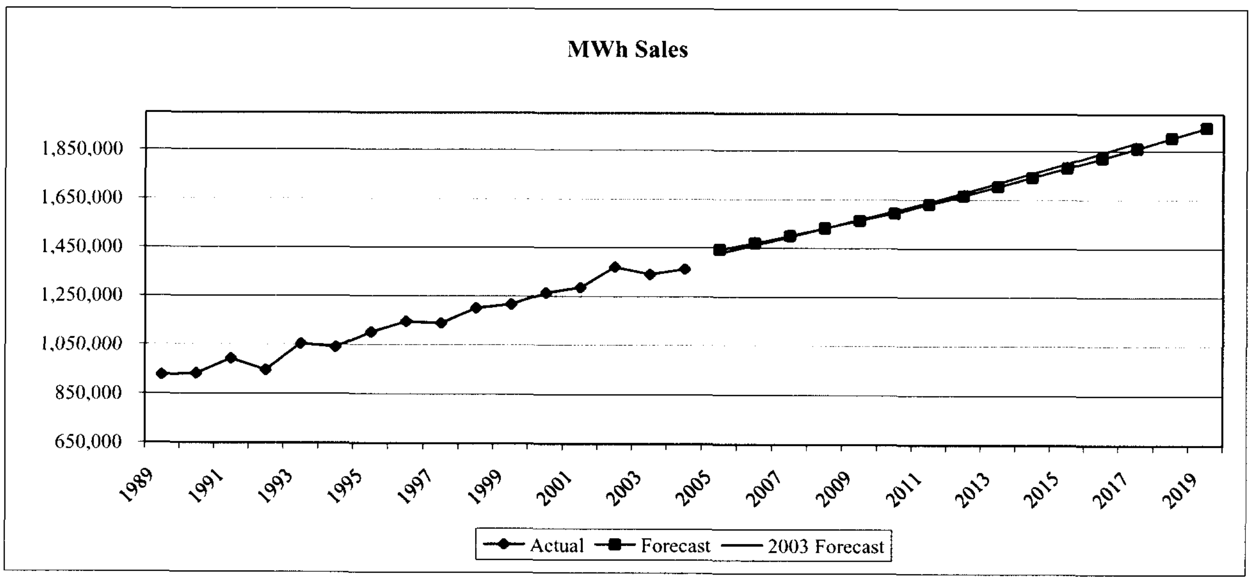
1989-1994	1.8%	2.4%	2.7%	0.6%	0.9%
1994-1999	2.2%	3.2%	3.7%	0.9%	1.4%
1999-2004	1.5%	2.3%	2.3%	0.8%	0.8%
2004-2009	1.3%		2.1%		0.7%
2009-2014	1.5%		2.2%		0.7%
2014-2019	1.5%		2.2%		0.7%
2004-2019	1.4%		2.2%		0.7%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION

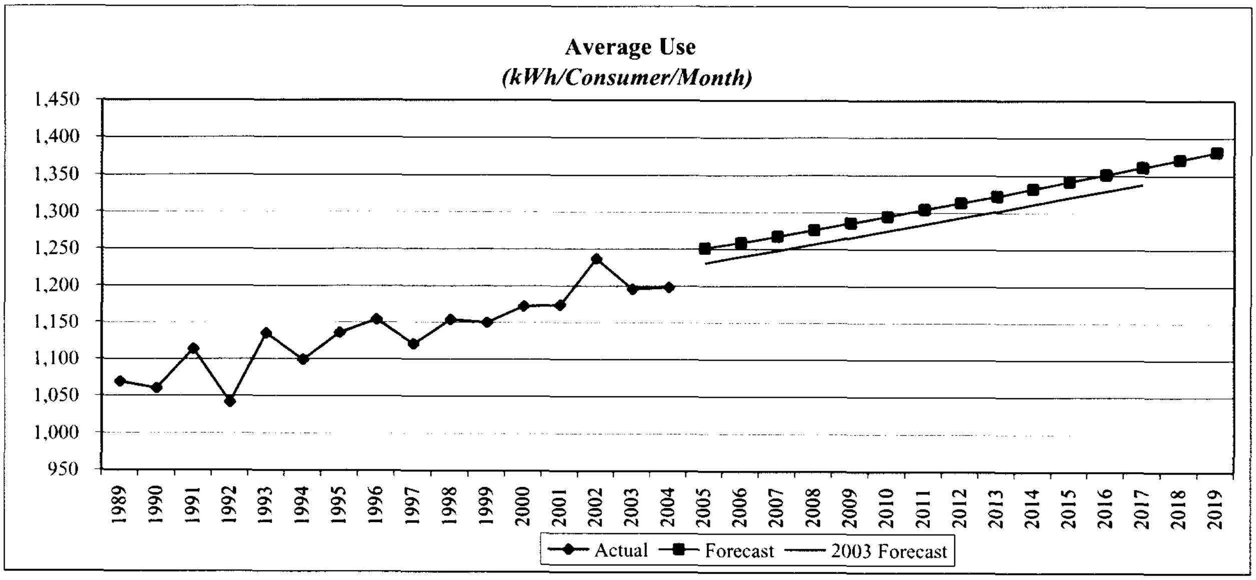




BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

RESIDENTIAL CLASSIFICATION



BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

SMALL COMMERCIAL CLASSIFICATION

Year	Consumers	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
1989								
1990								
1991			388,632					
1992			387,541					
1993			417,266					
1994	8,224		429,603	433,355		4,353	4,391	
1995	8,430	2.5%	448,782	444,608	2.6%	4,436	4,395	0.1%
1996	8,707	3.3%	466,450	466,322	4.9%	4,464	4,463	1.6%
1997	9,035	3.8%	502,803	507,099	8.7%	4,638	4,677	4.8%
1998	9,346	3.4%	513,762	513,282	1.2%	4,581	4,577	-2.2%
1999	9,879	5.7%	591,594	597,077	16.3%	4,991	5,037	10.1%
2000	10,206	3.3%	613,100	612,769	2.6%	5,006	5,003	-0.7%
2001	10,502	2.9%	602,412	605,352	-1.2%	4,780	4,804	-4.0%
2002	10,916	3.9%	627,652	619,679	2.4%	4,791	4,731	-1.5%
2003	11,185	2.5%	637,787	644,709	4.0%	4,752	4,803	1.5%
2004	11,539	3.2%	659,726	666,055	3.3%	4,764	4,810	0.1%
2005	11,814	2.4%		704,096	5.7%		4,967	3.3%
2006	12,102	2.4%		746,418	6.0%		5,140	3.5%
2007	12,390	2.4%		757,053	1.4%		5,092	-0.9%
2008	12,679	2.3%		766,477	1.2%		5,038	-1.1%
2009	12,969	2.3%		779,220	1.7%		5,007	-0.6%
2010	13,262	2.3%		789,065	1.3%		4,958	-1.0%
2011	13,558	2.2%		804,245	1.9%		4,943	-0.3%
2012	13,856	2.2%		814,363	1.3%		4,898	-0.9%
2013	14,157	2.2%		827,932	1.7%		4,873	-0.5%
2014	14,459	2.1%		838,426	1.3%		4,832	-0.8%
2015	14,766	2.1%		854,753	1.9%		4,824	-0.2%
2016	15,074	2.1%		865,967	1.3%		4,787	-0.8%
2017	15,387	2.1%		880,806	1.7%		4,770	-0.4%
2018	15,701	2.0%		892,415	1.3%		4,736	-0.7%
2019	16,018	2.0%		909,409	1.9%		4,731	-0.1%

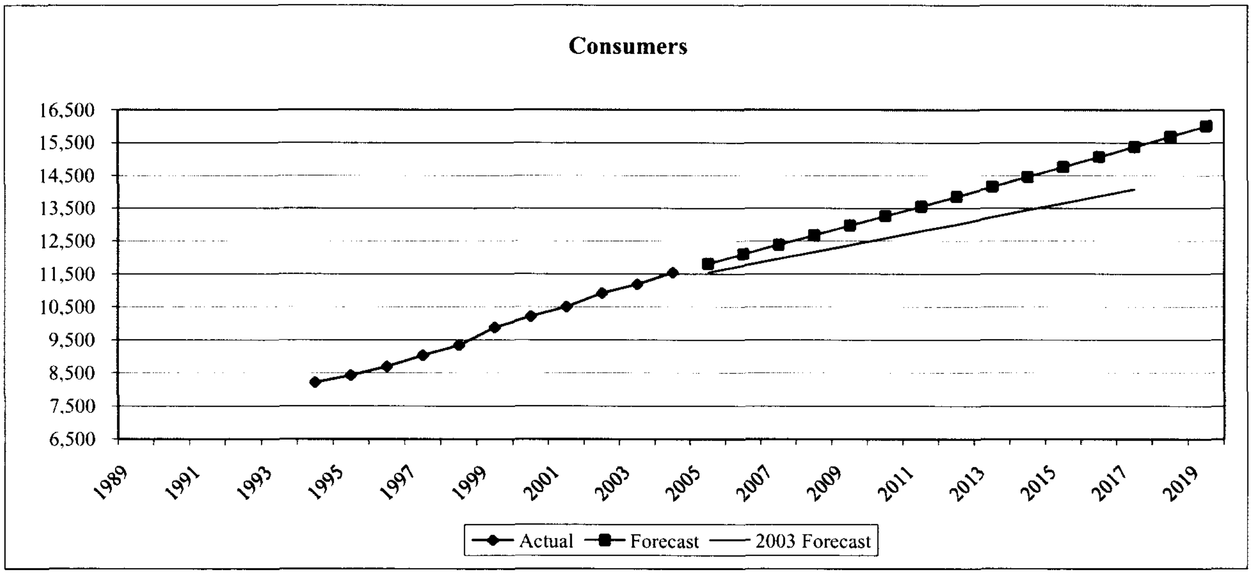
ANNUAL GROWTH RATES

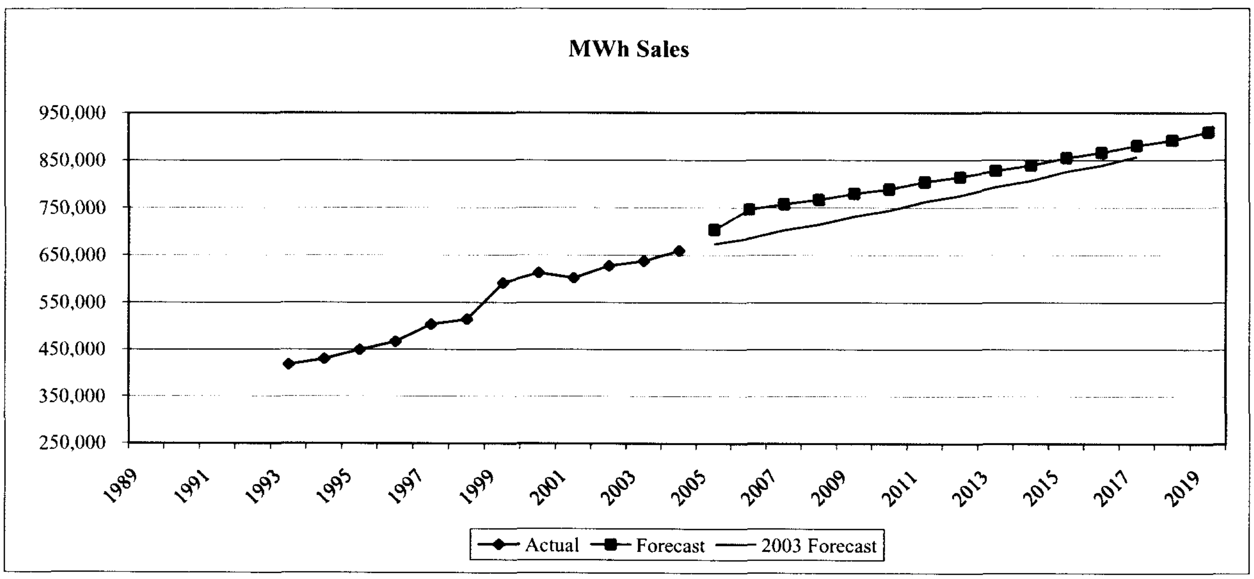
1989-1994								
1994-1999	3.7%		6.6%	6.6%		2.8%	2.8%	
1999-2004	3.2%		2.2%	2.2%		-0.9%	-0.9%	
2004-2009	2.4%			3.2%			0.8%	
2009-2014	2.2%			1.5%			-0.7%	
2014-2019	2.1%			1.6%			-0.4%	
2004-2019	2.2%			2.1%			-0.1%	

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

SMALL COMMERCIAL CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

20053 LONG-TERM LOAD FORECAST - BASE CASE

LARGE INDUSTRIAL - DIRECT SERVE CUSTOMERS

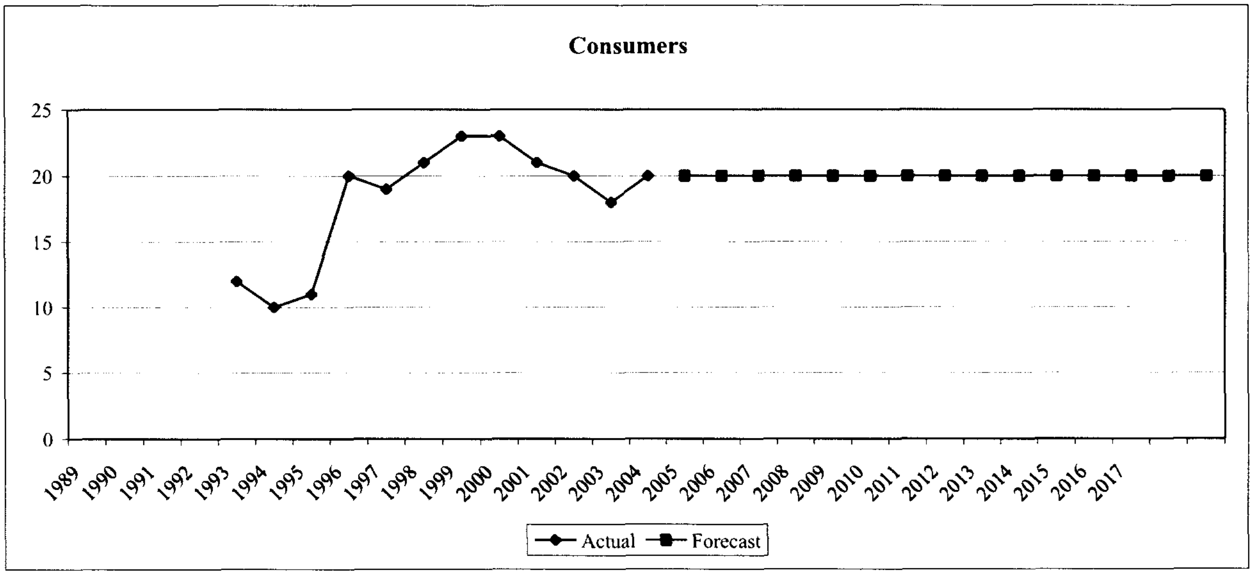
Year	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1989						
1990						
1991	12		6,826,037		47,403,035	
1992	12	0.0%	6,887,077	0.9%	47,826,922	0.9%
1993	12	0.0%	6,864,840	-0.3%	47,672,503	-0.3%
1994	10	-16.7%	5,882,738	-14.3%	49,022,819	2.8%
1995	11	10.0%	6,296,122	7.0%	47,697,892	-2.7%
1996	20	81.8%	6,317,276	0.3%	26,321,982	-44.8%
1997	19	-5.0%	6,368,964	0.8%	27,934,051	6.1%
1998	21	10.5%	4,235,544	-33.5%	16,807,715	-39.8%
1999	23	9.5%	1,544,587	-63.5%	5,596,330	-66.7%
2000	23	0.0%	1,539,384	-0.3%	5,577,478	-0.3%
2001	21	-8.7%	1,300,686	-15.5%	5,161,452	-7.5%
2002	20	-4.8%	1,118,264	-14.0%	4,659,432	-9.7%
2003	18	-10.0%	1,022,803	-8.5%	4,735,200	1.6%
2004	20	11.1%	1,001,791	-2.1%	4,174,128	-11.8%
2005	20	0.0%	1,008,068	0.6%	4,200,281	0.6%
2006	20	0.0%	1,008,068	0.0%	4,200,281	0.0%
2007	20	0.0%	1,018,580	1.0%	4,244,081	1.0%
2008	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2009	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2010	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2011	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2012	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2013	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2014	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2015	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2016	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2017	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2018	20	0.0%	1,018,580	0.0%	4,244,081	0.0%
2019	20	0.0%	1,018,580	0.0%	4,244,081	0.0%

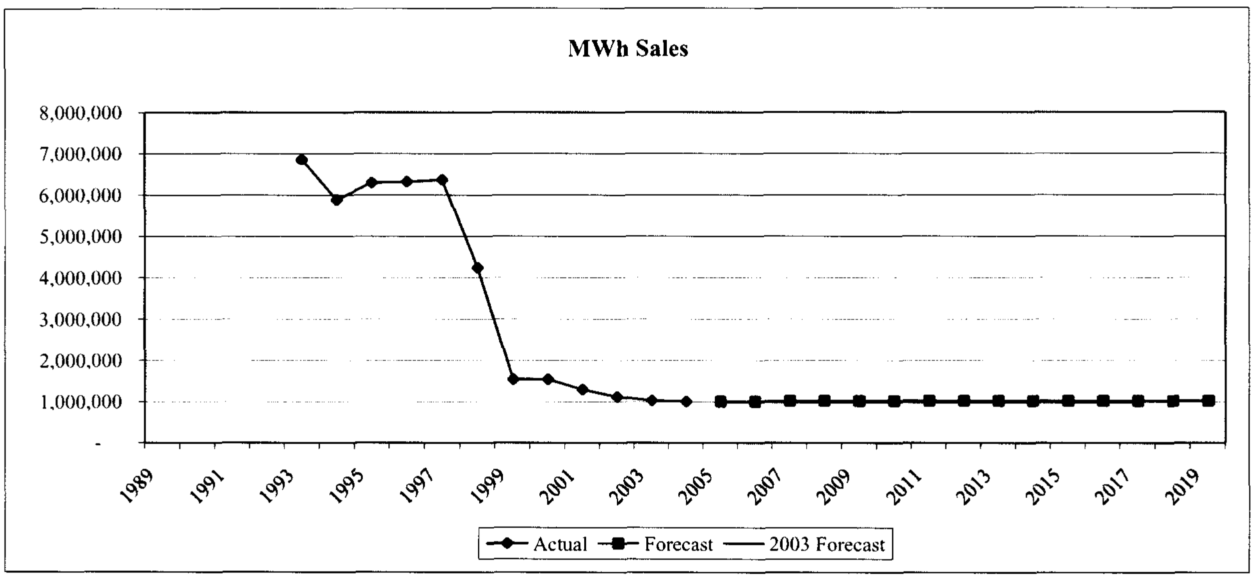
ANNUAL GROWTH RATES			
1989-1994			
1994-1999	18.1%	-23.5%	-35.2%
1999-2004	-2.8%	-8.3%	-5.7%
2004-2009	0.0%	0.3%	0.3%
2009-2014	0.0%	0.0%	0.0%
2014-2019	0.0%	0.0%	0.0%
2004-2019	0.0%	0.1%	0.1%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

LARGE INDUSTRIAL - DIRECT SERVE CUSTOMERS





BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

STREET LIGHTING CLASSIFICATION

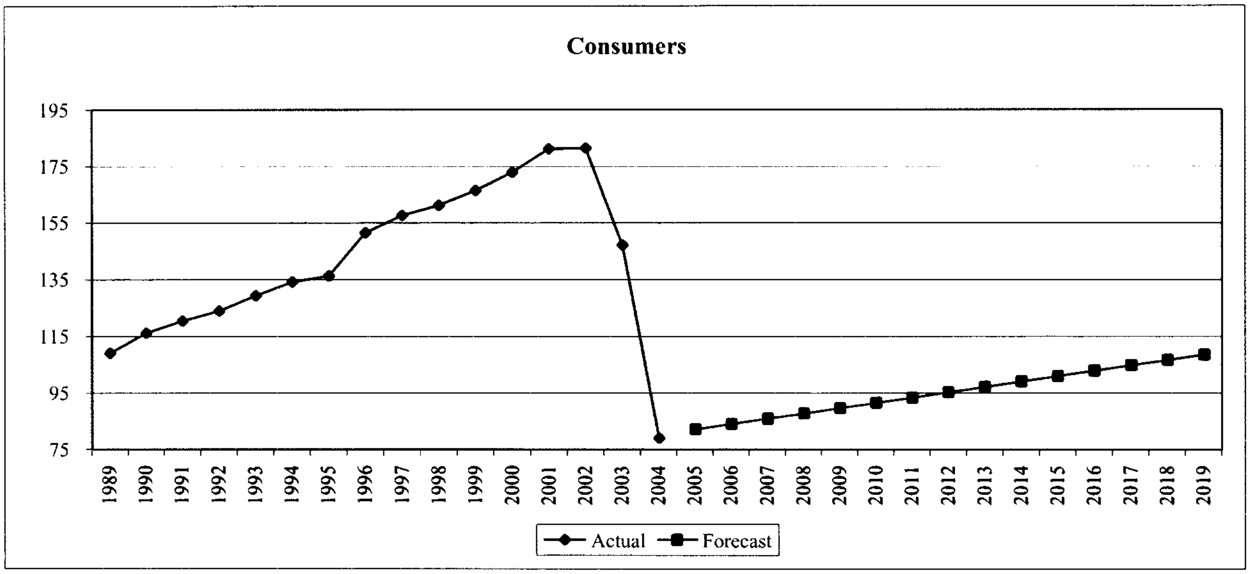
Year	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1989	109		2,154		1,646	
1990	116	6.4%	2,177	1.1%	1,563	-5.0%
1991	121	3.8%	2,276	4.5%	1,574	0.7%
1992	124	2.9%	2,275	-0.1%	1,529	-2.9%
1993	129	4.4%	2,417	6.2%	1,556	1.8%
1994	134	3.7%	2,509	3.8%	1,558	0.1%
1995	136	1.7%	2,641	5.2%	1,613	3.5%
1996	152	11.1%	2,661	0.8%	1,463	-9.3%
1997	158	4.0%	2,802	5.3%	1,481	1.2%
1998	161	2.3%	2,846	1.6%	1,470	-0.8%
1999	167	3.2%	3,138	10.3%	1,571	6.8%
2000	173	3.9%	3,191	1.7%	1,537	-2.1%
2001	181	4.8%	3,104	-2.7%	1,427	-7.2%
2002	182	0.1%	3,277	5.6%	1,505	5.4%
2003	147	-18.9%	3,235	-1.3%	1,831	21.7%
2004	79	-46.3%	2,997	-7.3%	3,158	72.5%
2005	82	3.9%	3,059	2.1%	3,101	-1.8%
2006	84	2.3%	3,120	2.0%	3,092	-0.3%
2007	86	2.2%	3,181	2.0%	3,084	-0.3%
2008	88	2.2%	3,243	1.9%	3,076	-0.3%
2009	90	2.1%	3,304	1.9%	3,069	-0.2%
2010	92	2.1%	3,366	1.9%	3,062	-0.2%
2011	93	2.1%	3,427	1.8%	3,055	-0.2%
2012	95	2.0%	3,489	1.8%	3,048	-0.2%
2013	97	2.0%	3,550	1.8%	3,042	-0.2%
2014	99	1.9%	3,612	1.7%	3,036	-0.2%
2015	101	1.9%	3,673	1.7%	3,030	-0.2%
2016	103	1.9%	3,734	1.7%	3,024	-0.2%
2017	105	1.8%	3,796	1.6%	3,019	-0.2%
2018	107	1.8%	3,857	1.6%	3,013	-0.2%
2019	109	1.8%	3,919	1.6%	3,008	-0.2%

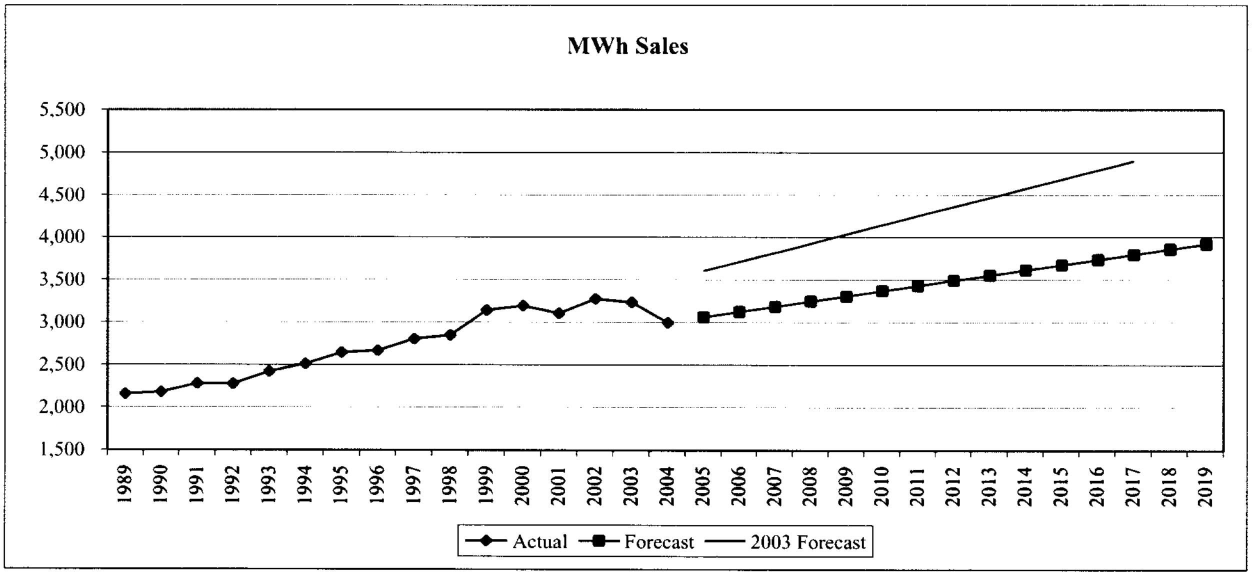
ANNUAL GROWTH RATES			
1989-1994	4.2%	3.1%	-1.1%
1994-1999	4.4%	4.6%	0.2%
1999-2004	-13.8%	-0.9%	15.0%
2004-2009	2.6%	2.0%	-0.6%
2009-2014	2.0%	1.8%	-0.2%
2014-2019	1.8%	1.6%	-0.2%
2004-2019	2.1%	1.8%	-0.3%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

STREET LIGHTING CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

IRRIGATION CLASSIFICATION

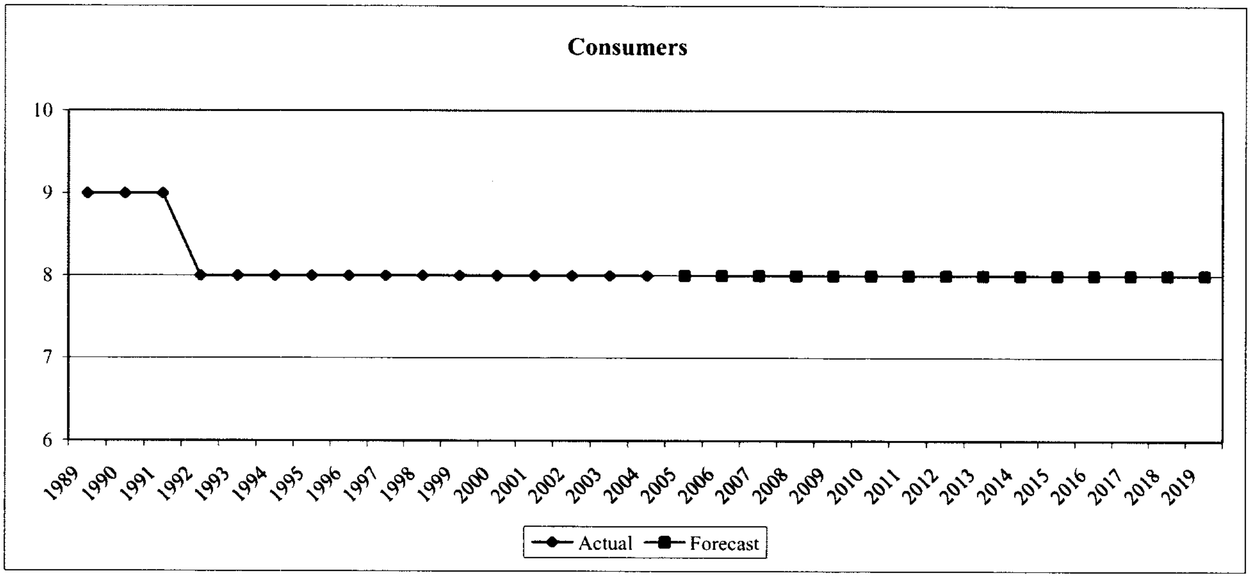
Year	Consumers	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1989	9		82		755	
1990	9	0.0%	48	-41.3%	443	-41.3%
1991	9	0.0%	86	79.1%	794	79.1%
1992	8	-11.1%	114	32.5%	1,184	49.0%
1993	8	0.0%	78	-31.2%	815	-31.2%
1994	8	0.0%	93	19.3%	972	19.3%
1995	8	0.0%	100	7.4%	1,044	7.4%
1996	8	0.0%	110	9.3%	1,141	9.3%
1997	8	0.0%	107	-2.6%	1,112	-2.6%
1998	8	0.0%	121	13.6%	1,263	13.6%
1999	8	0.0%	121	-0.2%	1,261	-0.2%
2000	8	0.0%	70	-42.0%	731	-42.0%
2001	8	0.0%	75	6.5%	778	6.5%
2002	8	0.0%	38	-49.1%	396	-49.1%
2003	8	0.0%	113	196.9%	1,176	196.9%
2004	8	0.0%	164	45.1%	1,706	45.1%
2005	8	0.0%	164	0.1%	1,708	0.1%
2006	8	0.0%	164	0.0%	1,708	0.0%
2007	8	0.0%	164	0.0%	1,708	0.0%
2008	8	0.0%	164	0.0%	1,708	0.0%
2009	8	0.0%	164	0.0%	1,708	0.0%
2010	8	0.0%	164	0.0%	1,708	0.0%
2011	8	0.0%	164	0.0%	1,708	0.0%
2012	8	0.0%	164	0.0%	1,708	0.0%
2013	8	0.0%	164	0.0%	1,708	0.0%
2014	8	0.0%	164	0.0%	1,708	0.0%
2015	8	0.0%	164	0.0%	1,708	0.0%
2016	8	0.0%	164	0.0%	1,708	0.0%
2017	8	0.0%	164	0.0%	1,708	0.0%
2018	8	0.0%	164	0.0%	1,708	0.0%
2019	8	0.0%	164	0.0%	1,708	0.0%

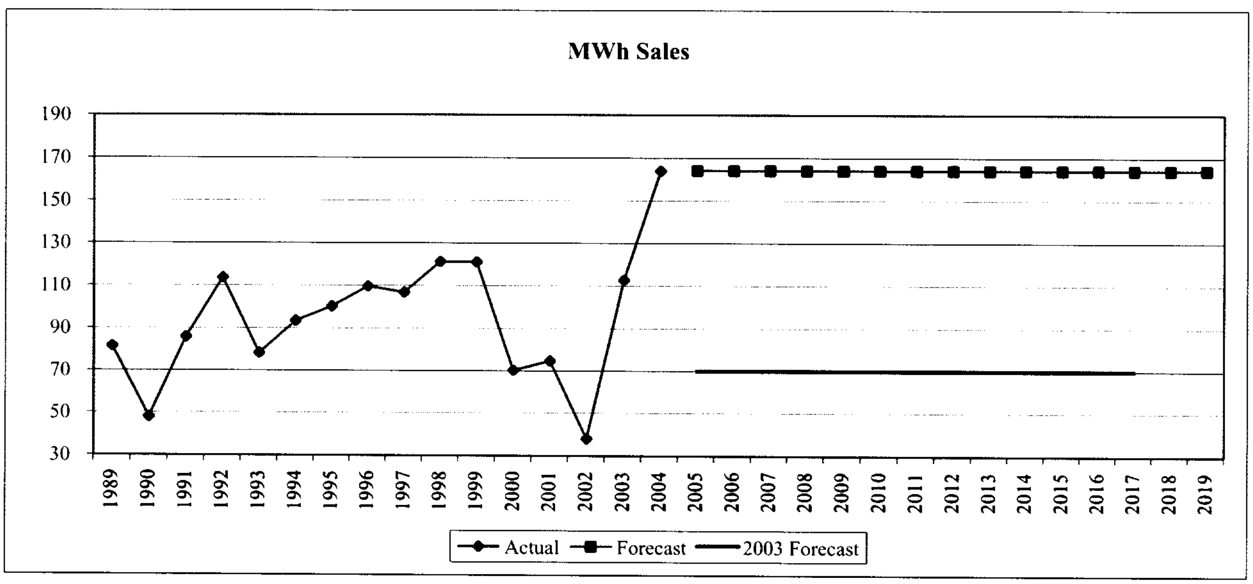
ANNUAL GROWTH RATES			
1989-1994	-2.3%	2.7%	5.2%
1994-1999	0.0%	5.3%	5.3%
1999-2004	0.0%	6.2%	6.2%
2004-2009	0.0%	0.0%	0.0%
2009-2014	0.0%	0.0%	0.0%
2014-2019	0.0%	0.0%	0.0%
2004-2019	0.0%	0.0%	0.0%

BIG RIVERS ELECTRIC CORPORATION

2005 LONG-TERM LOAD FORECAST - BASE CASE

IRRIGATION CLASSIFICATION





Appendix C
Tables – Range Forecasts

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL NATIVE REQUIREMENTS

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	Mild (MWh)
1989	8,246,176				
1990	8,428,685				
1991	8,503,057				
1992	8,475,933				
1993	8,688,975				
1994	7,721,677				
1995	8,026,476				
1996	8,235,361				
1997	8,380,094				
1998	6,208,552				
1999	3,532,841				
2000	3,597,500				
2001	3,331,207				
2002	3,232,553				
2003	3,087,548				
2004	3,158,698				
2005	3,306,259	3,347,145	3,265,263	3,495,258	3,117,259
2006	3,378,253	3,438,177	3,318,473	3,567,966	3,188,539
2007	3,431,620	3,508,092	3,355,930	3,622,079	3,241,160
2008	3,473,882	3,567,559	3,382,035	3,665,105	3,282,659
2009	3,519,951	3,632,272	3,410,936	3,711,927	3,327,975
2010	3,564,196	3,695,598	3,438,035	3,756,955	3,371,437
2011	3,616,207	3,768,262	3,471,810	3,809,814	3,422,599
2012	3,664,368	3,837,625	3,501,701	3,858,855	3,469,881
2013	3,717,197	3,913,297	3,535,158	3,912,592	3,521,801
2014	3,767,931	3,987,529	3,566,442	3,964,241	3,571,621
2015	3,825,636	4,070,465	3,603,569	4,022,878	3,628,395
2016	3,878,697	4,149,443	3,635,998	4,076,867	3,680,528
2017	3,936,470	4,234,968	3,671,975	4,135,587	3,737,354
2018	3,991,983	4,319,089	3,705,548	4,192,052	3,791,913
2019	4,054,080	4,411,758	3,744,490	4,255,111	3,853,049

ANNUAL GROWTH RATES					
1989-1994					
1994-1999					
1999-2004					
2004-2009	2.2%	2.8%	1.5%	3.3%	1.0%
2009-2014	1.4%	1.9%	0.9%	1.3%	1.4%
2014-2019	1.5%	2.0%	1.0%	1.4%	1.5%
2004-2019	1.7%	2.3%	1.1%	2.0%	1.3%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL SYSTEM CP DEMAND - SUMMER

Year	Base Case (kW)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1989					
1990					
1991	1,168,000				
1992	1,166,000				
1993	1,217,000				
1994	1,055,000				
1995	1,166,000				
1996	1,167,000				
1997	1,195,000				
1998	1,230,000				
1999	663,890				
2000	655,248				
2001	596,310				
2002	602,623				
2003	583,906				
2004	604,155				
2005	633,622	641,457	625,765	649,990	618,058
2006	641,362	652,739	630,013	657,771	625,752
2007	656,658	671,292	642,175	673,595	640,552
2008	665,642	683,592	648,043	682,835	649,294
2009	675,440	696,993	654,521	692,911	658,828
2010	684,845	710,094	660,604	702,584	667,980
2011	695,958	725,222	668,168	714,015	678,793
2012	706,235	739,627	674,884	724,585	688,792
2013	717,515	755,367	682,377	736,187	699,766
2014	728,343	770,792	689,395	747,325	710,302
2015	740,670	788,070	697,676	760,004	722,295
2016	751,973	804,463	704,920	771,630	733,292
2017	764,286	822,240	712,933	784,295	745,272
2018	776,107	839,702	720,419	796,453	756,774
2019	789,356	858,999	729,077	810,082	769,665

ANNUAL GROWTH RATES					
1989-1994					
1994-1999					
1999-2004					
2004-2009	2.3%	2.9%	1.6%	2.8%	1.7%
2009-2014	1.5%	2.0%	1.0%	1.5%	1.5%
2014-2019	1.6%	2.2%	1.1%	1.6%	1.6%
2004-2019	1.8%	2.4%	1.3%	2.0%	1.6%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL SYSTEM CP DEMAND - WINTER

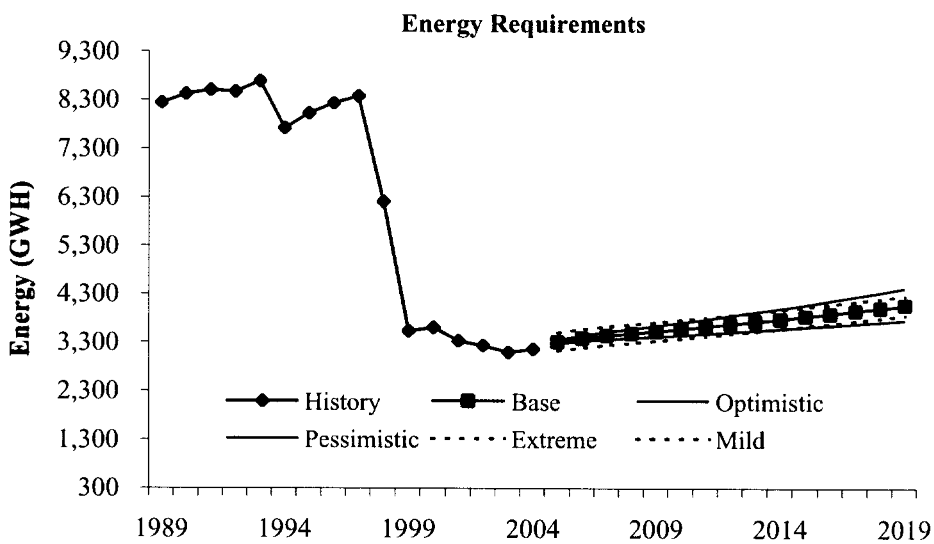
Year	Base Case (kW)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1989					
1990					
1991	1,140,000				
1992	1,149,000				
1993	1,137,000				
1994	1,189,000				
1995	1,080,000				
1996	1,154,000				
1997	1,156,000				
1998	1,123,000				
1999	577,320				
2000	576,843				
2001	614,496				
2002	530,467				
2003	585,549				
2004	539,476				
2005	569,524	576,567	562,463	601,280	540,954
2006	585,253	595,634	574,897	618,083	555,735
2007	595,002	608,262	581,878	628,409	564,968
2008	607,564	623,947	591,500	641,989	576,643
2009	616,200	635,863	597,116	651,149	584,811
2010	625,716	648,784	603,567	661,311	593,756
2011	635,069	661,772	609,710	671,210	602,621
2012	645,699	676,228	617,035	682,575	612,602
2013	655,578	690,163	623,473	693,054	621,948
2014	666,309	705,142	630,679	704,507	632,041
2015	676,791	720,103	637,505	715,605	641,970
2016	688,446	736,502	645,369	728,068	652,915
2017	699,312	752,340	652,325	739,596	663,190
2018	711,091	769,359	660,069	752,171	674,267
2019	722,483	786,225	667,311	764,241	685,052

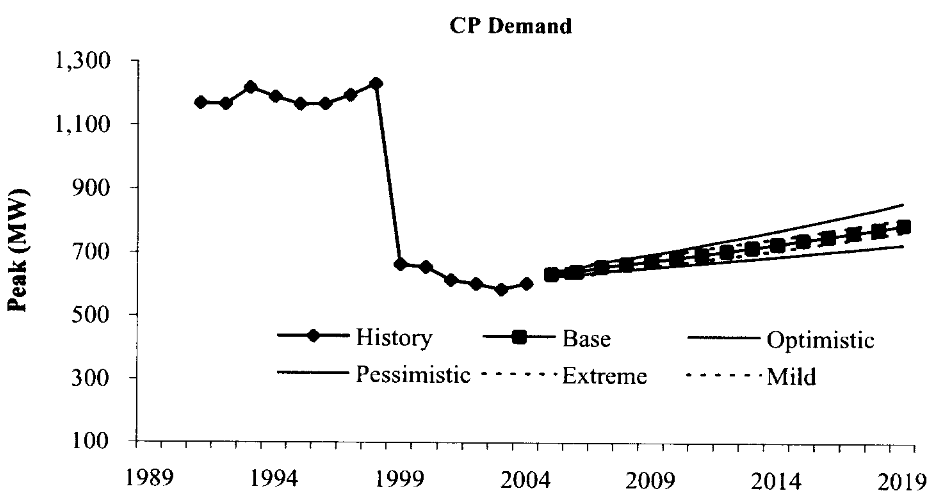
ANNUAL GROWTH RATES					
1989-1994					
1994-1999					
1999-2004					
2004-2009	2.7%	3.3%	2.1%	3.8%	1.6%
2009-2014	1.6%	2.1%	1.1%	1.6%	1.6%
2014-2019	1.6%	2.2%	1.1%	1.6%	1.6%
2004-2019	2.0%	2.5%	1.4%	2.3%	1.6%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

TOTAL NATIVE REQUIREMENTS





BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS

Year	Base Case (MWh)	ECONOMIC SCENARIOS		WEATHER SCENARIOS	
		Optimistic (MWh)	Pessimistic (MWh)	Extreme (MWh)	Mild (MWh)
1989					
1990					
1991	1,488,403				
1992	1,439,260				
1993	1,580,290				
1994	1,571,482				
1995	1,665,313				
1996	1,728,686				
1997	1,758,397				
1998	1,828,160				
1999	1,921,792				
2000	2,001,539				
2001	2,000,877				
2002	2,114,841				
2003	2,089,678				
2004	2,133,190				
2005	2,279,642	2,316,451	2,242,722	2,471,547	2,087,737
2006	2,352,923	2,409,047	2,296,945	2,545,546	2,160,299
2007	2,396,163	2,469,058	2,324,061	2,589,536	2,202,789
2008	2,438,985	2,529,320	2,350,504	2,633,126	2,244,844
2009	2,485,739	2,594,983	2,379,844	2,680,637	2,290,840
2010	2,530,572	2,659,154	2,407,297	2,726,257	2,334,886
2011	2,583,349	2,732,873	2,441,580	2,779,887	2,386,810
2012	2,632,109	2,803,118	2,471,824	2,829,532	2,434,687
2013	2,685,665	2,879,831	2,505,738	2,884,000	2,487,330
2014	2,737,034	2,955,007	2,537,398	2,936,289	2,537,779
2015	2,795,566	3,039,111	2,575,067	2,995,758	2,595,375
2016	2,849,293	3,119,094	2,607,888	3,050,418	2,648,168
2017	2,907,872	3,205,798	2,644,371	3,109,950	2,705,794
2018	2,964,093	3,290,999	2,678,362	3,167,130	2,761,056
2019	3,027,093	3,384,977	2,717,891	3,231,099	2,823,088

ANNUAL GROWTH RATES					
1989-1994					
1994-1999					
1999-2004	2.1%				
2004-2009	3.1%	4.0%	2.2%	4.7%	1.4%
2009-2014	1.9%	2.6%	1.3%	1.8%	2.1%
2014-2019	2.0%	2.8%	1.4%	1.9%	2.2%
2004-2019	2.4%	3.1%	1.6%	2.8%	1.9%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - SUMMER

Year	Base Case (kW)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1989					
1990					
1991	333,058				
1992	324,859				
1993	363,273				
1994	348,022				
1995	380,156				
1996	372,631				
1997	401,334				
1998	416,534				
1999	475,416				
2000	463,015				
2001	447,402				
2002	467,498				
2003	463,238				
2004	476,409				
2005	496,711	504,732	488,667	517,967	477,131
2006	504,452	516,485	492,451	525,678	484,873
2007	517,848	533,602	502,266	539,820	497,594
2008	526,832	546,345	507,720	549,174	506,237
2009	536,630	560,214	513,769	559,374	515,663
2010	546,035	573,780	519,436	569,166	524,711
2011	557,148	589,396	526,573	580,737	535,401
2012	567,425	604,291	532,871	591,439	545,285
2013	578,705	620,543	539,934	603,184	556,135
2014	589,533	636,483	546,533	614,460	566,550
2015	601,860	654,292	554,388	627,295	578,406
2016	613,163	671,223	561,213	639,064	589,279
2017	625,475	689,558	568,797	651,884	601,123
2018	637,297	707,583	575,863	664,193	612,494
2019	650,546	727,458	584,096	677,988	625,239

ANNUAL GROWTH RATES					
1989-1994					
1994-1999					
1999-2004	0.0%				
2004-2009	2.4%	3.3%	1.5%	3.3%	1.6%
2009-2014	1.9%	2.6%	1.2%	1.9%	1.9%
2014-2019	2.0%	2.7%	1.3%	2.0%	2.0%
2004-2019	2.1%	2.9%	1.4%	2.4%	1.8%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - WINTER

Year	Base Case (kW)	ECONOMIC SCENARIOS Optimistic (kW)	Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	Mild (kW)
1989					
1990					
1991	285,607				
1992	303,846				
1993	311,887				
1994	352,635				
1995	328,959				
1996	374,570				
1997	368,706				
1998	333,063				
1999	397,189				
2000	385,384				
2001	429,854				
2002	385,501				
2003	466,551				
2004	434,995				
2005	440,796	447,914	433,658	490,663	400,131
2006	456,525	467,415	445,664	508,368	414,277
2007	464,374	478,501	450,401	517,040	421,445
2008	476,936	494,601	459,634	531,570	432,485
2009	485,572	506,912	464,886	541,131	440,359
2010	495,088	520,244	470,970	551,833	448,925
2011	504,441	533,638	476,758	562,134	457,488
2012	515,071	548,535	483,705	574,121	467,035
2013	524,950	562,903	489,781	585,057	476,044
2014	535,682	578,342	496,610	597,105	485,717
2015	546,163	593,744	503,084	608,664	495,303
2016	557,818	610,639	510,558	621,801	505,775
2017	568,684	626,949	517,152	633,836	515,678
2018	580,464	644,482	524,508	647,066	526,293
2019	591,855	661,828	531,400	659,643	536,701

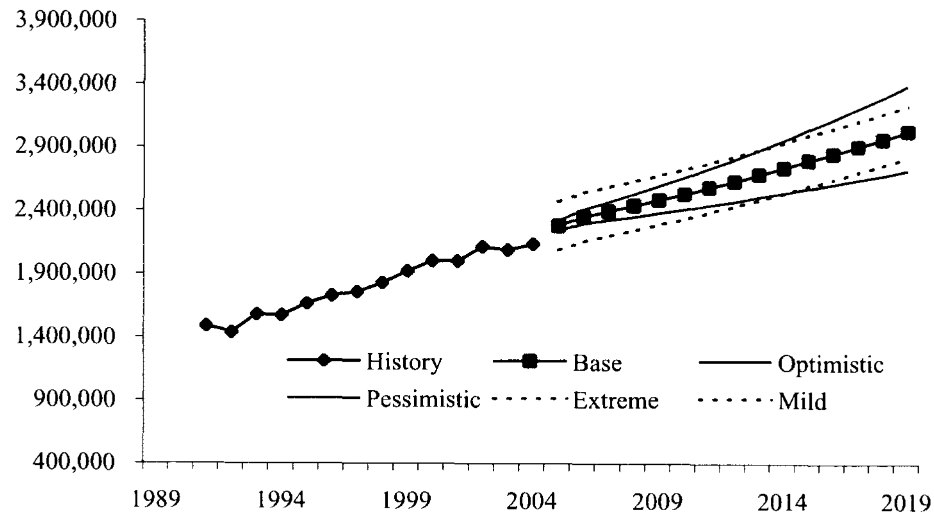
ANNUAL GROWTH RATES					
1989-1994					
1994-1999					
1999-2004	1.8%				
2004-2009	2.2%	3.1%	1.3%	4.5%	0.2%
2009-2014	2.0%	2.7%	1.3%	2.0%	2.0%
2014-2019	2.0%	2.7%	1.4%	2.0%	2.0%
2004-2019	2.1%	2.8%	1.3%	2.8%	1.4%

BIG RIVERS ELECTRIC CORPORATION

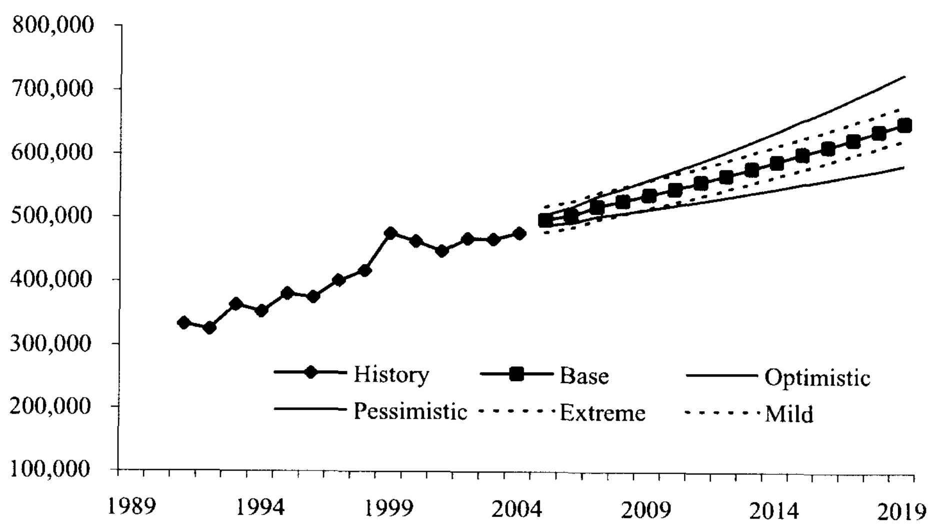
2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS

MWh Energy



CP kW



BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RESIDENTIAL ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1989	925,721				
1990	930,785				
1991	991,459				
1992	945,487				
1993	1,052,301				
1994	1,040,652				
1995	1,101,490				
1996	1,144,623				
1997	1,137,995				
1998	1,199,476				
1999	1,215,474				
2000	1,264,194				
2001	1,286,139				
2002	1,371,067				
2003	1,340,451				
2004	1,362,667				
2005	1,443,131	1,450,086	1,436,072	1,493,641	1,392,622
2006	1,470,294	1,484,624	1,455,870	1,521,480	1,419,107
2007	1,500,499	1,522,652	1,478,391	1,552,392	1,448,606
2008	1,531,519	1,561,961	1,501,395	1,584,136	1,478,903
2009	1,562,965	1,602,176	1,524,491	1,616,296	1,509,635
2010	1,595,467	1,643,958	1,548,288	1,649,539	1,541,395
2011	1,630,195	1,688,556	1,573,893	1,685,071	1,575,318
2012	1,666,143	1,734,959	1,600,318	1,721,853	1,610,433
2013	1,703,202	1,783,083	1,627,443	1,759,774	1,646,631
2014	1,741,243	1,832,833	1,655,116	1,798,682	1,683,805
2015	1,780,266	1,884,224	1,683,339	1,838,588	1,721,944
2016	1,819,809	1,936,797	1,711,660	1,879,012	1,760,606
2017	1,860,346	1,991,087	1,740,511	1,920,448	1,800,244
2018	1,901,856	2,047,098	1,769,861	1,962,863	1,840,848
2019	1,944,439	2,104,985	1,799,777	2,006,359	1,882,518

ANNUAL GROWTH RATES					
1989-1994	2.4%				
1994-1999	3.2%				
1999-2004	2.3%				
2004-2009	2.8%	3.3%	2.3%	3.5%	2.1%
2009-2014	2.2%	2.7%	1.7%	2.2%	2.2%
2014-2019	2.2%	2.8%	1.7%	2.2%	2.3%
2004-2019	2.4%	2.9%	1.9%	2.6%	2.2%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

SMALL COMMERCIAL ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1989					
1990					
1991	388,632				
1992	387,541				
1993	417,266				
1994	429,603				
1995	448,782				
1996	466,450				
1997	502,803				
1998	513,762				
1999	591,594				
2000	613,100				
2001	602,412				
2002	627,652				
2003	637,787				
2004	659,726				
2005	704,096	711,237	696,956	835,712	572,481
2006	746,418	761,048	732,020	878,033	614,802
2007	757,053	779,533	735,282	888,669	625,438
2008	766,477	797,185	737,209	898,092	634,861
2009	779,220	818,547	742,335	910,836	647,605
2010	789,065	837,426	744,424	920,680	657,449
2011	804,245	862,049	751,737	935,861	672,630
2012	814,363	882,058	753,844	945,978	682,747
2013	827,932	905,973	759,271	959,547	696,316
2014	838,426	927,303	761,472	970,042	706,811
2015	854,753	954,958	769,365	986,368	723,137
2016	865,967	978,008	772,007	997,582	734,351
2017	880,806	1,005,207	778,134	1,012,422	749,190
2018	892,415	1,029,759	780,857	1,024,030	760,799
2019	909,409	1,060,263	788,819	1,041,024	777,793

ANNUAL GROWTH RATES					
1989-1994					
1994-1999	6.6%				
1999-2004	2.2%				
2004-2009	3.4%	4.4%	2.4%	6.7%	-0.4%
2009-2014	1.5%	2.5%	0.5%	1.3%	1.8%
2014-2019	1.6%	2.7%	0.7%	1.4%	1.9%
2004-2019	2.2%	3.2%	1.2%	3.1%	1.1%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE INDUSTRIAL - DIRECT SERVE CUSTOMERS

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1989					
1990					
1991	6,826,037				
1992	6,887,077				
1993	6,864,840				
1994	5,882,738				
1995	6,296,122				
1996	6,317,276				
1997	6,368,964				
1998	4,235,544				
1999	1,544,587				
2000	1,539,384				
2001	1,300,686				
2002	1,118,264				
2003	1,022,803				
2004	1,001,791				
2005	1,008,068	1,033,085	983,050	1,008,068	1,008,068
2006	1,008,068	1,036,530	979,605	1,008,068	1,008,068
2007	1,018,580	1,047,256	989,903	1,018,580	1,018,580
2008	1,018,580	1,047,256	989,903	1,018,580	1,018,580
2009	1,018,580	1,047,781	989,378	1,018,580	1,018,580
2010	1,018,580	1,047,781	989,378	1,018,580	1,018,580
2011	1,018,580	1,048,307	988,852	1,018,580	1,018,580
2012	1,018,580	1,048,307	988,852	1,018,580	1,018,580
2013	1,018,580	1,048,833	988,326	1,018,580	1,018,580
2014	1,018,580	1,048,833	988,326	1,018,580	1,018,580
2015	1,018,580	1,049,358	987,801	1,018,580	1,018,580
2016	1,018,580	1,049,358	987,801	1,018,580	1,018,580
2017	1,018,580	1,049,884	987,275	1,018,580	1,018,580
2018	1,018,580	1,049,884	987,275	1,018,580	1,018,580
2019	1,018,580	1,050,409	986,750	1,018,580	1,018,580

ANNUAL GROWTH RATES					
1989-1994					
1994-1999	-23.5%				
1999-2004	-8.3%				
2004-2009	0.3%	0.9%	-0.2%	0.3%	0.3%
2009-2014	0.0%	0.0%	0.0%	0.0%	0.0%
2014-2019	0.0%	0.0%	0.0%	0.0%	0.0%
2004-2019	0.1%	0.3%	-0.1%	0.1%	0.1%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

STREET LIGHTING ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1989	2,154				
1990	2,177				
1991	2,276				
1992	2,275				
1993	2,417				
1994	2,509				
1995	2,641				
1996	2,661				
1997	2,802				
1998	2,846				
1999	3,138				
2000	3,191				
2001	3,104				
2002	3,277				
2003	3,235				
2004	2,997				
2005	3,059	3,180	2,937	3,059	3,059
2006	3,120	3,244	2,996	3,120	3,120
2007	3,181	3,308	3,055	3,181	3,181
2008	3,243	3,372	3,114	3,243	3,243
2009	3,304	3,436	3,173	3,304	3,304
2010	3,366	3,499	3,232	3,366	3,366
2011	3,427	3,563	3,291	3,427	3,427
2012	3,489	3,627	3,350	3,489	3,489
2013	3,550	3,691	3,409	3,550	3,550
2014	3,612	3,755	3,468	3,612	3,612
2015	3,673	3,818	3,528	3,673	3,673
2016	3,734	3,882	3,587	3,734	3,734
2017	3,796	3,946	3,646	3,796	3,796
2018	3,857	4,010	3,705	3,857	3,857
2019	3,919	4,074	3,764	3,919	3,919

ANNUAL GROWTH RATES					
1989-1994	3.1%				
1994-1999	4.6%				
1999-2004	-0.9%				
2004-2009	2.0%	2.8%	1.1%	2.0%	2.0%
2009-2014	1.8%	1.8%	1.8%	1.8%	1.8%
2014-2019	1.6%	1.6%	1.6%	1.6%	1.6%
2004-2019	1.8%	2.1%	1.5%	1.8%	1.8%

BIG RIVERS ELECTRIC CORPORATION

2004 LONG-TERM LOAD FORECAST - RANGE FORECASTS

IRRIGATION ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1989	82				
1990	48				
1991	86				
1992	114				
1993	78				
1994	93				
1995	100				
1996	110				
1997	107				
1998	121				
1999	121				
2000	70				
2001	75				
2002	38				
2003	113				
2004	164				
2005	164	180	148	180	148
2006	164	180	148	180	148
2007	164	180	148	180	148
2008	164	180	148	180	148
2009	164	180	148	180	148
2010	164	180	148	180	148
2011	164	180	148	180	148
2012	164	180	148	180	148
2013	164	180	148	180	148
2014	164	180	148	180	148
2015	164	180	148	180	148
2016	164	180	148	180	148
2017	164	180	148	180	148
2018	164	180	148	180	148
2019	164	180	148	180	148

ANNUAL GROWTH RATES					
1989-1994	2.7%				
1994-1999	5.3%				
1999-2004	6.2%				
2004-2009	0.0%	2.0%	-2.1%	2.0%	-2.1%
2009-2014	0.0%	0.0%	0.0%	0.0%	0.0%
2014-2019	0.0%	0.0%	0.0%	0.0%	0.0%
2004-2019	0.0%	0.6%	-0.7%	0.6%	-0.7%

Appendix D
Econometric Model Specifications

JACKSON PURCHASE ENERGY CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RURAL SUMMER COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Summer CP Demand

Model Type: Econometric

Model Specification:

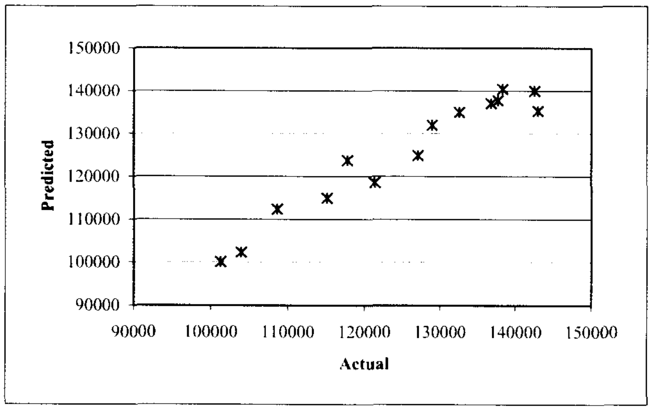
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(13,122)	9,930	(1.3)	21.58%
Rural_kWh	Rural Energy	0.239	0.017	14.004	0.000

Summary Model Statistics:

R-Squared	0.942342543
Adjusted R-Squared	0.937537755
Durbin-Watson Statistic	2.785348417
Mean Abs. % Err. (MAPE)	2.05%

Adjusted Observations	14
Deg. of Freedom for Error	12
F-Statistic	196
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	16.58
Model Sum of Squares	2,480,195,591
Sum of Squared Errors	151,751,369
Mean Squared Error	12,645,947.39
Std. Error of Regression	3,556.11
Mean Abs. Dev. (MAD)	2,569.92

Predicted vs. Actual



JACKSON PURCHASE ENERGY CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RURAL WINTER COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Winter CP Demand

Model Type: Econometric

Model Specification:

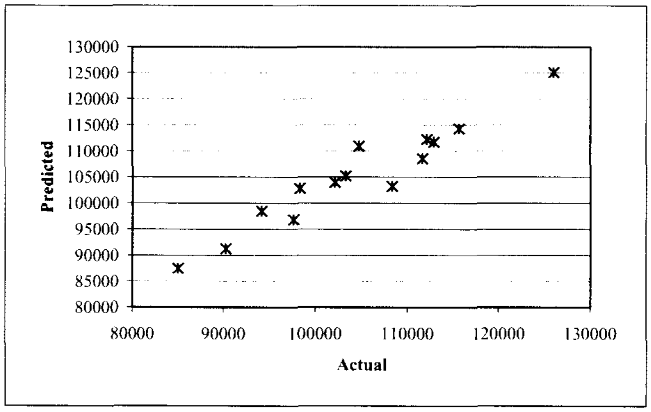
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	8,051	6,233	1.3	22.87%
Rural_kWh	Rural Energy Purchases	0.165	0.012	13.5	0.00%
MA(1)	Moving Average	-2.196	0.638	-3.440	0.007

Summary Model Statistics:

R-Squared	0.915670519
Adjusted R-Squared	0.900337886
Durbin-Watson Statistic	1.807759912
Mean Abs. % Err. (MAPE)	2.43%

Adjusted Observations	14
Deg. of Freedom for Error	11
F-Statistic	60
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	16.62
Model Sum of Squares	1,429,913,401
Sum of Squared Errors	131,689,131
Mean Squared Error	11,971,739.18
Std. Error of Regression	3,460.02
Mean Abs. Dev. (MAD)	2,473.29

Predicted vs. Actual



JACKSON PURCHASE ENERGY CORPORATION

2003 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Residential Consumers

Model Type: Econometric

Model Specification:

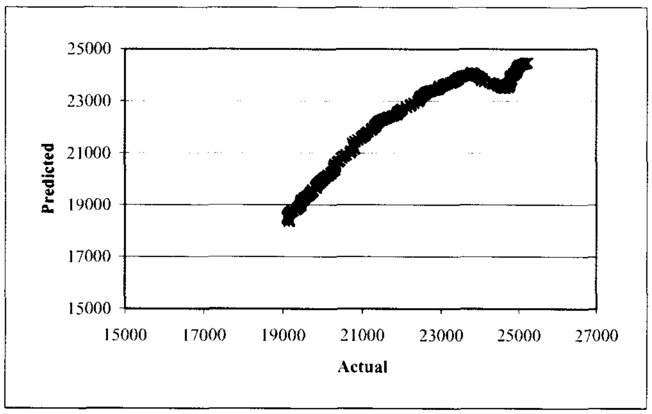
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(67,775)	2,222	(30.5)	0.00%
POP	Population	1,485.507	36.625	40.6	0.00%

Summary Model Statistics:

R-Squared	0.902362569
Adjusted R-Squared	0.901814045
Durbin-Watson Statistic	0.004782832
Mean Abs. % Err. (MAPE)	2.39%

Adjusted Observations	180
Deg. of Freedom for Error	178
F-Statistic	1,645
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	12.87
Model Sum of Squares	612,969,975
Sum of Squared Errors	66,324,574
Mean Squared Error	372,609.97
Std. Error of Regression	610.42
Mean Abs. Dev. (MAD)	541.84

Predicted vs. Actual



JACKSON PURCHASE ENERGY CORPORATION

2003 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL USE - LONG-TERM FORECAST

Dependent Variable: Residential Use

Model Type: Econometric

Model Specification:

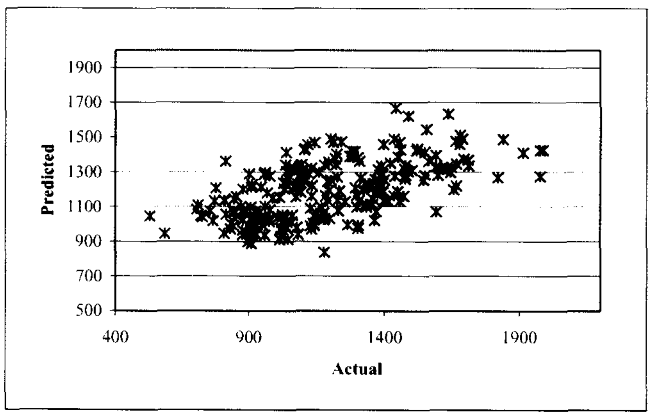
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	647.34	170	3.8	0.02%
PCAP	Per Capita Income	0.016	0.006	2.9	0.45%
CDD	Cooling Degree Days	0.653	0.161	4.0	0.01%
HDD	Heating Degree Days	0.313	0.074	4.2	0.00%
Price	Price	(3,466.393)	1,583.289	(2.2)	2.96%
LagHDD	Lag of Heating Degree Days	0.297	0.075	3.9	0.01%
LagCDD	Lag of Cooling Degree Days	1.040	0.164	6.3	0.00%

Summary Model Statistics:

R-Squared	0.360321097
Adjusted R-Squared	0.343848678
Durbin-Watson Statistic	1.390824687
Mean Abs. % Err. (MAPE)	16.42%

Adjusted Observations	240
Deg. of Freedom for Error	233
F-Statistic	22
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	10.99
Model Sum of Squares	6,826,668
Sum of Squared Errors	12,119,401
Mean Squared Error	52,014.59
Std. Error of Regression	228.07
Mean Abs. Dev. (MAD)	186.05

Predicted vs. Actual



JACKSON PURCHASE ENERGY CORPORATION

2003 LOAD FORECAST

MODEL SPECIFICATIONS

SMALL COMMERCIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Small Commercial Consumers

Model Type: Econometric

Model Specification:

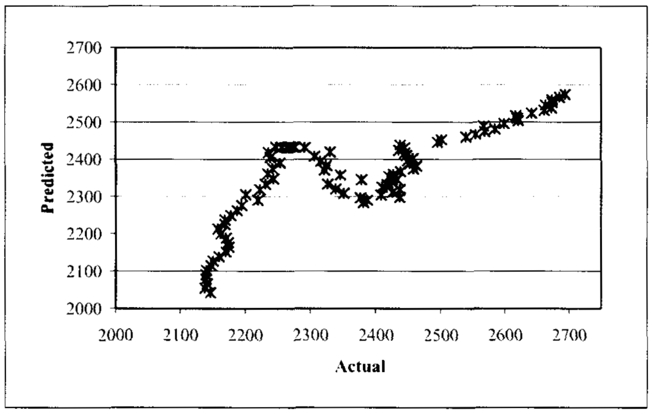
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(5,170)	619	(8.4)	0.00%
Empl	Employment	205.321	16.883	12.2	0.00%

Summary Model Statistics:

R-Squared	0.611398272
Adjusted R-Squared	0.607264211
Durbin-Watson Statistic	0.031551522
Mean Abs. % Err. (MAPE)	3.75%

Adjusted Observations	96
Deg. of Freedom for Error	94
F-Statistic	148
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	9.31
Model Sum of Squares	1,522,895
Sum of Squared Errors	967,945
Mean Squared Error	10,297.28
Std. Error of Regression	101.48
Mean Abs. Dev. (MAD)	88.34

Predicted vs. Actual



JACKSON PURCHASE ENERGY CORPORATION

2003 LOAD FORECAST

MODEL SPECIFICATIONS

SMALL COMMERCIAL ENERGY - LONG-TERM FORECAST

Dependent Variable: Small Commercial Energy

Model Type: Econometric

Model Specification:

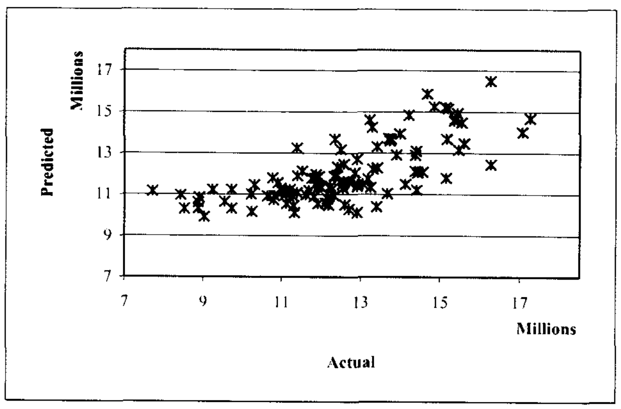
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	6,337,678	1,973,784	3.2	0.18%
RetSale	Retail Sales	4,755.087	2,880.082	1.7	10.18%
HDD	Heating Degree Days	2,571.439	543.624	4.7	0.00%
CDD	Cooling Degree Days	14,139.825	1,379.647	10.2	0.00%

Summary Model Statistics:

R-Squared	0.546540751
Adjusted R-Squared	0.533460195
Durbin-Watson Statistic	1.726849761
Mean Abs. % Err. (MAPE)	9.52%

Adjusted Observations	108
Deg. of Freedom for Error	104
F-Statistic	42
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	28.44
Model Sum of Squares	2.45E+14
Sum of Squared Errors	2.04E+14
Mean Squared Error	1.96E+12
Std. Error of Regression	1,399,382.69
Mean Abs. Dev. (MAD)	1,088,159.73

Predicted vs. Actual



KENERGY CORP.

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RURAL SUMMER COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Summer CP Demand

Model Type: Econometric

Model Specification:

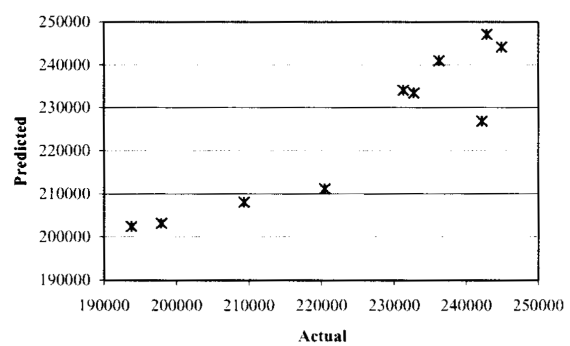
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	(119,836)	184,305	(0.7)	54.42%
Rural_kWh	Rural System Energy Purchases	0.214	0.041	5.2	0.35%
Max_Temp	Maximum Temperature	1,364.727	1,590.570	0.9	43.01%

Summary Model Statistics:

R-Squared	0.852182682
Adjusted R-Squared	0.809949163
Durbin-Watson Statistic	1.062443749
Mean Abs. % Err. (MAPE)	2.38%

Adjusted Observations	10
Deg. of Freedom for Error	7
F-Statistic	20
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	18.37
Model Sum of Squares	2,733,612,541
Sum of Squared Errors	474,165,084
Mean Squared Error	67,737,869.20
Std. Error of Regression	8,230.30
Mean Abs. Dev. (MAD)	5,290.06

Predicted vs. Actual



KENERGY CORP.

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RURAL WINTER COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Winter CP Demand

Model Type: Econometric

Model Specification:

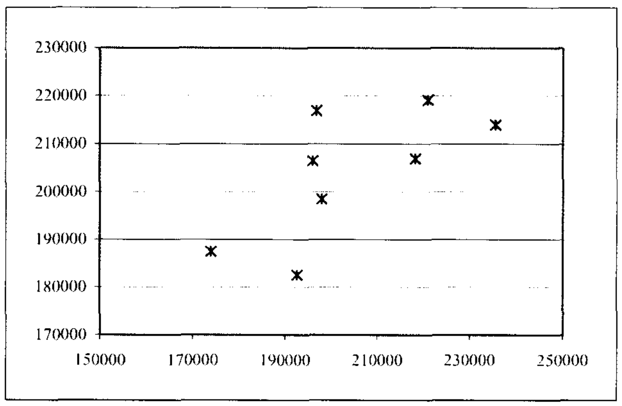
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	17,134	79,884	0.2	84.07%
Rural_kWh	Rural System Energy Purchases	0.182	0.078	2.3	7.90%

Summary Model Statistics:

R-Squared	0.478105218
Adjusted R-Squared	0.391122754
Durbin-Watson Statistic	3.162954156
Mean Abs. % Err. (MAPE)	5.50%

Adjusted Observations	8
Deg. of Freedom for Error	6
F-Statistic	5
Prob (F-Statistic)	6%
Bayesian Information Criterian (BIC)	19.49
Model Sum of Squares	1,274,685,730
Sum of Squared Errors	1,391,433,948
Mean Squared Error	231,905,657.97
Std. Error of Regression	15,228.45
Mean Abs. Dev. (MAD)	11,166.54

Predicted vs. Actual



KENERGY CORP.

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Residential Consumers

Model Type: Econometric

Model Specification:

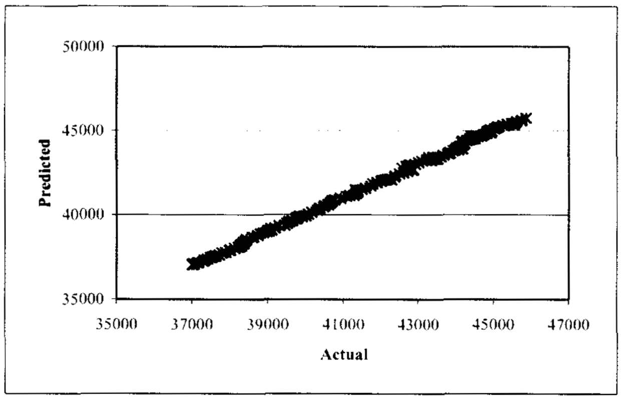
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(31,003)	1,890	(16.4)	0.00%
POP	Population	323.031	18.837	17.1	0.00%
LagDep(12)	Lag of Residential Customers	0.780	0.012	64.4	0.00%

Summary Model Statistics:

R-Squared	0.998683268
Adjusted R-Squared	0.998667308
Durbin-Watson Statistic	0.39529566
Mean Abs. % Err. (MAPE)	0.19%

Adjusted Observations	168
Deg. of Freedom for Error	165
F-Statistic	62,573
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	9.25
Model Sum of Squares	1,212,951,840
Sum of Squared Errors	1,599,238
Mean Squared Error	9,692.35
Std. Error of Regression	98.45
Mean Abs. Dev. (MAD)	79.40

Predicted vs. Actual



KENERGY CORP.

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL USE - LONG-TERM FORECAST

Dependent Variable: Residential Use

Model Type: Econometric

Model Specification:

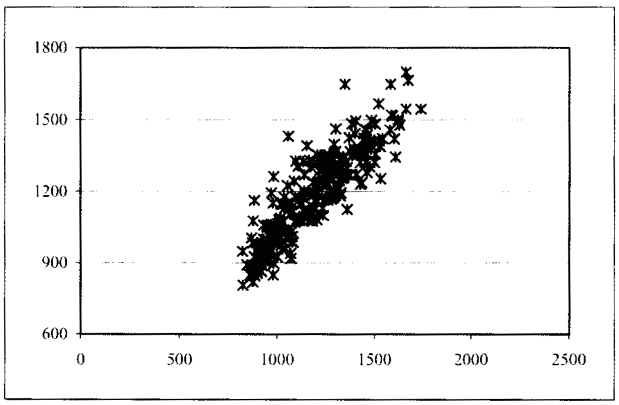
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	42	105	0.4	68.67%
RPRICE	Residential Price	(931.771)	1,091.854	(0.9)	39.43%
Lag_HDD	Lag of Heating Degree Days	0.384	0.033	11.5	0.00%
Lag_CDD	Lag of Cooling Degree Days	1.154	0.072	16.0	0.00%
PCAP	Per Capita Income	0.035	0.004	10.1	0.00%
HDD	Heating Degree Days	0.389	0.033	11.8	0.00%
CDD	Cooling Degree Days	0.812	0.072	11.4	0.00%

Summary Model Statistics:

R-Squared	0.792154351
Adjusted R-Squared	0.786755762
Durbin-Watson Statistic	1.262835006
Mean Abs. % Err. (MAPE)	6.45%

Adjusted Observations	238
Deg. of Freedom for Error	231
F-Statistic	147
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	9.36
Model Sum of Squares	8,926,727
Sum of Squared Errors	2,342,197
Mean Squared Error	10,139.38
Std. Error of Regression	100.69
Mean Abs. Dev. (MAD)	75.90

Predicted vs. Actual



KENERGY CORP.

2005 LOAD FORECAST

MODEL SPECIFICATIONS

SMALL COMMERCIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Small Commercial Consumers

Model Type: Econometric

Model Specification:

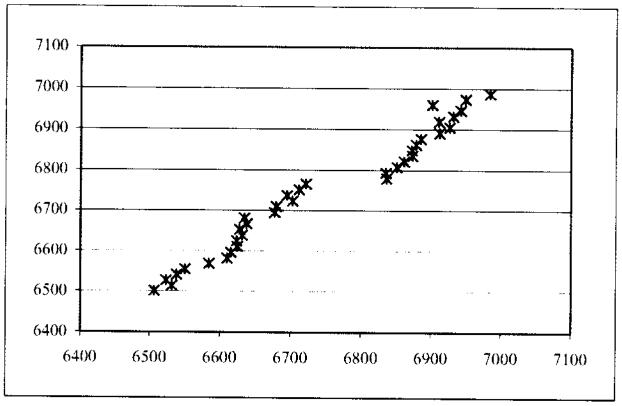
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	(10,150)	564	(18.0)	0.00%
Empl	Employment	242.578	8.097	30.0	0.00%

Summary Model Statistics:

R-Squared	0.963498579
Adjusted R-Squared	0.962425008
Durbin-Watson Statistic	0.706142492
Mean Abs. % Err. (MAPE)	0.34%

Adjusted Observations	36
Deg. of Freedom for Error	34
F-Statistic	897
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	6.88
Model Sum of Squares	756,525
Sum of Squared Errors	28,660
Mean Squared Error	842.95
Std. Error of Regression	29.03
Mean Abs. Dev. (MAD)	22.95

Predicted vs. Actual



KENERGY CORP.

2005 LOAD FORECAST

MODEL SPECIFICATIONS

SMALL COMMERCIAL ENERGY - LONG-TERM FORECAST

Dependent Variable: Small Commercial Energy

Model Type: Econometric

Model Specification:

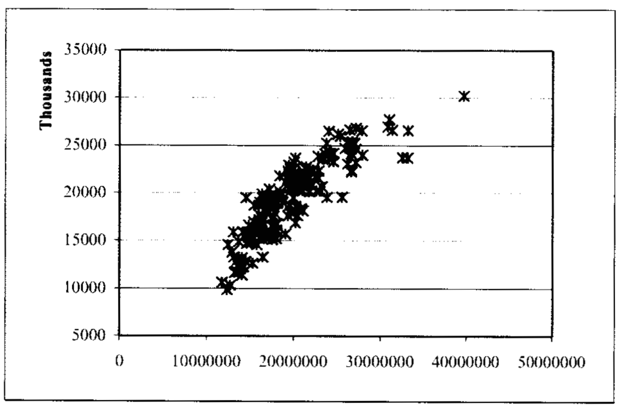
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	(12,612,422)	36,578,777	(0.3)	73.07%
Income	Income	8,567	9,472	0.9	36.71%
HDD	Heating Degree Days	16,451	3,363	4.9	0.00%
CDD	Cooling Degree Days	12,788	6,211	2.1	4.11%
Price	Price	(76,232,373)	182,605,753	(0.4)	67.69%
D02	Indicator - February	1,396,463	1,512,246	0.9	35.72%
D03	Indicator - March	4,109,871	1,815,918	2.3	2.49%
D04	Indicator - April	7,670,851	2,675,091	2.9	0.47%
D05	Indicator - May	12,625,250	3,332,298	3.8	0.02%
D06	Indicator - June	15,532,685	3,861,215	4.0	0.01%
D07	Indicator - July	14,973,573	4,261,661	3.5	0.06%
D08	Indicator - August	12,537,755	4,078,314	3.1	0.25%
D09	Indicator - September	12,449,252	3,508,379	3.5	0.05%
D10	Indicator - October	11,102,864	2,828,474	3.9	0.01%
D11	Indicator - November	9,115,881	1,977,293	4.6	0.00%
D12	Indicator - December	3,052,355	1,415,351	2.2	3.25%

Summary Model Statistics:

R-Squared	0.580329488
Adjusted R-Squared	0.54194499
Durbin-Watson Statistic	1.679403432
Mean Abs. % Err. (MAPE)	10.79%

Adjusted Observations	180
Deg. of Freedom for Error	164
F-Statistic	15
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	30.54
Model Sum of Squares	2.88E+15
Sum of Squared Errors	2,081,971,490,949,090
Mean Squared Error	12,694,948,115,543.30
Std. Error of Regression	3,562,997.07
Mean Abs. Dev. (MAD)	1,979,166.43

Predicted vs. Actual



MEADE RURAL ELECTRIC COOPERATIVE CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RURAL SUMMER COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Summer CP Demand

Model Type: Econometric

Model Specification:

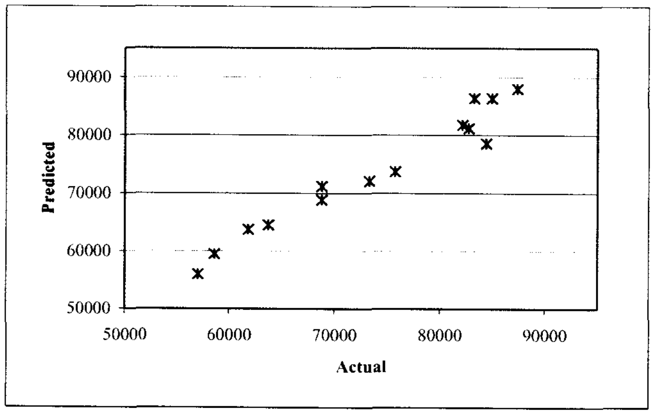
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(66,342)	36,881	(1.8)	10.56%
Rural_kWh	kWh Purchased	0.1964	0.0136	14.4	0.00%
Max_Temp	Maximum Temperature	758.816	355.341	2.1	6.15%

Summary Model Statistics:

R-Squared	0.955668775
Adjusted R-Squared	0.947608553
Durbin-Watson Statistic	0.849026311
Mean Abs. % Err. (MAPE)	2.20%

Adjusted Observations	14
Deg. of Freedom for Error	11
F-Statistic	119
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	15.92
Model Sum of Squares	1,405,909,468
Sum of Squared Errors	65,216,830
Mean Squared Error	5,928,802.76
Std. Error of Regression	2,434.91
Mean Abs. Dev. (MAD)	1,649.32

Predicted vs. Actual



MEADE RURAL ELECTRIC COOPERATIVE CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RURAL WINTER COINCIDENT PEAK DEMAND - LONG-TERM FORECAST

Dependent Variable: Rural Winter CP Demand

Model Type: Econometric

Model Specification:

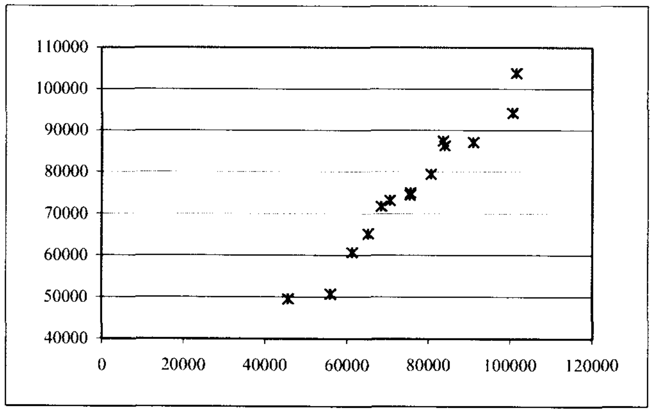
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(12,003)	6,097	(2.0)	8.05%
Rural_kWh	kWh Purchased	0.2586	0.0178	14.5	0.00%
Min_Temp	Minimum Temperature	(697.179)	133.338	(5.2)	0.05%

Summary Model Statistics:

R-Squared	0.957033513
Adjusted R-Squared	0.949221425
Durbin-Watson Statistic	3.109570115
Mean Abs. % Err. (MAPE)	3.64%

Adjusted Observations	14
Deg. of Freedom for Error	11
F-Statistic	123
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	16.71
Model Sum of Squares	3,205,320,191
Sum of Squared Errors	143,904,415
Mean Squared Error	13,082,219.55
Std. Error of Regression	3,616.94
Mean Abs. Dev. (MAD)	2,637.66

Predicted vs. Actual



MEADE RURAL ELECTRIC COOPERATIVE CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Residential Consumers

Model Type: Econometric

Model Specification:

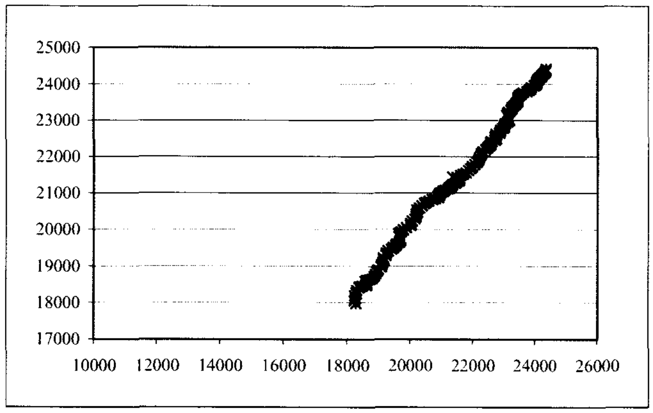
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	(20,662)	267	(77.4)	0.00%
POP	Population	830.682	5.280	157.3	0.00%

Summary Model Statistics:

R-Squared	0.994295834
Adjusted R-Squared	0.994255663
Durbin-Watson Statistic	0.113063761
Mean Abs. % Err. (MAPE)	0.57%

Adjusted Observations	144
Deg. of Freedom for Error	142
F-Statistic	24,752
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	10.00
Model Sum of Squares	517,178,824
Sum of Squared Errors	2,966,998
Mean Squared Error	20,894.35
Std. Error of Regression	144.55
Mean Abs. Dev. (MAD)	120.78

Predicted vs. Actual



MEADE RURAL ELECTRIC COOPERATIVE CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

RESIDENTIAL USE - LONG-TERM FORECAST

Dependent Variable: Residential Use

Model Type: Econometric

Model Specification:

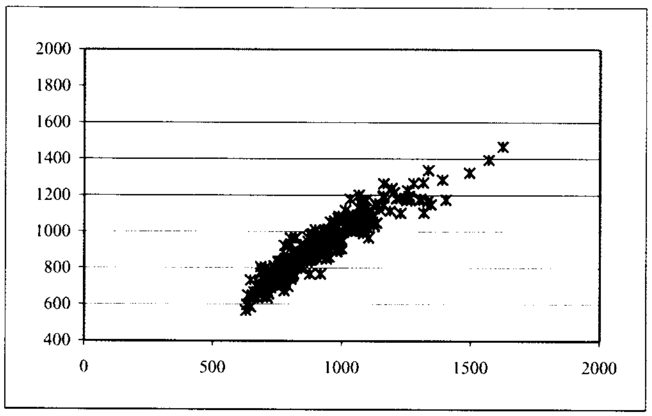
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	(275)	67	(4.1)	0.01%
PCAP	Per Capita Income	0.050	0.003	17.5	0.00%
RPRICE	Residential Energy Price	(1,151)	895	(1.3)	19.95%
HDD	Heating Degree Days	0.306	0.022	13.8	0.00%
CDD	Cooling Degree Days	0.507	0.048	10.5	0.00%
LagCDD	Lag of Cooling Degree Days	0.436	0.023	19.3	0.00%
LagHDD	Lag of Heating Degree Days	0.928	0.049	19.1	0.00%

Summary Model Statistics:

R-Squared	0.874151446
Adjusted R-Squared	0.87091071
Durbin-Watson Statistic	2.009427717
Mean Abs. % Err. (MAPE)	5.56%

Adjusted Observations	240
Deg. of Freedom for Error	233
F-Statistic	270
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	8.57
Model Sum of Squares	7,460,694
Sum of Squared Errors	1,074,090
Mean Squared Error	4,609.83
Std. Error of Regression	67.90
Mean Abs. Dev. (MAD)	51.99

Predicted vs. Actual



MEADE RURAL ELECTRIC COOPERATIVE CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

SMALL COMMERCIAL CONSUMERS - LONG-TERM FORECAST

Dependent Variable: Small Commercial Consumers

Model Type: Econometric

Model Specification:

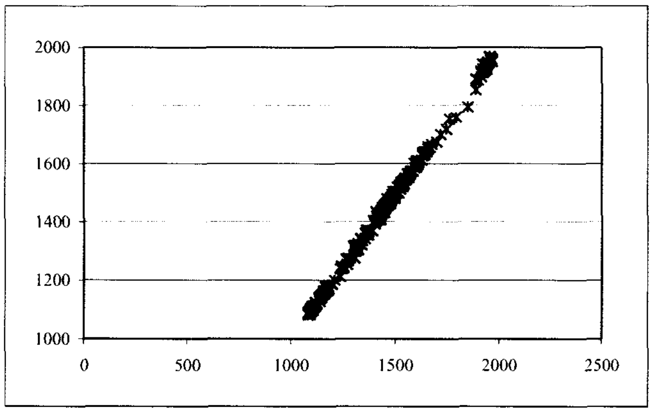
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
INT	Intercept	10,280	72,245	0.1	88.69%
Empl	Employment	9.566	23.590	0.4	68.54%
D_SHIFT	Indicator - Reclassification	6.949	8.452	0.8	41.16%
AR(1)	Autoregressive Parameter	1.000	0.002	411.1	0.00%
MA(1)	Moving Average Parameter	0.111	0.059	1.9	6.14%

Summary Model Statistics:

R-Squared	0.998865524
Adjusted R-Squared	0.998850089
Durbin-Watson Statistic	1.954556724
Mean Abs. % Err. (MAPE)	0.41%

Adjusted Observations	299
Deg. of Freedom for Error	294
F-Statistic	64,714
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	4.33
Model Sum of Squares	18,156,796
Sum of Squared Errors	20,622
Mean Squared Error	70.14
Std. Error of Regression	8.38
Mean Abs. Dev. (MAD)	5.99

Predicted vs. Actual



MEADE RURAL ELECTRIC COOPERATIVE CORPORATION

2005 LOAD FORECAST

MODEL SPECIFICATIONS

SMALL COMMERCIAL ENERGY - LONG-TERM FORECAST

Dependent Variable: Small Commercial Energy

Model Type: Econometric

Model Specification:

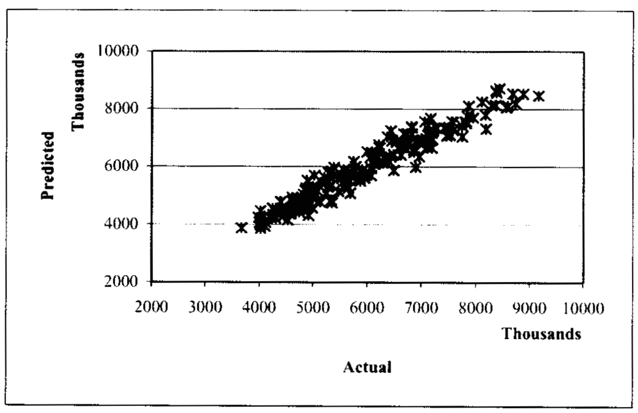
Variable	Description	Value	Standard Err.	t-Statistic	p-Value
CONST	Intercept	5,923,265	2,179,286	2.7	0.73%
Price	Price	(62,320,258.419)	14,798,008.596	(4.2)	0.00%
D02	Indicator - February	156,217	136,359	1.1	25.36%
D03	Indicator - March	(378,882)	163,539	(2.3)	2.18%
D04	Indicator -April	(78,046)	240,668	(0.3)	74.61%
D05	Indicator - May	(69,873)	299,256	(0.2)	81.57%
D06	Indicator - June	284,701	345,773	0.8	41.15%
D07	Indicator - July	618,142	381,024	1.6	10.67%
D08	Indicator - August	1,106,771	364,376	3.0	0.28%
D09	Indicator - September	1,387,286	313,632	4.4	0.00%
D10	Indicator - October	338,197	252,843	1.3	18.29%
D11	Indicator - November	37,281	175,617	0.2	83.22%
D12	Indicator - December	(305,027)	124,247	(2.5)	1.51%
Income	Personal Income	4,837	1,244	3.9	0.01%
HDD	Heating Degree Days	678	303	2.2	2.67%
CDD	Cooling Degree Days	1,848	558	3.3	0.11%

Summary Model Statistics:

R-Squared	0.943146197
Adjusted R-Squared	0.937946154
Durbin-Watson Statistic	1.808598234
Mean Abs. % Err. (MAPE)	4.08%

Adjusted Observations	180
Deg. of Freedom for Error	164
F-Statistic	181
Prob (F-Statistic)	0%
Bayesian Information Criterian (BIC)	25.73
Model Sum of Squares	2.81E+14
Sum of Squared Errors	16,958,953,544,093
Mean Squared Error	103,408,253,317.64
Std. Error of Regression	321,571.54
Mean Abs. Dev. (MAD)	241,292.44

Predicted vs. Actual



Appendix E
Weather Normalization

BIG RIVERS ELECTRIC CORPORATION

2005 LOAD FORECAST
NATIVE REQUIREMENTS - Actual vs. Weather Normalized

		Native System Energy Requirements (MWh)		Peak Demand (MW)	
Year	Month	Actual	Weather Normalized	Actual	Weather Normalized
2000	1	325,602	328,238	577	597
2000	2	282,421	288,036	524	544
2000	3	280,644	287,725	479	478
2000	4	257,304	260,174	445	485
2000	5	275,820	276,981	537	530
2000	6	306,549	309,081	589	599
2000	7	335,281	345,807	628	671
2000	8	342,741	350,380	655	672
2000	9	280,776	280,735	597	614
2000	10	265,165	266,056	503	500
2000	11	287,417	281,670	525	522
2000	12	357,781	338,608	614	613
2001	1	337,798	323,973	599	581
2001	2	281,314	282,788	551	558
2001	3	295,918	293,770	517	520
2001	4	259,829	255,205	468	443
2001	5	275,848	276,143	522	505
2001	6	284,122	290,985	596	646
2001	7	293,917	301,974	560	566
2001	8	313,456	315,688	590	612
2001	9	253,185	255,629	551	577
2001	10	234,470	239,367	404	429
2001	11	230,816	238,227	435	480
2001	12	270,534	282,229	498	522
2002	1	286,566	301,521	509	536
2002	2	252,384	261,981	530	589
2002	3	263,365	264,747	510	479
2002	4	231,008	229,959	430	405
2002	5	237,951	238,814	491	512
2002	6	287,888	287,532	558	569
2002	7	327,130	320,584	597	603
2002	8	312,941	303,888	603	608
2002	9	265,173	253,960	573	535
2002	10	233,586	225,152	487	456
2002	11	249,854	245,869	438	457
2002	12	284,707	286,013	496	506
2003	1	311,458	311,223	586	584
2003	2	270,205	262,734	513	498
2003	3	244,213	244,407	470	465
2003	4	221,212	229,157	406	409
2003	5	219,859	232,470	401	459
2003	6	240,536	262,903	536	565
2003	7	297,623	319,797	552	595
2003	8	301,425	308,899	584	612
2003	9	241,407	249,528	496	541
2003	10	225,385	238,699	379	405
2003	11	233,748	244,909	451	492
2003	12	280,477	293,152	478	547
2004	1	301,481	302,650	539	500
2004	2	269,384	265,200	497	504
2004	3	244,507	246,516	442	459
2004	4	221,929	226,129	424	418
2004	5	256,744	250,171	499	502
2004	6	272,105	267,576	546	575
2004	7	292,529	305,390	604	632
2004	8	278,782	300,662	561	602
2004	9	256,251	272,208	520	565
2004	10	228,447	235,355	395	410
2004	11	237,388	245,727	420	474
2004	12	299,151	301,083	562	480

Appendix B
Demand Side Planning

The Maximum Achievable Cost Effective Potential for Electric Energy Efficiency in the Service Territory of the Big Rivers Electric Corporation

Final Report

Prepared for

Big Rivers Electric Corporation (BREC)

November 10, 2005

Prepared and Submitted by:

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MAXIMUM ACHIEVABLE COST EFFECTIVE POTENTIAL FOR ELECTRIC EFFICIENCY IN THE BREC TERRITORY
FINAL REPORT – NOVEMBER 10, 2005

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ACKNOWLEDGEMENTS

This technical report was prepared for the Big Rivers Electric Corporation by GDS Associates, Inc. GDS would like to acknowledge the many helpful data sources provided by BREC staff.

This report provides valuable and up-to-date estimates of electric energy efficiency potential savings information for decision-makers at BREC and for interested stakeholders. This report includes a thorough and up-to-date assessment of the impacts that electric energy efficiency measures and programs can have on electricity use in the service territory of BREC, the economic costs and benefits of such energy efficiency programs, and the environmental benefits of the maximum achievable cost effective programs identified by this study.

Richard F. Spellman, Vice President
GDS Associates, Inc.
November 10, 2005

MAXIMUM ACHIEVABLE COST EFFECTIVE POTENTIAL FOR ELECTRIC ENERGY EFFICIENCY IN THE BREC TERRITORY
FINAL REPORT – November 10, 2005

1.0 EXECUTIVE SUMMARY – NATURAL GAS ENERGY EFFICIENCY POTENTIAL

This study estimates the maximum achievable cost effective potential for electric energy and peak demand savings from energy-efficiency measures in the geographic region of Kentucky served by the Big Rivers Electric Corporation. BREC). Energy-efficiency opportunities typically are physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining the same or improved levels of energy service. The study shows that there is significant savings potential in the BREC service area for cost effective energy-efficiency measures that save electricity. Capturing the maximum achievable cost effective potential for energy efficiency in the BREC service area would reduce electric energy use by 12.2% (463 GWh annually) by 2015. The magnitude of the potential savings is very comparable to results reported for recent studies in other States (see Table 1-4 for the results of other recent studies). Load reductions from load management and demand response measures, which were not analyzed in this study, would be in addition to these energy efficiency savings. Table 1-1 below provides a summary of the maximum achievable cost effective energy efficiency potential savings for the BREC service area by the year 2015.

Table 1-1: Maximum Achievable Cost Effective Electric Energy Efficiency Potential By 2015 in the Service Area of the Big Rivers Electric Corporation

Sector	Maximum Achievable Cost Effective kWh Savings by 2015 from Electric Energy Efficiency Measures/Programs for the BREC Service Area	2015 kWh Sales Forecast for This Sector	Percent of Sector 2015 kWh Sales Forecast
Residential Sector	277,744,782	1,780,266,000	15.6%
Commercial and Small Industrial	85,475,300	854,753,000	10.0%
Large Industrial	99,758,000	1,159,630,000	8.6%
Total	462,978,082	3,794,649,000	12.2%

The net present savings to BREC for long-term implementation of energy efficiency programs throughout the BREC service area over the next decade are **$39 million.** The Total Resource Cost benefit/cost ratio for the maximum achievable cost effective potential scenario is 1.35. Because the overall TRC benefit/cost ratio is relatively low due to BREC's forecast of very low avoided costs for electricity, BREC's preferred strategy for energy efficiency is to provide an array of information and education to customers about the benefits of purchasing and installing energy efficiency measures in homes and businesses.

1.1 Study Scope

The objective of the study was to estimate the maximum achievable cost effective potential for energy conservation and energy efficiency resources over the ten-year period from 2006 through 2015 in the BREC service area. The definitions used in this study for energy efficiency potential estimates are the following:

- **Technical potential** is defined in this study as the complete penetration of all measures analyzed in applications where they were deemed technically feasible from an engineering perspective.

- **Maximum achievable potential** is defined as the maximum penetration of an efficient measure that would be adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market intervention. BREC would need to undertake an extraordinary effort to achieve this level of savings. The term "maximum" refers to efficiency measure penetration, and means that the GDS Team has based our estimates of efficiency potential on the maximum realistic penetration that can be achieved by 2015. The term "maximum" does not apply to other factors used in developing these estimates, such as measures energy savings or measure lives.

- **Maximum achievable cost effective potential** is defined as the potential for maximum penetration of energy efficient measures that are cost effective according to the Total Resource Cost test, and would be adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market interventions. As demonstrated later tin this report, BREC would need to undertake an extraordinary effort to achieve this level of savings.

The main outputs of this study are summary data tables and graphs reporting the total cumulative maximum achievable cost effective potential for energy efficiency over the ten-year period, and the annual incremental achievable potential and cumulative potential, by year, for 2006 through 2015.

This study makes use of over 200 existing studies conducted throughout the US on the potential energy savings and penetration of energy efficiency measures. These other existing studies provided an extensive foundation for estimates of electric energy savings potential in existing residential, commercial and industrial facilities.

BREC has substantially expanded the assessment of electric energy efficiency potential savings in this new 2005 IRP to include additional energy efficiency equipment and building practices, and to include a detailed assessment of the maximum achievable cost effective electricity savings potential associated with aggressive energy efficiency measure/program implementation over the next decade in the BREC service area. While the prior IRP examined the cost effectiveness of many energy efficiency measures, this new energy efficiency potential assessment goes further to examine the magnitude of the potential savings that could be achieved throughout the BREC service area assuming aggressive implementation of programs over a ten-year period and assuming unlimited funding. The purpose of this analysis was to determine the maximum achievable kWh and dollar savings that could be achieved under such a scenario. This new energy efficiency analysis also provides a calculation of the net present value savings to BREC's members for the maximum achievable cost effective energy efficiency potential savings scenario.

1.2 Implementation Costs

Achieving the maximum achievable cost effective energy efficiency savings by 2015 would require programmatic support. Programmatic support includes financial incentives to customers, marketing, administration, planning, and program evaluation activities provided to ensure the delivery of energy efficiency products and services to consumers.

GDS estimates that costs for BREC (or its member distribution cooperatives) for program planning, administration, marketing, reporting and evaluation ("other program costs") would be 25% of efficiency measure incremental costs in the maximum achievable cost effective energy efficiency scenario.[1] Specifically, BREC would need to spend approximately $2.2 million a year for the next ten years for staffing, marketing, and administrative costs, plus approximately $4 to 5 million a year for financial incentives to electric consumers in order to achieve the maximum achievable cost effective potential savings. It is clear that to achieve all of the maximum achievable cost effective savings, BREC would have to undertake ***extraordinary*** steps to add staffing (either in-house staff or contractors), and BREC would have to spend close to **$8 million** a year to achieve such results.

1.3 Present Value of Savings and Costs (in $2006)

The results of this study demonstrate that energy-efficiency resources could play an expanded role in the BREC resource mix over the next decade. Table 1-2

[1] This estimate is based upon data collected by GDS for other electric utilities that have operated energy efficiency programs.

below shows the present value[2] of benefits and costs associated with implementing the maximum achievable potential energy savings in the BREC service area. The net present savings to BREC for long-term implementation of energy efficiency programs throughout the BREC service area are **$39 million.** The Total Resource Cost benefit/cost ratio for the maximum achievable cost effective potential scenario is 1.35. It is very important to note that the projected TRC benefit/cost ratio is lower than that found in for states with higher electricity costs. Because BREC's electric avoided costs are very, very low compared to other States, energy efficiency programs in the BREC service area typically have much lower TRC benefit/cost ratios than in high cost states in the Northeast, Midwest and the West coast.

Table 1-2: TOTAL RESOURCE COST TEST AND NET PRESENT VALUE SAVINGS FOR THE MAXIMUM ACHIEVABLE COST EFFECTIVE ELECTRICITY SAVINGS POTENTIAL SCENARIO FOR THE BREC SERVICE TERRITORY

Column #	1	2	3	4	5	6
	Present Value of Total Resource Benefits ($2006)	Present Value of Total Measure Incremental Costs ($2006)	Present Value of BREC Implementation Costs (Staffing, Marketing, Data Tracking & Reporting, etc., $2006)	Present Value Of Total Costs (Col 2 + Col 3)	Net Present Value savings ($2006)	Total Resource Cost (TRC) Benefit/Cost Ratio
Residential Sector	$114,046,771	$66,283,971	$16,570,993	$82,854,964	$31,191,807	1.38
Commercial Sector	$20,634,487	$13,270,543	$3,317,636	$16,588,179	$4,046,308	1.24
Industrial Sector	$16,012,307	$9,517,263	$2,379,316	$11,896,579	$4,115,728	1.35
Total	$150,693,565	$89,071,778	$22,267,944	$111,339,722	$39,353,843	1.35

Table 1-2 also provides the Total Resource Cost (TRC) Test benefit/cost ratio for the overall maximum achievable cost effective portfolio of energy efficiency measures, and the benefit/cost ratio by major market sector. The Total Resource Cost (TRC) Test is a standard benefit-cost test used by many of the public utilities commissions in the US and other organizations to compare the value of the avoided energy production and power plant construction to the costs of energy-efficiency measures and program activities necessary to deliver them. The value of both energy savings and peak demand reductions are incorporated into the TRC test.

1.4 Definitions of Benefit Cost Tests

A standard methodology for energy efficiency program cost effectiveness analysis was published in California in 1983 by the California Public Utilities Commission and updated in December 1987 and October 2001.[3] It was based

[2] The term "present value" refers to a mathematical technique used to convert a future stream of dollars into their equivalent value in today's dollars.

[3] California Public Utilities Commission and California Energy Commission, Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, 1987 and 2001.

on experience with evaluating conservation and load management programs in the late 1970's and early 1980's. This methodology examines five perspectives:

- the Total Resource Cost Test
- the Participant Test
- the Utility Cost Test (or Program Administrator Test)
- the Rate Impact Measure (RIM) Test
- the Societal Cost Test

Table 1-3 below summarizes the major components of these five benefit/cost tests. Examining this table is useful when trying to understand the differences among the five benefit/cost tests.

Table 1-3
Components of Energy Efficiency Benefit/Cost Tests

	PARTICIPANT TEST	RATE IMPACT MEASURE TEST	TOTAL RESOURCE COST TEST	UTILITY COST TEST	SOCIETAL TEST
BENEFITS:					
Reduction in Customer's Utility Bill	X				
Incentive Paid By Utility	X				
Any Tax Credit Received	X		X		
Avoided Supply Costs		X	X	X	X
Avoided Participant Costs	X		X		X
Participant Payment to Utility (if any)		X		X	
External Benefits					X
COSTS:					
Utility Costs		X	X	X	X
Participant Costs	X		X		X
External Costs					X
Lost Revenues		X			

The five cost-benefit tests are defined by the California Standard Practice Manual as follows:

1.4.1 The Total Resource Cost Test

The Total Resource Cost (TRC) test measures the net costs of a demand-side management or energy efficiency program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.[4]

Benefits and Costs: The TRC test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test include the avoided natural gas supply costs for the periods when there is a gas load reduction, as well as savings of other resources such as electricity and water. The avoided supply costs are calculated using net program savings, which are the savings net of changes in energy use that would have happened in the absence of the program.

The costs in this test are the program costs paid by the utility and the participants plus any increase in supply costs for periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test.

1.4.2 The Participant Test

The Participant Test is the measure of the quantifiable benefits and costs to program participants due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.[5] This test is designed to give an indication as to whether the program or measure is economically attractive to the customer. Benefits include the participant's retail bill savings over time, and costs include only the participant's costs.

[4]California Public Utilities Commission, California Standard Practice Manual, Economic Analysis of Demand-Side Management Programs and Projects, October 2001, page 18.
[5]Ibid., page 9.

1.4.3 The Rate Impact Measure Test

The Ratepayer Impact Measure (RIM) Test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by a program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer rate levels.[6] Thus, this test evaluates an energy efficiency program from the point of view of rate levels. The RIM test is a test of fairness or equity; it is not a measure of economic efficiency.

1.4.4 The Utility Cost Test

The Utility Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the utility (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the Total Resource Cost Test benefits. Costs are defined more narrowly, and only include the utility's costs.[7] This test compares the utility's costs for an energy efficiency program to the utility's avoided costs for electricity and/or gas. It is important to remember that the Utility Cost Test ignores participant costs. This means that a measure could pass the Utility Cost Test but not be cost effective from a more comprehensive perspective.

1.4.5 The Societal Test

The Societal Cost Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Cost Test utilizes essentially the same input variables as the TRC test, but they are defined with a broader societal point of view.[8] An example of a societal benefit is reduced emissions of carbon, nitrous and sulfur dioxide from electric utility power plants. One example of a societal cost is the incremental cost to the health care system in the United States for dealing with increased respiratory ailments (asthma, etc.) due to the construction of new power plants that produce emissions and particulates. When calculating the Societal Cost Test benefit/cost ratio, future streams of benefits and costs are discounted to the present using a societal discount rate. The avoided costs of natural gas, electricity and water used for the benefit/cost analyses in this report are provided in Appendix E.

[6] Ibid., page 17.
[7] Ibid., page 33.
[8] Ibid., page 27.

1.5 Definition of Electric Avoided Costs

The **avoided electric supply costs** for the BREC energy efficiency potential study consist of the electric supply costs avoided by BREC due to the implementation of electric energy efficiency programs. These avoided supply costs reflect the electric supply costs avoided by BREC when energy efficiency programs are implemented. These avoided electric system supply costs are those that would be avoided by BREC due to the implementation of a portfolio of energy efficiency programs The costs that are avoided depend on the amount electricity that is saved, and when it is saved (in peak heating season periods, seasonal or annual, etc.). The avoided costs of electricity, natural gas and water used in this study are provided in Appendix E.

Second, it is very important to note that the electricity avoided costs used in the Total Resource Cost (TRC) Test is not the retail rate for each customer class. While the actual retail rate is used in the calculation of the benefits for the Participant Test, the actual retail rate is not the avoided electric cost used in the calculation of the Total Resource Cost Test benefits.

1.6 Comparison of Results to Other Gas Savings Potential Studies

Table 1-4 presents a comparison of the results of this study to other recent electric potential studies. As shown in Table 1-6 below, the potential electricity savings available in the BREC service territory are very similar to the findings of these other recent studies.

Table 1-4: Comparison of Potential Electrcity Savings from Recent Studies in Other States

Percent of Total Electricity (GWh) Sales

Sector	Connecticut 2012	California 2011[2,3]	Vermont 2012[1,4]	Mass. 2007[1,4]	Southwest 2020[(6)]	Georgia 2015[(7)]	New York 2012[(8)]	Oregon 2013[(9)]
Technical Potential								
Residential	21%	28%			26%[(6)]	33%	43%	28%
Commercial	25%	18%			37%[(6)]	33%	42%	32%
Industrial	20%	15%			33%[(6)]	17%	22%	35%
Total	***24%***	***18%***			***33%***[(6)]	***29%***	***39%***	***31%***
Maximum Achievable Potential								
Residential	17%		30%			21%	32%	
Commercial	17%		32%			22%	39%	
Industrial	17%		32%			15%	20%	
Total	***17%***	***13%***	***31%***			***20%***	***34%***	
Maximum Achievable Cost Effective Potential								
Residential	13%	10%		31%		9%		
Commercial	14%	10%		21%		10%		
Industrial	13%	9%		21%		7%		
Total	***13%***	***10%***		***24%***		***9%***		

The footnotes to Table 1-4 are provided below.

1. Vermont and Massachusetts studies reported commercial and industrial sectors together.
2. "California's Secret Energy Surplus: The Potential For Energy Efficiency – Final Report", Prepared for The Energy Foundation and The Hewlett Foundation, prepared by XENERGY Inc., September 23, 2002. Page 3-3.
3. "CALIFORNIA STATEWIDE RESIDENTIAL SECTOR ENERGY EFFICIENCY POTENTIAL STUDY"; Study ID #SW063; FINAL REPORT VOLUME 1 OF 2; Prepared for Rafael Friedmann, Project Manager Pacific Gas & Electric Company San Francisco, California; Principal Investigator: F
4. "Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings; 2003-2012 – Results and Analysis Summary"; Public Review Draft of May 29, 2002; prepared for the Vermont Department of Public Service by Optimal Energy, Inc.; Pages 32 &
5. The Remaining Electric Energy Efficiency Opportunities in Massachusetts; Final Report June 7, 2001; prepared for Program Administrators and Massachusetts Division of Energy Resources by RLW Analytics, Inc. and Shel Feldman Management Consulting; Page i
6. Southwest Energy Efficiency Project; "The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest"; Prepared for: Hewlett Foundation Energy Series; prepared by Southwest Energy Efficiency Project; November 2002; Page ES-5. It
7. Georgia Environmental Facilities Authority, "Assessment of Energy Efficiency Potential in Georgia - Final Report" prepared by ICF Consulting, May 5, 2005. Maximum Achievable shown corresponds to "Economic" in report and Maximum Achievable Cost Effecti
8. New York State Energy Research and Development Authority, "Energy Efficiency and Renewable Energy Resource Development Potential in New York State - Final Report" prepared by Optimal Energy, Inc., August, 2003. Maximum Achievable shown corresponds to
9. ENERGY EFFICIENCY AND CONSERVATION MEASURE RESOURCE ASSESSMENT FOR THE RESIDENTIAL, COMMERCIAL, NDUSTRIAL AND AGRICULTURAL SECTORS Prepared for the Energy Trust of Oregon, Inc. By Ecotope, Inc., ACEEE, Tellus Institute, Inc. January, 2003.

2.0 INTRODUCTION

The main objective of this energy efficiency potential assessment is to assess and evaluate the potential for achievable and cost-effective electric energy efficiency measures and electricity savings for residential, commercial and industrial customers in the BREC service territory. The main outputs of this study include the following deliverables:

- A concise, fully documented report on the work performed and the results of the analysis of opportunities for achievable, cost effective electric energy efficiency in BREC's service territory.
- An overview of the impacts that energy efficiency measures and programs can have on electric use in the BREC service territory.
- A summary of the economic costs and benefits of potential energy efficiency measures and programs.
- An assessment of the environmental and other non-energy benefits of the maximum achievable cost effective electric energy efficiency options examined in this study.

2.1 Summary of Approach

A comprehensive discussion of the study methodology is presented in Section 4. GDS first developed estimates of the technical potential and the maximum achievable potential for electric energy efficiency opportunities for the residential, commercial and industrial sectors in BREC's service territory. The GDS analysis utilized the following models and information:

(1) an existing electric energy efficiency potential spreadsheet model[9];
(2) detailed information relating to the current and potential saturation of electric energy efficiency measures in the BREC service area; and
(3) available data on electric energy efficiency measure costs, saturations, energy savings, and useful lives.

The technical potential for electric energy efficiency was based upon calculations that assume one hundred percent penetration of all energy efficiency measures analyzed in applications where they were deemed to be technically feasible from an engineering perspective.

The maximum achievable potential for electric energy efficiency was estimated by determining the maximum penetration of an efficient measure that would be

[9] This GDS developed Excel spreadsheet model is used to estimate the energy efficiency potential for natural gas energy efficiency measures in New Mexico. It operates on a PC platform using the Microsoft Windows operating system, is documented, and can be followed by a technician with expertise. GDS has provided this model to the study sponsors as a deliverable of this project.

adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market intervention.

The third level of energy efficiency examined is the maximum achievable cost effective potential. The calculation of the cost effective maximum achievable potential is based, as the term implies, on the assumption that energy efficiency measures/bundles will only be included in BREC electric efficiency programs when it is cost effective to do so.

All cost effectiveness calculations for electric energy efficiency measures and programs were done using a spreadsheet model that operates in Excel and that has been approved by regulators in several states.

2.2 Report Organization

The remainder of this report is organized as follows:

- Section 3 – Electric Usage – Overview of BREC Electric Sales and Peak Load Forecast
- Section 4 – Methodology for Determining Energy Savings Potential
- Section 5 – Electric Energy Efficiency Potential – Residential Sector
- Section 6 – Electric Energy Efficiency Potential – Commercial Sector
- Section 7 – Electric Energy Efficiency Potential – Industrial Sector
- Section 8 – Environmental and Other Non-Energy Benefits of Electric Energy Efficiency Programs
- Section 9 – Summary of Findings

3.0 CHARACTERIZATION OF CUSTOMER BASE, ELECTRIC USAGE, AND EXISTING ENERGY EFFICIENCY PROGRAMS IN THE BREC SERVICE TERRITORY

3.1 Overview of Big Rivers Service Area

The Big Rivers Electric Corporation is an electric generation and transmission cooperative supplying the wholesale power needs of its three member cooperatives and marketing power to non-member utilities and power markets. These members provide retail electric power and energy to industrial, residential and commercial customers in portions of 22 western Kentucky counties. For the purposes of this energy efficiency potential report, all references made to Big Rivers' service territory is to the 22 counties served by the three member cooperatives. Headquartered in Henderson, Kentucky, Big Rivers is dedicated to the following:

- Providing reliable wholesale energy to its three member cooperative owners who serve approximately 106,000 customers in the Commonwealth of Kentucky.
- Marketing reliable energy to surrounding utilities.
- Protecting the environment through detailed planning
- In-house design and construction of transmission and substation facilities
- Adding value to the customer through conservative measures

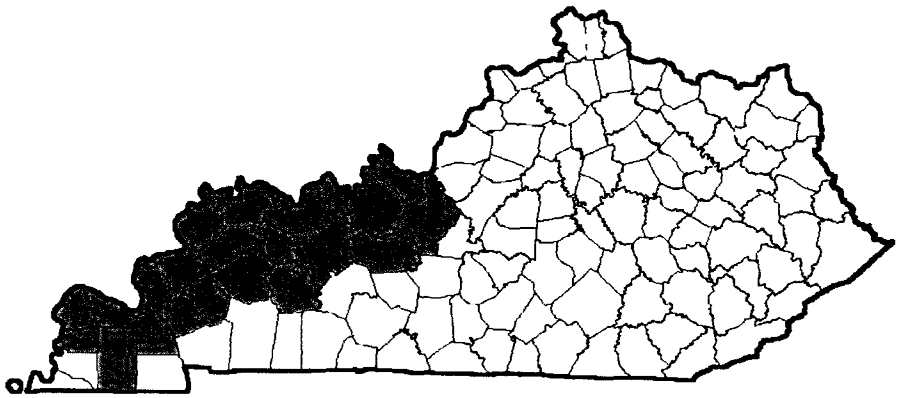
The distribution electric cooperatives that belong to Big Rivers are the following:

- Jackson Purchase Energy Corporation ("JPEC")
- Kenergy Corp. ("Kenergy")
- Meade County Rural Electric Cooperative Corporation ("MCRECC")

There are 22 counties included in the Big Rivers service area. Listed below are the counties in Kentucky served by each member distribution cooperative:

- JPEC - Ballard, Carlisle, Graves, Livingston, Marshall and McCracken
- Kenergy - Breckinridge, Daviess, Caldwell, Crittenden, Hancock, Henderson, Hopkins, Livingston, Lyon, McLean, Muhlenberg, Ohio, Union and Webster
- MCRECC - Breckinridge, Grayson, Hancock, Hardin, Meade and Ohio

3.2 BREC Service Area Map



3.3 Economic/Demographic Characteristics of the Service Area

The total population of the Big Rivers service area is 639,746[10] persons. Population in the past ten years has grown 0.5% per year in the region. The gender split is 51.2% female and 48.8% male. The summary below shows gender statistics for the counties that Big Rivers serves, Kentucky, and the United States.

Table 3-1: Gender Distribution

Gender	Big Rivers	Kentucky	US
Male	48.8%	49.0%	49.2%
Female	51.2%	51.0%	50.8%

The majority of the population in the BREC service area falls in the 20-44 years (33.7%) of age range. The median age for the region is 39.5 years.

Table 3-2: Age Distribution

Age	Big Rivers	Kentucky	US
Under 20	24.7%	25.2%	27.8%
20-44	33.7%	36.5%	35.8%
45-64	27.0%	25.8%	24.1%
65+	14.6%	12.5%	12.3%
Median Age	39.5	37.5	36.1

[10] This population estimate is higher than the total population value in the 2005 Load Forecast, which is weighted to reflect the population served by Big Rivers. The weighted population for Big Rivers in 2004 is 244,180.

The ethnicity of the population is predominantly white (93%). National, state, and local statistics are found below.

Table 3-3: Ethnicity Distribution

Ethnicity	Big Rivers	Kentucky	US
White	93.1%	89.4%	68.1%
Black	5.0%	7.6%	12.5%
Native American	0.2%	0.2%	0.8%
Asian and Pacific Islander	0.4%	1.0%	4.6%
Hispanic	1.3%	2%	14%

The Big Rivers service area:

- Covers approximately 8,000 square miles
- Contains 88-substations
- Utilizes just under 2,000 miles of transmission lines
- Has 7 surrounding utilities
- Serves 106,000 customers in 22 counties[11]

According to the estimates from the US Census[12], in 2003 the five largest cities (and their population counts) in the Big Rivers service territory are the following:

Table 3-4: Largest Cities

In the Service Area	
Owensboro, KY	54,312
Henderson, KY	27,468
Paducah, KY	25,565
Elizabethtown, KY	23,239
Radcliff, KY	21,894
Outside the Service Area	
Louisville, KY	248,762
Evansville, IN	121,582
Bowling Green, KY	50,663

The population density in the Big Rivers service area is approximately 80 persons per square mile[13]. This is less than the state population density, which is about 102.5 persons per square mile.

It is estimated that the proportion of single-family homes is 86.9% and the proportion of multi-family homes is 13.1% within the service area[14]. Average

[11] 2005 Big Rivers Load Forecast
[12] www.census.gov
[13] GDS estimate using 8,000 square miles and 640,000 for population.

household income for the counties served by Big Rivers is $58,986, which is lower than both the total state and national averages. The following table presents a distribution of household incomes for the area served by Big Rivers as well as for Kentucky and the entire U.S.

Table 3-5: Average Household Income

Income Range	Big Rivers	Kentucky	US
$9,999 or less	12.4%	13.0%	9.0%
$10,000 - $19,999	16.0%	15.2%	11.9%
$20,000 - $29,999	14.7%	14.4%	12.4%
$30,000 - $44,999	19.5%	18.4%	17.6%
$45,000 - $59,999	14.6%	13.9%	14.5%
$60,000 - $74,999	9.7%	9.4%	10.9%
$75,000 - $99,999	7.4%	8.1%	10.8%
$100,000 - $124,999	2.7%	3.4%	5.5%
$125,000 - $149,000	1.1%	1.5%	2.6%
$150,000 - $199,999	0.8%	1.3%	2.3%
$200,000 - or more	1.1%	1.5%	2.5%
Average Income	**$ 58,986**	**$ 66,591**	**$ 85,383**

The majority of the population in the Big Rivers service area is employed by careers in the services, retail trade and manufacturing industries. The following table presents a distribution of employment for the counties served by Big Rivers, the state of Kentucky, and the U.S.

Table 3-6: Area of Employment Distribution

Description	Big Rivers	Kentucky	US
Farm	6.5%	4.6%	1.8%
Other Agricultural	1.3%	1.3%	1.3%
Mining	1.4%	0.9%	0.0%
Construction	7.0%	5.9%	5.7%
Manufacturing	15.1%	13.6%	10.7%
Transport, Comm. and Public Utilities	4.8%	5.6%	5.0%
Wholesale Trade	3.6%	4.0%	4.4%
Retail Trade	17.5%	16.7%	16.1%
Finance, Insurance and Real Estate	4.5%	5.8%	8.0%
Services	25.1%	26.6%	32.7%
Federal Civilian Government	0.8%	1.5%	1.6%
Federal Military Government	0.6%	2.1%	1.2%
State and Local Government	11.8%	11.5%	11.0%

[14] ESRI

3.4 Latest Forecast of kWh Sales and Peak Demand

This latest BREC load forecast was completed in July 2005 and updates the prior load forecast that was completed in July 2003.[15] The forecast contains projections of energy and demand requirements for the 2005-2019 forecast horizon. High and low range forecast scenarios were developed to address uncertainties regarding the factors expected to influence energy consumption in the future.

The July 2005 forecast shows that total system native energy and peak demand requirements are projected to increase at average compound rates of 1.6% and 1.5%, respectively, from 2004 through 2019[16]. Growth in system requirements is projected to be conservative, as requirements for direct serve customers, which comprise approximately 32% of total system energy sales, have been held constant throughout the forecast period. Rural system energy and peak demand requirements, which are represented as total system requirements less those associated with direct-serve customers, are projected to increase at an average rate of 2.2% and 2.1%, respectively, over the same period.

The forecast is summarized in Tables 3-7 and 3-8 on the following page. The primary influences on long-term growth in BREC electric system requirements over the forecast period will continue to be growth in rural system requirements, which is primarily a function of growth in number of customers and changes in industrial activity. Industrial sales have declined in recent years due to economic conditions and the development of a cogeneration site by Weyerhauser. When combined with rural system sales, which have increased over the same period, total system sales growth has been low. Over the forecast horizon, industrial sales are projected to stay relatively level, and residential sales are expected to grow at 2.2% annually, resulting in overall system growth of 1.6% per year.

[15] Big Rivers Electric Corporation, 2005 Load Forecast, July 2005 (113 pages). Prepared by GDS Associates for BREC.
[16] Based on weather normalized values for 2005 and 2019.

Table 3-7
Load Forecast Summary

		Total System		Rural System	
Year	Consumers	Energy Requirements (MWH)	Peak Demand (CP kW)	Energy Requirements (MWH)	Peak Demand (CP kW)
1994	87,256	7,721,677	1,189,000	1,571,482	352,635
1999	98,168	3,532,841	663,890	1,921,792	475,416
2004	106,414	3,158,698	604,155	2,133,190	476,409
2009	114,383	3,519,951	675,440	2,485,739	536,630
2014	123,516	3,767,931	728,343	2,737,034	589,533
2019	133,462	4,054,080	789,356	3,027,093	650,546

Table 3-8
Load Forecast – Average Annual Growth Rates

Description	2004-2009	2004-2019
Total Native System Energy Requirements	1.8%	1.6%
Total Native System Peak Demand (CP)	1.3%	1.5%
Rural System Energy Requirements	2.6%	2.2%
Rural System Peak Demand (CP)	2.4%	2.1%
Residential Energy Sales	2.1%	2.2%
Residential Consumers	1.3%	1.4%
Small Commercial & Industrial Energy Sales	3.2%	2.1%
Small Commercial & Industrial Energy Consumers	2.4%	2.2%
Large Industrial – Direct Serve Energy Sales	0.3%	0.1%
Large Industrial – Direct Serve Consumers	0.0%	0.0%
Irrigation Sales	0.0%	0.0%
Public Street Lighting Sales	2.0%	1.8%

3.5 Existing Member Cooperative Demand-Side Programs

Kenergy
Kenergy offers educational and informative brochures, magazine articles, and television and radio commercials relating to energy efficiency topics. The ground source heat pump continues to be the central HVAC technology promoted.

Energy Resource Conservation Loans at 5 percent interest are available from Kenergy to qualifying customers installing a geothermal system in their existing homes. This offer is not available for new construction. The loans may finance up to 100 percent of the installation cost and may be amortized for up to 60 months. Kenergy publishes advertisements in newspapers and magazines that describe their 5% financing for installations in existing homes for geothermal energy systems. Informative pamphlets and magazine articles are used by Kenergy to educate customers on the energy savings gained by installing a geothermal system.

Following are annual operating cost estimates and efficiencies for different types of heating and cooling equipment in an average-size home (approximately 1,500 square feet). Resistance heat includes baseboards, ceiling cable and electric furnace. Propane based on $1.91 per gallon + $40 yearly tank rental. Natural gas based on $1.24 per CCF.

ANNUAL HEATING & COOLING OPERATING COSTS	
Resistance Heat	$816.05
Propane Heat 80% Efficient	$967.52
Natural Gas	$605.16
10 SEER Heat Pump	$594.58
12 SEER Heat Pump	$506.03
14 SEER Heat Pump	$440.62
Geothermal	$322.56

Kenergy is not currently conducting any load management programs.

Jackson Purchase Energy Corporation

JPEC provides similar informational articles and brochures for their members. One publication that they distribute is the Energy Savers Tips on Saving Energy & Money at Home, which is a brochure that compiles ideas and measures that will help reduce energy usage and save money for members. Magazine articles are also posted on the cooperative's web site with ideas on how to save energy (for example, by providing shade trees around a home to reduce peak air-conditioning loads). The JPEC web site provides the following additional links:

- a link to the electronic copy of the Energy Savers pamphlet.
- a link to the Department of Energy's Home Energy Saver Web Site. A cooperative member can go to that web site and obtain detailed information on energy use for their home and how to reduce their energy usage. A cooperative member can even customize the information for their specific type of home.

JPEC provides cash incentives for high efficiency heat pumps in new and existing residential homes. JPEC is not currently conducting any load management programs. JPEC provides free caulk to its member consumers in efforts to help consumers maintain adequate insulation of their homes.

Meade County Rural Electric Cooperative Corporation
MCRECC provides energy efficiency informational brochures on geothermal heating and cooling systems, and also publishes articles relating to energy efficiency tips in Kentucky Living magazine. The articles suggest ways to save on cooling costs during the summer and save on heating costs during the winter. Radio advertisements are also a way of educating their consumers about energy efficiency topics. Advertisements are also used to increase awareness of water and energy conservation issues such as leaking faucets and to increase awareness of energy efficiency measures that can be used to save money on heating and cooling bills while still making the home comfortable.

MCRECC offers the "All Seasons Comfort Home" program to a cooperative member that is building a new home. The program provides recommended, proven standards for insulation, energy-saving features, and assistance in the selection and installation of high efficiency heat pumps and geothermal heating and cooling systems. MCRECC provides information to members on the most efficient and economical heating and cooling system equipment. MCRECC is not currently conducting any load management programs.

The energy efficiency initiatives offered by Big Rivers' member system distribution cooperatives are summarized below in Table 3-10.

Table 3-10: Summary Of Existing Energy Efficiency Initiatives Offered By Big Rivers Electric Corporation And Its Distribution Cooperative Members

Kenergy

- Kentucky Living Magazine – Monthly magazine to all customers - focus articles on energy efficiency for the home and business and 4 page insert from local cooperative detailing programs, safety and customer service.
- DOE Pamphlet "Energy Savers - Tips on Saving Energy & Money at Home"
- Heat Pump Programs – Incentives Programs - 5% financing for Ground Source Heat Pumps for up to 5 years
- C/I News – Quarterly magazine to commercial and industrial customers – focus on energy related topics including conservation and efficiency improvements.
- Energy Efficiency Informational Brochures "Geothermal Heating and Cooling – The Answer to Comfortable and Affordable Living"
- Distribution of compact fluorescent bulbs to customers attending annual meeting

- Incentives Programs:
  - Touchstone Energy Home
  - Water Heater Replacement
  - Add-on Heat Pump
- Heat Loss / Gain analysis for HVAC contractors
- Web Site Information and Links
  - Geothermal Heat Pump Systems
  - USDOE – Energy Saving Tips for Consumers
  - USDOE – Home Energy Audit
  - Commercial Building Energy Checklist
- Energy Audits As Needed
  - Commercial / Industrial
  - Residential
- News Paper Advertising
  - Safety
  - Energy Efficiency

Jackson Purchase Energy

- DOE Pamphlet "Energy Savers - Tips on Saving Energy & Money at Home"
- Customer Newsletter – "Plugged In" Focus articles include energy efficiency, safety information and customer service
- C/I News – Quarterly magazine to commercial and industrial customers – focus on energy related topics including conservation and efficiency improvements.
- Pamphlet - "Keep An Eye On That Thermostat"
- Pamphlet - "How much will this light bulb save you?"
- Distribution of compact fluorescent bulbs to customers attending annual meeting
- Incentives Programs:
  - Touchstone Energy Home
  - Water Heater Replacement
  - Add-on Heat Pump
- Web Site Information and Links
  - USDOE – Energy Saving Tips for Consumers
  - USDOE – Home Energy Audit
- Energy Audits As Needed
  - Commercial / Industrial
  - Residential
- News Paper Advertising
  - Safety
  - Energy Efficiency
- Energy Efficiency Training for Employees
  - Basic – Employees with limited customer contact receive training in energy cost and efficiencies

- Advanced – Employees with extensive customer contact receive in addition to the basic course. Training includes additional training in HVAC, water heating, lighting, building envelope and construction techniques who in turn will provide that guidance to customers.

Meade County RECC

- DOE Pamphlet "Energy Savers - Tips on Saving Energy & Money at Home"
- C/I News – Quarterly magazine to commercial and industrial customers – focus on energy related topics including conservation and efficiency improvements.
- Kentucky Living Magazine – Monthly magazine to all customers - focus articles on energy efficiency for the home and business and 4 page insert from local cooperative detailing programs, safety and customer service.
- Brochure – "Planting Trees to Save Money"
- Distribution of compact fluorescent bulbs to customers attending annual meeting
- Web Site Information and Links
  - Geothermal Heat Pump Systems
  - USDOE – Energy Saving Tips for Consumers
  - USDOE – Home Energy Audit
  - Commercial Building Energy Checklist
- Energy Audits As Needed
  - Commercial / Industrial
  - Residential
- News Paper Advertising
  - Safety
  - Energy Efficiency
- Energy Efficiency Training for Employees
- Basic – Employees with limited customer contact receive training in energy cost and efficiencies

4.0 Overall Approach To Assess Achievable Potential for Energy Efficiency Measures

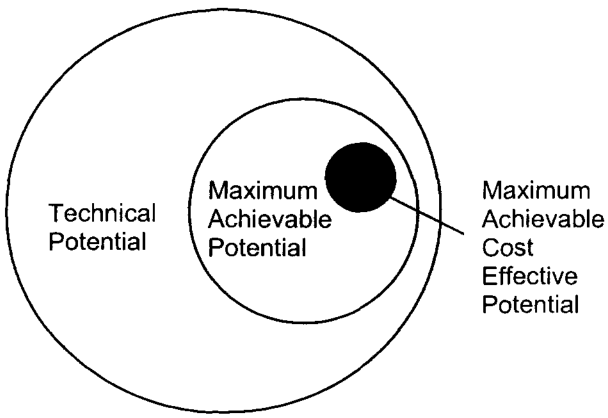
This section of the report presents an overview of the approach and methodology that was used to determine the maximum achievable cost-effective potential for electric energy efficiency measures in the service territory of BREC. The three key calculations that have been undertaken to complete this assessment are described below. Following the descriptions, the three stages of potential energy savings are shown graphically in a Venn diagram in Figure 4-1.

The first step was to estimate the technical potential for electric energy efficiency savings in the BREC service territory. **Technical potential** is defined as the complete penetration of all measures analyzed in applications where they are deemed to be technically feasible from an engineering perspective. The total technical potential for electric energy efficiency for each sector was developed from estimates of the technical potential of individual energy efficiency measures applicable to each sector (energy efficient space heating, energy efficient water heating, etc.). For each energy efficiency measure, GDS calculated the electricity savings that could be captured if 100 percent of inefficient electric appliances and equipment were replaced instantaneously (where they are deemed to be technically feasible).

The second step was to estimate the maximum achievable efficiency potential. **Maximum achievable potential** is defined as the maximum penetration of an efficient measure that would be adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market intervention over the next decade. The term "maximum" refers to efficiency measure penetration, and means that the GDS Team based its estimates of efficiency potential on the maximum realistic penetration that can be achieved. For similar studies recently completed by GDS in Connecticut, Florida, Utah, and New Mexico, GDS selected a long-term (over ten years) maximum achievable penetration rate of **80 percent** for all sectors. GDS has conducted additional secondary research on electric energy efficiency programs and determined that this long-term 80 percent penetration estimate is also applicable to this study.

The third step in this study was to estimate the maximum achievable cost effective potential. The **maximum achievable cost effective potential** is defined as the potential for maximum penetration of energy efficient measures that are cost effective according to the Total Resource Cost (TRC) test (TRC benefit/cost ratio of 1.0 or greater), and would be adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market interventions over the next decade. To develop the cost effective achievable potential, the GDS Team only retained those electric energy efficiency measures in the analysis that were found to be cost effective (according to the Total Resource Cost Test) based on the individual measure cost effective analyses conducted in this Study. Energy efficiency measures that are not cost effective were excluded from the estimate of cost effective achievable electric energy efficiency potential. Figure 4-1 below shows these three stages of the electric energy savings potential.

Figure 4-1 – Venn Diagram of the Stages of Energy Savings Potential



4.1 Overview of Methodology

Our analytical approach began with a careful assessment of the existing level of electric energy efficiency that has already been accomplished in the BREC service territory. For each electric energy efficiency measure, this analysis assessed how much energy efficiency has already been accomplished as well as the remaining potential for energy efficiency savings for a particular electric end use. For example, if 100 percent of the homes in the BREC service territory had electric lighting, and 30 percent of light bulbs were already high efficiency compact fluorescent bulbs (CFLs), then the remaining potential for energy efficiency savings is the 70 percent of light bulbs in the residential sector that are not already high efficiency bulbs.

The general methodology used for estimating the potential for electric energy efficiency in the residential, commercial and industrial sectors of the BREC service area included the following steps:

1. Identification of data sources for electric energy efficiency measures.
2. Identification of electric energy efficiency measures to be included in the assessment.
3. Determination of the characteristics of each energy efficiency measure including its incremental cost, energy savings, operations and maintenance savings, current saturation, and useful life.

4. Calculation of initial cost-effectiveness screening metrics (e.g., the total resource cost (TRC) benefit cost ratio) and sorting of measures from least-cost to highest cost.
5. Collection and analysis (where data was available) of the baseline and forecasted characteristics of the electric end use markets, including electric equipment saturation levels and consumption, by market segment and end use over the forecast period.
6. Integration of measure characteristics and baseline data to produce estimates of cumulative costs and savings across all measures (supply curves).
7. Determination of the cumulative technical and maximum achievable potentials using supply curves.
8. Determination of the annual maximum achievable cost effective potential for electricity savings over the forecast period.

A key element in this approach is the use of energy efficiency supply curves. The advantage of using an energy efficiency supply curve is that it provides a clear, easy-to-understand framework for summarizing a variety of complex information about energy efficiency technologies, their costs, and the potential for energy savings. Properly constructed, an energy-efficiency supply curve avoids the double counting of energy savings across measures by accounting for interactions between measures. The supply curve also provides a simplified framework to compare the costs of electric energy efficiency measures with the costs of electric energy supply resources.

The supply curve is typically built up across individual measures that are applied to specific base-case practices or technologies by market segment. Measures are sorted on a least-cost basis and total savings are calculated incrementally with respect to measures that precede them. Supply curves typically, but not always, end up reflecting diminishing returns, i.e., costs increase rapidly and savings decrease significantly at the end of the curve. There are a number of other advantages and limitations of energy-efficiency supply curves (see, for example, Rufo 2003).[17]

4.2 General Methodological Approach

This section describes the calculations used to estimate the natural gas energy efficiency potential in the residential, commercial, and industrial sectors. There is a core equation, shown in Table 4-2, used to estimate the technical potential for each individual electric efficiency measure and it is essentially the same for each

[17] Rufo, Michael, 2003. *Attachment V – Developing Greenhouse Mitigation Supply Curves for In-State Sources, Climate Change Research Development and Demonstration Plan,* prepared for the California Energy Commission, Public Interest Energy Research Program, P500-03-025FAV, April. http://www.energy.ca.gov/pier/reports/500-03-025fs.html

sector. However, for the residential sector, the equation is applied to a "bottom-up" approach where the equation inputs are displayed in terms of the number of homes or the number of high efficiency units (e.g., compact fluorescent light bulbs, high efficiency air conditioning systems, programmable thermostats, etc.). For the commercial and industrial (C&I) sectors, a "top-down" approach was used for developing the technical potential estimates. In this case, the data is displayed in terms of energy rather than number of units or square feet of floor area.[18] Furthermore, due to the lack of readily available equipment saturation and electric end use data in the commercial sector, the energy savings potential estimates for the BREC commercial sector were based upon savings estimates from similar studies conducted recently in other States.

4.2.1 Core Equation for Estimating Technical Potential

The core equation used to calculate the electric energy efficiency technical potential for each individual efficiency measure for the residential and industrial sectors is shown below in Table 4-2.

Table 4-2 – Core Equation

Technical Potential of Efficient Measure	=	Total Number of Residential Households *[C&I : Total End Use Dth (by segment)]*	X	Base Case Equipment End Use Intensity (annual kWh use per home) *[C&I: NA]*	X	Base Case Factor	X	Remaining Factor	X	Convertible Factor	X	Savings Factor

where:

- **Number of Households** is the number of residential electric customers in the market segment. *(Residential only)*

- **Total end use decatherms (by segment)** is the forecasted level of electric gas sales for a given end-use (e.g., space heating) in a C&I market segment (e.g., office buildings). *(Industrial only)*

- **Base-case equipment end use intensity** is the electricity used per customer per year by each base-case technology in each market segment. This is the consumption of the electric energy using equipment that the efficient technology replaces or affects. For example, if the

[18] It is important to note that square-foot based saturation assumptions cannot be applied to energy use values without taking into account differences in energy intensity (e.g., an area covered by a unit heater may represent two percent of floor space but a larger percent of space heating energy in the building because it is likely to be less efficient than the main heating plant).

efficient measure were a high efficiency light bulb (CFL), the base end use intensity would be the annual kWh use per bulb per household associated with an incandescent light bulb that provides equivalent lumens. *(Residential only)*

- **Base Case factor** is the fraction of the end use electric energy that is applicable for the efficient technology in a given market segment. For example, for residential lighting, this would be the fraction of all residential electric customers that have electric lighting in their household.

- **Remaining factor** is the fraction of applicable dwelling units that have not yet been converted to the efficient electric energy efficiency measure; that is, one minus the fraction of households that already have the energy-efficiency measure installed.

- **Convertible factor** is the fraction of the applicable dwelling units that is technically feasible for conversion to the efficient technology from an *engineering* perspective (e.g., it may not be possible to install CFLs in all light sockets in a home because they may not fit).

- **Savings factor** is the percentage reduction in electricity consumption resulting from application of the efficient technology.

Technical electric energy efficiency savings potential was calculated in two steps. In the first step, all measures are treated *independently*; that is, the savings of each measure are not reduced or otherwise adjusted for overlap between competing or synergistic measures. By treating measures independently, their relative economics are analyzed without making assumptions about the order or combinations in which they might be implemented in customer buildings. However, the total technical potential across measures cannot be estimated by summing the individual measure potentials directly because some savings would be double-counted. For example, the savings from a weatherization measure, such as low-e ENERGY STAR® windows, are partially dependent on other measures that affect the efficiency of the system being used to cool or heat the building, such as high-efficiency gas furnaces or high efficiency air conditioning systems; the more efficient the gas furnace or electric air conditioner, the less energy saved from the low-e ENERGY STAR windows.

Due to the unique nature of industrial customers, the approach to develop savings potential for this sector is generally done on an industrial subsector (e.g. Food, Paper, Petroleum, Agriculture, etc.) basis. GDS used data provided by BREC on their largest eighteen industrial customers to develop the estimates of the industrial sector electricity savings potential.

For the residential and commercial sectors, the GDS Team addressed the new construction market separately. In the residential sector, detailed savings estimates for the ENERGY STAR Homes (Plus) program were used as a basis for determining electricity savings for this potential program in the BREC service territory.

4.2.2 Rates of Implementation for Energy Efficiency Measures

For new construction, energy efficiency measures can be implemented when each new home or building is constructed, thus the rate of availability is a direct function of the rate of new construction. For existing buildings, determining the annual rate of availability of savings is more complex. Energy efficiency potential in the existing stock of buildings can be captured over time through two principal processes:

1. as equipment replacements are made normally in the market when a piece of equipment is at the end of its useful life (we refer to this as the "market-driven" case); and,
2. at any time in the life of the equipment or building (which we refer to as the "retrofit" case).

Market-driven measures are generally characterized by *incremental* measure costs and savings (e.g., the incremental costs and savings of a high-efficiency versus a standard efficiency natural gas furnace); whereas retrofit measures are generally characterized by full costs and savings (e.g., the full costs and savings associated with retrofitting ceiling insulation into an existing attic). A specialized retrofit case is often referred to as "early replacement". This refers to a piece of equipment whose replacement is accelerated by several years, as compared to the market-driven assumption, for the purpose of capturing energy savings earlier than they would otherwise occur.

For the market driven measures, we assumed that existing equipment will be replaced with high efficiency equipment at the time a consumer is shopping for a new appliance or other energy using equipment, or if the consumer is in the process of building or remodeling. Using this assumption, equipment that needs to be replaced (replaced on burnout) in a given year is eligible to be upgraded to high efficiency equipment. For the retrofit measures, savings can theoretically be captured at any time; however, in practice it takes many years to retrofit an entire stock of buildings, even with the most aggressive of efficiency programs.

4.2.3 Development of Maximum Achievable Cost Effective Potential Estimates for Energy Efficiency

To develop the **maximum achievable cost effective potential** for electric energy efficiency, energy efficiency measures that were found to be cost effective (according to the Total Resource Cost Test) were retained in the energy efficiency supply curves. Electric energy efficiency measures that were not cost effective were excluded from the estimate of maximum achievable cost effective energy efficiency potential.

4.2.4 Free-Ridership and Free-Driver Issues

Free-riders are defined as participants in an energy efficiency program who would have undertaken the energy-efficiency measure or improvement in the absence of a program or in the absence of a monetary incentive. Free-drivers are those who adopt an energy efficient product or service because of the intervention, but are difficult to identify either because they do not collect an incentive or they do not remember or are not aware of exposure to the intervention.[19] GDS has not included the impact of free-drivers in this study.

The issue of free-ridership is important. In summary, free-riders are accounted for through the electric energy and peak demand forecast provided by BREC. This electric kWh sales forecast already includes the impacts of naturally occurring energy efficiency (including impacts from vintaging of electric appliances, electric price impacts, and electric appliance efficiency standards). Because naturally occurring energy savings are already reflected in the electricity sales forecast used in this study, these electric savings will not be available to be saved again through the GDS energy efficiency supply curve analysis. GDS used this process to **ensure** that there is no "double-counting" of energy efficiency savings. This technical methodology for accounting for free-riders is consistent with the standard practice used in other recent technical potential studies, such as those conducted in California, Connecticut, Florida, Idaho, New Mexico and Utah.

4.3 Basis for Long Term Maximum Market Penetration Rate for High Efficiency Equipment and Building Practices

This section explains the basis used in this study for the maximum achievable penetration rate that cost effective electric energy efficiency programs can attain over the long-term (ten years) with well-designed programs and unlimited funding. GDS is using a maximum achievable penetration rate of **80 percent** by 2015 for BREC's residential, commercial and industrial sectors.

The maximum achievable natural gas energy efficiency potential for BREC's residential, commercial and industrial sectors is a subset of the technical potential estimates. The term "maximum" refers to efficiency measure penetration, and means that the GDS Team has based the estimates of

[19] Pacific Gas and Electric Company, "A Framework for Planning and Assessing Publicly Funded Energy Efficiency Programs", Study ID PG&E-SW040, March 1, 2001.

efficiency potential on the maximum realistic penetration that can be achieved by 2015 (ten years from now). The term "maximum" does not apply to other factors used in developing these estimates, such as measure costs, measure energy savings or measure lives.

The maximum achievable potential estimate for energy efficiency defines the upper limit of savings from market interventions. For each sector, the GDS Team developed the initial year (2006) and terminal year (2015) penetration rate that is likely to be achieved over the long term for groups of measures (space heating equipment, water heating equipment, etc.) by end use for the "naturally occurring scenario" and the "aggressive programs and unlimited funding" scenario. GDS reviewed maximum penetration forecasts from other recent energy efficiency technical potential studies, actual penetration experience for natural gas energy efficiency programs operated by energy efficiency organizations (Pacific Gas and Electric, KeySpan Energy Delivery, NEEP, NYSERDA, NEEA, BPA, Focus on Energy, other gas utilities, etc.), and penetration data from other sources (program evaluation reports, market progress reports, etc.) to estimate terminal penetration rates in 2015 for the maximum achievable scenario. In addition, the GDS Team conducted a survey of nationally recognized energy efficiency experts requesting their estimate of the maximum achievable penetration rate over the long-term for a state or region, assuming implementation of aggressive programs and assuming unlimited funding. The terminal year (2015) penetration estimates used by GDS for use in this study for BREC are based on the information gathered through this process. Based on a thorough review of all of this information, GDS used a maximum achievable penetration rate of **80 percent** by 2015 for BREC's residential, commercial and industrial sectors.

4.3.1 Examples of US Efficiency Programs with High Market Penetration

GDS collected information on energy efficiency programs conducted during the past three decades where high penetration has been achieved. Examples of seven such programs are listed below:

1. In the State of Wisconsin, a natural gas energy efficiency program to promote high efficiency gas furnaces attained a penetration rate of over 90 percent.[20]
2. KeySpan Energy Delivery's high efficiency residential furnace program has achieved a market share of approximately 70 percent over seven years (1997-2004).

[20] Hewitt, David. C., "The Elements of Sustainability", paper presented at the 2000 ACEEE Summer Study on Energy Efficiency in Buildings. Washington: American Council for an Energy Efficient Economy. Pages 6.179-6.190. The Wisconsin furnaces case study data can be found on pages 6.185-6.186.

3. The Residential Multifamily/Low-Income Program administered by Efficiency Vermont achieved a market share of over 90 percent for new construction and nearly 30 percent for existing housing.[21]
4. The Northwest Energy Efficiency Alliance reported that the market share of ENERGY STAR windows in the Northwest reached 75 percent by mid-2002 and is continuing to increase.[21]
5. Vermont Gas Systems' reported that 68 percent of new homes in their service territory were ENERGY STAR Homes in 2002.[21]
6. Gaz Metro in Quebec reported that the national market share of high efficiency furnaces in Canada has reached 40 percent due to years of energy efficiency programs.[21]
7. Residential weatherization and insulation programs implemented by electric and gas utilities in New England have achieved high participation rates.

GDS finds that the actual market penetration experience from electric and gas energy efficiency programs in other States is useful and pertinent information that should be used as a basis for developing long-term market penetration estimates for electric energy efficiency programs in the BREC service territory. In addition, recent natural gas technical potential studies in California, Connecticut, Florida, New Mexico, and Utah also used a maximum achievable penetration rate of 80 percent.

4.3.2 Lessons Learned from America's Leading Efficiency Programs

GDS also reviewed program participation and penetration data included in ACEEE's March 2003 report on America's leading energy efficiency programs.[22] The information presented in this ACEEE report clearly demonstrates the wide range of high-quality energy efficiency programs that are being offered in various areas of the United States today. A common characteristic of the programs profiled in this ACEEE report is their success in reaching customers with their messages and changing behavior, whether regarding purchasing of new appliances, designing new office buildings, or operating existing buildings.

[21] ACEEE - America's Best Natural Gas Energy Efficiency Programs, 2003.
[22] York, Dan; Kushler, Martin; "America's Best: Profiles of America's Leading Energy Efficiency Programs," published by the American Council for an Energy Efficient Economy, March 2003, Report Number U032.

5.0 RESIDENTIAL SECTOR ELECTRIC EFFICIENCY POTENTIAL

This section of the report presents the estimates of electric technical, maximum achievable and maximum achievable cost effective energy efficiency potential for the existing and new construction market segments of the residential sector in the BREC service territory. According to this analysis, there is still a large remaining potential for electric energy efficiency savings in this sector. Table 5-1 below summarizes the technical, maximum achievable, and maximum achievable cost effective savings potential by the year 2015.

Table 5-1: Summary of Residential Electric Energy Efficiency Savings Potential in BREC Service Territory

	Estimated Cumulative Annual Savings by 2015 (kWh)	Savings in 2015 as a Percent of Total 2015 Residential Sector Electricity Sales
Technical Potential	462,490,556	26.0%
Maximum Achievable Potential	312,355,072	17.5%
Maximum Achievable Cost Effective Potential	277,744,782	15.6%

The maximum achievable cost effective potential in the residential sector is 277,745 mWh, or 15.6 percent of the BREC residential kWh sales forecast in 2015.

5.1 Residential Sector Electric Energy Efficiency Programs

Twenty-four residential electric energy efficiency programs or measures were included in the analysis for the residential sector. The set of electric energy efficiency measures considered was pre-screened to only include those measures that are currently commercially available. Thus, emerging technologies were not included in the analysis. Tables 5-2, 5-3, and 5-4 below list the residential sector electric energy efficiency programs or measures included in the technical, maximum achievable, and maximum achievable cost effective potential analyses.

In this report we also present the technical achievable potential results in the form of electric supply curves. The supply curve for electric energy efficiency savings is shown in Figure 5-1 below. This analysis is based on BREC's most recent residential electric sales forecast for the years 2006 to 2015. Energy-efficiency measures were analyzed for the most important electric consuming end uses: space heating, water heating, refrigeration, and lighting.

Table 5-2: Total Cumulative Annual Maximum Technical Potential kWh Savings for Electric Energy Efficiency In the BREC Service Territory By 2015

Residential Sector - Market Driven and Retrofit Savings

1	2	3	4	5
Measure #	**Measure Description**	**Single-Family**	**Multi-Family**	**Total**
1	CFL Replacing Incandescent for 2.7 hrs/day	93,548,202	14,652,128	108,200,330
2	CFL Torchiere (Halogen)	3,208,961	502,608	3,711,570
3	CFL Torchiere (Incandescent)	967,782	151,580	1,119,362
4	ES Single Room AC	3,737,987	585,468	4,323,455
5	ES Freezer-Top Refrigerator	51,557,193	8,075,223	59,632,416
6	ES Side-by-Side Refrigerator	21,655,248	3,391,786	25,047,033
7	ES Upright Freezer	1,829,434	286,538	2,115,972
8	ES Chest Freezer	594,443	93,106	687,549
9	ES Built-In Dishwasher	5,160,892	808,333	5,969,225
10	ES Washing Machine with Electric Clothes Dryer and Electric Water Heater	7,348,325	1,150,942	8,499,267
11	ES Washing Machine with Electric Clothes Dryer and Gas Water Heater	4,447,670	696,623	5,144,293
12	ES Washing Machine with Gas Clothes Dryer and Gas Water Heater	0	0	0
13	Programmable Thermostat	1,621,979	254,045	1,876,024
14	Water Heater Blanket	11,773,179	1,843,992	13,617,171
15	Low Flow Shower Head	9,098,685	1,425,095	10,523,781
16	Pipe Wrap	5,532,001	866,458	6,398,459
17	Air Sealing (Low Income)	20,188,284	0	20,188,284
18	Reset Water Heater Thermostat (Low Income)	6,561,192	0	6,561,192
19	Water Heater Wrap (Low Income)	1,009,414	0	1,009,414
20	Attic Insulation (Low Income)	15,141,213	0	15,141,213
21	Air Sealing	23,590,443	3,691,706	27,282,149
22	Attic Insulation	69,323,323	2,768,779	72,092,102
23	Wall Insulation	13,876,731	4,346,928	18,223,659
24	Window Construction	39,015,737	6,110,899	45,126,636
	Total kilowatt hours (kWh)	410,788,320	51,702,236	462,490,556
	Forecast 2015 BREC Residential kWh Sales			1,780,266,000
	As a percent of forecasted residential sales 2015			26.0%

Note: Maximum Technical potential kWh savings were obtained from Appendix A column 28

The forecast of annual BREC residential kWh sales was obtained from the report titled "Big Rivers Electric Corporation, 2005 Long-Term Load Forecast - Base Case, Residential Classification" Appendix B, page 13 by GDS Associates in July, 2005

Table 5-3: Total Cummulative Annual Maximum Achievable Potential kWh Savings for Electric Energy Efficiency In BREC Service Territory By 2015

Residential Sector - Market Driven and Retrofit Savings

1	2	3	4	5
Measure # from GDS Electric DSM Data Base	Measure Description	Single-Family	Multi-Family	Total
1	CFL Replacing Incandescent for 2.7 hrs/day	70,161,152	10,989,096	81,150,248
2	CFL Torchiere (compared to Halogen Torchiere)	3,123,389	489,205	3,612,594
3	CFL Torchiere (compared to Incandescent Torchiere)	941,974	147,538	1,089,513
4	Energy Star Single Room Air Conditioner	2,236,402	350,280	2,586,682
5	Energy Star Compliant Freezer-Top Refrigerator	23,435,088	3,670,556	27,105,644
6	Energy Star Compliant Side-By-Side Refrigerator	9,843,294	1,541,721	11,385,015
7	Energy Star Compliant Upright Freezer	912,034	142,849	1,054,883
8	Energy Star Compliant Chest Freezer	296,350	46,416	342,766
9	Energy Star Built-In Dishwasher	3,087,713	483,618	3,571,331
10	Energy Star Washing Machine with Electric Water Heater and Electric Clothes Dryer	4,166,576	652,596	4,819,172
11	Energy Star Washing Machine with Gas Water Heater and Electric Clothes Dryer	2,521,875	394,992	2,916,867
12	Energy Star Washing Machine with Gas Water Heater and Gas Clothes Dryer	0	0	0
13	Programmable Thermostat	1,257,489	196,956	1,454,446
14	Water Heater Blanket	8,310,479	1,301,641	9,612,121
15	Low Flow Shower Head	6,499,061	1,017,925	7,516,986
16	Pipe Wrap	4,149,001	649,843	4,798,844
17	Air Sealing (Low Income)	15,477,999	0	15,477,999
18	Reset Water Heater Thermostat (Low Income)	5,030,350	0	5,030,350
19	Water Heater Wrap (Low Income)	773,900	0	773,900
20	Attic Insulation (Low Income)	4,643,400	0	4,643,400
21	Air Sealing	18,872,355	1,476,682	20,349,037
22	Attic Insulation	55,458,658	1,107,512	56,566,170
23	Wall Insulation	11,101,385	1,738,771	12,840,156
24	Window Construction	31,212,590	2,444,359	33,656,949

Maximum Achievable kWh Savings by 2015	283,512,514	28,842,558	312,355,072
Forecast 2015 BREC Residential kWh Sales			1,780,266,000
As a percent of forecasted residential sales 2015			17.5%

Table 5-4: Total Annual Maximum Achievable Cost-Effective Potential kWh Savings for Electric Energy Efficiency In BREC Service Territory By 2015

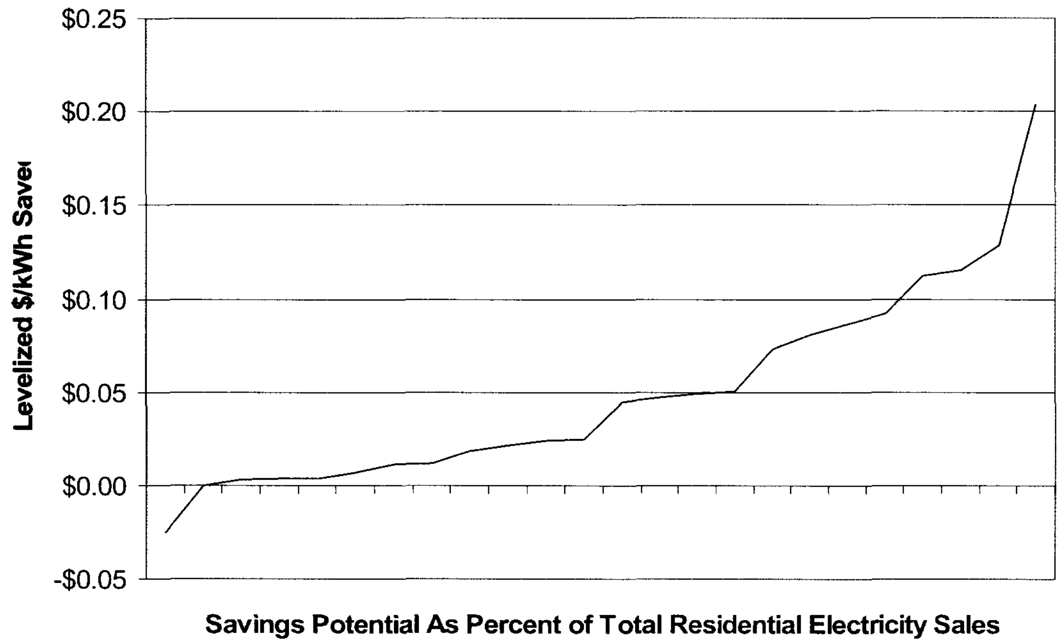
Residential Sector - Market Driven and Retrofit Savings

1	2	3	4	5	6	7
Measure #	**Measure Description**	**Single-Family kWh Savings**	**Multi-Family kWh Savings**	**Measure Level TRC Benefit/Cost Ratio SF**	**Measure Level TRC Benefit/Cost Ratio MF**	**Total Cumulative Annual kWh Savings by 2015 (for cost effective measures)**
1	CFL Replacing Incandescent Bulb for 2.7 hrs/day	70,161,152	10,989,096	1.47	1.47	81,150,248
2	CFL Torchiere (compared to Halogen Torchiere)	0	0	0.56	0.56	0
3	CFL Torchiere (compared to Incandescent Torchiere)	0	0	0.22	0.22	0
4	Energy Star Single Room Air Conditioner	0	0	0.29	0.29	0
5	Energy Star Compliant Freezer-Top Refrigerator	23,435,088	3,670,556	2.39	2.39	27,105,644
6	Energy Star Compliant Side-By-Side Refrigerator	9,843,294	1,541,721	1.16	1.16	11,385,015
7	Energy Star Compliant Upright Freezer	0	0	0.54	0.54	0
8	Energy Star Compliant Chest Freezer	0	0	0.21	0.21	0
9	Energy Star Built-In Dishwasher	3,087,713	483,618	>1	>1	3,571,331
10	Energy Star Washing Machine with Electric Water Heater and Electric Clothes Dryer	4,166,576	652,596	2.16	2.16	4,819,172
11	Energy Star Washing Machine with Gas Water Heater and Electric Clothes Dryer	2,521,875	394,992	3.07	3.07	2,916,867
12	Energy Star Washing Machine with Gas Water Heater and Gas Clothes Dryer	0	0	3.36	3.36	0
13	Programmable Thermostat	1,257,489	196,956	5.64	5.64	1,454,446
14	Water Heater Blanket	8,310,479	1,301,641	3.98	3.98	9,612,121
15	Low Flow Shower Head	6,499,061	1,017,925	60.70	60.70	7,516,986
16	Pipe Wrap	4,149,001	649,843	7.38	7.38	4,798,844
17	Air Sealing (Low Income)	0	0	0.55	NA	0
18	Reset Water Heater Thermostat (Low Income)	5,030,350	0	6.83	NA	5,030,350
19	Water Heater Wrap (Low Income)	0	0	0.30	NA	0
20	Attic Insulation (Low Income)	0	0	0.38	NA	0
21	Air Sealing	18,872,355		1.11	0.55	18,872,355
22	Attic Insulation	55,458,658		2.80	0.36	55,458,658
23	Wall Insulation	11,101,385	1,738,771	1.44	1.44	12,840,156
24	Window Construction	31,212,590		1.45	0.72	31,212,590

Maximum Achievable Cost Effective kWh Savings	255,107,065	22,637,717		277,744,782
Forecast 2015 BREC Residential kWh Sales				1,780,266,000
Savings as a percent of forecasted residential sales in 2015				15.6%

Note: The TRC Benefit/Cost Ratios were obtained from the GDS Benefit/Cost Screening Model, from the Program Cost Effectiveness Worksheet. The kWh savings shown above are from table 5-3, and kWh savings in the last column in the above table are counted only for those measures that have a TRC benefit/cost ratio greater than or equal to 1.0.

Figure 5-1 Residential Electric Energy Efficiency Supply Curve for BREC Service Territory



Figures 5-2 to 5-4 provide information on the potential electric savings in the residential sector. Thirty-six percent of the technical potential savings is in the residential lighting end use, and sixteen percent is in the refrigeration end use. Figure 5-5 presents the cost of conserved energy (CCE) for residential electric energy efficiency measures included in this study. Note that the CCE figures shown below only include electric savings, and do not include savings of other fuels (gas, oil, wood, etc.) or water. Note that Figure 5-5 is not a supply curve; rather, it simply provides a picture of the relative cost of conserved energy for the electric energy efficiency measures examined in this study. Note that there are **eight** energy efficiency measures having a cost of conserved energy less than $.02 per kWh saved.

Figure 5-2 Summary of Potential Savings

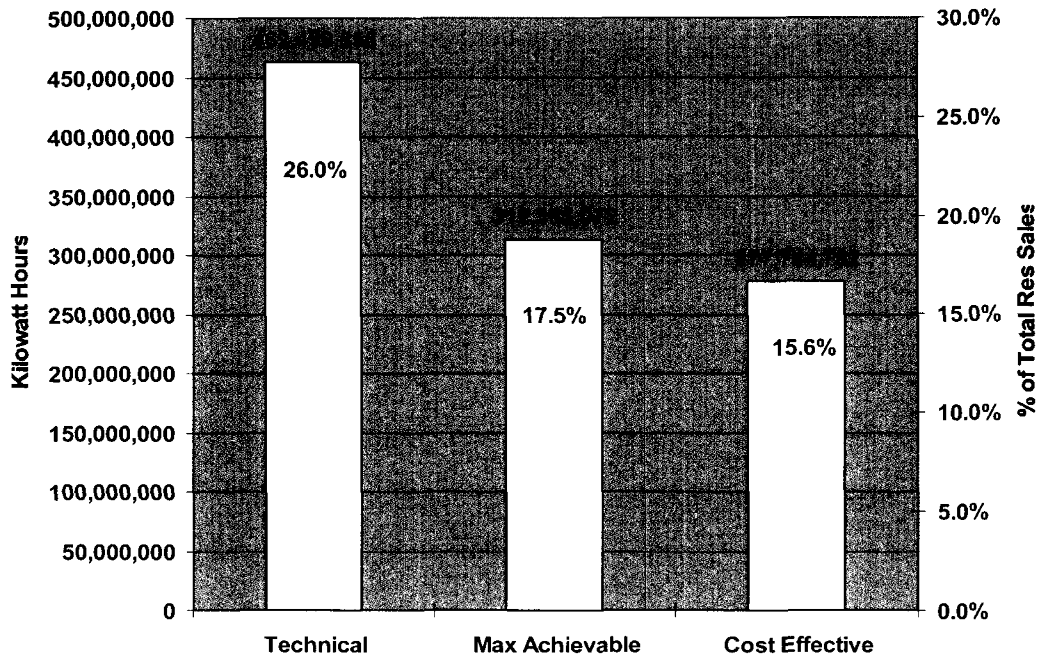


Figure 5-3 Residential Sector Technical Potential Savings By Measure Type - Kilowatt Hours

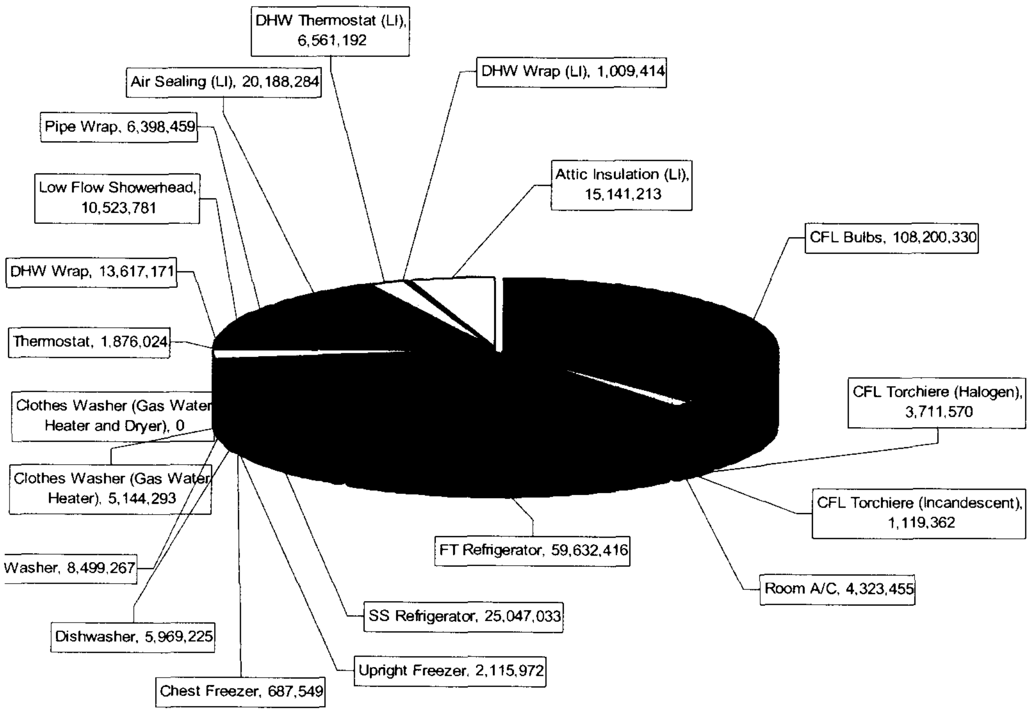


Figure 5-4 Residential Sector Technical Potential Savings By Measure Type - Percent of Total Savings

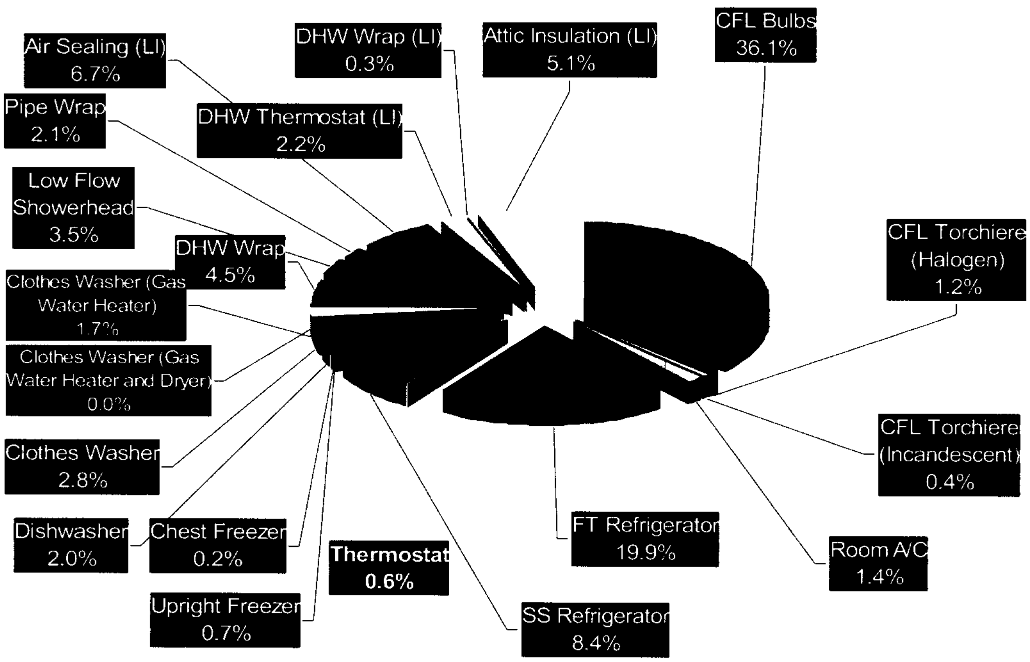
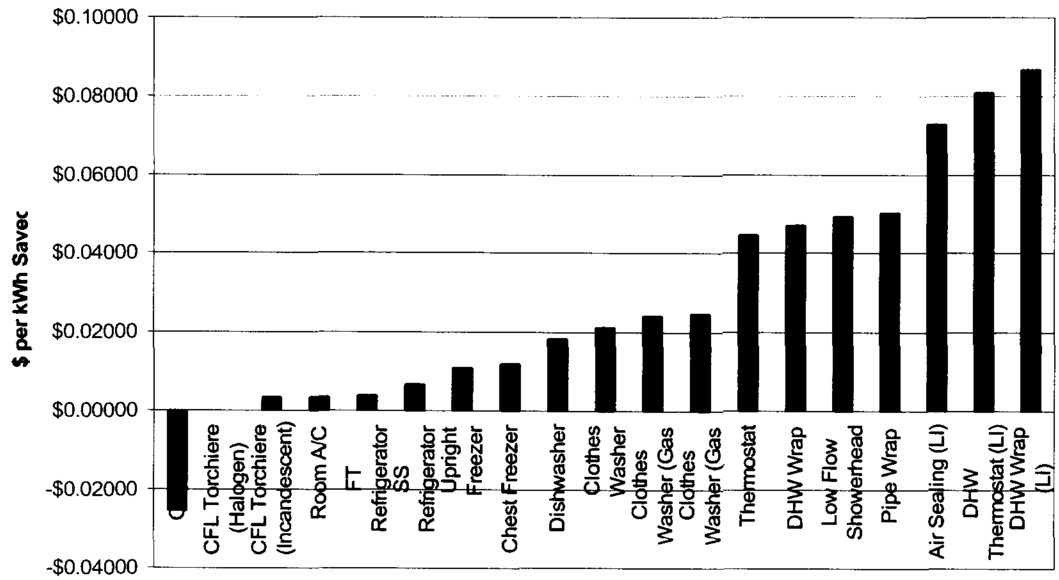


Figure 5-5 Cost of Conserved Energy - Residential Electric Energy Efficiency Measures ($ Per kWh Saved)



6.0 COMMERCIAL SECTOR GAS ENERGY EFFICIENCY POTENTIAL

Due to the lack of readily available equipment saturation and electric end use data for the BREC commercial sector, the energy savings potential estimates for the BREC commercial sector were based upon savings estimates from similar studies conducted recently in other States. Based on a thorough review of these other recent studies, GDS estimates that the maximum achievable cost effective potential for electric energy efficiency in the BREC service area the year 2015 is approximately 10% of 2015 commercial sector kWh sales. For the commercial sector, interior lighting still represents the largest end-use savings potential in absolute terms for both energy and peak demand, despite the significant adoption of high-efficiency lighting throughout the 1990's. The distribution of commercial sector potential savings of electricity by end use is shown in Figure 6-1.

As expected, the space cooling electric end use represents a significant portion of the total peak demand savings potential. Refrigeration energy savings potential is roughly equal to that of cooling but is significantly less important in terms of peak demand potential. In terms of energy savings, the Super T8 lamp/electronic ballast (SuperT8/EB) combination likely holds the largest potential, even though we estimate that current saturation levels of standard T-8's are well over 50 percent. Refrigeration compressor and motor upgrades, occupancy sensors for lighting, office equipment power management, and hard-wired CFL fixtures round out the measures that represent the largest opportunities for energy savings.

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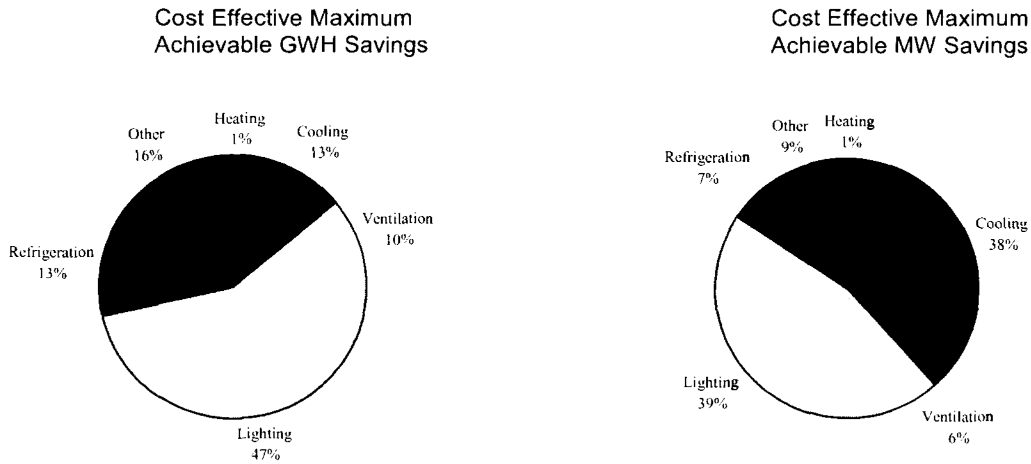
With respect to peak demand savings, such technologies as comparative enthalpy economizers represent a large peak demand savings opportunity, followed by the Super T8/EB combination. Cooling measures become more significant in terms of peak impacts with high-efficiency chillers and packaged units, as well as chiller tune-ups making up a large share of total potential demand savings. Occupancy sensors and Super T8/EB also represent a significant percent of total demand savings potential, as they did with respect to energy savings. These measures, when combined, represent approximately 45% of the electric peak demand reduction potential.

Figure 6-1 Distribution of Commercial Sector Maximum Achievable Potential Savings by End Use



The maximum achievable cost effective cumulative annual kWh savings by the year 2015 for the BREC commercial sector are shown in Table 6-1 below.

Table 6-1: Cumulative Annual Maximum Achievable Cost Effective kWh and kW Savings by 2015 – BREC Commercial Sector		
	Cumulative Annual kWh Savings by 2015	% of 2015 BREC System kWh Sales
Potential kWh Savings	85,475,300	10%

Appendix B of this report provides detailed information on the costs, savings and useful lives of commercial sector energy efficiency technologies.

7.0 LARGE INDUSTRIAL SECTOR ENERGY EFFICIENCY POTENTIAL IN THE BREC SERVICE AREA

The Large Industrial classification contains commercial and industrial customers that are directly served customers of Big Rivers. These customers are usually large industrial operations, and there are few customers in the class. These 20 large C&I customers in 2004 represented just under 32% of total system energy sales. The number of consumers for the class is expected to remain level at 20 from 2005 through 2019. Energy sales are projected to remain nearly constant throughout the forecast period.

7.1 Introduction

This section of the report provides the estimates of technical, maximum achievable, and maximum achievable cost effective energy-efficiency potential for electric energy efficiency measures for the industrial sector of the BREC service territory. There are still significant electric savings opportunities in this sector of the service area. Technical electric energy savings potential is estimated to be approximately 124,697 MWH by 2015, maximum achievable potential is estimated to be approximately 99,758 MWH and maximum achievable cost effective potential is estimated to be 99,758 MWH by 2015 (or between 8.6% and 10.8% of expected industrial electric consumption in the year 2015). The electric energy efficiency potential estimates are based on a detailed analysis of the electric usage and potential savings for eighteen large industrial customers represented in the BREC sales forecast.

Table 7-1 below summarizes the three types of electric energy efficiency savings potential for the industrial sector in the BREC service territory. It is important to note that the energy efficiency measures examined for the industrial sector proved to be cost effective according to the TRC test.

Table 7-1: Summary of Industrial Sector Electric Savings Potential in the BREC Service Area

	Estimated Cumulative Annual Savings in 2015 (MWH)	BREC Industrial Sector MWH Sales Foreacst for 2015	Savings in 2015 as a Percent of Total 2015 Industrial Sector Electric Sales
Technical Potential	124,697	1,159,630	10.8%
Maximum Achievable Potential	99,758	1,159,630	8.6%
Maximum Achievable Cost Effective Potential	99,758	1,159,630	8.6%

Overall Approach for the Industrial Sector

A literature review of several recent industrial electric potential studies indicates that due to the unique nature of industrial customers, the approach to develop savings potential generally is done on industrial sub-sectors (e.g. Food, Paper, Petroleum, Agriculture, etc.) basis. The specific data sources used by GDS for the development of the industrial sector electric savings potential estimates are listed in Appendix C of this report. Appendix C also provides detailed information on the costs, savings and useful lives of industrial sector energy efficiency technologies.

Steps to Develop Electric Energy Efficiency Potential for the Industrial Sector

The steps used by GDS to develop the estimates of energy efficiency potential for the industrial sector are listed below:

- Start with the Industrial annual electric use by customer information that was supplied.
- Classify the customers by Industrial sub-sector according to the ACEEE report.
- Apply the Percent of Sub-Sector Electricity Consumption by Sub-Sector found in Table 8 of 2003 ACEEE report.
- For 10-year Savings Potential use twice the "5-year Savings factors by End-use" found in Table 7, ACEEE, 2003 report. Rationale: The ACEEE numbers were based on an earlier XENERGY report[23] that estimated 10-year savings potential.
- Calculate the individual electric energy efficiency savings by end-use by customer.
- Sum information to determine maximum achievable electric energy efficiency savings potential.
- For estimating annual electric energy efficiency impact between 2006 and 2015 assume that an energy efficiency program achieved 10 percent of the total 2015 impact each year. Measure life is assumed to be a minimum of 10 years.

7.2 Efficiency Measures Examined

Four end-use categories (motors, process heating, HVAC, and lighting) were considered for the analysis. The analysis was kept at the aggregate end-use level since the level of detailed information that would be needed to provide a measure-by-measure analysis similar to that found in the residential and

[23] XENERGY, 2001, California Industrial Energy Efficiency Market Characterization Study, Oakland, CA.

commercial sector analyses was beyond the scope of the current study. However, examples of energy efficiency measures that can be included in an industrial program for the four end-uses are listed in Table 7-2.

Table 7-2 Industrial Sector Energy Efficiency Measures

Motors
Process Pumps and Fans
Ventilation Fans
Heating Pumps
Compressor motors
Process Heating
Process Heat Recovery
Performance Optimization
HVAC
High Efficiency Cooling Systems
EMS install
EMS Optimization
Heat Recovery from Air to Air
Retrocommissioning
Lighting
High Efficiency Lighting Technologies
Daylighting
Occupancy Sensors and Photocells

As shown below in Table 7-3, estimates of the potential annual electric savings vary by end use. ACEEE and Xenergy used the following energy savings potential estimates for 5-year and 10-year estimates, respectively:

Table 7-3 – Potential Industrial Electric Savings by End Use

Industrial End-use	5-Year Savings Potential	10-Year Saving Potential
Motors	7%	14%
Process Heating	5%	10%
HVAC	12%	24%
Lighting	10%	20%

Emerging electric energy efficiency technologies were not considered in the analysis.

The end-use analysis was segmented into seven industrial types for the BREC service territory. The technical and economic potential results are presented in aggregate and by end use in the form of electric supply curves. We provide estimates of savings in both absolute MWH and percentage terms, and we express percent savings in two ways:

- percent of total industrial electric consumption; and
- percent of energy addressed, as discussed in more detail below.

We based the technical and maximum achievable cost effective potential energy savings analysis on BREC's industrial electric sales forecast data for the period 2006 to 2015.

Table 7-4 shows an estimated breakdown of 2004 industrial electric sales in the BREC service area by sector.

Table 7-4 2004 Industrial Electric Sales by Sector in BREC Service Territory

Industrial Sector	% of Industrial Sales in 2004
Food	7.8%
Paper	54.7%
Petroleum And Coal Products	9.0%
Chemicals	0%
Non-metallic Mineral products	0%
Primary metals	22.1%
All Other Manufacturing	6.5%

7.3 Technical and Maximum Achievable Economic Potential

This section presents technical and economic potential estimates for the industrial and agriculture sector for the year 2015.

Technical savings potential is estimated to be approximately 124,697 MWH by 2015, maximum achievable potential is estimated to be approximately 99,758 MWH and maximum achievable cost effective potential is estimated to be 99,758 MWH (or between 8.6 and 10.8 percent of expected industrial electric consumption in the year 2015). The savings level for the maximum achievable and the maximum achievable cost effective scenarios are identical for the industrial sector because all energy efficiency measures considered in the industrial sector analysis were cost effective (according to the TRC test). Figure 7-1 illustrates the three values along with the associated percent of electric sales in 2014.

Figure 7-1 Estimated Technical, Maximum Achievable and Maximum Achievable Cost Effective Potential for Electric Savings in the Industrial Sector in the BREC Service Area

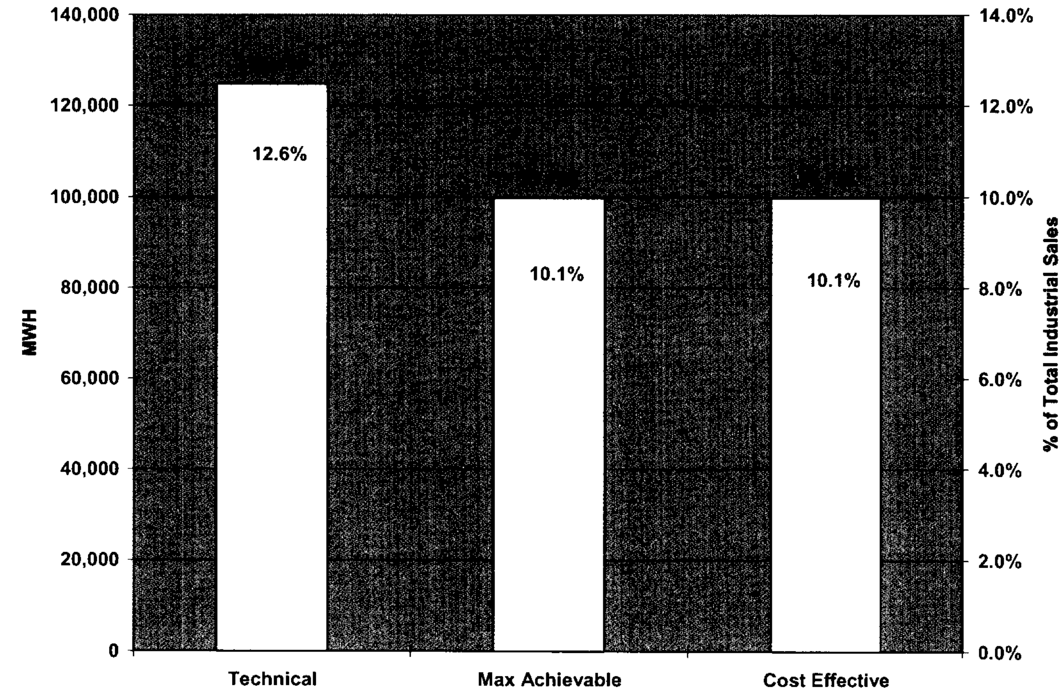
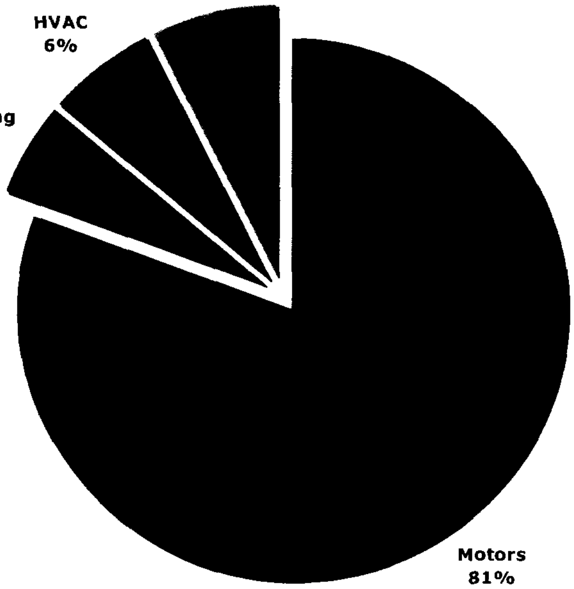


Figure 7-2 shows the percentage of total technical potential savings within each of the industrial end uses. Motors accounts for the largest percentage of technical potential at 81 percent, with lighting being the distant second at 7 percent. Process heating and HVAC both represent approximately 6 percent each. These percentages are identical for the maximum achievable cost effective potential savings estimates.

Figure 7-2 Industrial Sector Technical Potential Savings



In Table 7-5, we present estimates of the technical savings potential by end use in terms of energy saved in the year 2015 and in terms of percent of base end use energy consumption. The electric motors end use has the largest technical savings potential at approximately 100,573 MWH annually by 2015.

Table 7-5 2014 Industrial Electric Technical Potential by End Use

End Use	Savings Potential (MWH)	Savings Potential (% of Base Sales)
Motors	100,573	10.2%
Process Heating	6,876	0.7%
HVAC	7,939	0.8%
Lighting	9,309	0.9%
Total	124,697	12.6%

In Table 7-6, we present estimates of maximum achievable cost effective savings potential by end use in terms of energy saved in the year 2015 and in terms of percent of base end use energy consumption[24]. Motors is the end use with the largest technical potential at 80,458 MWH.

Table 7-5 2014 Industrial Electric Maximum Achievable Cost Effective Savings by End Use		
End Use	**Savings Potential (MWH)**	**Savings Potential (% of Base Sales)**
Motors	80,458	8.2%
Process Heating	5,501	0.6%
HVAC	6,351	0.6%
Lighting	7,447	0.8%
Total	99,758	10.1%

Key Data Limitations Associated with Estimates of Industrial Electric Potential

- **End-use costs:** Estimates of aggregate measure costs for each end-use category were developed using several sources, including electric savings potential studies recently conducted in California, Connecticut and Iowa, as well as many other sources compiled for this study. While the sources used offer reasonable values for the end-use costs, GDS was unable (within the budget for this project) to gather end-use cost data specific to the BREC service area for every energy efficiency measure for the industrial sector.

- **End-use savings**. Estimates of aggregate measure savings for each end-use category were developed using several sources, including electric savings potential studies recently conducted in California, Connecticut and Iowa, as well as many other sources compiled for this study. While the sources used offer reasonable values for the end-use savings, GDS was unable (within the budget for this project) to gather energy savings data specific to BREC service area for every industrial energy efficiency measure.

[24] Maximum achievable savings breakdown is not shown because, as stated previously, the savings level for the maximum achievable and the maximum achievable cost effective scenarios are identical for the industrial sector because only cost effective measures were considered in this analysis.

7.4 Energy-Efficiency Supply Curves

Due to the aggregated measure approach used in the industrial sector, a supply curve was not developed.

8.0 NON-ENERGY BENEFITS OF ELECTRIC ENERGY EFFICIENCY PROGRAMS

In addition to saving energy, electric energy efficiency programs can provide a variety of non-energy benefits.[25] Implementing energy efficiency programs in the BREC service territory will save electricity gas and will provide several other benefits to the State's economy.

Listed below are examples of non-energy benefits that will result from implementation of the electric energy efficiency measures included in the portfolio of gas energy efficiency programs recommend by this study:

- Electric energy efficiency programs can help reduce emissions of air pollutants[26] and greenhouse gases
  - Saving one kwh saves 1.39 lbs. of C02.
  - Saving one kwh saves .002960 lbs. of NOX.
  - Saving one kwh saves .006040 lbs. of SO2.
- Electric energy efficiency programs can be more reliable than increasing the infrastructure of the electric generation supply system because electric energy efficiency measures are "distributed resources" and require no on-going fuel supply. As such, they are not subject to potential supply interruptions and/or fuel price increases.
- Electric energy efficiency can make homes and businesses more comfortable - less drafty, etc.
- Electric energy efficiency programs can make businesses in Kentucky more efficient, and thus more competitive with businesses in other states and other countries.
- Electric energy efficiency programs can help homes and businesses reduce operating costs. As a result, there are economic multiplier effects, such as increased productivity and increased jobs.

8.1 Residential Sector Non Energy Benefits

Electric energy efficiency measures installed in homes or businesses can be more reliable than investments in electric supply-side resources. Unlike transmission and distribution lines, for example, the location of electric energy efficiency projects may not be as vulnerable to severe storms (ice storms, snow

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[25] The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest, Southwest Energy Efficiency Project (SWEEP), November 2002.

[26] GDS uses the following definitions of these emissions: CO2 is the major green house gas; NOx contributes to ground level ozone, particulate matter, acid rain, visibility impairment and nitrogen deposition; and SO2 contributes visibility impairment, acid rain, and particulate matter. GDS obtained the emissions rates shown here for SOX, NOX and CO2 from the US Environmental Protection Agency (see http://www.epa.gov/cleanenergy/egrid/samples.htm#highlights).

storms, wind storms, or spikes in the price of electricity. Contractors or homeowners, depending on the complexity of the measure, can easily install the electric energy efficiency measures. Energy efficiency measures are designed not only to save energy but also to improve the comfort of the occupant. Caulking, weather-stripping, insulation, ENERGY STAR windows, infiltration measures, CFLs and high efficiency air conditioners will reduce household and business operating costs and will decrease infiltration and heat loss.

The following benefits of energy efficiency programs have been noted in a recent evaluation report from the Wisconsin Focus on Energy Program[27]:

- Increased safety resulting from a reduction of gases emitted into the atmosphere, such as carbon monoxide.
- Fewer illnesses resulting from elimination of mold problems due to proper sealing, insulating and ventilation of a home
- Reduced repair and maintenance expense due to having newer, higher quality equipment
- Increased property values resulting from installation of new equipment

Non-energy benefits can play a key role for residential builders who promote energy efficiency in new home construction as seen in Wisconsin's Energy Star Home Program (WESH). Given that WESH homes are reported as selling at a higher price for 79 percent of homebuilders and the fact that 86 percent of homebuilders are more inclined to promote themselves as energy efficient builders, WESH homebuilders can view and market themselves as high-end homebuilders. WESH program implementers market the program by telling prospective homebuilders that they will be able to expand their business as a result of the WESH program. Also, given the frequency that comfort and safety improvements are cited as non-energy benefits associated with both WESH and Home Performance with Energy Star Program (HPWES), emphasizing these two non-energy benefits in program marketing efforts may help to increase program participation. In addition, increased durability and longevity of household equipment can be a selling point for the Wisconsin HPWES program, where 84 percent of contractors cite this as a non-energy benefit.[28]

[27] State of Wisconsin Department of Administration Division of Energy, Focus on Energy Public Benefits Statewide Evaluation, Quarterly Summary Report: Contract Year 2, Second Quarter, March 31, 2003, Evaluation Contractor: PA Government Services Inc. Prepared by: Focus Evaluation Team.

[28] State of Wisconsin Department of Administration, Division of Energy, Focus on Energy Statewide Evaluation, Non-Energy Benefits Cross-Cutting Report, Year 1 Efforts, *Evaluation Contractor: PA Government Services Inc., Prepared by: Nick Hall, TecMarket Works, Oregon, Wisconsin Under Contract To PA Consulting,* January 20, 2003

8.2 Commercial Sector Non Energy Benefits

By utilizing electric energy efficiency programs, businesses in Kentucky can become more efficient and lower their monthly utility bills. The energy and monetary savings from electric energy efficiency programs can provide businesses with additional capital to invest in business infrastructure. Electric energy efficiency programs can help businesses in Kentucky become more competitive with other businesses in the United States and in other countries. Implementing electric energy efficiency measures may also increase productivity and afford the business with the opportunity to add new jobs, further bolstering the economy in the BREC service area.

Examples of Non Energy Benefits from The Wisconsin Focus on Energy Business Programs:[29]

- Increased productivity
- Improvement in morale
- Reduced repair and maintenance costs
- Reduced waste
- Reduced defect or error rates

8.3 Societal Related Benefits

Economic impact

The spending of dollars to provide electric energy efficiency programs creates jobs and increases the economic activity associated with local spending streams. As labor and material dollars are "turned-over" in the local economy, the people in that economy benefit.[30] In the Wisconsin Focus on Energy Program, for example, the Program Evaluation contractor reports that 46 new full-time jobs are created in the state for every $1 million invested in energy efficiency programs.

Environmental

Increased energy efficiency is in the public interest for environmental, economic and national security reasons. The production and use of energy causes a large portion of the nation's air pollution. Fossil fuel combustion and the resulting emissions can be harmful to public health in a variety of ways:

- by harming to ecological systems, especially by increasing the acidity of rainfall and water bodies, and

[29] Ibid.
[30] Beyond Energy Savings: A Review of the Non-Energy Benefits Estimated for Three Low-Income Programs, ACEEE Paper 326, *Nick Hall, TecMarket Works, Jeff Riggert, TecMarket Works,* From: 2002 ACEEE Summer Study Proceedings

- by being a major source of greenhouse gases causing climate change.

A reduction in energy consumption through greater efficiency of energy use is a means to reduce all emissions from burning fossil fuels, including NO_x, SO_2, and CO_2.[31]

Table 8-1 illustrates the level of pollutants and greenhouse gases that can be avoided if the maximum achievable cost effective savings from this report are realized. The estimates in Table 8-1 include only those emissions that are avoided from the avoidance of electric generation. Per the February 2005 Cantor Fitzgerald Market Price Index for SO_2 at \$657.04 per ton and NO_x at \$2,400 per ton, the values in Table 8-1 would result in a market value of over \$1.6 million annually for avoided NO_x emissions and slightly more than \$918,000 for avoided SO_2 emissions. In addition, a recent California Public Utilities Commission report[32] provides a value of avoided CO_2 emissions of \$8 per ton in 2005. Using this \$8 per ton value, the avoided CO_2 emissions are worth \$2.6 million annually by 2015.

Table 8-1: Market Value of Avoided Emissions

		Tons of Pollutant Avoided by 2015		
	Cumulative Annual kWh Saved by Sector by 2015	SO2 Emissions Avoided (in lbs)	NOX Emissions Avoided (in lbs)	CO2 Emissions Avoided (in lbs)
Residential	277,744,782	1,677,578	822,125	386,756,831
Commercial	85,475,300	516,271	253,007	119,023,500
Industrial	99,758,000	602,538	295,284	138,912,017
Emissions rate (lbs. per kWh)	NA	0.006040	0.002960	1.392490
Total Avoided Emissions in Tons	NA	1398.2	685.2	322346.2
Value Per Ton	NA	$657.00	$2,400.00	$8.00
Total $ Value of Pollutants Avoided	NA	$918,613.33	$1,644,498.15	$2,578,769.40

Cost-effective energy efficiency actions are beneficial (1) to individual users of natural gas by reducing consumer costs and (2) to the economy by increasing discretionary income. The implementation of energy efficiency measures can help consumers save money.[33]

A recent American Council for An Energy Efficient Economy (ACEEE) analysis found that modestly reducing both natural gas and electricity consumption, and increasing the installation of renewable energy generation could dramatically affect natural gas price and availability. According to the ACEEE report, in just 12

[31] Energy Efficiency and Renewables Sources: A Primer, Prepared by the National Association of State Energy Officials Updated by Global Environment & Technology Foundation, October 2001.
[32] California Public Utilities Commission, Methodology and Forecasts of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, E3 Research Report Submitted to the CPUC Energy Division, October 25, 2004.
[33] Ibid.

months, nationwide efforts to expand energy efficiency and renewable energy could reduce wholesale natural gas prices by 20 percent and save consumers $15 billion/year in retail gas and electric power costs.[34] [35]

8.4 Job Creation Benefits of Energy Efficiency Identified in SWEEP Report

The November 2002 Southwest Energy Efficiency Project "Mother Lode" report[36] determined that investing in electric energy efficiency measures can lower electricity and natural gas bills for residents and businesses in the Southwest. This report notes that these lower energy bills, in turn, promote overall economic efficiency and create additional jobs. The High Energy Efficiency Scenario included in the SWEEP report shows significant macroeconomic benefits for each of the states in the Southwest and the region as a whole. By 2020, SWEEP estimates that the efficiency investments and energy bill savings add more than $1.3 billion in new wage and salary income (in 2000 dollars) and support a net increase of 58,400 jobs for the Southwest region as a whole. These income and jobs gains reflect differences between a business-as-usual Base Scenario and a High Energy Efficiency Scenario. Although the job gains are distributed throughout much of the economy, several sectors, including services, retail trade, and government show the largest gains. Not surprisingly, the energy industries (electric and gas utilities, and coal mining) exhibit the largest losses.

The report found that a total job loss of 7,500 jobs is projected to occur in the region by 2020 in the High Energy Efficiency Scenario, compared to a total job gain of about 66,000 jobs and a net increase of **58,400** jobs in this scenario. Furthermore, the projected losses can be overcome if the energy industries recognize the new and expanding opportunities and transition to providing more efficiency-related products and services. In short, accelerating energy efficiency improvements can help to create a strong economic future in the southwest region.

8.5 Non Energy Benefits of Low Income Weatherization and Insulation Programs

GDS also conducted a literature search on the non-energy benefits of programs targeted at low-income households. One of the most comprehensive studies of low-income program non-energy benefits was recently completed for five

[34] The ACEEE study notes how natural gas energy efficiency programs can help reduce prices of natural gas.
[35] R. Neal Elliot, PH.D., P.E., et al., Natural Gas Price Effects of Energy Efficiency and Renewable Energy Practices and Policies, ACEEE, December 2003.
[36] Southwest Energy Efficiency Project, "The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest", November 2002, Section 4 of the report.

investor-owned utilities in California. The two documents listed below provide documentation of these non-energy benefits:

1. TecMRKT Works, Skumatz Economic Research Associates, and Megdal & Associates, Low-income Public Purpose Test, (The LIPPT), Final Report, Up-Dated for LIPPT Version 2.0, A Report Prepared for the RRM Working Group's Cost Effectiveness Committee, April 2001. This report provides a description of each non-energy benefit included in the KeySpan analysis of non-energy benefits, and provides the methodology for calculating the value of each category of non-energy benefits.

2. TecMRKT Works, Skumatz Economic Research Associates, and Megdal & Associates, User's Guide for California Utility's Low-Income Program Cost Effectiveness Model, The Low-Income Public Purpose Test, Version 2.0, A Microsoft Excel Based Model, Prepared for The RRM Cost Effectiveness Subcommittee, May 25, 2001.

Table 8-2 below provides examples of non-energy benefits that are applicable to weatherization and insulation programs that might be targeted at low income customers in the BREC service area.

Table 8-2
Summary of Potential Non-Energy Benefits for a Low Income Energy Efficiency Program

Benefit Number in LIPPT Model	Name of Non Energy Benefit	Non-Energy Benefit Description
	Utility Perspective	
7A	Carrying cost on arrearages	Energy Efficiency Programs reduce customer bills, improving the likelihood that customers will be able to keep up with payments.
7B	Lower bad debt write-offs	Makes energy bills more manageable for program participants, potentially reducing the bad debt for these customers.
7C	Fewer shut-offs	As a result of the customers ability to pay their bills, a similar reduction in the number of customers with service disconnects is expected.
7D	Fewer reconnects	As a result of the reduction in the number of shut-offs, the number of reconnects needed would also decline.
7E	Fewer notices	More affordable energy bills leads to more on-time payments and fewer notices from the utility.
7F	Fewer customer	More affordable energy bills leads to more on-time

	calls	payments and fewer customer calls.
7H	Reduction in emergency gas service calls.	
7J	Transmission and/or distribution savings (distribution only).	
	Societal Perspective	
8A	Economic impact	Estimate of economic impact to regional economy based upon using local labor for energy efficiency services instead of importing energy, and using bill savings being spent into local economy.
8B	Environmental benefits	Provides environmental benefits to the region and to society, particularly due to their role as a pollution abatement strategy. These include assisting in meeting Clean Air Act requirements, reduction in acid rain, and a variety of other benefits.
	Participant Perspective	
9B	Fewer shutoffs	Providing customers with services and education that reduces energy use also helps customers reduce bills and may help improve their payment record. As a result, participants experience fewer arrearages and are less likely to be disconnected.
9C	Fewer calls to the utility	Without payment problems the customer is less likely to make calls to the utility concerning payments.
9D	Fewer reconnects	Reconnections are reduced in response to the lower shutoff numbers.
9H	Moving costs/mobility	High energy costs can make it difficult for residential customers to keep up with all of their household bills, including rent or mortgage payments. By keeping their bills down, this will reduce non-payment on living expenses.
9I	Fewer Illnesses and lost days from work/school	Households with sufficient and continuous heating may experience changes in the number of colds and other illnesses per year.
9K	Net household benefits from more comfort, less noise, net of negatives	Weatherization of homes allows these homes to be kept warmer at lower costs, reduces drafts, and insulates them from noise and weather outside their homes.
9K	Net household benefits from additional hardship benefits	The additional hardship benefits are those associated non-dollar benefits from reduced disconnects, reconnects, and bill collection, such as reduced stress as perceived and valued by participant.

9.0 SUMMARY OF FINDINGS

In summary, the maximum achievable cost effective potential for electric energy efficiency in the BREC service territory by 2015 is significant. GDS estimates that the maximum achievable cost effective potential natural gas savings would amount to 463 million kWh a year (a 12.2 percent reduction in the BREC projected 2015 kWh sales forecast in the BREC service territory). Table 9-1 below summarizes the electricity savings potential in the BREC service territory by 2015.

Table 9-1: Maximum Achievable Cost Effective Electric Energy Efficiency Potential By 2015 in the Service Area of the Big Rivers Electric Corporation

Sector	Maximum Achievable Cost Effective kWh Savings by 2015 from Electric Energy Efficiency Measures/Programs for the BREC Service Area	2015 kWh Sales Forecast for This Sector	Percent of Sector 2015 kWh Sales Forecast
Residential Sector	277,744,782	1,780,266,000	15.6%
Commercial and Small Industrial	85,475,300	854,753,000	10.0%
Large Industrial	99,758,000	1,159,630,000	8.6%
Total	462,978,082	3,794,649,000	12.2%

The results of this study demonstrate that cost effective electric energy-efficiency resources can play a significantly expanded role in BREC's energy resource mix over the next decade. Table 1-2 in the Executive Summary shows the present value of benefits and costs associated with implementing the maximum achievable potential energy savings in the BREC service territory. The potential net present savings to BREC customers for implementation of electric energy efficiency programs over the next decade are approximately **$39 million** in 2005 dollars.

The Total Resource Cost benefit/cost ratio for the maximum achievable cost effective potential savings scenario is 1.35.

It is clear that electric energy efficiency programs could save BREC members a significant amount of electricity by 2015. The electric energy efficiency potential estimates and Total Resource savings provided in this report are based upon the most recent BREC electric energy and peak load forecast, appliance saturation data, economic forecasts, data on energy efficiency measure costs and savings, and energy efficiency measure lives available to GDS at the time of this study. All input assumptions and data have been reviewed by GDS and staff of BREC. GDS has conducted extra market research to ensure that data for residential energy efficiency weatherization and insulation measure costs and savings are applicable and up to date.

There are also significant environmental benefits with the maximum achievable cost effective scenario. If implemented, by 2015 this scenario would result in a market value of over $1.6 million annually for avoided NO_x emissions and slightly more than $918,000 for avoided SO_2 emissions. In addition, a recent California Public Utilities Commission report[37] provides a value of avoided CO_2 emissions of $8 per ton in 2005. Using this $8 per ton value, the avoided CO_2 emissions are worth $2.6 million annually by 2015.

[37] California Public Utilities Commission, Methodology and Forecasts of Long-Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, E3 Research Report Submitted to the CPUC Energy Division, October 25, 2004.

APPENDIX A

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

AENDIX- MEASURE SAING,USEBL LIES,CS AND SAURAS B RESIDENAL ENERICIENCWEASURES
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HDD:

Big Rivers Service Area in Kentucky

Discount Rate: 5.35%

Measure #	Single- or Multi-family	Measure Description	Ttal Numbr of Residential Husehoids (Bend Mllmes)	Market Driven or Retrofit	Savings Units	Cost Units	Eqipment Cost	Labr Cost	Ttal Installed Cost	Cost Type: Incremental = 0 Fll =1	Measure Life (yrs)	Base Case Eqipment End Use Intensity (Annual kWh per appliance)	Annual kWh Savings Pr Unit Installed	Estimated Annual MMBT (Natural Gs) Savings Pr Unit Installed	Annual Amortized Cost Pr Unit	Levelized Cost Pr kWh Saved	Annual Gllons of ater saved	Electric End Use Affected	Implementation Type 1=One 2RB
1	2	3	4	5	6	7	8	9	0	1 2	2	3	4	5	6 7	8	9		
1	Single-family	CE replacing Incandescent bllfor 2 braliay	96,076	Market Driven	Per bulb	Per bulb	$5.97	$0.00	$5.97	0	10.1	65.17	48.86	0	$0.76	$0.0160	0	Lighting	2
2	Single-family	CE Erchiere (compared to Hlogen Erchiere)	96,076	Retrofit	Per lamp	Per lamp	$60.00	$0.00	$60.00	1	8.2	275.76	223.56	0	$9.21	$0.0412	0	Lighting	1
3	Single-family	CE Erchiere (compared to Incandescent Erchiere)	96,076	Retrofit	Per lamp	Per lamp	$60.00	$0.00	$60.00	1	8.2	136.86	86.60	0	$9.21	$0.1063	0	Lighting	1
4	Single-family	Energy Star Single Room Air Conditioner	96,076	Market Driven	Per air conditioner	Per air conditioner	$69.00	$0.00	$69.00	0	13	706.00	118.75	0	$9.88	$0.0816	0	Room AC	2
5	Single-family	Energy Star Compliant Reezer Tp Refrigerator	96,076	Market Driven	Per refrigerator	Per refrigerator	$115.00	$0.00	$115.00	0	17	1362.00	1029	0	$10.47	$0.0102	0	Refrigerator	2
6	Single-family	Energy Star Compliant Side-by-Side Refrigerator	96,076	Market Driven	Per refrigerator	Per refrigerator	$247.50	$0.00	$247.50	0	17	1679.00	1079	0	$22.53	$0.0209	0	Refrigerator	2
7	Single-family	Energy Star Compliant Upright Reezer	96,076	Market Driven	Per freezer	Per freezer	$50.00	$0.00	$50.00	0	15.5	692.00	110	0	$4.83	$0.0439	0	Freezer	2
8	Single-family	Energy Star Compliant Chest Reezer	96,076	Market Driven	Per freezer	Per freezer	$50.00	$0.00	$50.00	0	15.5	397.00	43	0	$4.83	$0.1123	0	Freezer	2
9	Single-family	Energy Star Built-in Dishasher	96,076	Market Driven	Per dishwasher	Per dishwasher	($29.46)	$0.00	($29.46)	0	13	506.50	141	0	($3.20)	($0.0227)	0	Dishwasher	2
10	Single-family	Energy Star Washing Machine th Electric Water Hater and Electric Clothes Dryer	96,076	Market Driven	Per clothes washer	Per clothes washer	$200.00	$0.00	$200.00	0	14		475	0	$20.66	$0.0435	5400	Clothes Washer	2
11	Single-family	Energy Star Washing Machine th Gs Water Hater and Electric Clothes Dryer	96,076	Market Driven	Per clothes washer	Per clothes washer	$200.00	$0.00	$200.00	0	14		115	1.9	$20.66	$0.1796	5400	Clothes Washer	2
12	Single-family	Energy Star Washing Machine th Gs Water Hater and Gs Clothes Dryer	96,076	Market Driven	Per clothes washer	Per clothes washer	$200.00	$0.00	$200.00	0	14		0	2.5	$20.66	N/A	5400	Clothes Washer	2
13	Single-family	Energy Star Compliant Pgrammable Termostat	96,076	Market Driven	Per home	Per home	$49.00	$0.00	$49.00	0	10	779.00	87.9	2.5	$6.45	$0.0734	0	Central AC	2
14	Single-family	Water Hater Blanket	96,076	Retrofit	Per water heater	Per water heater	$15.00	$0.00	$15.00	1	10	3330.00	333	0	$1.96	$0.0059	0	Water Heating	1
15	Single-family	Low-flow Shower Hed	96,076	Retrofit	Per shower head	Per shower head	$5.77	$0.00	$5.77	1	10	3330.00	250	0	$0.76	$0.0030	6789	Water Heating	1
16	Single-family	Pe Wrap	96,076	Retrofit	Per home	Per home	$3.23	$0.00	$3.23	1	10	3330.00	133	0	$0.43	$0.0032	0	Water Heating	1
17	Single-family, Low Income	Air Sealing	96,076	Retrofit	Per home	Per home			$360.00	1	10		1171.99	0	$60.05	$0.0427	0	Space Heating	1
18	Single-family, Low Income	Reset Water Hater Termostat (from medium to med-low)	96,076	Retrofit	Per home	Per water heater	$0.00	$10.00	$10.00	1	10		380.90	0	$1.32	$0.0035	0	Water Heating	1
19	Single-family, Low Income	Water Hater Wrap (from Ello Ef	96,076	Retrofit	Per home	Per water heater			$35.00	1	10		58.60	0	$4.61	$0.0787	0	Water Heating	1

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

APPENDIX - MEASURE SAVINGS,USEFUL LIVES,COSTS A
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Big Rivers Service Area in Kentucky

Measure #	Single- or Multi-family	Measure Description	End Use Saturation (Percentage of total homes that contain the electric end use for the measure)	Base Case Factor (fraction of the end use energy that is already energy efficient)	Remaining Factor (in how many homes can this be installed)	Convertibility Factor	Single-Multi-Family Fraction	Type of home where applicable	Number of applicable homes in BREC (before applying remaining factor and convertibility factor)[1]	Total Homes Remaining without measure (after applying remaining factor and convertibility factor)	Technical Potential-Total annual kWh savings potential in BREC if 100% penetration attained "overnight"	Maximum Achievable Program Participants per year (at penetration limit, and before application of convertibility factor)[2]	Maximum Achievable Program Participants per year (at penetration limit, and after application of convertibility factor)[2]	Maximum Achievable kWh Savings (at penetration limit, and after application of convertibility factor)[2]	Savings Factor (Percentage reduction in electric energy consumption)	Total annual gallons of water savings potential in BREC	Annual Maximum Achievable Therm Savings Potential in BREC	On-going annual O&M cost (or savings) ()
1	Single-family	CE replacing Incandescent bilfer 2 hrs/day	100.0%	20.00%	80.0%	100%	83%	Homes in BREC service territory (for CFLs, the numbers reported here represent light bulb sockets)	2,392,292	1,913,834	93,546,202	143,536	143,536	70,161,152	75.00%	0	0	-$0.42
2	Single-family	CE Torchiere (compared to Halogen Torchiere)	18.0%	0.00%	100%	100%	83%	Homes in BREC service area with halogen torchieres	14,354	14,354	3,208,981	1,397	1,397	3,123,389	81.67%	0	0	$0.00
3	Single-family	CE Torchiere (compared to Incandescent Torchiere)	14.0%	0.00%	100%	100%	83%	Homes in BREC service area with incandescent torchieres	11,164	11,164	967,782	1,087	1,087	941,974	83.33%	0	0	$0.00
4	Single-family	Energy Star Single Room Air Conditioner	25.8%	10.00%	90%	100%	83%	Homes in BREC service area with one or more window A/C units	34,975	31,478	3,737,987	1,883	1,883	2,236,402	16.82%	0	0	$0.00
5	Single-family	Energy Star Compliant Freezer Top Refrigerator	71.4%	12.00%	88%	100%	83%	Homes in BREC service area	56,937	50,104	51,557,193	2,277	2,277	23,435,068	75.58%	0	0	$0.00
6	Single-family	Energy Star Compliant Side-by-Side Refrigerator	28.6%	12.00%	88%	100%	83%	Homes in BREC service area	22,807	20,070	21,865,248	912	912	9,843,294	64.26%	0	0	$0.00
7	Single-family	Energy Star Compliant Upright Freezer	23.7%	12.00%	88%	100%	83%	Homes in BREC service area which contain a freezer	18,899	16,631	1,829,434	829	829	912,034	15.90%	0	0	$0.00
8	Single-family	Energy Star Compliant Chest Freezer	19.7%	12.00%	88%	100%	83%	Homes in BREC service area which have a freezer	15,709	13,824	594,443	689	689	296,350	10.83%	0	0	$0.00
9	Single-family	Energy Star Built-in Dishwasher	51.0%	10.00%	90%	100%	83%	Homes in Kentucky with a dishwasher	40,889	36,802	5,160,882	2,190	2,190	3,087,713	27.84%	0	0	$0.00
10	Single-family	Energy Star Washing Machine with Electric Water Heater and Electric Clothes Dryer	20.0%	3.00%	97%	100%	83%	Homes in BREC service area with an electric water heater and an electric clothes dryer	15,949	15,470	7,348,325	877	877	4,166,576		4,736,739	0	$0.00
11	Single-family	Energy Star Washing Machine with Gas Water Heater and Electric Clothes Dryer	50.0%	3.00%	97%	100%	83%	Homes in BREC service area with a gas water heater and an electric clothes dryer	39,872	38,675	4,447,670	2,193	2,193	2,521,875		11,841,847	41,868	$0.00
12	Single-family	Energy Star Washing Machine with Gas Water Heater and Gas Clothes Dryer	20.0%	3.00%	97%	100%	83%	Homes in BREC service area with a gas water heater and a gas clothes dryer	15,949	15,470	0	877	877	0		4,736,739	21,929	$0.00
13	Single-family	Energy Star Compliant Programmable Thermostat	26.0%	11.00%	89%	100%	83%	Homes in BREC service area with central air conditioning and or electric space heat	20,733	18,453	1,621,979	1,431	1,431	1,267,489	11.30%	0	35,786	$0.00
14	Single-family	Water Heater Blanket	65.2%	32.00%	88%	100%	83%	Homes in BREC service territory with an electric water heater	51,992	35,355	11,773,179	2,496	2,496	8,310,479	10.00%	0	0	$0.00
15	Single-family	Low Flow Shower Head	65.2%	30.00%	70%	100%	83%	Homes in BREC service territory with an electric water heater	51,992	36,395	9,096,686	2,800	2,800	6,499,061	7.51%	17,848,850	0	$0.00
16	Single-family	Pipe Wrap	65.2%	20.00%	80%	100%	83%	Homes in BREC service territory with an electric water heater	51,992	41,594	5,632,001	3,120	3,120	4,148,001	3.99%	0	0	$0.00
17	Single-family, Low Income	Air Sealing	25.2%	14.28%	86%	100%	83%	BREC Homes that are at or below 125% of poverty level	20,095	17,226	20,188,264	1,321	1,321	15,477,999		0	0	$0.00
18	Single-family, Low Income	Reset Water Heater Thermostat (from medium to med-low)	25.2%	14.28%	86%	100%	83%	BREC Homes that are at or below 125% of poverty level	20,095	17,226	6,561,192	1,321	1,321	5,030,350		0	0	$0.00
19	Single-family, Low Income	Water Heater Wrap (from Big Rivers)	25.2%	14.28%	86%	100%	83%	BREC Homes that are at or below 125% of poverty level	20,095	17,226	1,009,414	1,321	1,321	773,900		0	0	$0.00

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

AENDIX- MEASURE SAVNG,USEBL LIES,CGS AND SAURAES D RESIDENAL ENERCIENCYMEASURES
Ctobr

HDD:

Big Rivers Service Area in Kentucky

Discount Rate: 5.35%

1	2	3	4	5	6	7	8	9	0	1 2	2	3	4	5	6	7 8	9		
Measure #	Single- or Multi-family	Measure Description	tal Numbr of Residential Husehoids (and Mimes)	Market Driven or Retrofit	Savings Units	Cost Units	Eqipment Cost	Labr Cost	tal Installed Cost	Cost Type: Incremental = 0 Ell =1	Measure Life (yrs)	Base Case Eqipment End Use Intensity (Annual kWh per appliance)	Annual kWh Savings Pr Unit Installed	Estimated Annual MMBU (Natural Gs) Savings Pr Unit Installed	Annual Amortized Cost Pr Unit	Levelized Cost Pr kWh Saved	Annual Gllons of ater saved	Electric End Use Affected	Implementation Type 1=ne 2RB
20	Single-family, Low Income	Attic Insulation (from R to R)	96,076	Retrofit	Per home	Per home			$720.00	1	25		878.99	0	$52.89	$0.0602	0	Space Heating	1
21	Single-family - Non Low Income	Air Sealing Retrofit	96,076	Retrofit	Per home	Per home			$360.00	1	10		2346.00	0	$50.05	$0.0213		Space Heating	1
22	Single-family - Non Low Income	Attic Insulation Retrofit	96,076	Retrofit	Per home	Per home			$847.80	1	25		6694.00	0	$62.26	$0.0090		Space Heating	1
23	Single-family - Non Low Income	Wall Insulation Retrofit	96,076	Retrofit	Per home	Per home			$330.00	1	25		1380.00	0	$24.24	$0.0176		Space Heating	1
24	Single-family - Non Low Income	WindowConstruction (from single-pane Uto doule pane,low U)	96,076	Retrofit	Per home	Per home			$1,223.00	1	40		3880.00	0	$74.72	$0.0193		Space Heating	1

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

ARNDIX- MEASURE SAING,USEBL LIES,C8S A
Ctobr [illegible]

Big Rivers Service Area in Kentucky

1	2	3	8	2	2	2 8		5 8	2	8	9	0 3	2	3	8	9		
Measure #	Single- or Multi-family	Measure Description	End Use Saturation (rcentage of total homes that contain the electric end use or the measure)	Base Case ctor (raction of the end use energy that is already energy efficient)	Remaining ctor (n howmany homes can this b installed)	Convertibility ctor	Single-Multi-mily ction	ype of home here applicabl	Numbr of applicabl homes in 8 (ore applying remaining factor and convertibility factor)[1]	tal imes Remaining ithout measure (fter applying remaining factor and convertibility factor)	chnical tential-tal annual kWh savings potential in 8 f % penetration attained overnight"	Maximum Achievabl ogram rticipants per year (% penetration limit,and efore application of convertibility factor)[2]	Maximum Achievabl ogram rticipants per year (% penetration limit,and after application of convertibility factor)[2]	Maximum Achievabl kWh Savings) % penetration limit,and after application of convertibility factor)[2]	Savings ctor (rcentage reduction in electric energy consumption)	tal annual gallons of ter savings potential in 8	Annual Maximum Achievabl erm Savings tential in 8	-going annual 8 cost (or savings ()
20	Single-family, Low Income	Attic Insulation (from R to R)	25.2%	14.28%	86%	100%	83%	BREC Homes with electric space heat that are at or below 125% of poverty level	20,095	17,226	15,141,213	528	528	4,643,400		0	0	$0.00
21	Single-family - Non Low Income	Air Sealing Retrofit	38.8%	35.00%	65%	50%	83%	SF, non-low income homes in the BREC service area with electric space heat	30,940	10,056	23,590,443	1,609	804	18,872,355		0	0	$0.00
22	Single-family - Non Low Income	Attic Insulation Retrofit	38.8%	35.00%	65%	50%	83%	SF, non-low income homes in the BREC service area with electric space heat	30,940	10,056	69,323,323	1,609	804	55,458,858		0	0	$0.00
23	Single-family - Non Low Income	Wall Insulation Retrofit	38.8%	35.00%	65%	50%	83%	SF, non-low income homes in the BREC service area with electric space heat	30,940	10,056	13,876,731	1,609	804	11,101,385		0	0	$0.00
24	Single-family - Non Low Income	WindowConstruction (from single-pane U to doub pane,low U)	38.8%	35.00%	65%	50%	83%	SF, non-low income homes in the BREC service area with electric space heat	30,940	10,056	39,015,737	1,609	804	31,212,590		0	0	$0.00

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

AENDIX- MEASURE SAVING,USEBL LIES,COS AND SATURATIS O RESIDENTIAL ENERGY EFFICIENCY MEASURES
Ctobr
HDD:

Big Rivers Service Area in Kentucky

Discount Rate: 5.35%

Measure #	Single- or Multi-family	Measure Description	Ttal Numbr of Residential Husehölds (Sind Mltmes)	Market Driven or Retrofit	Savings Units	Cost Units	Eqipment Cost	Labr Cost	Ttal Installed Cost	Cost Type: Incremental = 0 Full =1	Measure Life (yrs)	Base Case Eqipment End Use Intensity (Annual kWh per appliance)	Annual kWh Savings Pr Unit Installed	Estimated Annual MMBtu (Natural Gas) Savings Pr Unit Installed	Annual Amortized Cost Pr Unit	Levelized Cost Pr kWh Saved	Annual Gllons of Water saved	Electric End Use Affected	Implementation Type 1=One 2=RB
1	2	3	4	5	6	7	8	9	0	1	2	3	4	5	6	8	9		
1	Multi-family	CE replacing Incandescent for 3hrsday	96,076	Market Driven	Per bulb	Per bulb	$5.97	$0.00	$5.97	0	10.1	65.17	48.88	0	$0.78	$0.0160	0	Lighting	2
2	Multi-family	CE Frchiers (compared to Hlogen Frchiers)	96,076	Retrofit	Per lamp	Per lamp	$60.00	$0.00	$60.00	0	8.2	273.75	223.56	0	$9.21	$0.0412	0	Lighting	1
3	Multi-family	CE Frchiers (compared to Incandescent Frchiers)	96,076	Retrofit	Per lamp	Per lamp	$60.00	$0.00	$60.00	0	8.2	136.88	86.69	0	$9.21	$0.1063	0	Lighting	1
4	Multi-family	Energy Star Single Room Air Conditioner	96,076	Market Driven	Per air conditioner	Per air conditioner	$89.00	$0.00	$89.00	0	13	1020.00	118.75	0	$9.68	$0.0815	0	Room AC	2
5	Multi-family	Energy Star Compliant Freezer Top Refrigerator	96,076	Market Driven	Per refrigerator	Per refrigerator	$115.00	$0.00	$115.00	0	17	1362.00	1029	0	$10.47	$0.0102	0	Refrigerator	2
6	Multi-family	Energy Star Compliant Side-by-Side Refrigerator	96,076	Market Driven	Per refrigerator	Per refrigerator	$247.50	$0.00	$247.50	0	17	1679.00	1079	0	$22.53	$0.0209	0	Refrigerator	2
7	Multi-family	Energy Star Compliant Upright Freezer	96,076	Market Driven	Per freezer	Per freezer	$50.00	$0.00	$50.00	0	15.5	692.00	110	0	$4.83	$0.0439	0	Freezer	2
8	Multi-family	Energy Star Compliant Chest Freezer	96,076	Market Driven	Per freezer	Per freezer	$50.00	$0.00	$50.00	0	15.5	397.00	43	0	$4.83	$0.1123	0	Freezer	2
9	Multi-family	Energy Star Built-in Dishwasher	96,076	Market Driven	Per dishwasher	Per dishwasher	($29.46)	$0.00	($29.46)	0	13	506.50	141	0	($3.20)	($0.0227)	0	Dishwasher	2
10	Multi-family	Energy Star Washing Machine with Electric Water Heater and Electric Clothes Dryer	96,076	Market Driven	Per clothes washer	Per clothes washer	$200.00	$0.00	$200.00	0	14		475	0	$20.66	$0.0435	5400	Clothes Washer	2
11	Multi-family	Energy Star Washing Machine with Gas Water Heater and Electric Clothes Dryer	96,076	Market Driven	Per clothes washer	Per clothes washer	$200.00	$0.00	$200.00	0	14		115	1.9	$20.66	$0.1786	5400	Clothes Washer	2
12	Multi-family	Energy Star Washing Machine with Gas Water Heater and Gas Clothes Dryer	96,076	Market Driven	Per clothes washer	Per clothes washer	$200.00	$0.00	$200.00	0	14		0	2.5	$20.66	#DIV/0!	5400	Clothes Washer	2
13	Multi-family	Energy Star Compliant Programmable Thermostat	96,076	Market Driven	Per Home	Per home	$49.00	$0.00	$49.00	0	10	778.00	87.9	2.5	$6.45	$0.0734	0	Central AC	2
14	Multi-family	Water Heater Blanket	96,076	Retrofit	Per water heater	Per water heater	$15.00	$0.00	$15.00	1	10	3330.00	333	0	$1.98	$0.0059	0	Water Heating	1
15	Multi-family	Low-Flow Shower Head	96,076	Retrofit	Per water heater	Per shower head	$5.77	$0.00	$5.77	1	10	3330.00	250	0	$0.76	$0.0030	6789	Water Heating	1
16	Multi-family	Pipe Wrap	96,076	Retrofit	Per home	Per home	$3.23	$0.00	$3.23	1	10	3330.00	133	0	$0.43	$0.0032	0	Water Heating	1
17	Multi-family	Reset Water Heater Thermostat (from medium to med-low)	96,076	Retrofit	Per home	Per home			$10.00	1	10		380.90	0	$1.32	$0.0035	0	Water Heating	1
18	Multi-family	Water Heater Wrap (from Ellie EE)	96,076	Retrofit	Per home	Per home			$35.00	1	10		58.60	0	$4.61	$0.0787	0	Water Heating	1
19	Multi-family	Air Sealing	96,076	Retrofit	Per home	Per home			$380.00	1	10		1171.99	0	$50.05	$0.0427	0	Space Heating	1

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

AENDIA- MEASURE SAING,USEBL LIES,C8S A
Gobr 8

Big Rivers Service Area in Kentucky

1	2	3	8	2	2	2 8		8 8	2	8	9	0 3	3	3	8	9		
Measure #	Single- or Multi-family	Measure Description	End Use Saturation (Prcentage of total homes that contain the electric end use or the measure)	Base Case Factor (fraction of the end use energy that is already energy efficient)	Remaining Factor (n howmany homes can this b installed)	Convertibility Factor	Single-Multi-family Fraction	Type of home here applicable	Number of applicable homes in 8 (before applying remaining factor and convertibility factor)[1]	Total times Remaining Without measure after applying remaining factor and convertibility factor)	Technical Potential-Total annual kWh savings potential in 8f % penetration attained Overnight"	Maximum Achievable Program Participants per year (% penetration limit, and before application of convertibility factor)[2]	Maximum Achievable Program Participants per year (% penetration limit, and after application of convertibility factor)[2]	Maximum Achievable kWh Savings (% penetration limit, and after application of convertibility factor)[2]	Savings Factor (Percentage reduction in electric energy consumption)	Total annual gallons of water savings potential in 8	Annual Maximum Achievable Therm Savings Potential in 8	On-going annual 8 cost for savings ()
1	Multi-family	CE replacing Incandescent for 3railey	100.0%	20.00%	80.0%	100%	13%	Homes in BREC service territory (for CFLs, the numbers reported here represent light bulb sockets)	374,696	299,757	14,652,128	22,482	22,482	10,989,096	75.00%	0	0	$0.00
2	Multi-family	CE Erchiers (compared to Mogen Erchiers)	18.0%	0.00%	100.0%	100%	13%	Homes in BREC service area with halogen torchieres	2,248	2,248	502,608	219	219	489,205	81.67%	0	0	$0.00
3	Multi-family	CE Erchiers (compared to Incandescent Erchiers)	14.0%	0.00%	100.0%	100%	13%	Homes in BREC service area with incandescent torchieres	1,749	1,749	151,580	170	170	147,538	63.33%	0	0	$0.00
4	Multi-family	Energy Star Single Room Air Conditioner	25.8%	10.00%	90%	100%	13%	Homes in Kentucky with one or more A/C units	5,478	4,930	585,468	295	295	350,280	11.64%	0	0	$0.00
5	Multi-family	Energy Star Compliant Reezer Up Refrigerator	71.4%	12.00%	88%	100%	13%	Homes in BREC service area	8,918	7,848	8,075,223	357	357	3,670,556	75.55%	0	0	$0.00
6	Multi-family	Energy Star Compliant Side-b-Side Refrigerator	28.6%	12.00%	88%	100%	13%	Homes in BREC service area	3,572	3,143	3,391,786	143	143	1,541,721	64.26%	0	0	$0.00
7	Multi-family	Energy Star Compliant Upright Reezer	23.7%	12.00%	88%	100%	13%	Homes in BREC service area which contain a freezer	2,960	2,605	286,538	130	130	142,849	15.90%	0	0	$0.00
8	Multi-family	Energy Star Compliant Chest Reezer	19.7%	12.00%	88%	100%	13%	Homes in BREC service area which contain a freezer	2,461	2,165	93,106	108	108	46,416	10.83%	0	0	$0.00
9	Multi-family	Energy Star Built-in Dishasher	51.0%	10.00%	90%	100%	13%	Homes in Kentucky with a dishwasher	6,370	5,733	808,333	343	343	483,618	27.84%	0	0	$0.00
10	Multi-family	Energy Star Washing Machine ith Electric Water Hater and Electric Clothes Dryer	20.0%	3.00%	97%	100%	13%	Homes in BREC service area with an electric water heater and an electric clothes dryer	2,498	2,423	1,150,942	137	137	652,596		741,899	0	$0.00
11	Multi-family	Energy Star Washing Machine ith Gs Water Hater and Electric Clothes Dryer	50.0%	3.00%	97%	100%	13%	Homes in BREC service area with a gas water heater and an electric clothes dryer	6,245	6,058	696,623	343	343	394,992		1,854,747	6,526	$0.00
12	Multi-family	Energy Star Washing Machine ith Gs Water Hater and Gs Clothes Dryer	20.0%	3.00%	97%	100%	13%	Homes in BREC service area with a gas water heater and a gas clothes dryer	2,498	2,423	0	137	137	0		741,899	3,435	$0.00
13	Multi-family	Energy Star Compliant Programmable Thermostat	26.0%	11.00%	89%	100%	13%	Homes in BREC service area with central air conditioning	3,247	2,890	254,045	224	224	196,956	11.30%	0	5,602	$0.00
14	Multi-family	Water Hater Blanket	65.2%	32.00%	68%	100%	13%	Homes in BREC service territory with an electric water heater	8,143	5,538	1,843,992	391	391	1,301,641	10.00%	0	0	$0.00
15	Multi-family	Low Flow Shower Had	65.2%	30.00%	70%	100%	13%	Homes in BREC service territory with an electric water heater	8,143	5,700	1,425,095	407	407	1,017,925	7.51%	2,764,278	0	$0.00
16	Multi-family	Pipe Wrap	65.2%	20.00%	80%	100%	13%	Homes in BREC service territory with an electric water heater	8,143	6,515	866,458	489	489	649,843	3.99%	0	0	$0.00
17	Multi-family	Reset Water Hater Thermostat (from medium to med-low)	65.2%		100%	100%	13%	BREC homes at or below 125% of poverty level	8,143	8,143	3,101,794	651	651	2,481,435		0	0	$0.00
18	Multi-family	Water Hater Wrap (from Silo EF)	65.2%		100%	100%	13%	BREC homes at or below 125% of poverty level	8,143	8,143	477,199	651	651	381,759		0	0	$0.00
19	Multi-family	Air Sealing	38.8%	35.00%	65%	100%	13%	MF, non-low income homes in the BREC service area with electric space heat	4,846	3,150	3,691,706	252	126	1,476,682		0	0	$0.00

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

AENDIX- MEASURE SAING,USEBL LIES,COS AND SAURAS B RESIDENIAL ENEREICIENCMEASURES
Gtobr
HDD:

Big Rivers Service Area in Kentucky

Discount Rate: 5.35%

1	2	3	4	5	6	7	8	9	0	1 2	2	3	4	5	6 7	8	9		
Measure #	Single- or Multi-family	Measure Description	Stal Numbr of Residential usehoids (Sand Mimes)	Market Driven or Retrofit	Savings Units	Cost Units	Eqipment Cost	Labr Cost	Stal Installed Cost	Cost Ype: Incremental = 0 Ful =1	Measure Life (yrs)	Base Case Eqipment End Use Intensity (Annual kWh per appliance)	Annual kWh Savings Pr Unit Installed	Estimated Annual MMBU Natural (s) Savings Pr Unit Installed	Annual Amortized Cost Pr Unit	Levelized Cost Pr kWh Saved	Annual lons of ater saved	Electric End Use Affected	Implementation Ype 1=ne 2RB
20	Multi-family	Attic insulation	96,076	Retrofit	Per home	Per home			$720.00	1	25		878.99	0	$52.89	$0.0602	0	Space Heating	1
21	Multi-family	Wall insulation (from Rlo RI)	96,076	Retrofit	Per home	Per home			$330.00	1	25		1380.00	0	$24.24	$0.0176		Space Heating	1
22	Multi-family	WindowConstruction (from single-pane Uto doub pane,low U)	96,076	Retrofit	Per home	Per home			$611.50	1	40		1940.00	0	$37.36	$0.0193		Space Heating	1

Appendix A: Input Assumptions - Residential Energy Efficiency Measures

APPENDIX- MEASURE SAVINGS,USEFUL LIVES,COSTS A
October [illegible]

Big Rivers Service Area in Kentucky

Measure #	Single- or Multi-family	Measure Description	End Use Saturation (Percentage of total homes that contain the electric end use or the measure)	Base Case Factor (fraction of the end use energy that is already energy efficient)	Remaining Factor (in how many homes can this be installed)	Convertibility Factor	Single-Multi-Family Fraction	Type of home where applicable	Number of applicable homes in BREC before applying remaining factor and convertibility factor)[1]	Total Homes Remaining without measure (after applying remaining factor and convertibility factor)	Technical Potential- Total annual kWh savings potential in BREC (% penetration attained overnight"	Maximum Achievable Program Participants per year (% penetration limit,and before application of convertibility factor)[2]	Maximum Achievable Program Participants per year (% penetration limit,and after application of convertibility factor)[2]	Maximum Achievable kWh Savings (% penetration limit,and after application of convertibility factor)[2]	Savings Factor (Percentage reduction in electric energy consumption)	Total annual gallons of water savings potential in BREC	Annual Maximum Achievable Therm Savings Potential in BREC	On-going annual O&M cost (or savings ()
20	Multi-family	Attic insulation	38.8%	35.00%	65%	100%	13%	MF, non-low income homes in the BREC service area with electric space heat	4,846	3,150	2,768,779	252	126	1,107,512		0	0	$0.00
21	Multi-family	Wall insulation (from R[illegible] to R[illegible])	38.8%	35.00%	65%	100%	13%	MF, non-low income homes in the BREC service area with electric space heat	4,846	3,150	4,346,928	252	126	1,738,771		0	0	$0.00
22	Multi-family	Window Construction (from single-pane to double pane,low E)	38.8%	35.00%	65%	100%	13%	MF, non-low income homes in the BREC service area with electric space heat	4,846	3,150	6,110,899	252	126	2,444,359		0	0	$0.00

APPENDIX A- SOURCES AND REFERENCES FOR RESIDENTIAL NATURAL GAS ENERGY EFFICIENCY INPUT ASSUMPTIONS - OCTOBER 20, 2005

1	2	3	4	5	6	7	8
Measure # from GDS Natural Gas Energy Efficiency Data Base	**Measure Description**	**Source for MMBTU, Therm, kWh and Water savings**	**How savings numbers were calculated**	**Source for Useful Life**	**Source for Incremental Cost**	**Source for End Use Saturation**	**Source for Saturation of Energy Efficient Measure (Base Case factor)**
1	**Compact Fluorescent Lighting**	Table 1-8 (Average Wattage Reduction Results) and 1-9 (Average Daily Hours of Use Results) in "Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs," July 29, 2004, by Nexus Market Research, Inc. and RLW Analytics, Inc.	The average hours of daily use and the average wattage reduction values were taken from the chart and multiplied together to arrive at Wh/day. That value was then multiplied by the number of days in the year and divided by 1000 to calculate the average number of kWh saved in a year.	Useful life of 10000 hours were taken from manufacturer data on product package and used to calculate useful life in years. Hour use of 2.7 hours/day came from the Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs on July 29, 2004.	Data collected by Courtney Denman at Home Depot store on June 7, 2005. Presented is the average incremental cost of available CFL bulbs.	End-Use Consumption of Electricity 2001	PowerPoint Presentation by Brad Kates and Steve Bonano on the results of the "Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs" on July 29, 2004.
2	**CFL Torchieres**	"Residential Torchiere Assumptions" from Energy Star's "Torchiere Savings Calculator." EnergyStar.gov. March, 2000. Base case incandescent torchiere energy use came from "Alternatives to Halogen Torchieres" on the Lighting Research Center's website (www.lrc.rpi.edu).	Average energy use per fixture (for a halogen torchiere and for a CFL torchiere) were compared and subtracted. Then the wattage difference was multiplied by 2.5 hours per day and 365 days per year.	Useful life hours were calculated based on an advertised life of 7500 hours and usage of 2.5 hours per day, 365 days per year, according to Table 1-9 (Average Daily Hours of Use Results) from Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs by Nexus Market Research, Inc. in July, 2004.	"Residential Torchiere Assumptions" from Energy Star's "Torchiere Savings Calculator." EnergyStar.gov. March, 2000.	Email from Jean Shelton at Itron on Wednesday, August 3, 2005.	Email from Jean Shelton at Itron on Wednesday, August 3, 2005.
3	**Energy Star Single-Room, Window-Mounted Air Conditioner**	kWh data came from energy labels for each model as advertised on Sears' website (Sears.com)	Savings were calculated by averaging kWh for each capacity air-conditioning unit (in BTUs/hr) and finding the difference between corresponding Energy Star and non-Energy Star model energy use. Then the differences were averaged to find a mean value for energy savings.	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Incremental cost was computed by comparing model prices as advertised on Sears' website (Sears.com)	Results from the final report of "Home Appliance Saturation and Length of First Ownership Study," May, 2001, by NFO WorldGroup	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
4-5	**Energy Star Freezer-Top Refrigerator Models and Side-by-Side Refrigerator Models**	Table 1 (Annual Refrigerator Usage--Averages and Comparisons to Rated) in "Statewide Refrigerator *Monitoring and Verification Study & Results*," by Dana Teague and Michael Blasnik	Savings were calculated by GDS by comparing the annual kWh usage for existing vs. energy efficient refrigerators as reported in Table 1.	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Data collected by Courtney Denman at Sears Department store on June 9, 2005	Table D6 (Appliances in East South Central Households) in "Regional Energy Profile: East South Central Appliance Report 2001," by the Energy Information Administration, and results from the final report of "Home Appliance Saturation and Length of First Ownership Study," May, 2001, by NFO WorldGroup	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
6	**Energy Star Upright Freezer Models**	kWh data came from energy labels for each model as advertised on Lowe's website (Lowes.com)	Savings were calculated by averaging kWh for each size freezer (in cu. Ft.) and finding the difference between corresponding Energy Star and non-Energy Star model energy use. Then the differences were averaged to find a mean value for energy savings.	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Incremental cost was computed by comparing model prices as advertised on Lowe's website (Lowes.com)	Results from the final report of "Home Appliance Saturation and Length of First Ownership Study," May, 2001, by NFO WorldGroup	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
7	**Energy Star Chest Freezer Models**	kWh data came from energy labels for each model as advertised on Home Depot's website (homedepot.com)	Savings were calculated by averaging kWh for each size freezer (in cu. Ft.) and finding the difference between corresponding Energy Star and non-Energy Star model energy use. Then the differences were averaged to find a mean value for energy savings.	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Incremental cost was computed by comparing model prices as advertised on Home Depot's website (homedepot.com)	Results from the final report of "Home Appliance Saturation and Length of First Ownership Study," May, 2001, by NFO WorldGroup	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
8	**Energy Star Dishwasher**	kWh data came from energy labels for each model as advertised on Sears' website (Sears.com)	Energy usage data was collected from website and then averaged for Energy Star-compliant models and non-Energy Star-compliant models. The averages were subtracted to find the difference.	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Incremental cost was computed by comparing model prices as advertised on Sears' website (Sears.com)	Table D6 (Appliances in East South Central Households) in "Regional Energy Profile: East South Central Appliance Report 2001," by the Energy Information Administration	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
9-11	**Energy Star Clothes Washers**	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah" Southwest Energy Efficiency Project. October 17, 2002	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah" Southwest Energy Efficiency Project. October 17, 2002	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah" Southwest Energy Efficiency Project. October 17, 2002	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah" Southwest Energy Efficiency Project. October 17, 2002	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah" Southwest Energy Efficiency Project. October 17, 2002	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah" Southwest Energy Efficiency Project. October 17, 2002
12	**Energy Star Compliant Programmable Thermostat**	Appendix A (Input Assumptions) in the 2005 report "The Maximum Achievable Cost Effective Potential for Natural Gas Demand Side Management in the Service Territory of PNM"	Appendix A (Input Assumptions) in the 2005 report "The Maximum Achievable Cost Effective Potential for Natural Gas Demand Side Management in the Service Territory of PNM"	Table B-5 (Supply Curve Development) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Appendix A (Input Assumptions) in the May, 2005 report "The Maximum Achievable Cost Effective Potential for Natural Gas Demand Side Management in the Service Territory of PNM" by GDS Associates, Inc.	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
13	**Water Heater Blanket - Non Low Income Market Segment**	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Costs were recorded from advertisements on Lowes' (Lowes.com) and Home Depot's (homedepot.com) websites	PowerPoint Presentation by E. A. Torrero and R. H. McClelland, "State of the Art of Residential Fuel Cells, Market, and Implementation Issues" in June, 2001	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
14	**Low Flow Shower Head**	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Appendix A (Input Assumptions) in the May, 2005 report "The Maximum Achievable Cost Effective Potential for Natural Gas Demand Side Management in the Service Territory of PNM" by GDS Associates, Inc.	PowerPoint Presentation by E. A. Torrero and R. H. McClelland, "State of the Art of Residential Fuel Cells, Market, and Implementation Issues" in June, 2002	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
15	**Pipe Wrap**	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Appendix A (Input Assumptions) in the May, 2005 report "The Maximum Achievable Cost Effective Potential for Natural Gas Demand Side Management in the Service Territory of PNM" by GDS Associates, Inc.	PowerPoint Presentation by E. A. Torrero and R. H. McClelland, "State of the Art of Residential Fuel Cells, Market, and Implementation Issues" in June, 2003	Table B-7 (Database of Energy Efficiency Measures) in Appendix B of "Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates
16	**Air Sealing**	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	"2004 Poverty Income Guidelines, Contiguous U.S. Grantees, Effective February 13, 2004," from http://chfs.ky.gov/dcbs/dfs/Watherization.htm and "Detailed Demographic Update: 2004/2009" by Scan/US, Inc.	Email from Gary Brown, Program Specialist of the Kentucky Weatherization Assistance Program, on July 27, 2005
17	**Reset Water Heater Thermostat**	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	"2004 Poverty Income Guidelines, Contiguous U.S. Grantees, Effective February 13, 2004," from http://chfs.ky.gov/dcbs/dfs/Watherization.htm and "Detailed Demographic Update: 2004/2009" by Scan/US, Inc.	Email from Gary Brown, Program Specialist of the Kentucky Weatherization Assistance Program, on July 27, 2005

APPENDIX A- SOURCES AND REFERENCES FOR RESIDENTIAL NATURAL GAS ENERGY EFFICIENCY INPUT ASSUMPTIONS - OCTOBER 20, 2005

1	2	3	4	5	6	7	8
Measure # from GDS Natural Gas Energy Efficiency Data Base	Measure Description	Source for MMBTU, Therm, kWh and Water savings	How savings numbers were calculated	Source for Useful Life	Source for Incremental Cost	Source for End Use Saturation	Source for Saturation of Energy Efficient Measure (Base Case factor)
18	Water Heater Wrap - Low Income Market Segment	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	"2004 Poverty Income Guidelines, Contiguous U.S. Grantees, Effective February 13, 2004," from http://chfs.ky.gov/dcbs/dfs/Watherization.htm and "Detailed Demographic Update: 2004/2009" by Scan/US, Inc.	Email from Gary Brown, Program Specialist of the Kentucky Weatherization Assistance Program, on July 27, 2005
19	Attic Insulation - Low Income Market Segment	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in "Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table 8 (Weatherization Measures, Costs, and Savings for Typical House in South) in *"Meeting the Challenge:* The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	Table B-4 (Supply Curve Development...) in Appendix B of *"Independent assessment of Conservation and Energy* Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Table 8 (Weatherization Measures, Costs, and Savings *for Typical House in South) in "Meeting the Challenge:* The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program" by Mark Schweitzer and Joel F. Eisenberg of Oak Ridge National Laboratory, May 2002	"2004 Poverty Income Guidelines, Contiguous U.S. *Grantees, Effective February 13, 2004,"* from http://chfs.ky.gov/dcbs/dfs/Watherization.htm and "Detailed Demographic Update: 2004/2009" by Scan/US, Inc.	Email from Gary Brown, Program Specialist of the *Kentucky Weatherization Assistance Program,* on July 27, 2005
20	Air Sealing	Energy 10 Simulations	Energy 10 Simulations	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Energy 10 Simulations	The source for the electric space heating saturation of 38.8% for Kentucky is from the US Bureau of the Census, 2000 Housing Census, Table DP-4, Profile of Selected Housing Characteristics for Kentucky for the Year 2000.	September 2005 Big Rivers Electric Corporation Market Research Study with Weatherization and Insulation Service Providers in the BREC Service Area, prepared by GDS Associates, September 9, 2005.
21	Attic Insulation - Non Low Income Market Segment	Energy 10 Simulations	Energy 10 Simulations	Table B-4 (Supply Curve Development...) in Appendix B of *"Independent assessment of Conservation and Energy* Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Energy 10 Simulations	The source for the electric space heating saturation of 38.8% for Kentucky is from the US Bureau of the Census, 2000 Housing Census, Table DP-4, Profile of Selected Housing Characteristics for Kentucky for the Year 2000.	September 2005 Big Rivers Electric Corporation Market Research Study with Weatherization and Insulation Service Providers in the BREC Service Area, prepared by GDS Associates, September 9, 2005.
22	Wall Insulation	Energy 10 Simulations	Energy 10 Simulations	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region," June, 2004, by GDS Associates	Energy 10 Simulations	The source for the electric space heating saturation of 38.8% for Kentucky is from the US Bureau of the Census, 2000 Housing Census, Table DP-4, Profile of Selected Housing Characteristics for Kentucky for the Year 2000.	September 2005 Big Rivers Electric Corporation Market Research Study with Weatherization and Insulation Service Providers in the BREC Service Area, prepared by GDS Associates, September 9, 2005.
23	Window Construction	Energy 10 Simulations	Energy 10 Simulations	Table B-4 (Supply Curve Development...) in Appendix B of "Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest *Connecticut Region," June, 2004, by GDS Associates*	Energy 10 Simulations	The source for the electric space heating saturation of 38.8% for Kentucky is from the US Bureau of the Census, 2000 Housing Census, Table DP-4, Profile of Selected Housing Characteristics for Kentucky for the Year 2000.	September 2005 Big Rivers Electric Corporation Market Research Study with Weatherization and Insulation Service Providers in the BREC Service Area, prepared by GDS Associates, September 9, 2005.

APPENDIX A - ELECTRIC END USE LOAD SHAPES FOR RESIDENTIAL ENERGY EFFICIENCY MEASURES

Loadshape Name	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy	kWh check	Summer Gener. Capacity	Winter Gener. Capacity	Transm. Capacity	Distribution Capacity
Indoor Lighting	0.2870	0.0760	0.3600	0.2770	1.00	0.1230	0.2320	0.1230	0.1230
Refrigerator	0.2250	0.1080	0.3370	0.3300	1.00	0.6000	0.6230	0.6000	0.6000
Space Heat	0.6220	0.3780	0.0000	0.0000	1.00	0.0000	1.0000	0.0000	0.0000
AC	0.0000	0.0000	0.5000	0.5000	1.00	0.8000	0.0000	0.8000	0.8000
DHW Insulation	0.2230	0.1110	0.3330	0.3330	1.00	1.0000	1.0000	1.0000	1.0000
DHW Conserve	0.2840	0.0310	0.4650	0.2200	1.00	0.4810	0.7750	0.4810	0.4810
Clothes Washer	0.3420	0.0370	0.4200	0.2010	1.00	0.5000	0.5000	0.5000	0.5000

Source:	"Loadshape Table of Contents," page 9 in Technical Reference User Manual (TRM) No. 2004-31: Measure *Savings Algorithms and Cost Assumptions Through Portfolio 31*, by *Efficiency Vermont*, December, 2004.

Note:	Select numbers have been edited by GDS: Space Heat peak load (on the assumption that heat is not used in the summer months), Space Heat Summer and Winter Generation Capacity, AC Summer Generation Capacity, Clothes Washer Summer and Winter Generation Capacity

APPENDIX B

Appendix B: Input Assumptions - Commercial Energy Efficiency Measures

Discount Ra 5.35%

#	Commercial Market Segment	Retrofit or Market Driven	End Use	Measure Name	Annual kWh Savings	kWh Savings Source	Incremental Cost	Cost Source	Measure Life	Measure Life Source	Annualized cost	Levelized cost per kWh saved
				Interior Lighting								
1	Existing	Retrofit	Interior	CFL - screw-in	90	GDS calculation: (75-15)W * 1500hr/yr	$6	Home Depot website	8		$0.94	$0.0105
2	Existing	Market	Interior	CFL - Hard Wired	228	National Grid, 2000 Energy Initiative Program (Large C&I) Data, 2000 DSM Performance	$27	Mike Rufo, 2003.	8	National	$4.24	$0.0186
3	Existing	Market	Interior	Biax Fluorescents	480	CL&P Program Data, 2003. 6 lamp 300 W Biax replacing 460 W HID. 3,000 hrs	$400	Environmental Building News, Volume 9, Aug. 2000	7	Northeast	$70.01	$0.1458
4	Existing	Market	Interior	Energy-efficient Torchiere	296	Lawrence Berkley Lab. "An Energy-Efficient, Safer Torchiere".	$20	ACEEE Selecting Targets for Market Transformation Program:	7	GDS	$3.50	$0.0118
5	Existing	Market	Interior	Halogen PAR Flood, 90W	180	GDS calculation. 3,000 hrs vs. 150 w halogen.	$12	California Statewide Commercial Sector Energy Efficiency	1	California	$12.64	$0.0702
6	Existing	Market	Interior	Ret 1L4'T5, 1EB	39	Lighting Research Center energy use data compared to 34W T12 fixtures. 3000 hrs.	$64	Lighting Research Center, 2003.	9	Northeast	$9.15	$0.2345
7	Existing	Market Driven	Interior Lighting	Ret 4L4' HO T5, 1EB (repl 400 w Metal halide)	648	GDS Calculation based on 3000 hrs assumed annual use. (234 W fixture replacing 450 W metal halide). Reference: Sacramento Municipal Utility District Technology Evaluation Report, T5 High Bay Lighting Systems, May 2002.	$400	Environmental Building News, Volume 9, Aug. 2000	9	Northeast Utilities, Action	$57.16	$0.0882
8	Existing	Market	Interior	Ret 1L4'T5, 1EB, Reflector	63	Lighting Research Center energy use data compared to 34W T12 fixtures. 3000 hrs. E-source	$98	Lighting Research Center, 2003. and California Statewide	9	Northeast	$14.00	$0.2223
9	Existing	Market Driven	Interior Lighting	RET T8, EB, Reflector	54	National Grid, 2000 Small C&I Program Data, 2000 DSM Performance Measurement Report, Appendix 3, December 2001	$72	California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002, C.1-1.	9	Northeast Utilities,	$10.29	$0.1905
10	Existing	Market	Interior	RET 2L4'T8, 1EB	72	GDS Calculation based on 34WT12.	$27	Maine Cost Effectiveness Model, March 2003.	9	Northeast	$3.86	$0.0536
11	Existing	Market Driven	Interior Lighting	RET 2L4' Super T8, 1EB	36	Lighting Research Center energy use data compared to Standard T8 fixtures. 3000 hrs.	$10	Lighting Research Center cost data (1.75 standard bulb and ballast cost) compared to standard T8 fixtures. Standard amp and ballast cost of $27 from California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002, C.1-1.	9	Northeast Utilities, Action Program C&I Persistenc	$1.43	$0.0397
12	Existing	Market Driven	Interior Lighting	RET 2L4' Super T8, 1EB, Reflector	84	Lighting Research Center energy use data compared to Standard T8 fixtures. 3000 hrs. E-source Technology Atlas Series 2001, 7.3.1. 33% delamping in addition to T8 to super T8 savings.	$45	California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002, C.1-1. ($72 - $27)	9	Northeast Utilities,	$6.43	$0.0765
13	Existing	Market	Interior	RET 2L4'T5, 1EB	84	Lighting Research Center energy use data compared to 34W T12 fixtures. 3000 hrs.	$64	Lighting Research Center, 2003.	9	Northeast	$9.15	$0.1089
14	Existing	Market Driven	Interior Lighting	RET 2L4'T5, 1EB, Reflector	132	Lighting Research Center energy use data compared to 34W T12 fixtures. 3000 hrs. E-source Technology Atlas Series 2001, 7.3.1. 33% delamping in addition to T12 to T5 savings.	$72	California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002, C.1-1.	9	Northeast Utilities,	$10.29	$0.0779
15	Existing	Market	Interior	RET 2L8'T8, 1EB	144	GDS calculation. Assumes 3,000 hrs. replacing 34 w T12	$27	Maine Cost Effectiveness Model, March 2003.	9	Northeast	$3.86	$0.0268
16	Existing	Market	Interior	RET 4L4' Super T8, 1EB	72	Lighting Research Center energy use data compared to standard T8 fixtures. 3000 hrs.	$12	Lighting Research Center cost data (1.75 standard bulb and	9	Northeast	$1.71	$0.0238
17	Existing	Market	Interior	250 Watt Metal Halide Lighting	513	Maine Cost Effectiveness Model, March 2003.	$65	Maine Cost Effectiveness Model, March 2003.	12	Northeast	$7.48	$0.0146
18	Existing	Market	Interior	High Intensity Discharge Systems, 250 W	510	National Grid, 2000 Energy Initiative Program (Large C&I) Data, 2000 DSM Performance	$65	Maine Cost Effectiveness Model, March 2003.	15	National	$6.41	$0.0126
19	New	Market	Interior	High Intensity Discharge Systems, 50 W	291	National Grid, 2000 Design 2000plus Program (Large C&I) Data, 2000 DSM Performance	$65	Maine Cost Effectiveness Model, March 2003.	15	National	$6.41	$0.0220
20	Existing	Market Driven	Interior Lighting	Pulse Start HID	330	GDS Calculation based on 3000 hrs assumed annual use. (350 W fixture replacing 450 W metal halide). Reference Energy Center of Wisconsin fact sheet "Pulse Start Metal Halide Lamps".	$200	Federal Energy Management Program, Technology Profile, "Metal Halide Lighting"	12	Northeast Utilities,	$23.01	$0.0697
21	Existing	Market	Exterior	High Pressure Sodium 250W Lamp	513	Maine Cost Effectiveness Model, March 2003.	$65	Maine Cost Effectiveness Model, March 2003.	12	Northeast	$7.48	$0.0146
22	Existing	Market	Interior	LED Exit Signs	184	Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	$30	Northeast Energy Efficiency Partnership, Energy Efficiency	30	Northeast	$2.03	$0.0110
23	Existing	Market	Interior	Solid State Exit Signs	348	Maine Cost Effectiveness Model, March 2003.	$38	Maine Cost Effectiveness Model, March 2003.	30	Maine Cost	$2.57	$0.0074
24	Existing	Market	Interior	LED Signage	690	WI Focus on Energy Program. Assumes 3,000 hrs. 20 w LED vs. 250 w neon.	$100	WI Focus on Energy Program	20	Northeast	$8.26	$0.0120
25	Existing	Market	Exterior	LED Traffic Lights	430	Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	$125	Northeast Energy Efficiency Partnership, Energy Efficiency	15	Northeast	$12.33	$0.0287
26	Existing	Market	Exterior	LED Traffic Lights (Yellow signals only)	22	assumes 5% of total savings per discussion with CL&P	$42	assumes 1/3 of total cost	15	Northeast	$4.11	$0.1912
27	Existing	Market	Interior	Occupancy Sensor	302	Northeast Utilities C&I Persistence Study Final Report, Oct 2001, Table 8.	$120	Maine Cost Effectiveness Model, March 2003.	15	Northeast	$11.84	$0.0392
28	Existing	Market	Interior	Daylight Dimming	353	National Grid, 2000 Energy Initiative Program Data, 2000 DSM Performance Measurement Report,	$181	California Statewide Commercial Sector Energy Efficiency	20	National	$14.96	$0.0424
29	New	Market	Interior	Daylight Dimming	252	National Grid, 2000 Design 2000plus Program (Large C&I) Data, 2000 DSM Performance	$181	California Statewide Commercial Sector Energy Efficiency	20	National	$14.96	$0.0594
30	Existing	Market Driven	Interior Lighting	Continuous Dimming, 10L4' Fluorescent Fixtures	945	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-1 and GDS calculation of 1,260 KWh baseline of 10 lamp, 34-W fixture (420 W) and 3,000 hours of use.	$288	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-1.	20	National Grid, 2000 Energy	$23.80	$0.0252
31	Existing	Market Driven	Interior Lighting	Continuous Dimming, 5L4' Fluorescent Fixtures	472	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-1 and GDS calculation of 1,260 KWh baseline of 10 lamp, 34-W fixture (210 W) and 3,000 hours of use.	$288	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-1.	20	National Grid, 2000 Design	$23.80	$0.0504
32	Existing	Market Driven	Interior Lighting	Continuous Dimming, 5L8' Fluorescent Fixtures	945	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-1 and GDS calculation of 1,260 KWh baseline of 10 lamp, 34-W fixture (420 W) and 3,000 hours of use.	$288	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-1.	20	National Grid, 2000 Design	$23.80	$0.0252
33	New	Market	Interior	15 % More Efficient Design (Lighting)	27,000	GDS Calculation based on 1,000, 2 lamp T8 and 3,000 hrs	$4,000	Assumes 40 hrs of Archit design work at $100/hr	20	Assumed	$330.56	$0.0122
34	New	Market	Interior	30 % More Efficient Design (Lighting)	54,000	GDS Calculation based on 1,000, 2 lamp T8 and 3,000 hrs	$8,000	Assumes 80 hrs of Archit design work at $100/hr	20	Assumed	$661.13	$0.0122
35	New	Market	Interior	5 % More Efficient Design (Lighting)	9,000	GDS Calculation based on 1,000, 2 lamp T8 and 3,000 hrs	$4,000	Assumes 40 hrs of Archit design work at $100/hr	20	Assumed	$330.56	$0.0367
36	New	Market	Interior	10 % More Efficient Design (Lighting)	18,000	GDS Calculation based on 1,000, 2 lamp T8 and 3,000 hrs	$8,000	Assumes 40 hrs of Archit design work at $100/hr	20	Assumed	$661.13	$0.0367
				Refrigeration								
37	Existing	Market	Refrigeration	Vender Miser	1,551	Northeast Utilities Vending Miser Monitoring Project Final Report, April 2001, p. 8	$179	USA Technologies, formerly Bayview Technology Group,	5	USA	$41.75	$0.0269
38	Existing	Market	Refrigeration	ENERGY STAR Beverage Vending Machines	330	Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	$25	Northeast Energy Efficiency Partnership, Energy Efficiency	8.5	Northeast	$3.74	$0.0113
39	Existing	Market Driven	Refrigeration	Refrigeration Commissioning	190	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 3,800 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$113	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per ton)	3	California Statewide Commercia	$41.77	$0.2198
40	Existing	Market Driven	Refrigeration	Refrigeration Commissioning	375	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 7,500 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$113	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per ton)	3	California Statewide Commercia	$41.77	$0.1114
41	Existing	Market Driven	Refrigeration	Efficient compressor motor retrofit	266	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 3,800 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$62	Motorup Evaluation and Market Assessment, Xenergy, Inc, Nov. 2001. AND base efficiency motor costs from Grainger Industrial Supply 2001-2002 Catalog, pp. 41-44.	10	California Statewide Commercia	$8.17	$0.0307
42	Existing	Market Driven	Refrigeration	Efficient compressor motor retrofit	525	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 7,500 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$62	Motorup Evaluation and Market Assessment, Xenergy, Inc, Nov. 2001. AND base efficiency motor costs from Grainger Industrial Supply 2001-2002 Catalog, pp. 41-44.	10	California Statewide Commercia	$8.17	$0.0156

Appendix B: Input Assumptions - Commercial Energy Efficiency Measures

#	Commercial Market Segment	Retrofit or Market Driven	End Use	Measure Name	Annual kWh Savings	kWh Savings Source	Incremental Cost	Cost Source	Measure Life	Measure Life Source	Annualized cost	Levelized cost per kWh saved
43	Existing	Market Driven	Refrigeration	Compressor VSD retrofit - refrig	228	CEE website (average usage for reach in refrigerators 3,800 KWh) and California Statewide Commercial Sector Energy Efficiency Potential Study (6% savings), July, 2002, C.2-4. Per unit savings.	$2,000	Wisconsin Focus on Energy Program, VFD analysis spreadsheet.	20	Northeast Utilities, Action	$165.28	$0.7249
44	Existing	Market Driven	Refrigeration	Compressor VSD retrofit - freezer	450	CEE website (average usage for reach in refrigerators 7,500 KWh) and California Statewide Commercial Sector Energy Efficiency Potential Study (6% savings), July, 2002, C.2-4. Per Unit Savings.	$2,000	Wisconsin Focus on Energy Program, VFD analysis spreadsheet.	20	Northeast Utilities, Action	$165.28	$0.3673
45	Existing	Market Driven	Refrigeration	Demand Defrost Electric - Refrig	304	CEE website (average usage for reach in refrigerators 3,800 KWh) and California Statewide Commercial Sector Energy Efficiency Potential Study (8% savings), July, 2002, C.2-4.	$25	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. $25/hp	10	California Statewide Commercia	$3.29	$0.0108
46	Existing	Market Driven	Refrigeration	Demand Defrost Electric - Freezers	600	CEE website (average usage for reach in refrigerators 7,500 KWh) and California Statewide Commercial Sector Energy Efficiency Potential Study (8% savings), July, 2002, C.2-4.	$25	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. $25/hp	10	California Statewide Commercia	$3.29	$0.0055
47	Existing	Market Driven	Refrigeration	Floating head pressure controls-Refrig	266	CEE website (average usage for reach in refrigerators 3,800 KWh) and California Statewide Commercial Sector Energy Efficiency Potential Study (7% savings), July, 2002, C.2-4. Per unit savings.	$4,995	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4.	14	California Statewide Commercia	$515.97	$1.9397
48	Existing	Market Driven	Refrigeration	Floating head pressure controls-Freezers	525	CEE website (average usage for reach in refrigerators 7,500 KWh) and California Statewide Commercial Sector Energy Efficiency Potential Study (7% savings), July, 2002, C.2-4. Per Unit Savings.	$4,995	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4.	14	California Statewide Commercia	$515.97	$0.9828
49	Existing	Market	Refrigeration	High Efficiency Ice Maker	2,365	Federal Energy Management Program, Fact Sheet, "How to Buy an Energy Efficient Commercial Ice	$300	Maine Cost Effectiveness Model, March 2003.	7	Federal	$52.51	$0.0222
50	Existing	Market	Refrigeration	Beverage Merchandisers	1,730	Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	$166	Northeast Energy Efficiency Partnership, Energy Efficiency	8.5	Northeast	$24.81	$0.0143
51	Existing	Market	Refrigeration	High Efficiency Reach in Refrigerator	1,330	CEE website. Www.cee1.org/com/com-ref/com-ref-main.php3	$400	Select Appliances website. Www.selectappliance.com	10	Federal	$52.69	$0.0396
52	Existing	Market	Refrigeration	High Efficiency Reach in Freezer	2,625	CEE website. Www.cee1.org/com/com-ref/com-ref-main.php3	$400	Select Appliances website. Www.selectappliance.com	10	Federal	$52.69	$0.0201
53	Existing	Market Driven	Refrigeration	High-efficiency fan motors - refrig	152	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 3,800 KWh/yr and savings estimate from Technology Data Characterizing Refrigeration in Commercial Buildings: Application to End-use Forecasting wit	$62	Motorup Evaluation and Market Assessment, Xenergy, Inc, Nov. 2001. AND base efficiency motor costs from Grainger Industrial Supply 2001-2002 Catalog, pp. 41-44.	12	Northeast Utilities, Action	$7.13	$0.0469
54	Existing	Market Driven	Refrigeration	High-efficiency fan motors - freezer	300	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 7,500 KWh/yr and savings estimate from Technology Data Characterizing Refrigeration in Commercial Buildings: Application to End-use Forecasting wit	$62	Motorup Evaluation and Market Assessment, Xenergy, Inc, Nov. 2001. AND base efficiency motor costs from Grainger Industrial Supply 2001-2002 Catalog, pp. 41-44.	12	Northeast Utilities, Action	$7.13	$0.0238
55	Existing	Market Driven	Refrigeration	Anti-sweat (humidistat) controls - refrig	190	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 3,800 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$6,500	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per HP)	12	California Statewide Commercia	$747.91	$3.9364
56	Existing	Market Driven	Refrigeration	Anti-sweat (humidistat) controls - freezer	375	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 7,500 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$6,500	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per HP)	12	California Statewide Commercia	$747.91	$1.9944
57	Existing	Market Driven	Refrigeration	Demand Hot Gas Defrost - refrig	114	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 3,800 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$25	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per HP)	10	California Statewide Commercia	$3.29	$0.0289
58	New	Market Driven	Refrigeration	Demand Hot Gas Defrost -freezer	225	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 7,500 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$25	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per HP)	10	California Statewide Commercia	$3.29	$0.0146
59	Existing	Market Driven	Refrigeration	Night covers for display cases - refrig	228	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 3,800 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$9	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per linear foot)	5	California Statewide Commercia	$2.10	$0.0092
60	New	Market Driven	Refrigeration	Night covers for display cases - freezers	450	GDS calculation from CEE website (www.cee1.org/com/com-ref/com-ref-main.php3) reach-in freezer base use of 7,500 KWh/yr and savings estimate from California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4	$9	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4. (per linear foot)	5	California Statewide Commercia	$2.10	$0.0047
61	Existing	Market	Refrigeration	Strip curtains for walk-ins - refrig	368	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4. and	$200	California Statewide Commercial Sector Energy Efficiency	4	California	$56.86	$0.1545
62	Existing	Market	Refrigeration	Strip curtains for walk-ins - freezer	613	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-4. and	$200	California Statewide Commercial Sector Energy Efficiency	4	California	$56.86	$0.0928
63	Existing	Market Driven	Refrigeration	Walk-In Cooler Economizers	1,149	National Grid, 2000 Small C&I Program Data, 2000 DSM Performance Measurement Report, Appendix 3, December 2001	$300	E-source Technology Atlas 2001, p. 6.3.1. $50-100/ton. 3-ton capacity assumed	15	National Grid, 1999 Small C&I	$29.59	$0.0258
64	Existing	Market Driven	Refrigeration	Walk-In Cooler Fan Control	1,487	National Grid, 2000 Small C&I Program Data, 2000 DSM Performance Measurement Report, Appendix 3, December 2001	$300	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-4.	16	National Grid, 2000 Small C&I	$28.37	$0.0191
65	Existing	Market Driven	Refrigeration	Walk-In Cooler Door Heater Control	4,202	National Grid, 2000 Small C&I Program Data, 2000 DSM Performance Measurement Report, Appendix 3, December 2001	$2,000		17	National Grid, 2000 Small C&I	$182.07	$0.0433
66	Existing	Market Driven	Refrigeration	Walk-In Freezer Door Heater Control	2,055	National Grid, 2000 Small C&I Program Data, 2000 DSM Performance Measurement Report, Appendix 3, December 2001	$2,000		18	National Grid, 2000 Small C&I	$175.80	$0.0856
				Space Cooling								
67	New	Market Driven	Space Cooling	Centrifugal Chiller, 0.51 kW/ton, 300 tons	55,968	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on EFLH average from Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report, June 1999, p. 3-12 (1,091 EFLH) and Base efficiency from FEMP Fact Sheet, "How to Buy an Energy Efficient Water Cooled Electric Chiller", Nov. 2000, p.2. Average efficiency (0.60 KW/ton) from www.trane.com/commercial/issues/environmental/ashrae_journal02.asp.	$16,200	Trane Company, "Chilled Water Plant Costs Estimated", www.trane.com/commercial/issues/earthwise_systems AND LADWP Purchasing Advisor www.ladwp.com/energyadvisor/PA_14.html (Difference in first cost of efficient chiller vs 0.60 KW/ton system. Total first c	23	FEMP Fact Sheet, "How to Buy an Energy	$1,240.95	$0.0222

Appendix B: Input Assumptions - Commercial Energy Efficiency Measures

#	Commercial Market Segment	Retrofit or Market Driven	End Use	Measure Name	Annual kWh Savings	kWh Savings Source	Incremental Cost	Cost Source	Measure Life	Measure Life Source	Annualized cost	Levelized cost per kWh saved
68	New	Retrofit	Space Cooling	Centrifugal Chiller, 0.51 kW/ton, 300 tons - Retrofit	118,155	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on EFLH average from Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report, June 1999, p. 3-12 (1,091 EFLH) and Base efficiency from FEMP Fact Sheet, "How to Buy an Energy Efficient Water Cooled Electric Chiller", Nov. 2000, p.2. 1990 Average efficiency (0.70 KW/ton) from www.trane.com/commercial/issues/environmental/ashrae_journal02.asp.	$202,200	$674 per ton cost from tristate.apogee.net/cool/cmnch.asp	23	FEMP Fact Sheet, "How to Buy an Energy	$15,488.86	$0.1311
69	Existing	Market Driven	Space Cooling	Centrifugal Chiller, 0.51 kW/ton, 500 tons	93,281	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on EFLH average from Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report, June 1999, p. 3-12 (1,091 EFLH) and Base efficiency from FEMP Fact Sheet, "How to Buy an Energy Efficient Water Cooled Electric Chiller", Nov. 2000, p.2. Average efficiency (0.60 KW/ton) from www.trane.com/commercial/issues/environmental/ashrae_journal02.asp.	$27,000	Trane Company, "Chilled Water Plant Costs Estimated", www.trane.com/commercial/issues/earthwise_systems AND LADWP Purchasing Advisor www.ladwp.com/energyadvisor/PA_14.html (Difference in first cost of efficient chiller vs 0.60 KW/ton system. Total first c	23	FEMP Fact Sheet, "How to Buy an Energy	$2,068.25	$0.0222
70	Existing	Retrofit	Space Cooling	Centrifugal Chiller, 0.51 kW/ton, 500 tons - Retrofit	196,926	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on EFLH average from Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report, June 1999, p. 3-12 (1,091 EFLH) and Base efficiency from FEMP Fact Sheet, "How to Buy an Energy Efficient Water Cooled Electric Chiller", Nov. 2000, p.2. 1990 Average efficiency (0.70 KW/ton) from www.trane.com/commercial/issues/environmental/ashrae_journal02.asp.	$281,500	$563 per ton cost from tristate.apogee.net/cool/cmnch.asp	23	FEMP Fact Sheet, "How to Buy an Energy	$21,563.38	$0.1095
71	New	Market Driven	Space Cooling	Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	207,290	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on EFLH average from Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report, June 1999, p. 3-12 (1,091 EFLH) and Base efficiency from FEMP Fact Sheet, "How to Buy an Energy Efficient Water Cooled Electric Chiller", Nov. 2000, p.2. Average efficiency (0.60 KW/ton) from www.trane.com/commercial/issues/environmental/ashrae_journal02.asp.	$60,000	Trane Company, "Chilled Water Plant Costs Estimated", www.trane.com/commercial/issues/earthwise_systems AND LADWP Purchasing Advisor www.ladwp.com/energyadvisor/PA_14.html (Difference in first cost of efficient chiller vs 0.60 KW/ton system. Total first c	23	FEMP Fact Sheet, "How to Buy an Energy	$4,596.10	$0.0222
72	Existing	Retrofit	Space Cooling	Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	310,935	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on EFLH average from Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report, June 1999, p. 3-12 (1,091 EFLH) and Base efficiency from FEMP Fact Sheet, "How to Buy an Energy Efficient Water Cooled Electric Chiller", Nov. 2000, p.2. Average efficiency (0.70 KW/ton) from www.trane.com/commercial/issues/environmental/ashrae_journal02.asp.	$314,500	$563 per ton cost from tristate.apogee.net/cool/cmnch.asp + $33K design and equipment premium.	23	FEMP Fact Sheet, "How to Buy an Energy	$24,091.24	$0.0775
73	Existing	Market Driven	Space Cooling	Chiller Tune Up/Diagnostics - 300 ton	25,207	CT estimate x ratio of CDD; CT estimate: GDS calculation of base use of 0.8 KW/ton chiller and 1,091 EFLH estimate for CT as used in chiller replacement. California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-3.	$5,100	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-3. $17/ton	10	California Statewide Commercia	$671.75	$0.0266
74	Existing	Market Driven	Space Cooling	Chiller Tune Up/Diagnostics - 500 ton	25,207	CT estimate x ratio of CDD; CT estimate: GDS calculation of base use of 0.8 KW/ton chiller and 1,091 EFLH estimate for CT as used in chiller replacement. California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-3.	$8,500	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-3. $17/ton	10	California Statewide Commercia	$1,119.58	$0.0444
75	New	Market Driven	Space Cooling	Cooling Circ. Pumps - VSD	3,486	GDS Calculation. 20 HP chilled water pumps per 500 tons chiller capacity (based on FEMP case study, Internal Revenue Service, Fresno, Aug 2001).	$6,280	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-3.	20	Northeast Utilities, Action	$518.99	$0.1489
76	New	Market Driven	Space Cooling	DX Packaged System, EER=10.9, 10 tons	4,818	CT estimate x ratio of CDD; CT estimate: GDS Calculation. Maine Cost Effectiveness Model, March 2003 as reality check.	$607	Maine Cost Effectiveness Model, March 2003.	15	Maine Cost Effectiveness Model,	$59.87	$0.0124
77	Existing	Market Driven	Space Cooling	DX Packaged System, CEE Tier 2, <20 Tons	7,226	CT estimate x ratio of CDD; CT estimate: GDS Calculation. Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12 as reality check.	$910	Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	15	Northeast Energy Efficiency	$89.76	$0.0124
78	Existing	Market Driven	Space Cooling	DX Packaged System, CEE Tier 2, >20 Tons	14,453	CT estimate x ratio of CDD; CT estimate: GDS Calculation. Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	$1,813	Northeast Energy Efficiency Partnership, Energy Efficiency Standards, Summer 2002, p. 12.	15	Northeast Energy Efficiency	$178.83	$0.0124
79	Existing	Market Driven	Space Cooling	DX Tune Up/ Advanced Diagnostics	3,110	CT estimate x ratio of CDD; CT estimate: 10 % savings per California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-3. Assumes 1.5 KW/ton. 1,091 EFLH, and 10 ton unit.	$340	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002. 20 ton chiller, C.1-3.	2		$183.76	$0.0591
80	Existing	Market Driven	Space Cooling	Packaged AC - 3 tons, Tier 1	918	CT estimate x ratio of CDD; CT estimate: "Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	$138	"Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	15	National Grid, 2000 Design	$13.61	$0.0148
81	Existing	Market Driven	Space Cooling	Packaged AC - 3 tons, Tier 2	1,273	CT estimate x ratio of CDD; CT estimate: "Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	$207	"Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	15	National Grid, 2000 Design	$20.42	$0.0160
82	Existing	Market Driven	Space Cooling	Packaged AC - 7.5 tons, Tier 1	2,056	CT estimate x ratio of CDD; CT estimate: "Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	$405	"Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	15	National Grid, 2000 Design	$39.95	$0.0194
83	Existing	Market Driven	Space Cooling	Packaged AC - 7.5 tons, Tier 2	2,890	CT estimate x ratio of CDD; CT estimate: "Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	$607	"Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	15	National Grid, 2000 Design	$59.87	$0.0207
84	Existing	Retrofit	Space Cooling	Packaged AC - 7.5 tons, Tier 1	6,202	CT estimate x ratio of CDD; CT estimate: Calculation of base use from 7.5 EER existing system (average efficiency of 1980's vintage unit, ARI, 1997). Per unit incremental Costs and Savings of High Efficiency Packaged Commercial A/C. ACEEE 2000.	$6,105	$760 per ton estimate for air cooled units from tristate.apogee.net/cool/cmnch.asp. With incremental cost from above added	15	National Grid, 2000 Design	$602.17	$0.0971
85	Existing	Retrofit	Space Cooling	Packaged AC - 7.5 tons, Tier 2	7,036	CT estimate x ratio of CDD; CT estimate: Calculation of base use from 7.5 EER existing system (average efficiency of 1980's vintage unit, ARI, 1997). Per unit incremental Costs and Savings of High Efficiency Packaged Commercial A/C. ACEEE 2000.	$6,307	$760 per ton estimate for air cooled units from tristate.apogee.net/cool/cmnch.asp. With incremental cost from above added	15	National Grid, 2000 Design	$622.09	$0.0884

Appendix B: Input Assumptions - Commercial Energy Efficiency Measures

#	Commercial Market Segment	Retrofit or Market Driven	End Use	Measure Name	Annual kWh Savings	kWh Savings Source	Incremental Cost	Cost Source	Measure Life	Measure Life Source	Annualized cost	Levelized cost per kWh saved
86	Existing	Market Driven	Space Cooling	Packaged AC - 15 tons, Tier 1	3,827	CT estimate x ratio of CDD; CT estimate: "Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	$791	"Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	15	National Grid, 2000 Design	$78.02	$0.0204
87	Existing	Market Driven	Space Cooling	Packaged AC - 15 tons, Tier 2	6,606	CT estimate x ratio of CDD; CT estimate: "Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	$1,516	"Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C", ACEEE 2000	15	National Grid, 2000 Design	$149.53	$0.0226
88	Existing	Market Driven	Space Cooling	Economizer, Single Set Point Dry Bulb	5,970	CT estimate x ratio of CDD; CT estimate: Economizer Spreadsheet from CL&P. 30 ton cooling load. Hartford, CT	$1,500	E-source Technology Atlas 2001, p. 6.3.1. $50-100/ton	15	National Grid, 1999 Small C&I	$147.95	$0.0248
89	Existing	Market Driven	Space Cooling	Economizer, Single Set Point Entalpy	15,764	CT estimate x ratio of CDD; CT estimate: Economizer Spreadsheet from CL&P. 30 ton cooling load. Hartford, CT	$2,250	E-source Technology Atlas 2001, p. 6.3.1. $50-100/ton	15	National Grid, 1999 Small C&I	$221.93	$0.0141
90	Existing	Market Driven	Space Cooling	Economizer, Comparitive Enthalpy	28,916	CT estimate x ratio of CDD; CT estimate: Economizer Spreadsheet from CL&P. 30 ton cooling load. Hartford, CT	$3,000	E-source Technology Atlas 2001, p. 6.3.1. $50-100/ton	15	National Grid, 1999 Small C&I	$295.90	$0.0102
91	Existing	Market Driven	Space Cooling	EMS - Chiller 500 ton	82,916	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on TMY data for Hartford from University of Wisconsin Solar Energy Lab, cooling load diversity from"Implications of Measured Commercial Building Loads on Geothermal System Sizing", ASHRAE Annual Meeting, CDH Energy Corp., 1999 (691 E	$30,000	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002. 300 ton chiller, C.1-3.	10	California Statewide Commercial Sector Energy Efficiency	$3,951.45	$0.0477
92	Existing	Market Driven	Space Cooling	Prog. Thermostat	3,110	CT estimate x ratio of CDD; CT estimate: National Grid, 2000 Energy Initiative (Large C&I) Program Data, 2000 DSM Performance Measurement Report, Appendix 3, December 2001	$55	Maine Cost Effectiveness Model, March 2003.	5	National Grid, 2000 Energy	$12.83	$0.0041
				Ventilation								
93	Existing	Market	Ventilation	Fan Motor, 15hp, 1800rpm, 92.4%	1,053	GDS calculation. Maine Cost Effectiveness Model, March 2003 as reality check..	$46	Maine Cost Effectiveness Model, March 2003.	12	Northeast	$5.29	$0.0050
94	Existing	Market	Ventilation	Fan Motor, 40hp, 1800rpm, 94.1%	2,354	GDS calculation. Maine Cost Effectiveness Model, March 2003 as reality check..	$286	Maine Cost Effectiveness Model, March 2003.	12	Northeast	$32.91	$0.0140
95	Existing	Market	Ventilation	Fan Motor, 5hp, 1800rpm, 89.5%	393	GDS calculation. Maine Cost Effectiveness Model, March 2003 as reality check..	$34	Maine Cost Effectiveness Model, March 2003.	12	Northeast	$3.91	$0.0100
96	Existing	Market Driven	Ventilation	Variable Speed Drive Control, 15 HP	12,000	GDS base use Calculation based on 5,000 hrs, 90% motor efficiency, 65% load. 30% savings from California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002.	$3,465	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-3.	20	Northeast Utilities, Action	$286.35	$0.0239
97	New	Market Driven	Ventilation	Variable Speed Drive Control, 40 HP	32,000	GDS base use Calculation based on 5,000 hrs, 90% motor efficiency, 65% load. 30% savings from California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002.	$6,280	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-3.	20	Northeast Utilities, Action	$518.99	$0.0162
98	New	Market Driven	Ventilation	Variable Speed Drive Control, 5 HP	4,000	GDS base use Calculation based on 5,000 hrs, 90% motor efficiency, 65% load. 30% savings from California Statewide Commercial Sector Energy Efficiency Potential Study, July 2002.	$1,925	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-3.	20	Northeast Utilities, Action	$159.08	$0.0398
99	Existing	Market Driven	Ventilation	Heat Recovery	203,300	CT estimate x ratio of CDD; CT estimate: GDS Calculation based on Hartford TMY data and assuming 80% energy recovery (cooling only)	$400,000	WI Focus on Energy Cost Data (VA Hospital)	23		$30,640.68	$0.1507
100				Exterior Lighting								
101	Existing	Market	Exterior	Outdoor Lighting Controls (Photocell/Timeclock)	165	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-2, GDS	$108	California Statewide Commercial Sector Energy Efficiency	15	California	$10.65	$0.0646
102	Existing	Market	Exterior	ROB 2L4'T8, 1EB	72	GDS calculation. 3,000 hrs vs. 34 w T12.	$27	Maine Cost Effectiveness Model, March 2003.	9	Northeast	$3.86	$0.0536
103	Existing	Market	Heating	Hydronic Heating Pump VFD	10,875	National Grid, 2000 Energy Initiative Program Data, 2000 DSM Performance Measurement Report,	$3,465	California Statewide Commercial Sector Energy Efficiency	20	Northeast	$286.35	$0.0263
				Office equipment								
104	Existing	Market Driven	Office Equipment	External hardware control	146	Electricity Used by Office Equipment and Network Equipment in the U.S.: Detailed Report and Appendices, LBL, Feb. 2001, p. 7, and California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-5.	$173	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-5.	4	California Statewide Commercia	$49.19	$0.3369
105	Existing	Market Driven	Office Equipment	Nighttime shutdown - Laptop	13	Electricity Used by Office Equipment and Network Equipment in the U.S.: Detailed Report and Appendices, LBL, Feb. 2001, p. 7, and California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-5.	$0	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-5.	4	California Statewide Commercia	$0.00	$0.0000
106	Existing	Market Driven	Office Equipment	Nighttime shutdown - Desktop	115	Electricity Used by Office Equipment and Network Equipment in the U.S.: Detailed Report and Appendices, LBL, Feb. 2001, p. 7, and California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.2-5.	$0	California Statewide Commercial Sector Energy Efficiency Potential Study, July, 2002, C.1-5.	4	California Statewide Commercia	$0.00	$0.0000
107	Existing	Market Driven	Office Equipment	Power Management Enabling	201	Energy Star web site, savings calculator using default assumptions (55% already have power management enabled)	$4	Energy Star Power Management Program, assume range of IT staff time of 9-40 hours @ $100/hr. Average of 20 hours used for 500 computer project per discussion with Energy Star staff 4/11/03.	4	Energy Star Power Manageme nt	$1.14	$0.0056
108	New	Market Driven	Office Equipment	Purchase LCD monitor	77	ENERGY EFFICIENCY AND CONSERVATION MEASURE RESOURCE ASSESSMENT FOR THE RESIDENTIAL, COMMERCIAL, INDUSTRIAL AND AGRICULTURAL SECTORS. Prepared for the Energy Trust of Oregon, Inc. By Ecotope, Inc., ACEEE, and Tellus Institute, Inc.	$200	ENERGY EFFICIENCY AND CONSERVATION MEASURE RESOURCE ASSESSMENT FOR THE RESIDENTIAL, COMMERCIAL, INDUSTRIAL AND AGRICULTURAL SECTORS.	4	California Statewide Commercia l Sector	$56.86	$0.7385
				Other								
109	Existing	Market Driven	Other	Dry Type Transformers	30	Thomas, Alison Department of Energy, Federal Energy Management Program, "Replacing Distribution Transformers - A Hidden Opportunity for Energy Savings" http://www.dc.lbl.gov/Replacing%20Distribution%20Transformers.pdf	$11	Thomas, Alison Department of Energy, Federal Energy Management Program, "Replacing Distribution Transformers A Hidden Opportunity for Energy Savings"	30	Northeast Energy Efficiency	$0.72	$0.0241

APPENDIX C

Appendix C - Industrial Energy Efficiency Measures			
Count	Measure Name	2003-$ CCE	Measure Life
1	Near Net Shape Casting	($0.093)	15
2	Injection Moulding - Impulse Cooling	($0.060)	12
3	Intelligent extruder (DOE)	($0.028)	10
4	Clean rooms - Controls	($0.025)	10
5	Process Controls (batch + site)	($0.023)	10
6	Machinery	($0.019)	10
7	Machinery	($0.014)	10
8	Machinery	($0.014)	10
9	Machinery	($0.014)	10
10	Machinery	($0.014)	10
11	Compressed Air - System Optimization	($0.013)	10
12	O&M/scheduling spinning machines	($0.012)	10
13	Scheduling	($0.008)	10
14	Optimize drying process	($0.007)	10
15	O&M - Extruders/Injection Moulding	($0.006)	12
16	Compressed Air- Sizing	($0.005)	10
17	Efficient practices printing press	($0.004)	20
18	Efficient Machinery	($0.004)	10
19	Optimization (painting) process	($0.003)	10
20	Pumps - System Optimization	($0.002)	10
21	Pumps - Sizing	($0.001)	10
22	Fans- Improve components	($0.001)	10
23	Process control	($0.001)	10
24	Switch-off/O&M	$0.001	8
25	New transformers welding	$0.004	15
26	New transformers welding	$0.004	15
27	New transformers welding	$0.004	15
28	New transformers welding	$0.004	15
29	Pumps - O&M	$0.005	10
30	Fans - O&M	$0.005	10
31	Setback temperatures (wkd/off duty)	$0.005	10
32	Bakery - Process (Mixing) - O&M	$0.005	10
33	Replace V-belts	$0.005	5
34	Compressed Air-O&M	$0.005	10
35	Efficient Refrigeration - Operations	$0.005	10
36	Curing ovens	$0.006	15
37	ASD (6-100 hp)	$0.006	10
38	Heat Pumps - Drying	$0.007	15
39	Efficient Printing press (fewer cylinders)	$0.007	10
40	Bakery - Process	$0.007	15
41	Optimization (painting) process	$0.007	10
42	Optimization Process	$0.007	10
43	Optimization (painting) process	$0.007	10
44	Air conveying systems	$0.007	14
45	Efficient processes (welding, etc.)	$0.008	15
46	Scheduling	$0.008	10
47	Scheduling	$0.008	10
48	Scheduling	$0.008	10
49	Scheduling	$0.008	10
50	Pumps - Controls	$0.008	10
51	Curing ovens	$0.008	15
52	Curing ovens	$0.008	15
53	Curing ovens	$0.008	15
54	Curing ovens	$0.008	15
55	Replace V-Belts	$0.009	10

Appendix C - Industrial Energy Efficiency Measures

Count	Measure Name	2003-$ CCE	Measure Life
56	Compressed Air - Controls	$0.010	10
57	Optimization Refrigeration	$0.010	15
58	Energy Star Transformers	$0.010	25
59	Top-heating (glass)	$0.011	8
60	Process Control	$0.011	15
61	Motor practices-1 (100+ HP)	$0.013	6
62	High-efficiency motors	$0.014	10
63	Efficient drives	$0.014	10
64	Efficient drives - rolling	$0.014	10
65	Membranes for wastewater	$0.015	15
66	Motor practices-1 (6-100 HP)	$0.015	10
67	Drives - EE motor	$0.016	10
68	Fans - System Optimization	$0.017	10
69	Optimization control PM	$0.018	10
70	Scheduling	$0.018	10
71	High Consistency forming	$0.018	20
72	Process control	$0.018	15
73	Electronic Ballasts	$0.019	12
74	ASD (100+ hp)	$0.020	6
75	Metal Halides/Fluorescent	$0.021	12
76	Drying (UV/IR)	$0.022	8
77	High efficiency motors	$0.024	6
78	Gap Forming paper machine	$0.024	20
79	Replace by T8	$0.025	12
80	Controls/sensors	$0.027	12
81	Autoclave optimization	$0.027	10
82	Process Drives - ASD	$0.028	10
83	Process Heating	$0.028	15
84	Drives - ASD	$0.029	10
85	HVAC Management System	$0.030	10
86	Programmable Thermostat	$0.030	10
87	Clean Room - Controls	$0.030	10
88	Efficient electric melting	$0.031	20
89	Duct/Pipe Insulation/leakage	$0.033	10
90	Window film	$0.037	8
91	Motor practices-1 (1-5 HP)	$0.038	14.5
92	Injection Moulding - Direct drive	$0.039	12
93	Extruders/injection Moulding-multipump	$0.040	12
94	Fans - Controls	$0.042	10
95	Chiller O&M/tune-up	$0.042	10
96	Light cylinders	$0.053	10
97	Direct drive Extruders	$0.055	12
98	Replace 100+ HP motor	$0.057	6
99	Clean Room - New Designs	$0.060	10
100	Efficient grinding	$0.078	15

APPENDIX D

Appendix D - Database of Data Sources - Energy Efficiency Technical Potential Studies Recently Conducted

	STATE	Name of Technical Potential Study	Date Study Completed (Date on the final report)	Sponsoring Organization	Final Study Report Available to GDS in electronic or hard copy	Study Completed by Who (What Consultant)	Estimate of maximum technical potential for energy efficiency developed? (Yes or No)
1	Washington	Assessment of Long Term Electricity and Natural Gas Conservation Potential in Puget Sound Energy Service Area 2003-2024	August-03	Puget Sound Energy	Electronic	KEMA-Xenergy/Quantec	Yes
2	Connecticut	Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region	June-04	Connecticut Energy Conservation Management Board	Both	GDS Associates, Inc.	Yes
3	Wisconsin	Wisconsin Tech Potential	1994	Public Service Commission of Wisconsin	Electronic	Energy Center of WI	Yes
4	New York	Energy Efficiency and Renewable Energy Resource Develop Potential in New York State	2003	NYSERDA	Electronic	Optimal Energy	Yes
5	Minnesota	The Energy Conservation Potential for Retro-Commissioning in Xcel Energy's Minnesota Area	2003	Xcel Energy	Electronic	Summit Blue	Yes
6	California	California's Secret Energy Surplus: The Potential For Energy Efficiency - Final Report"	Sep-02	The Energy Foundation and The Hewlett Foundation	Electronic	Xenergy, Inc.	Yes
7	Arizona, Colorado, Nevada, New Mexico, Utah, Wyoming	The Mother Lode, The Potential for More Efficient Energy Use in the Southwest	Nov-02	Southwest Energy Efficiency Project (SWEEP)	Electronic	SWEEP along with the American Council for an Energy-Efficient Economy, Robert Mowris and Associates, the Etc Group, Inc., and MRG & Associates	Yes
8	California	California Statewide Residential Sector Energy Efficiency Potential Study	Apr-05	PG & E	Electronic	Xenergy, Inc.	Yes

Appendix D - Database of Data Sources - Energy Efficiency Technical Potential Studies Recently Conducted

	STATE	Name of Technical Potential Study	Date Study Completed (Date on the final report)	Sponsoring Organization	Final Study Report Available to GDS in electronic or hard copy	Study Completed by Who (What Consultant)	Estimate of maximum technical potential for energy efficiency developed? (Yes or No)
9	Vermont	Electric and Economic Impacts of Maximum Achievable Statewide Efficiency Savings; 2003-2012 - Results and Analysis Summary	May-02	Vermont Department of Public Service	Electronic	Optimal Energy	Yes
10	Massachusetts	The Remaining Electric Efficiency Opportunities in Massachusetts	Jun-01	Program Admins. & Mass. Division of Energy Resources	Electronic	RLW Analytics, Inc. & Shel FeldmanManagement Consulting.	No
11	Georgia	Assessment of Engery Efficiency Potential in Georgia-Final Report	May-05	Division of Energy Resources, GEFA	Electronic	Val Jensen and Eric Lounsbury of IFC Consulting	Yes
12	Oregon	Energy Efficiency and Conservation Measure Resource Assessment for the Residential, Commercial, Industrial, and Agricultural Sectors	Jan-03	Energy Trust of Oregon	Electronic	Ecotope	Not Available
13	Utah	The Maximum Achievable Cost Effective Potential for Gas DSM for Questar Gas	Jun-04	Utah Energy Office and Questar Gas Company	Both	GDS Associates, Inc.	Yes
14	New Mexico	The Maximum Achievable Cost Effective Potential for Natural Gas Energy Efficiency in the Service Terriroty of PNM	May-05	Public Service of New Mexico	Both	GDS Associates, Inc.	Yes
15	Service Area of Big Rivers Electric Corporation in Kentucky	2002 Big Rivers Electric Corporation DSM Report	Nov-02	Big Rivers Electric Corporation	Both	GDS Associates, Inc.	Yes
16	National Meta Analysis	The Technical, Economic and Achievable Potential for Energy Efficiency in the US - A Meta Analysis of Recent Studies	Aug-04	American Council for an Energy Efficient Economy - Summer Study on Building Energy Efficiency	Both	ACEEE	Yes

Appendix D - Database of Data Sources - Relevant Residential Sector Studies and Reports

Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
1	California Statewide Residential Sector Energy Efficiency Potential Study (ID #SW063) Final Report; Volume 1	April-03	165	Coito, Fred; Rufo, Mike KEMA-XENERGY Inc.	Pacific Gas & Electric Company	Residential	Efficiency Potential Study	California	Yes/PDF
2	California Statewide Residential Sector Energy Efficiency Potential Study (ID #SW063) Final Report; Volume 2 (Appendices)	April-03	232	Coito, Fred; Rufo, Mike KEMA-XENERGY Inc.	Pacific Gas & Electric Company	Residential	Efficiency Potential Study	California	Yes/PDF
3	NJ Appliance/Window	March-01	125	RLW	GPU Energy, PSE&G, Conectiv, NJ NG, Elizabethtown Gas, So Jersey Gas, and Rockland Electric	Residential	Baseline	New Jersey	Yes/PDF
4	NJ Res HVAC	November-01	152	Xenergy, Inc	Xenergy and NJ Res HVAC Working Group	Residential	Baseline	New Jersey	Yes/PDF
5	NJ Statewide EE Market Assessment	August-99	77	Xenergy, Inc	Xenergy and NJ Utilities Working Group	All	Market Assessment	New Jersey	Yes/PDF
6	So Cal Gas EE Program Report	May-03	64	Sempra Energy/SoCal Gas	Sempra Energy/SoCal Gas	Residential	Annual Report	So. Cal.	Yes/PDF
7	So Cal Gas LI Program Report	May-03	24	Sempra Energy/SoCal Gas	Sempra Energy/SoCal Gas	Residential	Annual Report	So. Cal.	Yes/PDF
8	Natural Gas Price and Availability Effects of Aggressive Energy Efficiency and Renewable Energy Policies: A Methodology White Paper	December-03	98	Elliot, R; Shipley, A; Nadel, S; Brown, E	ACEEE	All	Whitepaper	National	Yes/PDF
9	Recent Trends in WI Residential Gas Use	August-99	76	Scott Pigg, Rich Hasselman	Energy Center of WI	Residential	Baseline	Wisconsin	Yes/PDF
10	Appliance Sales Tracking: 1999 Residential Survey	March-02	190	ODC	Energy Center of WI	Residential	Sales Tracking	Wisconsin	Yes/PDF

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11	Selecting Targets for Market Transformation Programs, A National Analysis	August-98	174	Suozzo, M; Nadel, S	ACEEE	All	Market Research	National	No
12	Gas Appliance Manufacturers Association (GAMA)	October-05	14	n/a	GAMA	All	Water Heater Ratings	National	Yes/PDF
13	Technology Forecast Updates - Residential and Commercial Building Technologies	September-04	n/a	Navigant Consulting	U.S. DOE/EIA	All	Technology Forecast	National	Yes
14	Policies and Programs for Expanding the Use of High Efficiency Fenestration Products in Homes in the Southwest	September-04	18	Howard Geller	SWEEP	Residential	Whitepaper	Southwestern States	Yes/PDF
15	Increasing Energy Efficiency in the Southwest	August-03	115	Larry Kinney, Howard Geller, Mark Ruzzin	SWEEP	All	Whitepaper	Southwestern States	Yes/PDF
16	Utility Energy Efficiency Policies in the Southwest	September-04	12	Howard Geller	SWEEP	All	Whitepaper	Southwestern States	Yes/PDF
17	Energy Star Clothes Washer and Dishwasher Promotion and Incentives for Utah	Oct-02		Howard Geller	Utah Energy Office	Residential	Evaluation	Utah	Yes/PDF
18	Impact Evaluation of the Massachusetts, Rhode Island, and Vermont 2003 Residential Lighting Programs	Jun-05		Nexus Market Research and GDS Associates, Inc.	Joint Management Committee of the New England Energy Star Homes Program	Residential	Evaluation	Massachusetts, Rhode Island, and Vermont	Yes/PDF
19	Incemental Cost of Compact Flourescent Lighting	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	In store research at Home Depot	National	Not applicable
20	Residential Torchiere Assumptions" from Energy Star's "Torchiere Savings Calculator. www.EnergyStar.gov	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes
21	"Alternatives to Halogen Torchieres" on the Lighting Research Center's website (www.lrc.rpi.edu)	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes

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Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
22	kWh and Incremental Cost data for Energy Star Single-Room, Window-Mounted Air Conditioning Units on Sears website (www.sears.com)	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes
23	Independent assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwest Connecticut Region	June-04	92	GDS Associates & Quantum Consulting	Conneticut ECMB	All	Efficiency Potential	Conneticut	Yes/PDF
24	Home Appliance Saturation and Length of First Ownership Study	May-01	61	NFO Worldgroup	Assoc. of Home Applianc Manufacturers (AHAM)	Residential	Appliance Saturation Report	National	No
25	Statewide Refrigerator Monitoring and Verification Study & Results (Conference Paper Presented at 2004 ACEEE Summer Study on Building Energy Efficiency)	January-04	n/a	Dana Teague (NSTAR Electric & Gas) and Michael Blasnik	ACEEE	Residential	Conference Paper	National	Yes
26	Incremental Cost of Energy Star Refridgerator Models. In-store research at Sears Company.	Summer 05	not applicable	GDS Associates Consultant	not applicable	Residential	In store research at Sears	National	Not applicable
27	Regional Energy Profile: East South Central Appliance Report 2001	/01	n/a	Energy Information Administration	Energy Information Administration, Dept. of Energy	Residential	Profile	Regional	Yes
28	kWh and Incremental Cost data for Energy Star Upright Freezer Models on Lowe's website (www.lowes.com)	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes
29	kWh and Incremental Cost data for Energy Star Chest Freezer Models on the Home Depot website (www.homedepot.com)	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes
30	kWh and Incremental Cost data for Energy Star Dishwasher Models on Sears website (www.sears.com)	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes

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Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
31	The Maximum Achievable Cost Effective Potential for Natural Gas Demand Side Management in the Service Territory of PNM	May-05	157	GDS Associates	PNM	All	Cost Effective Potential Study	New Mexico	Yes/PDF
32	Incremental Cost of Water Heater Blankets derived from listings at Home Depot (www.homedepot.com) and Lowe's (www.lowes.com)	Summer-05	not applicable	Research by GDS Consultant	not applicable	Residential	website	National	Yes
33	State of the Art of Residential Fuel Cells, Market, and Implementation Issues	June-01	3	E. A. Torrero and R. H. McClelland	EPA	Residential	Evaluation	National	Yes/PDF
34	Meeting the Challenge: The Prospect of Achieving 30 Percent Energy Savings Through the Weatherization Assistance Program	May-02	64	Mark Schweitzer and Joel F. Eisenberg (ORNL)	Dept. of Energy.	Residential	Evaluation	National	Yes/PDF
35	2004 Poverty Income Guidelines, Contiguous U.S. Grantees, Effective February 13, 2004 from http://aspe.hhs.gov/poverty/shtml	February-04	not applicable	Department of Health and Human Services	Department of Health and Human Services	Residential	website	National	Yes
36	Detailed Demographic Update: 2004/2009 (for the BREC Service Area) - Compiled in June 2005 by GDS, from Scan/US Inc website	June-05	6	Research by GDS Consultant	BREC	All	website	BREC Service Area	Yes
37	Energy 10 Model Simulations	Summer 2005	Numerous Model Runs	Research by GDS Consultant	BREC	Residential	Energy 10 Model	Residental	Yes

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1	NJ Electric & Gas Utilities: Comm EE Construction Baseline Study: Task 1 Final Report: On-Site Survey of New Construction & Renovation Projects	January-00	101	RLW	Atlantic, PSE&G, GPU	C/I	Baseline	NJ	Yes/PDF
2	NJ Electric & Gas Utilities: Comm EE Lighting and HVAC Baseline Study: Task II Report Decision-Maker Interviews	February-00	16	Roper Starch, RLW	Atlantic, PSE&G, GPU	C/I	Baseline	NJ	Yes/PDF
3	NJ Electric & Gas Utilities: Comm EE Lighting and HVAC Baseline Study Task III Report: Equipment Replacement and Remodeling Interviews	February-00	24	RLW	Atlantic, PSE&G, GPU	C/I	Baseline	NJ	Yes/PDF
4	R.S. Means Construction Cost Estimation Data	2004	CD-ROM	RS Means	--	All	Construction Costs	National (w/ city level detail)	Yes
5	Database for Energy Efficient Resources (DEER) 2001 Update	2001	NA	Xenergy and others	California Energy Commission	All	Efficiency Measure Database	California	Yes
6	EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case	September-04	69	Navigant Consulting	EIA	Commercial	Market Research	National	Yes
7	Methodology and Forecasts of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs	Oct-04	290	Energy and Environmenal Economics, Inc.	California Public Utilities Comission	All	Forecast	California	Yes/PDF
8	2000 Energy Initiative Program (Large C&I) Data, 2000 DSM Performance Measurement Report	01/01/00		National Grid		C/I	Performance Measurement Report	Massachusetts	No
10	Alternatives to Energy Hogging Halogen Torchieres Invented here (http://www.lbl.gov/Science-Articles/Archive/fluorescent-torchiere.html) (Article on LBL website)	6/12/1997	not applicable	Chen, Allen	Lawrence Berkley Lab	Residential	website article	National	Yes

Appendix D - Database of Data Sources - Relevant Commercial Sector Studies and Reports

Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
11	Selecting Targets for Market Transformation Program: A National Analysis	Aug-98	200	ACEEE	Consortium for Energy Efficiency	All	Report	National	Yes/PDF
12	California Statewide Commercial Sector Energy Efficiency Potential Study	Jul-02		Xenergy, Inc.	California Energy Commission	Commercial	Efficiency Potential	California	Yes/PDF
14	Pulse Start Metal Halide Lamps	1999	1	Energy Center of Wisconsin	Energy Center of Wisconsin	All	Fact Sheet on Metal Halide Lamps	National	Yes/PDF
15	How to Buy Energy Efficient Commercial Downlight Luminaires	2004	2	Federal Emergency Management Program	Federal Energy Management Program	All	Fact Sheet	National	Yes/PDF
16	Energy Efficiency Standards, Summer 2002	2002			Northeast Energy Efficiency Partnership	All			
17	Northeast Utilities C&I Persistence Study Final Report	Oct-01	47	RLW Analytics	Northeast Utilities	C/I	Report	Northeast Utilities Service Area	No
18	Northeast Utilities Vending Miser Monitoring Project Final Report	Apr-01	22	The Nicholas Group P.C.	Northeast Utilities	Commercial	Report	Northeast Utilities Service Area	No
19	USA Technologies, formerly Bayview Technology Group, Miser Products Price List	2-Sep							
21	Motorup Evaluation and Market Assessment	Nov-01	93	Motorup Working Group	Xenergy Inc.	Commercial	Market Assessment	Vermont	Yes/PDF
22	Grainger Industrial Supply 2005 Catalog	2001	3818	Grainger Industrial Supply	Grainger Industrial Supply	Industrial	Catalog	National	No
23	How to Buy an Energy Efficient Commercial Ice Machine	2000	1	Federal Emergency Management Program	Federal Energy Management Program	Commercial	Fact Sheet	National	Yes/PDF

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Study #	Title of Document	Date of Publication	Number of Pages in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format (Yes/No)?
24	E-source Technology Atlas	2001							
25	Northeast Utilities System 1999 Express Services Program Impact Evaluation Final Report	Jun-01	54	Sabo, C and Griffin, T.	Evans, Kate	C/I	Report	Conneticut and Massachusetts	No
26	Chilled Water Plant Costs Estimated (www.trane.com/commercial/issues/earthwise_systems)		not applicable		Trane Company	Commercial	website	National	Yes
27	LADWP Purchasing Advisor (www.ladwp.com/energyadvisor/PA_14.html)				Los Angeles Deprtment of Water and Power				
28	Per Unit Incremental Costs and Savings of High Efficiency Packaged Commercial A/C	2000	1	ACEEE	ACEEE	Commercial	Fact Sheet	National	Yes/PDF
29	Implications of Measured Commercial Building Loads on Geothermal System Sizing	1999	9	Henderson, Hugh	CDH Energy Corp (ASHRAE Annual Meeting)	Commercial	Report	National	
30	Electricity Used by Office Equipment and Network Equipment in the U.S.: Detailed Report and Appendices	Feb-01	50	Kawamoto, K et al.	LBNL	Commercial	Report	National	Yes/PDF
31	Energy Efficiency and Conservation Measure Resource Assessment for the Residential, Commercial, Industrial, and Agricultural Sectors	2003	115	Ecotope	Energy Trust of Oregon, Inc	All	Technical Potential	Oregon	Yes/PDF
32	Replacing Distribution Transformers - A Hidden Opportunity for Energy Savings	2002	9	Thomas, Alison et al.	Federal Emergency Management Program (Department of Energy)	Commercial	Online Brochure	National	Yes/PDF

Appendix D - Database of Data Sources - Other Documents Reviewed by GDS

File #	Title of Document	Date of Publication	Number of Pages/Tabs in Main Body of Report	Author or Consulting Firm	Organization Publishing the Report	Sector (Residential, Commercial, Industrial)	Type (Program Evaluation, Load Forecast, Market Research Study, Appliance Saturation Survey, Energy Efficiency Plan, etc.)	Market Segment or End Use Targeted by the Report	Report or Study Available to GDS Team in Electronic Format?
24	Low-income Public Purpose Test, (The LIPPT), Final Report, Up-Dated for LIPPT Version 2.0	Apr-01	238	TecMarket Works, Inc, Skumatz Economic Research and Megdal & Assoc.	RRM Working Group		Report		Yes/PDF
25	User's Guide for California Utility's Low-Income Program Cost Effectiveness Model, The Low-Income Public Purpose Test, Version 2.0, A Microsoft Excel Based Model	May-01		TecMarket Works, Inc, Skumatz Economic Research and Megdal & Assoc.	RRM Working Group		Report		Yes/PDF

APPENDIX E

Appendix E.2 - Avoided Costs for Electricity, Natural Gas and Water ($2006)

	General Rate of Inflation (2005-2025)	Avoided Cost for Electricity in Real $2006 Dollars[1] ($/kWh)	Avoided Cost for Transmission in Real $2006 Dollars[2] ($/kW)	Avoided Cost for Natural Gas - Residential Sector[3] - $2006 per mmbtu	Avoided Cost for Natural Gas - Commercial Sector[3] - $2006 per mmbtu	Avoided Cost for Water (Real $2006 per gallon)[4]
2006	0.031	[REDACTED]	$19.20	$10.05	$8.71	$0.00482
2007	0.031	[REDACTED]	$19.20	$9.42	$8.21	$0.00482
2008	0.031	[REDACTED]	$19.20	$8.89	$7.82	$0.00482
2009	0.031	[REDACTED]	$19.20	$8.77	$7.83	$0.00482
2010	0.031	[REDACTED]	$19.20	$8.57	$7.75	$0.00482
2011	0.031	[REDACTED]	$19.20	$8.52	$7.82	$0.00482
2012	0.031	[REDACTED]	$19.20	$8.64	$7.93	$0.00482
2013	0.031	[REDACTED]	$19.20	$8.78	$8.04	$0.00482
2014	0.031	[REDACTED]	$19.20	$8.99	$8.23	$0.00482
2015	0.031	[REDACTED]	$19.20	$9.15	$8.36	$0.00482
2016	0.031	[REDACTED]	$19.20	$9.13	$8.32	$0.00482
2017	0.031	[REDACTED]	$19.20	$9.24	$8.41	$0.00482
2018	0.031	[REDACTED]	$19.20	$9.44	$8.58	$0.00482
2019	0.031	[REDACTED]	$19.20	$9.63	$8.74	$0.00482
2020	0.031	[REDACTED]	$19.20	$9.77	$8.86	$0.00482
2021	0.031	[REDACTED]	$19.20	$9.88	$8.93	$0.00482
2022	0.031	[REDACTED]	$19.20	$9.90	$8.93	$0.00482
2023	0.031	[REDACTED]	$19.20	$9.90	$8.90	$0.00482
2024	0.031	[REDACTED]	$19.20	$9.95	$8.93	$0.00482

1. Power Purchase Agreement between Big Rivers Electric Corporation and LG&E Energy Marketing, Inc, dated 7/15/1998, pages 25-26.

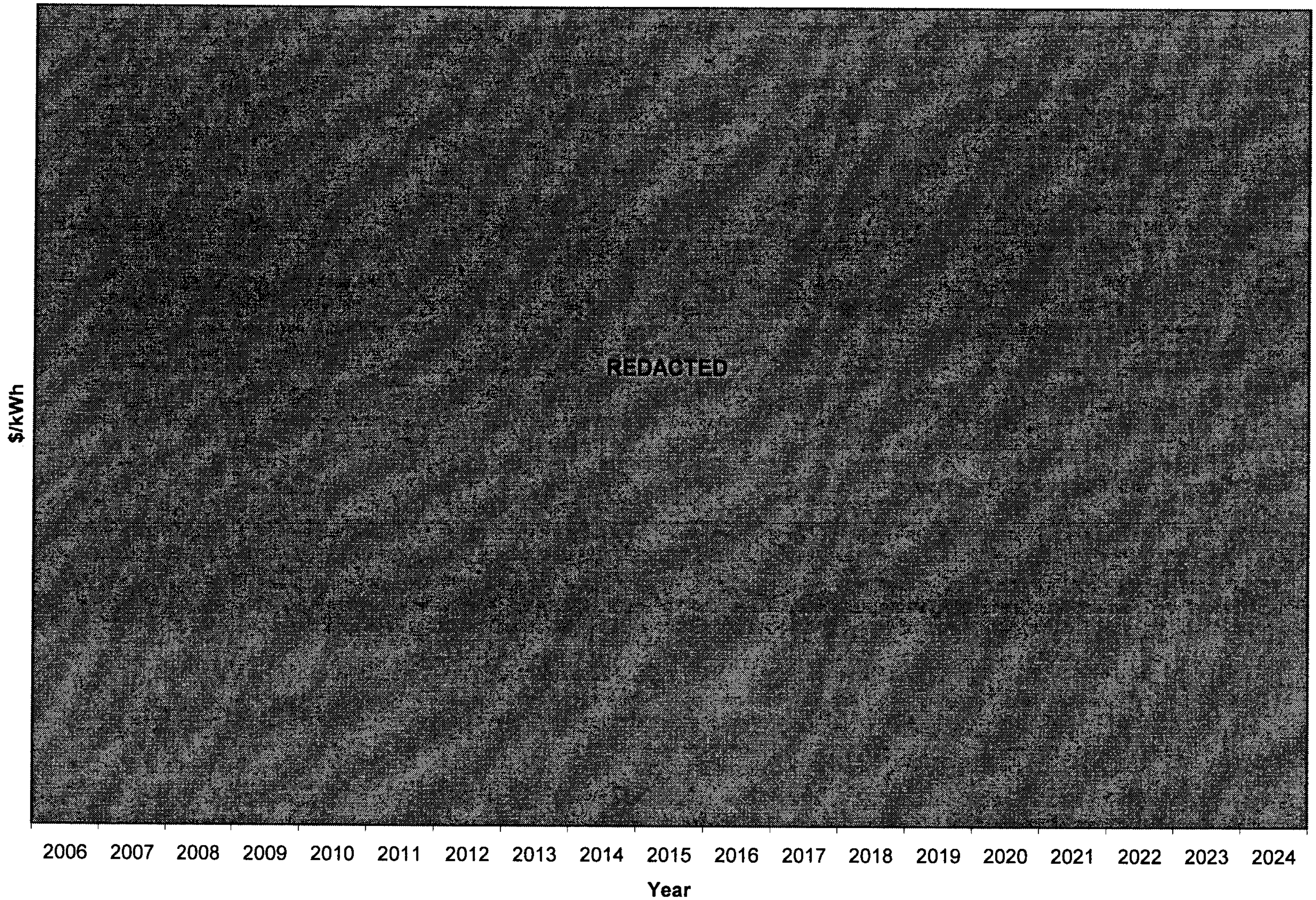
2. Annual Energy Outlook 2005. US Department of Energy, Energy Information Administration. February 2005, page 89, Table 27.

3. Annual Energy Outlook 2005. US Department of Energy, Energy Information Administration. February 2005. Supplemental data tables for energy prices, Table 106.

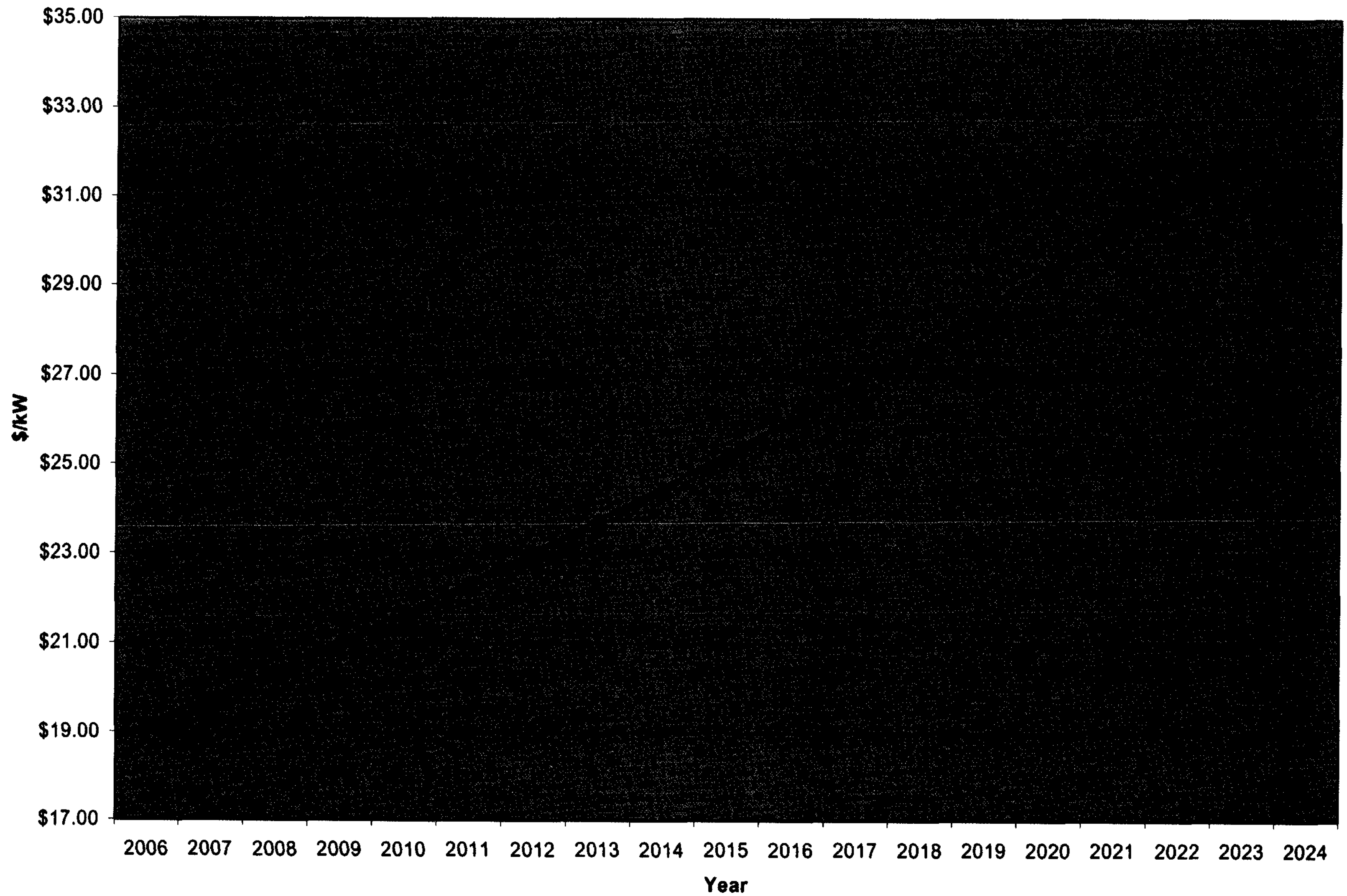
4. Public Service Commision. PSC Rules on Kentucky-American Water Rate Request. <http://www.environment.ky.gov/press/press2005/february2005/2-28kyamericanwater.htm> Accessed 06 Oct 2005.

Appendix E.2 - Avoided Costs for Electricity, Natural Gas and Water (in Nominal Dollars)						
	General Rate of Inflation (2005-2025)	Avoided Cost for Electricity in Nominal Dollars ($/kWh)	Avoided Cost for Transmission in Nominal Dollars ($/kW)	Avoided Cost for Natural Gas - Residential Sector ($/mmbtu)	Avoided Cost for Natural Gas - Commercial Sector ($/mmbtu)	Avoided Cost for Water ($/gal.)
2006	0.031	[REDACTED]	$19.20	$10.05	$8.71	$0.00482
2007	0.031	[REDACTED]	$19.80	$9.71	$8.46	$0.00497
2008	0.031	[REDACTED]	$20.41	$9.45	$8.31	$0.00512
2009	0.031	[REDACTED]	$21.04	$9.61	$8.58	$0.00528
2010	0.031	[REDACTED]	$21.69	$9.69	$8.76	$0.00545
2011	0.031	[REDACTED]	$22.37	$9.92	$9.11	$0.00561
2012	0.031	[REDACTED]	$23.06	$10.37	$9.52	$0.00579
2013	0.031	[REDACTED]	$23.77	$10.87	$9.95	$0.00597
2014	0.031	[REDACTED]	$24.51	$11.48	$10.50	$0.00615
2015	0.031	[REDACTED]	$25.27	$12.04	$11.00	$0.00634
2016	0.031	[REDACTED]	$26.05	$12.39	$11.29	$0.00654
2017	0.031	[REDACTED]	$26.86	$12.93	$11.76	$0.00674
2018	0.031	[REDACTED]	$27.70	$13.61	$12.38	$0.00695
2019	0.031	[REDACTED]	$28.55	$14.32	$13.00	$0.00717
2020	0.031	[REDACTED]	$29.44	$14.98	$13.59	$0.00739
2021	0.031	[REDACTED]	$30.35	$15.61	$14.12	$0.00762
2022	0.031	[REDACTED]	$31.29	$16.14	$14.56	$0.00786
2023	0.031	[REDACTED]	$32.26	$16.63	$14.95	$0.00810
2024	0.031	[REDACTED]	$33.26	$17.23	$15.47	$0.00835

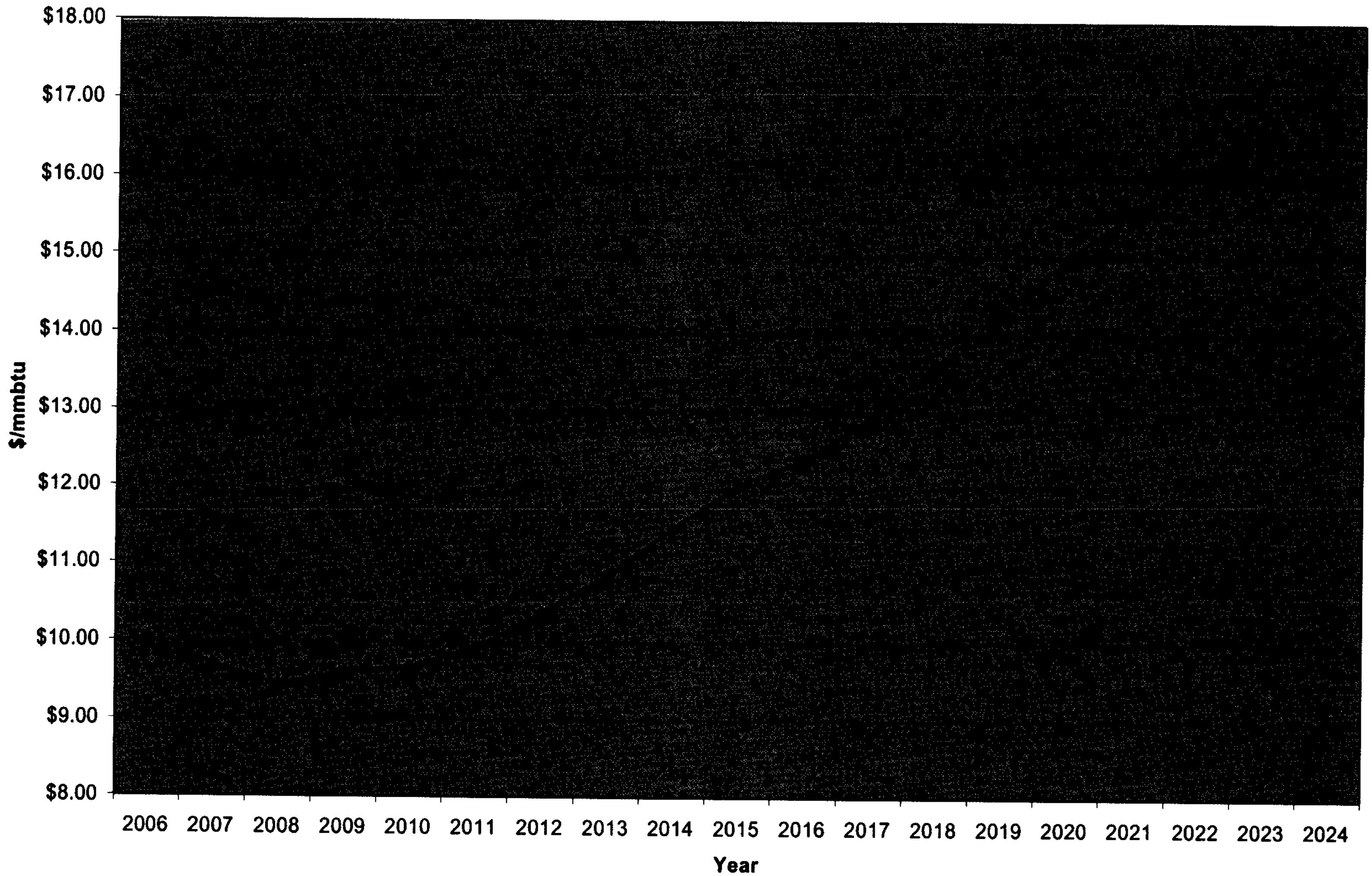
Avoided Cost for Electricity in Nominal Dollars



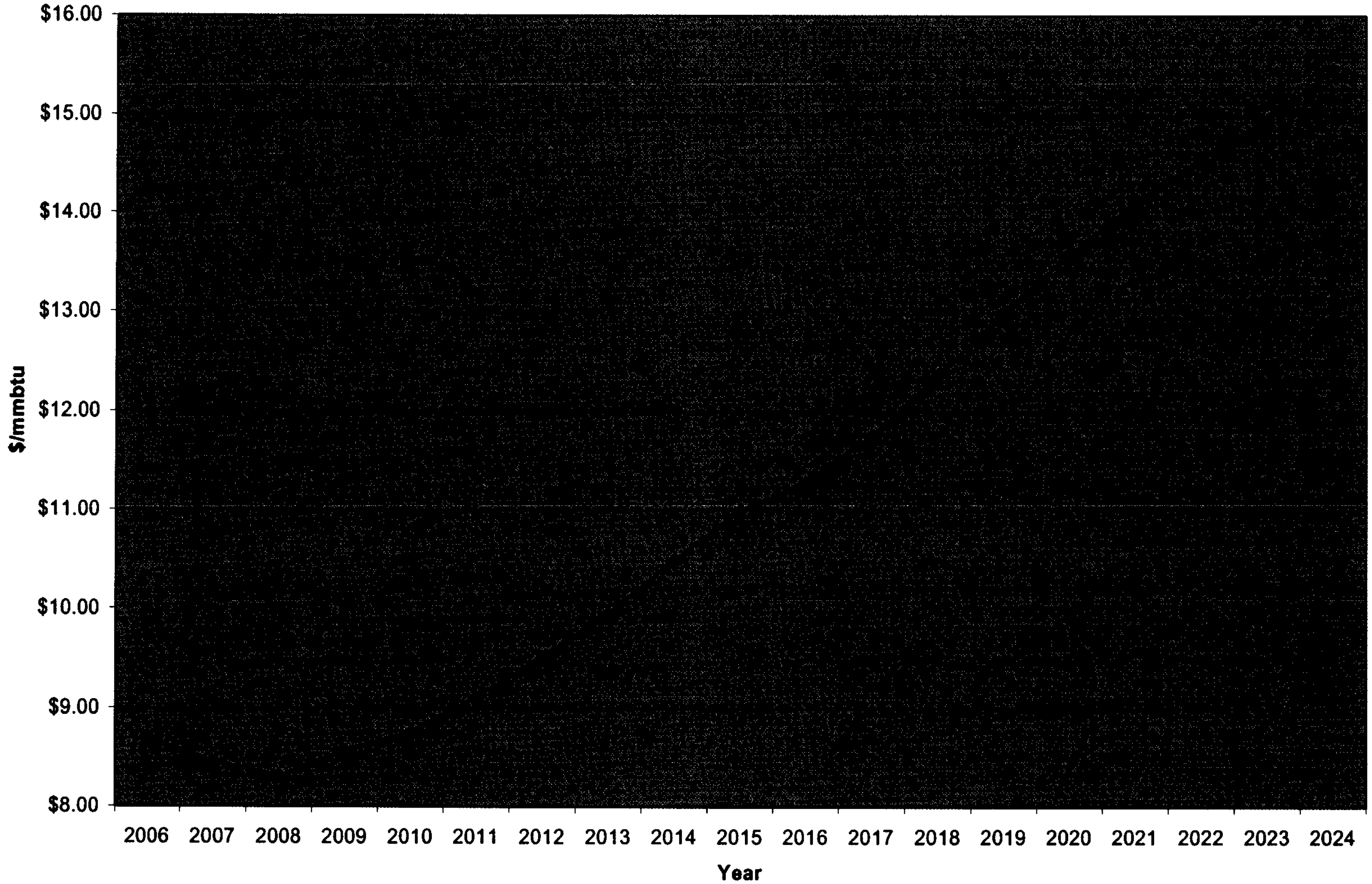
Page 4 - Avoided Cost for Transmission in Nominal Dollars



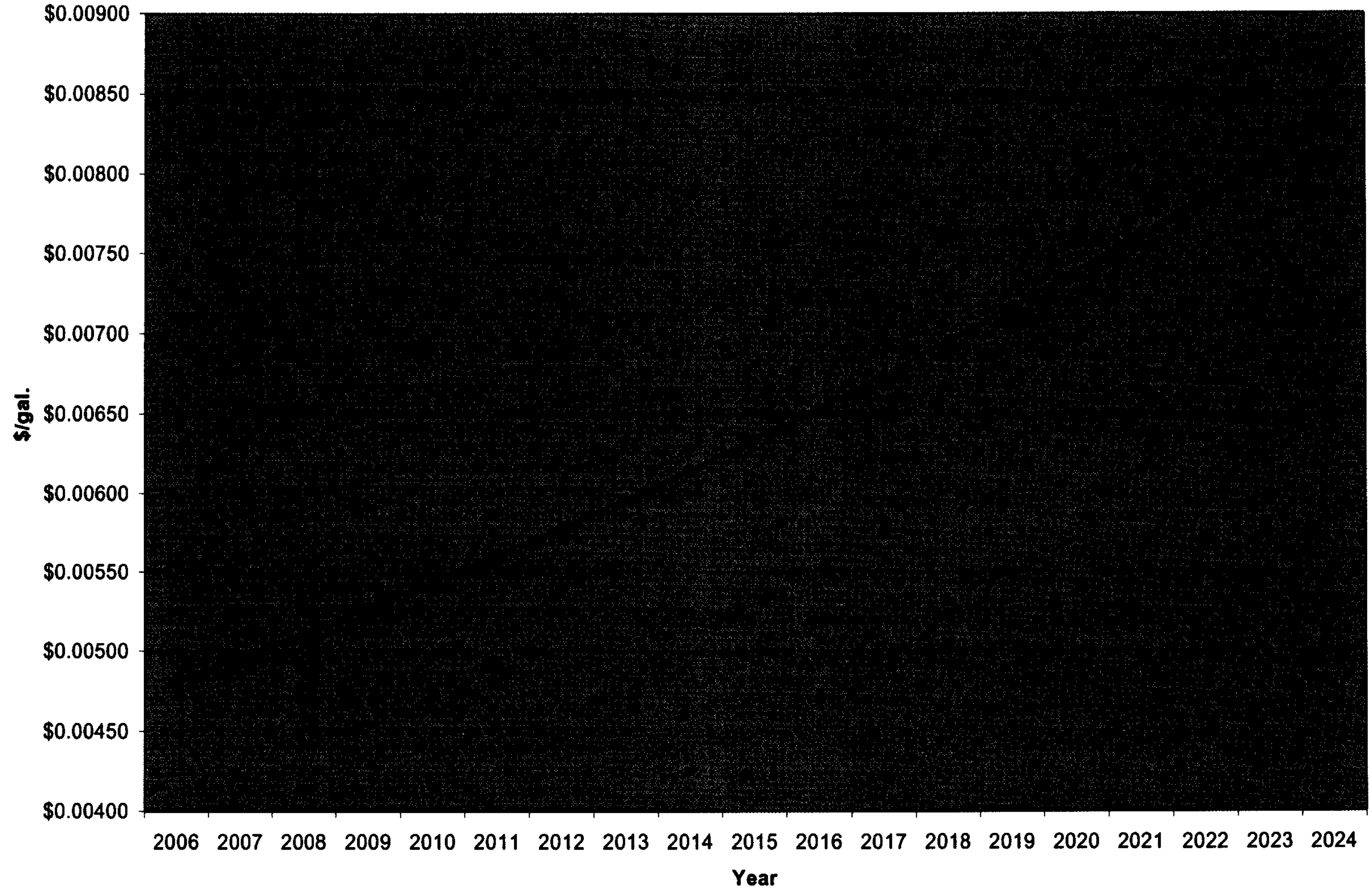
Page 5 - Avoided Costs for Natural (Residential Sector) in Nominal Dollars



Page 6 - Avoided Cost for Natural Gas (Commercial Sector) in Nominal Dollars



Page 7 - Avoided Cost for Water in Nominal Dollars



APPENDIX F

al Report

nd Insulation Services
esearch with
ompanies Serving the
rporation Service Area

2005

Submitted by:

ssociates, Inc.
and Consultants

Suite 800 • Marietta, GA 30067 • www.gdsassociates.com
AL • Manchester, NH • Madison, WI

Results of Interviews with energy services contractors (insulation/weatherization/windows contractors) in the Kentucky service area of the Big Rivers Electric Corporation (BREC).

Questions

1. *During the year 2004, to how many homes did you provide weatherization and insulation services:*

Average: 160
Range: 4 to 750
Number of respondents: 10

Comments:

Mostly do new construction - insulation is part of the job
We mostly do new construction -- have a blower door - used to do energy audits
there is a coop program in our area - Kenergy -- not as good as it used to be with the "All-Seasons Comfort Home"
do more heating and air than insulation

2. *For your residential customers, what is the size of the typical single-family home?*

Average: 1850 sf
Range: 1300-3000 sf; 900-1600 sf renovations
Number of respondents: 9

Comments:

1800-2ksf existing; 2500-3ksf new construction
2300-2400 new const - actually they usually insulate the garages too -- 3000 including garages
average 900-1600 sf. Renovations
now they might average 2000 sf
at least 2000 sf - new construction

3. *What is the size of the typical Multi-family home?*

Average: 1060 sf
Range: 600-2250 sf;
Number of respondents: 7

Comments: none

Attic insulation

4. To how many homes did you add attic insulation in 2004?

Average: 95
Range: 2 to 250
Number of respondents: 9

Comments: none

5. On average, how much insulation do you add to homes needing such insulation? (of what material?)

Survey respondents report that existing homes have inadequate attic insulation. Often there is 4" to 6" of insulation existing and the contractors add 6" to 12" to bring the attic up to R-30, R-38, or R-40.

Average: 9"
Range: 6"to 12"
Number of respondents: 9

Fiberglass: 4 respondents, representing approximately 500 jobs per year
Cellulose: 5 respondents, representing approximately 300 jobs per year

Comments:

Usually find 4-6" existing; add 8-10"
Usually add r-30 on existing to bring total to R-40. Install R40 on new construction
Usually find R-19 and add another R-19 by putting in 6" of blown cellulose
Existing: had rolled fiberglass and we added 12"
They usually have 5-6 inches - we add 6-8 inches to reach R-38 I use Nu.wool; it's a cellulose with fire additives and doesn't support mold growth or insects www.nuwool.com. It comes from Michigan
Generally find 0 to 6" add 6" fiberglass
Finding older homes with R-19 or less - most of the calls are on heating or air conditioning - and attic insulation is the first thing I look at. Bring to R-38
More than anything most of the time I recommend adding R-30 whether they have anything or not

6. What is your best estimate of the installed cost for attic insulation per square foot?

Average: $0.48
Range: $0.26 to $0.60; most common answer was $.50 to $.60
Number of respondents: 7

Comments: none

7. To the best of your knowledge, what percent of existing single-and multi-family homes need additional attic insulation?

Average: 65%
Range: 35% to 85%
Number of respondents: 8

Comments:

It's a bunch - most built back in the late 60's. Even since then a lot of builders don't put enough in. And I'm not a fan of blown fiberglass - when it gets really cold, you use 40% of the R value - blown fiberglass should be capped with cellulose. You can tell by driving around on a cold day - if the frost has melted on the roof then they need more insulation.
if the house is 10 years old or more

Wall insulation

8. During 2004, in how many homes did you install wall insulation?

Average: 50
Range: 0 to 100
Number of respondents: 5 contractors active in this market and 3 who do this type of work but did zero or 1 such job in the past year.

Comments:

Do very few – it is a poor system [blown cellulose] - don't do it very often - can inject into wall - but it settles and doesn't do a good job
most that I've done had no insulation previously or just a little blown-in
A lot of walls don't have anything. Probably 2x4 would be the most common 3.5 inches Didn't do any last year - stay covered up with the new construction . Do that work when new construction slows down.
I do wet-blown on new construction. I have done it in the past - there is a lot of competition - it's hard for a big company to compete with guys who work out of their garage.

9. On average, how much insulation do you add to walls needing such insulation? What insulating material do you normally use in the walls?

Average: 3.5" is most common
Range: 3.5" R-13 for 2x4 construction; 5.5" R-19 for 2x6 construction
Number of respondents: 8

Fiberglass: Represents approximately 60 jobs per year
Cellulose: Represents approximately 250 jobs per year

Comments:
None

10. What is your best estimate of the installed cost for wall insulation per square foot?

Average: (weighted by number of jobs) $0.92/s.f.
Range: $0.55 to $1.30 one volume contractor quoted $0.55/s.f.; remaining volume contractors quoted $1 to $1.3 per square foot.
Number of respondents: 8; 5 who have done this work recently

Comments:
[By surveyor:] There does not seem to be a price difference between fiberglass and cellulose insulation.

11. To the best of your knowledge, what percent of existing single and multi-family homes need additional wall insulation?

Average: 50%
Range: 15% to 95%
Number of respondents: 5

Comments:

not a good application -- the question is moot
if the house is more than 10-15 years old then almost 100%

Floor insulation

12. During 2004, in how many homes did you install floor insulation?

Average: 66
Range: 2 to 150
Number of respondents: 6

Comments:

Don't do floor insulation -- there is duct work under the floor. Instead we insulate the perimeter foundation wall
I don't believe in insulating the floor – we insulate outside foundation walls - most heat/air systems are in the crawl typical 15% loss in that duct. The insulation is mostly used for sealing rather than for insulating – use about 1.5" cellulose -- used to use styrofoam but it is a fire hazard
only do perimeter foundation - put styrofoam on new construction
It's not really required - a lot of builders don't really do it. What I do is the perimeter - put a heavy 6 mil barrier for ground cover. Treat it like a half-basement. Insulate the band boards, seal the vent. Don't have to worry about the pipes freezing.
I do the perimeter
95% of the time the only place you can put it is underneath the house if you have a crawl space. That can get pretty expensive.

13. On average, how many inches of floor insulation do you add to homes needing such insulation? Of what material?

Average: 1.5 inches
Range: 1 to 1.5 inches; R-7 to R-19; fiberglass batts, cellulose, and styrofoam
Number of respondents: 7

Comments:

1 to 1.5" depends on the people's preference - a lot of people don't want it because they fear insects would get between the insulation and the foundation
R-8 on perimeter walls and band joists of the crawl space. Plus plastic vapor barrier.
We do a lot where they just want the crawl band insulated -- it's not required by code, so a lot of times it is not done.

14. What is your best estimate of the installed cost for floor insulation per square foot?

	Perimeter wall insulation	Floor insulation
Average:	$0.675	$0.723
Range:	$0.21 to $0.75	$0.52 to $0.85
	$0.60 to $0.75 from contractors active in this type of work.	

15. To the best of your knowledge, what percent of existing single and multi-family homes need additional floor insulation?

Average: 73%
Range: 40% to 100%
Number of respondents: 6

Comments:

Big Rivers used to recognize foundation perimeter cellulose as being superior and used to pay incentives -- Contractor is familiar with programs and used to work for Kenergy
There are a lot of existing homes on brick piers - would be hard to insulate, but perhaps as many as 85% would benefit
Need to insulate the crawl band: 95% of W Ky homes - not even doing new construction. In S. Indiana most counties require that you do at least the crawl band.

Air sealing, caulking or weather-stripping

16. During 2004, in how many homes did you provide air sealing, caulking or weather-stripping services?

Only one of the contractors surveyed provides this service as a retrofit.

Average: 26
Range: 1 to 100
Number of respondents: 6

Comments:

On the houses that we build, we have an insulation contractor put up a mesh on the wall then blow in fiberglass through the joints, etc.
Used to do that with the blower door - haven't been doing it lately
Do that just on new construction
Only do air-sealing in new construction. It is the most important part
Only in new construction.

17. What is your best estimate of the installed cost for air sealing per home?

Average: (weighted by number of jobs) $250/home
Range: $0.10 per square foot of wall area; $150 to $1400 per home.
Number of respondents: 6

Comments:

We used to charge $50 for blower door test then estimate. We used to think that the air losses were around windows and such, but now we know that the losses are up and down - like the chimney effect.

18. To the best of your knowledge, what percent of existing single and multi-family homes need additional air sealing, caulking or weather-stripping services?

Average: 67%
Range: 35% to 90%
Number of respondents: 4

Comments:
None

Windows

19. During 2004, in how many homes did you install vinyl replacement windows?

Average: 81
Range: 4 to 175
Number of respondents: 3

Comments:
None

20. Are the replacement windows Energy Star Rated?

Three respondents: two answered yes and one answered don't know.

21. On average, how many vinyl replacement windows do you install per home?

Average: 11
Range: 10 to 14
Number of respondents: 3

Comments:
None

22. What is the average cost per window for vinyl replacement windows?

Average: $433/window
Range: $375 to $500 per home.
Number of respondents: 3

Comments:
None

23. To the best of your knowledge, what percent of existing single and multi-family homes need vinyl replacement windows?

Average: 55%
Range: 30% to 75%
Number of respondents: 3

Comments:
None

APPENDIX G

Appendix G - Payback Data for Energy Efficiency Measures - Residential Sector

Residential Energy Efficiency Measure	Incremental Cost	Annual kWh Savings	Average Residential Retail Rate for Members (2004)	Annual Bill Savings	Payback (in years)
CFL replacing Incandescents for 2.7 hrs/day	5.97	48.88	$0.0616	$ 3.01	1.98
CFL Torchiere (compared to Halogen Torchiere)	60	223.56	$0.0616	$ 13.78	4.35
CFL Torchiere (compared to Incandescent Torchiere)	60	86.69	$0.0616	$ 5.34	11.23
Energy Star Single Room Air Conditioner	89	118.75	$0.0616	$ 7.32	12.16
Energy Star Compliant Freezer Top Refrigerator	115	1029.00	$0.0616	$ 63.43	1.81
Energy Star Compliant Side-by-Side Refrigerator	247.5	1079.00	$0.0616	$ 66.51	3.72
Energy Star Compliant Upright Freezer	50	110.00	$0.0616	$ 6.78	7.37
Energy Star Compliant Chest Freezer	50	43.00	$0.0616	$ 2.65	18.86
Energy Star Built-In Dishwasher	-29.46	141.00	$0.0616	$ 8.69	0.00
Energy Star Washing Machine with Electric Water Heater and Electric Clothes Dryer	200	475.00	$0.0616	$ 29.28	6.83
Energy Star Washing Machine with Gas Water Heater and Electric Clothes Dryer	200	115.00	$0.0616	$ 7.09	28.21
Energy Star Washing Machine with Gas Water Heater and Gas Clothes Dryer	200	0.00	$0.0616	$ -	0.00
Energy Star Compliant Programmable Thermostat	49	87.90	$0.0616	$ 5.42	9.04
Water Heater Blanket	15	333.00	$0.0616	$ 20.53	0.73
Low Flow Shower Head	5.77	250.00	$0.0616	$ 15.41	0.37
Pipe Wrap	3.23	133.00	$0.0616	$ 8.20	0.39
Air Sealing	380	1171.99	$0.0616	$ 72.24	5.26
Reset Water Heater Thermostat (from medium to med-low)	10	380.90	$0.0616	$ 23.48	0.43
Water Heater Wrap (from EF86 to EF88)	35	58.60	$0.0616	$ 3.61	9.69
Attic Insulation (from R9 to R38)	720	878.99	$0.0616	$ 54.18	13.29
Air Sealing Retrofit	380	2346.00	$0.0616	$ 144.61	2.63
Attic Insulation Retrofit	847.8	6894.00	$0.0616	$ 424.94	2.00
Wall Insulation Retrofit	330	1380.00	$0.0616	$ 85.06	3.88
Window Construction (from single-pane U=1.11 to double pane, low-e U=2.6)	1223	3880.00	$0.0616	$ 239.16	5.11

Note: The 2004 average residential retail rate of $.0616 was obtained by GDS from BREC, and it is the weighted average retail rate per kWh for residential members of BREC's three member distirbution cooperatives.

Appendix G - Payback Data for Energy Efficiency Measures - Commercial Sector						
Commercial Market Segment	**Measure Name**	**Incremental Cost**	**Annual kWh Savings**	**Average Commercial Retail Rate (2004)**	**Annual Bill Savings**	**Payback (in years)**
	Interior Lighting					
Existing	CFL - screw-in	$6	90	$ 0.0285	$ 2.57	2.34
Existing	CFL - Hard Wired	$27	228	$ 0.0285	$ 6.50	4.15
Existing	Biax Fluorescents	$400	480	$ 0.0285	$ 13.68	29.23
Existing	Energy-efficient Torchiere	$20	296	$ 0.0285	$ 8.44	2.37
Existing	Halogen PAR Flood, 90W	$12	180	$ 0.0285	$ 5.13	2.34
Existing	Ret 1L4'T5, 1EB	$64	39	$ 0.0285	$ 1.11	57.56
Existing	Ret 4L4' HO T5, 1EB (repl 400 w Metal halide)	$400	648	$ 0.0285	$ 18.47	21.65
Existing	Ret 1L4'T5, 1EB, Reflector	$98	63	$ 0.0285	$ 1.80	54.56
Existing	RET T8, EB, Reflector	$72	54	$ 0.0285	$ 1.54	46.77
Existing	RET 2L4'T8, 1EB	$27	72	$ 0.0285	$ 2.05	13.15
Existing	RET 2L4' Super T8, 1EB	$10	36	$ 0.0285	$ 1.03	9.74
Existing	RET 2L4' Super T8, 1EB, Reflector	$45	84	$ 0.0285	$ 2.39	18.79
Existing	RET 2L4'T5, 1EB	$64	84	$ 0.0285	$ 2.39	26.72
Existing	RET 2L4'T5, 1EB, Reflector	$72	132	$ 0.0285	$ 3.76	19.13
Existing	RET 2L8'T8, 1EB	$27	144	$ 0.0285	$ 4.11	6.58
Existing	RET 4L4' Super T8, 1EB	$12	72	$ 0.0285	$ 2.05	5.85
Existing	250 Watt Metal Halide Lighting	$65	513	$ 0.0285	$ 14.63	4.44
Existing	High Intensity Discharge Systems, 250 W	$65	510	$ 0.0285	$ 14.53	4.47
New	High Intensity Discharge Systems, 50 W	$65	291	$ 0.0285	$ 8.30	7.83
Existing	Pulse Start HID	$200	330	$ 0.0285	$ 9.41	21.26
Existing	High Pressure Sodium 250W Lamp	$65	513	$ 0.0285	$ 14.63	4.44
Existing	LED Exit Signs	$30	184	$ 0.0285	$ 5.25	5.72
Existing	Solid State Exit Signs	$38	348	$ 0.0285	$ 9.92	3.83
Existing	LED Signage	$100	690	$ 0.0285	$ 19.67	5.08
Existing	LED Traffic Lights	$125	430	$ 0.0285	$ 12.26	10.20
Existing	LED Traffic Lights (Yellow signals only)	$42	22	$ 0.0285	$ 0.61	67.98
Existing	Occupancy Sensor	$120	302	$ 0.0285	$ 8.61	13.94
Existing	Daylight Dimming	$181	353	$ 0.0285	$ 10.06	17.99
New	Daylight Dimming	$181	252	$ 0.0285	$ 7.18	25.19
Existing	Continuous Dimming, 10L4' Fluorescent Fixtures	$288	945	$ 0.0285	$ 26.94	10.69
Existing	Continuous Dimming, 5L4' Fluorescent Fixtures	$288	472	$ 0.0285	$ 13.46	21.40
Existing	Continuous Dimming, 5L8' Fluorescent Fixtures	$288	945	$ 0.0285	$ 26.94	10.69
New	15 % More Efficient Design (Lighting)	$4,000	27,000	$ 0.0285	$ 769.74	5.20
New	30 % More Efficient Design (Lighting)	$8,000	54,000	$ 0.0285	$ 1,539.49	5.20
New	5 % More Efficient Design (Lighting)	$4,000	9,000	$ 0.0285	$ 256.58	15.59
New	10 % More Efficient Design (Lighting)	$8,000	18,000	$ 0.0285	$ 513.16	15.59
	Refrigeration					
Existing	Vender Miser	$179	1,551	$ 0.0285	$ 44.22	4.05
Existing	ENERGY STAR Beverage Vending Machines	$25	330	$ 0.0285	$ 9.41	2.66
Existing	Refrigeration Commissioning	$113	190	$ 0.0285	$ 5.42	20.86
Existing	Refrigeration Commissioning	$113	375	$ 0.0285	$ 10.69	10.57
Existing	Efficient compressor motor retrofit	$62	266	$ 0.0285	$ 7.58	8.18
Existing	Efficient compressor motor retrofit	$62	525	$ 0.0285	$ 14.97	4.14
Existing	Compressor VSD retrofit - refrig	$2,000	228	$ 0.0285	$ 6.50	307.69
Existing	Compressor VSD retrofit - freezer	$2,000	450	$ 0.0285	$ 12.83	155.90
Existing	Demand Defrost Electric - Refrig	$25	304	$ 0.0285	$ 8.67	2.88
Existing	Demand Defrost Electric - Freezers	$25	600	$ 0.0285	$ 17.11	1.46
Existing	Floating head pressure controls-Refrig	$4,995	266	$ 0.0285	$ 7.58	658.67
Existing	Floating head pressure controls-Freezers	$4,995	525	$ 0.0285	$ 14.97	333.73
Existing	High Efficiency Ice Maker	$300	2,365	$ 0.0285	$ 67.42	4.45

Appendix G - Payback Data for Energy Efficiency Measures - Commercial Sector						
Commercial Market Segment	Measure Name	Incremental Cost	Annual kWh Savings	Average Commercial Retail Rate (2004)	Annual Bill Savings	Payback (in years)
Existing	Beverage Mechandisers	$166	1,730	$ 0.0285	$ 49.32	3.37
Existing	High Efficiency Reach in Refrigerator	$400	1,330	$ 0.0285	$ 37.92	10.55
Existing	High Efficiency Reach in Freezer	$400	2,625	$ 0.0285	$ 74.84	5.34
Existing	High-efficiency fan motors - refrig	$62	152	$ 0.0285	$ 4.33	14.31
Existing	High-efficiency fan motors - freezer	$62	300	$ 0.0285	$ 8.55	7.25
Existing	Anti-sweat (humidistat) controls - refrig	$6,500	190	$ 0.0285	$ 5.42	1199.99
Existing	Anti-sweat (humidistat) controls - freezer	$6,500	375	$ 0.0285	$ 10.69	607.99
Existing	Demand Hot Gas Defrost - refrig	$25	114	$ 0.0285	$ 3.25	7.69
New	Demand Hot Gas Defrost -freezer	$25	225	$ 0.0285	$ 6.41	3.90
Existing	Night covers for display cases - refrig	$9	228	$ 0.0285	$ 6.50	1.38
New	Night covers for display cases - freezers	$9	450	$ 0.0285	$ 12.83	0.70
Existing	Strip curtains for walk-ins - refrig	$200	368	$ 0.0285	$ 10.49	19.06
Existing	Strip curtains for walk-ins - freezer	$200	613	$ 0.0285	$ 17.48	11.44
Existing	Walk-In Cooler Economizers	$300	1,149	$ 0.0285	$ 32.75	9.16
Existing	Walk-In Cooler Fan Control	$300	1,487	$ 0.0285	$ 42.39	7.08
Existing	Walk-In Cooler Door Heater Control	$2,000	4,202	$ 0.0285	$ 119.79	16.70
Existing	Walk-In Freezer Door Heater Control	$2,000	2,055	$ 0.0285	$ 58.58	34.14
	Space Cooling					
New	Centrifugal Chiller, 0.51 kW/ton, 300 tons	$16,200	55,968	$ 0.0285	$ 1,595.60	10.15
New	Centrifugal Chiller, 0.51 kW/ton, 300 tons - Retrofit	$202,200	118,155	$ 0.0285	$ 3,368.50	60.03
Existing	Centrifugal Chiller, 0.51 kW/ton, 500 tons	$27,000	93,281	$ 0.0285	$ 2,659.34	10.15
Existing	Centrifugal Chiller, 0.51 kW/ton, 500 tons - Retrofit	$281,500	196,926	$ 0.0285	$ 5,614.16	50.14
New	Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	$60,000	207,290	$ 0.0285	$ 5,909.64	10.15
Existing	Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	$314,500	310,935	$ 0.0285	$ 8,864.47	35.48
Existing	Chiller Tune Up/Diagnostics - 300 ton	$5,100	25,207	$ 0.0285	$ 718.64	7.10
Existing	Chiller Tune Up/Diagnostics - 500 ton	$8,500	25,207	$ 0.0285	$ 718.64	11.83
New	Cooling Circ. Pumps - VSD	$6,280	3,486	$ 0.0285	$ 99.38	63.19
New	DX Packaged System, EER=10.9, 10 tons	$607	4,818	$ 0.0285	$ 137.37	4.42
Existing	DX Packaged System, CEE Tier 2, <20 Tons	$910	7,226	$ 0.0285	$ 206.00	4.42
Existing	DX Packaged System, CEE Tier 2, >20 Tons	$1,813	14,453	$ 0.0285	$ 412.05	4.40
Existing	DX Tune Up/ Advanced Diagnostics	$340	3,110	$ 0.0285	$ 88.67	3.83
Existing	Packaged AC - 3 tons, Tier 1	$138	918	$ 0.0285	$ 26.16	5.27
Existing	Packaged AC - 3 tons, Tier 2	$207	1,273	$ 0.0285	$ 36.29	5.70
Existing	Packaged AC - 7.5 tons, Tier 1	$405	2,056	$ 0.0285	$ 58.61	6.91
Existing	Packaged AC - 7.5 tons, Tier 2	$607	2,890	$ 0.0285	$ 82.39	7.37
Existing	Packaged AC - 7.5 tons, Tier 1	$6,105	6,202	$ 0.0285	$ 176.80	34.53
Existing	Packaged AC - 7.5 tons, Tier 2	$6,307	7,036	$ 0.0285	$ 200.58	31.44
Existing	Packaged AC - 15 tons, Tier 1	$791	3,827	$ 0.0285	$ 109.09	7.25
Existing	Packaged AC - 15 tons, Tier 2	$1,516	6,606	$ 0.0285	$ 188.34	8.05
Existing	Economizer, Single Set Point Dry Bulb	$1,500	5,970	$ 0.0285	$ 170.19	8.81
Existing	Economizer, Single Set Point Entalpy	$2,250	15,764	$ 0.0285	$ 449.43	5.01
Existing	Economizer, Comparitive Enthalpy	$3,000	28,916	$ 0.0285	$ 824.37	3.64
Existing	EMS - Chiller 500 ton	$30,000	82,916	$ 0.0285	$ 2,363.86	12.69
Existing	Prog. Thermostat	$55	3,110	$ 0.0285	$ 88.67	0.62
	Ventilation					
Existing	Fan Motor, 15hp, 1800rpm, 92.4%	$46	1,053	$ 0.0285	$ 30.02	1.53
Existing	Fan Motor, 40hp, 1800rpm, 94.1%	$286	2,354	$ 0.0285	$ 67.11	4.26
Existing	Fan Motor, 5hp, 1800rpm, 89.5%	$34	393	$ 0.0285	$ 11.20	3.03
Existing	Variable Speed Drive Control, 15 HP	$3,465	12,000	$ 0.0285	$ 342.11	10.13
New	Variable Speed Drive Control, 40 HP	$6,280	32,000	$ 0.0285	$ 912.29	6.88

Appendix G - Payback Data for Energy Efficiency Measures - Commercial Sector						
Commercial Market Segment	Measure Name	Incremental Cost	Annual kWh Savings	Average Commercial Retail Rate (2004)	Annual Bill Savings	Payback (in years)
New	Variable Speed Drive Control, 5 HP	$1,925	4,000	$ 0.0285	$ 114.04	16.88
Existing	Heat Recovery	$400,000	203,300	$ 0.0285	$ 5,795.89	69.01
	Exterior Lighting					
Existing	Outdoor Lighting Controls (Photocell/Timeclock)	$108	165	$ 0.0285	$ 4.70	22.96
Existing	ROB 2L4'T8, 1EB	$27	72	$ 0.0285	$ 2.05	13.15
Existing	Hydronic Heating Pump VFD	$3,465	10,875	$ 0.0285	$ 310.04	11.18
	Office equipment					
Existing	External hardware control	$173	146	$ 0.0285	$ 4.16	41.56
Existing	Nighttime shutdown - Laptop	$0	13	$ 0.0285	$ 0.37	0.00
Existing	Nighttime shutdown - Desktop	$0	115	$ 0.0285	$ 3.28	0.00
Existing	Power Management Enabling	$4	201	$ 0.0285	$ 5.74	0.70
New	Purchase LCD monitor	$200	77	$ 0.0285	$ 2.20	91.11
	Other					
Existing	Dry Type Transformers	$11	30	$ 0.0285	$ 0.86	12.50

Note: The 2004 average residential retail rate of $.0616 was obtained by GDS from BREC, and it is the weighted average retail rate per kWh for residential members of BREC's three member distirbution cooperatives.

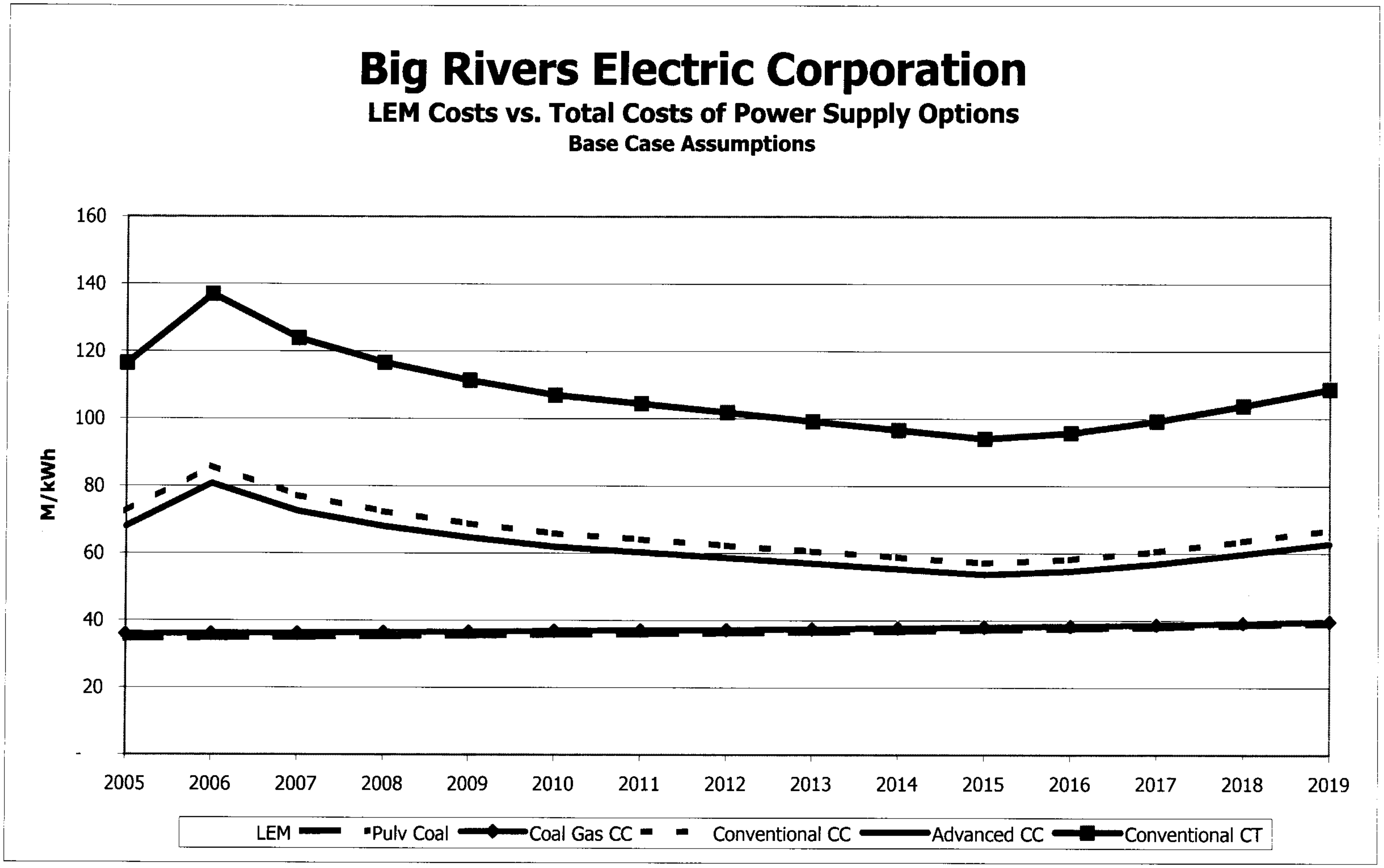
Appendix G - Payback Data for Energy Efficiency Measures - Industrial Sector

Count	Measure Name	2003-$ CCE	Measure Life	Payback (Years)
1	Near Net Shape Casting	($0.093)	15	< 1
2	Injection Moulding - Impulse Cooling	($0.060)	12	< 1
3	Intelligent extruder (DOE)	($0.028)	10	< 1
4	Clean rooms - Controls	($0.025)	10	< 1
5	Process Controls (batch + site)	($0.023)	10	< 1
6	Machinery	($0.019)	10	< 1
7	Machinery	($0.014)	10	< 1
8	Machinery	($0.014)	10	< 1
9	Machinery	($0.014)	10	< 1
10	Machinery	($0.014)	10	< 1
11	Compressed Air - System Optimization	($0.013)	10	< 1
12	O&M/scheduling spinning machines	($0.012)	10	< 1
13	Scheduling	($0.008)	10	< 1
14	Optimize drying process	($0.007)	10	< 1
15	O&M - Extruders/Injection Moulding	($0.006)	12	< 1
16	Compressed Air- Sizing	($0.005)	10	< 1
17	Efficient practices printing press	($0.004)	20	< 1
18	Efficient Machinery	($0.004)	10	< 1
19	Optimization (painting) process	($0.003)	10	< 1
20	Pumps - System Optimization	($0.002)	10	< 1
21	Pumps - Sizing	($0.001)	10	< 1
22	Fans- Improve components	($0.001)	10	< 1
23	Process control	($0.001)	10	< 1
24	Switch-off/O&M	$0.001	8	0.2
25	New transformers welding	$0.004	15	3.1
26	New transformers welding	$0.004	15	3.1
27	New transformers welding	$0.004	15	3.1
28	New transformers welding	$0.004	15	3.1
29	Pumps - O&M	$0.005	10	1.1
30	Fans - O&M	$0.005	10	1.1
31	Setback temperatures (wkd/off duty)	$0.005	10	1.1
32	Bakery - Process (Mixing) - O&M	$0.005	10	1.1
33	Replace V-belts	$0.005	5	1.6
34	Compressed Air-O&M	$0.005	10	1.3
35	Efficient Refrigeration - Operations	$0.005	10	1.3
36	Curing ovens	$0.006	15	6.2
37	ASD (6-100 hp)	$0.006	10	1.4
38	Heat Pumps - Drying	$0.007	15	6.1
39	Efficient Printing press (fewer cylinders)	$0.007	10	3.7
40	Bakery - Process	$0.007	15	2.1
41	Optimization (painting) process	$0.007	10	1.7
42	Optimization Process	$0.007	10	1.7
43	Optimization (painting) process	$0.007	10	1.7
44	Air conveying systems	$0.007	14	2.1
45	Efficient processes (welding, etc.)	$0.008	15	4.2
46	Scheduling	$0.008	10	3.1
47	Scheduling	$0.008	10	3.1
48	Scheduling	$0.008	10	3.1
49	Scheduling	$0.008	10	3.1
50	Pumps - Controls	$0.008	10	1.9
51	Curing ovens	$0.008	15	4.9
52	Curing ovens	$0.008	15	4.9
53	Curing ovens	$0.008	15	4.9
54	Curing ovens	$0.008	15	4.9
55	Replace V-Belts	$0.009	10	2.1

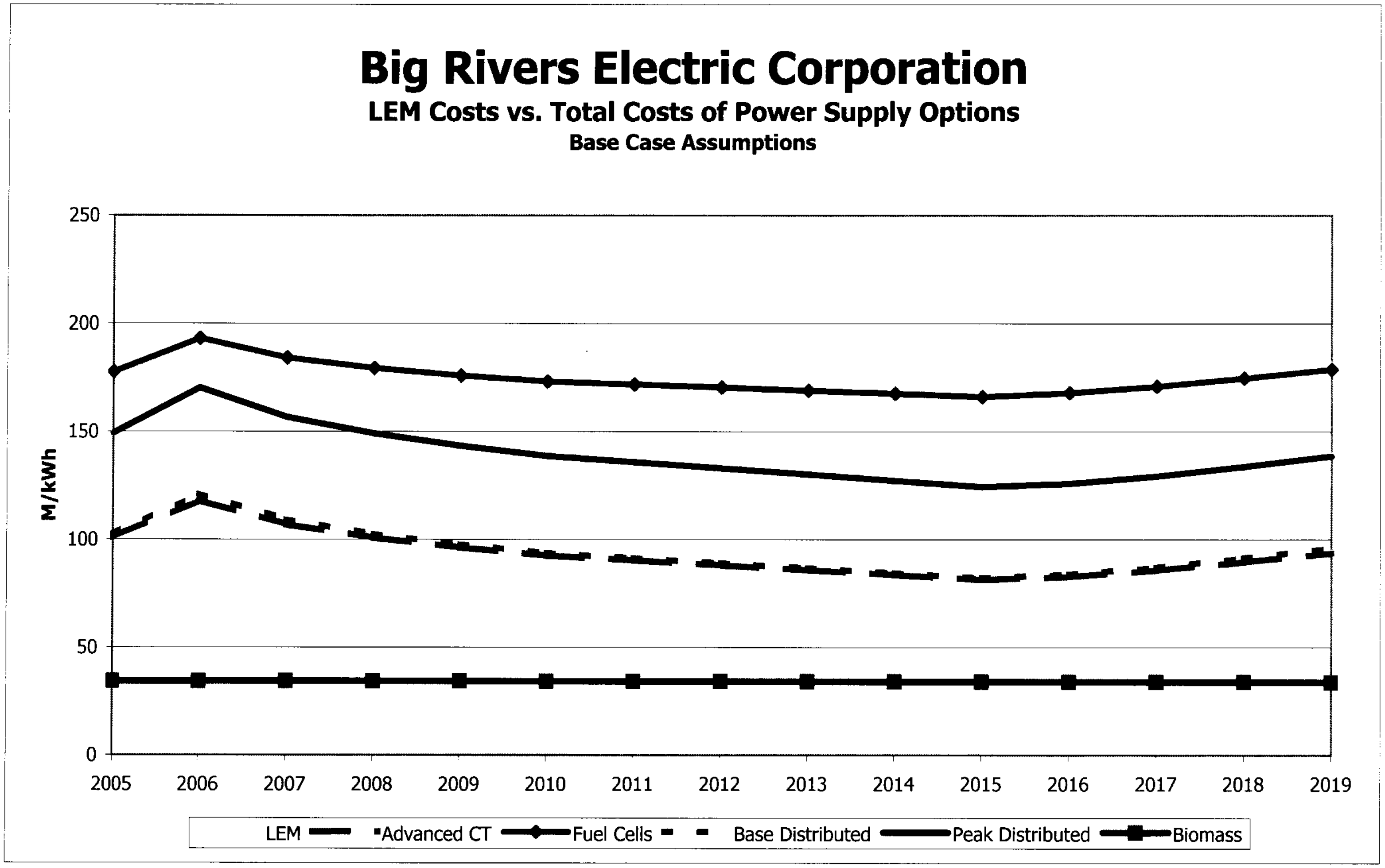
Appendix G - Payback Data for Energy Efficiency Measures - Industrial Sector				
Count	Measure Name	2003-$ CCE	Measure Life	Payback (Years)
56	Compressed Air - Controls	$0.010	10	3.4
57	Optimization Refrigeration	$0.010	15	5.2
58	Energy Star Transformers	$0.010	25	5.5
59	Top-heating (glass)	$0.011	8	2.1
60	Process Control	$0.011	15	4.7
61	Motor practices-1 (100+ HP)	$0.013	6	3.0
62	High-efficiency motors	$0.014	10	3.2
63	Efficient drives	$0.014	10	3.4
64	Efficient drives - rolling	$0.014	10	3.4
65	Membranes for wastewater	$0.015	15	5.5
66	Motor practices-1 (6-100 HP)	$0.015	10	4.6
67	Drives - EE motor	$0.016	10	3.8
68	Fans - System Optimization	$0.017	10	4.7
69	Optimization control PM	$0.018	10	4.5
70	Scheduling	$0.018	10	4.2
71	High Consistency forming	$0.018	20	3.6
72	Process control	$0.018	15	6.2
73	Electronic Ballasts	$0.019	12	4.9
74	ASD (100+ hp)	$0.020	6	3.2
75	Metal Halides/Fluorescent	$0.021	12	6.2
76	Drying (UV/IR)	$0.022	8	4.7
77	High efficiency motors	$0.024	6	3.8
78	Gap Forming paper machine	$0.024	20	5.7
79	Replace by T8	$0.025	12	6.6
80	Controls/sensors	$0.027	12	7.0
81	Autoclave optimization	$0.027	10	6.3
82	Process Drives - ASD	$0.028	10	6.5
83	Process Heating	$0.028	15	8.4
84	Drives - ASD	$0.029	10	6.7
85	HVAC Management System	$0.030	10	7.0
86	Programmable Thermostat	$0.030	10	7.0
87	Clean Room - Controls	$0.030	10	7.0
88	Efficient electric melting	$0.031	20	10.5
89	Duct/Pipe Insulation/leakage	$0.033	10	7.2
90	Window film	$0.037	8	7.0
91	Motor practices-1 (1-5 HP)	$0.038	14.5	10.4
92	Injection Moulding - Direct drive	$0.039	12	9.1
93	Extruders/injection Moulding-multipump	$0.040	12	10.5
94	Fans - Controls	$0.042	10	9.8
95	Chiller O&M/tune-up	$0.042	10	9.8
96	Light cylinders	$0.053	10	10.9
97	Direct drive Extruders	$0.055	12	11.5
98	Replace 100+ HP motor	$0.057	6	9.1
99	Clean Room - New Designs	$0.060	10	14.0
100	Efficient grinding	$0.078	15	23.2

Appendix C
Supply Side Resource Alternatives

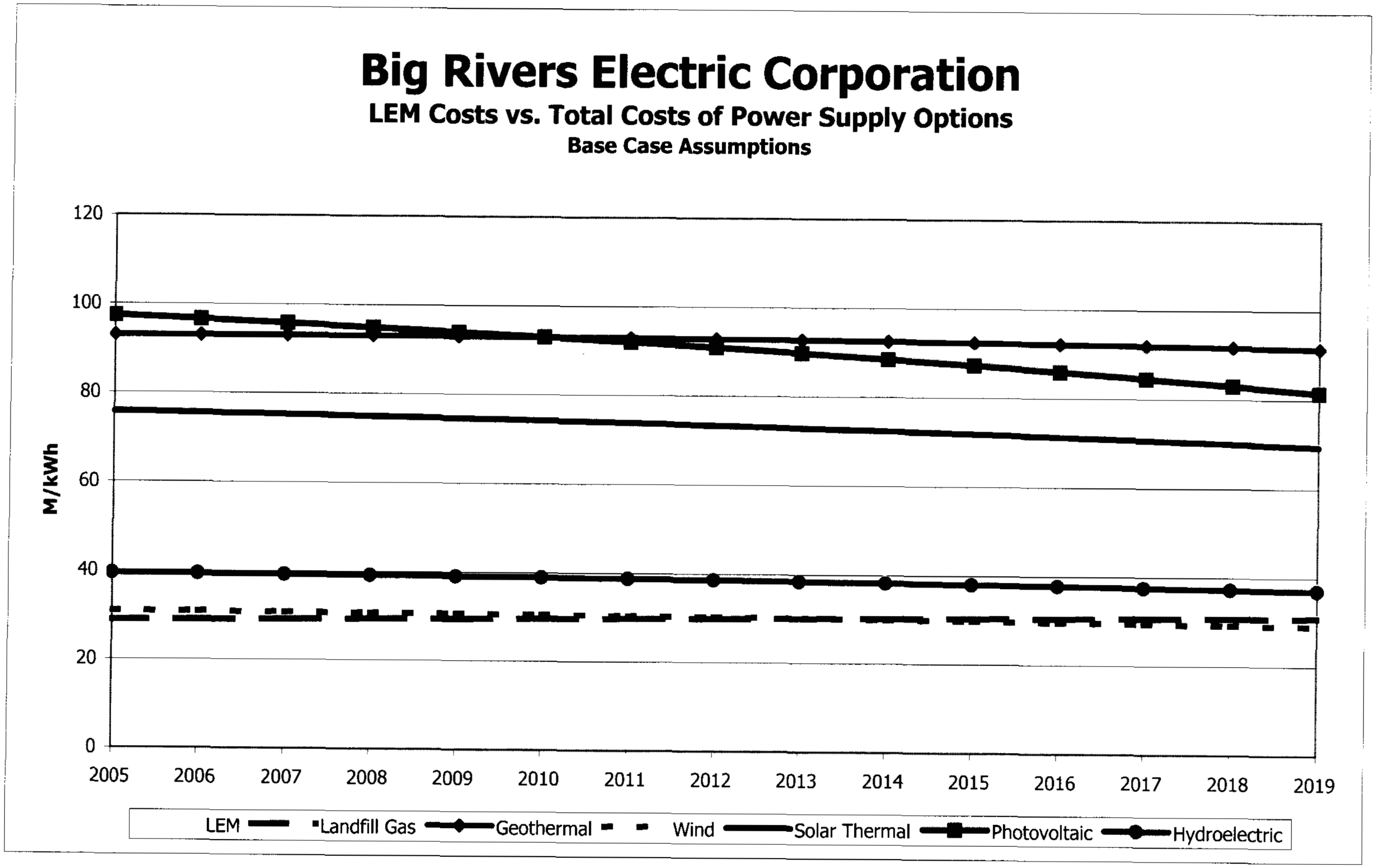
Base Case



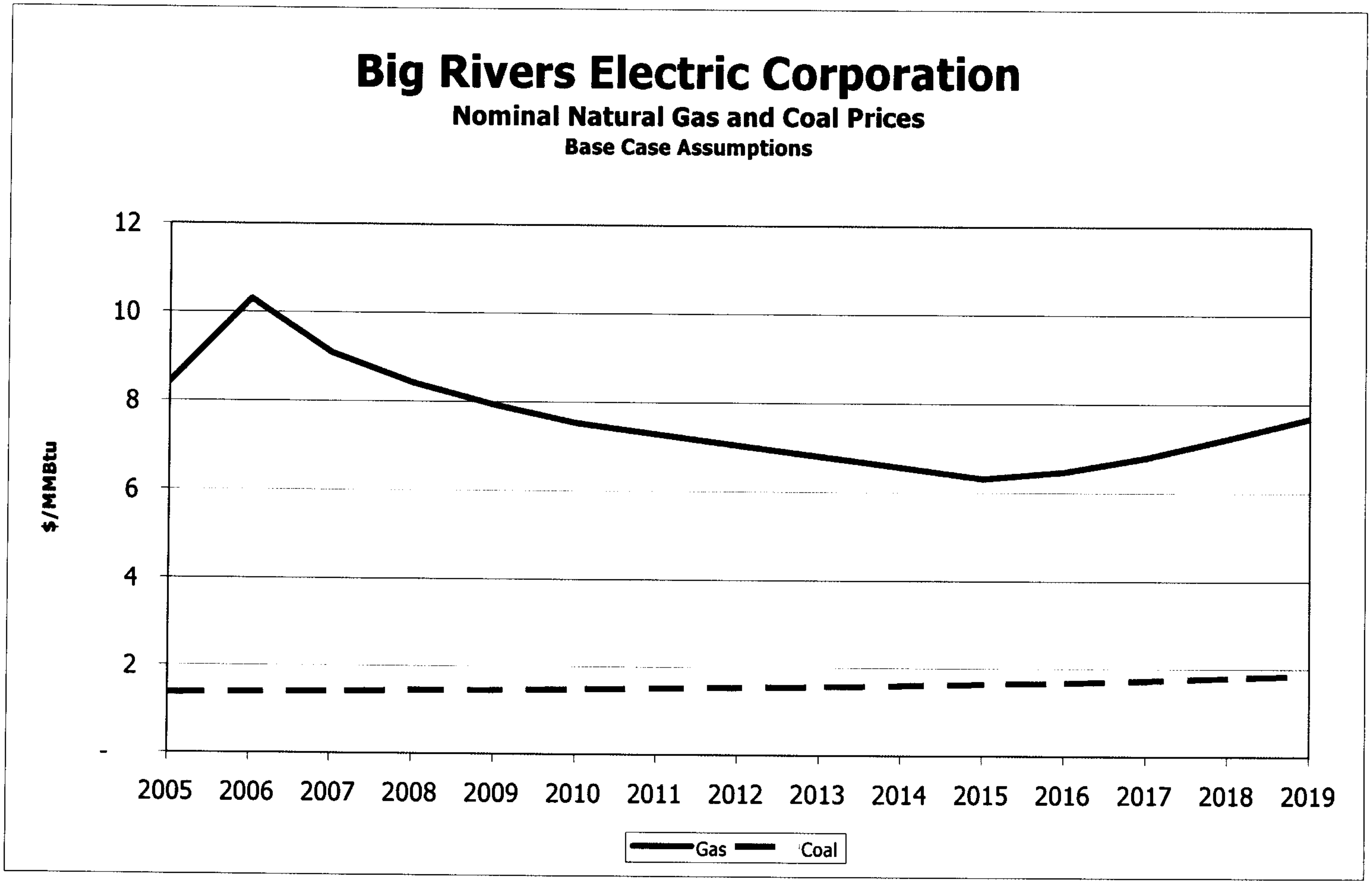
Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
Base Case Assumptions
M/kWh
160
140
120
100
80
60
40
20
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Pulv Coal
Coal Gas CC
Conventional CC
Advanced CC
Conventional CT



Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
Base Case Assumptions
M/kWh
250
200
150
100
50
0
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Advanced CT
Fuel Cells
Base Distributed
Peak Distributed
Biomass



Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
Base Case Assumptions
M/kWh
0
20
40
60
80
100
120
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Landfill Gas
Geothermal
Wind
Solar Thermal
Photovoltaic
Hydroelectric



Big Rivers Electric Corporation
Nominal Natural Gas and Coal Prices
Base Case Assumptions
$/MMBtu
12
10
8
6
4
2
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Gas
Coal

Big Rivers Electric Corporation
Comparison of LEM Contract Costs to Power Supply Options

Base Case Assumptions

Resource:	LEM	Pulv Coal	Coal Gas CC	Conventional CC	Advanced CC	Conventional CT	Advanced CT	Fuel Cells	Base Distributed	Peak Distributed	Biomass	Landfill Gas	Geothermal	Wind	Solar Thermal	Photovoltaic	Hydroelectric
Capacity Factor:		90.00%	90.00%	80.00%	80.00%	25.00%	25.00%	70.00%	90.00%	25.00%	80.00%	98.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Levelized Rate:	[REDACTED]	$37.04	$37.95	$68.62	$64.45	$111.24	$96.20	$177.77	$97.97	$142.51	$34.24	$30.13	$92.44	$30.04	$72.60	$89.11	$38.30
Annual Rates:																	
2005	[REDACTED]	34.51	35.82	72.10	67.80	116.36	100.65	177.59	101.98	148.97	34.16	28.86	93.05	30.85	75.80	97.36	39.48
2006	[REDACTED]	34.82	36.08	85.72	80.57	136.85	118.04	193.14	120.90	170.10	34.21	29.03	93.10	30.80	75.54	96.60	39.40
2007	[REDACTED]	34.97	36.21	77.04	72.41	123.82	106.97	184.11	108.98	156.51	34.25	29.20	93.12	30.74	75.27	95.79	39.31
2008	[REDACTED]	35.28	36.47	72.25	67.91	116.64	100.86	179.37	102.45	148.97	34.29	29.37	93.13	30.68	74.97	94.93	39.21
2009	[REDACTED]	35.47	36.62	68.72	64.59	111.35	96.36	176.01	97.67	143.37	34.32	29.54	93.12	30.60	74.65	94.03	39.10
2010	[REDACTED]	35.82	36.92	65.83	61.87	107.02	92.67	173.35	93.77	138.76	34.35	29.70	93.09	30.52	74.29	93.08	38.97
2011	[REDACTED]	36.06	37.11	64.12	60.25	104.47	90.49	172.00	91.51	135.99	34.37	29.87	93.04	30.43	73.92	92.08	38.84
2012	[REDACTED]	36.32	37.33	62.41	58.64	101.92	88.31	170.64	89.24	133.19	34.38	30.03	92.96	30.32	73.51	91.02	38.69
2013	[REDACTED]	36.62	37.58	60.70	57.02	99.36	86.12	169.27	86.98	130.38	34.38	30.20	92.87	30.21	73.07	89.90	38.52
2014	[REDACTED]	36.97	37.87	58.98	55.40	96.79	83.93	167.89	84.72	127.55	34.38	30.36	92.74	30.08	72.59	88.72	38.34
2015	[REDACTED]	37.37	38.21	57.27	53.78	94.22	81.73	166.50	82.46	124.70	34.36	30.52	92.58	29.94	72.08	87.47	38.14
2016	[REDACTED]	37.68	38.46	58.42	54.86	95.97	83.20	168.26	84.18	126.32	34.34	30.68	92.40	29.79	71.53	86.16	37.93
2017	[REDACTED]	38.19	38.90	60.74	57.01	99.45	86.14	171.29	87.50	129.71	34.30	30.83	92.18	29.63	70.94	84.77	37.70
2018	[REDACTED]	38.80	39.43	63.83	59.90	104.11	90.07	175.16	91.90	134.29	34.26	30.98	91.93	29.45	70.31	83.31	37.44
2019	[REDACTED]	39.36	39.90	67.10	62.96	109.02	94.22	179.22	96.54	139.13	34.20	31.13	91.64	29.25	69.64	81.76	37.17
2020	[REDACTED]	39.94	40.39	69.73	65.41	112.98	97.56	182.55	100.31	142.97	34.13	31.27	91.31	29.04	68.91	80.13	36.87
2021	[REDACTED]	40.62	40.98	72.16	67.68	116.62	100.63	185.65	103.80	146.46	34.04	31.41	90.93	28.80	68.14	78.41	36.56
2022	[REDACTED]	41.26	41.53	74.03	69.42	119.43	102.99	188.10	106.53	149.06	33.94	31.54	90.51	28.55	67.31	76.60	36.21
2023	[REDACTED]	41.91	42.08	75.48	70.77	121.60	104.81	190.08	108.68	150.98	33.82	31.67	90.04	28.28	66.42	74.68	35.84
2024	[REDACTED]	42.57	42.64	77.98	73.09	125.34	107.95	193.18	112.27	154.50	33.69	31.79	89.52	27.99	65.47	72.66	35.44

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Pulv Coal
Capital Cost		1,213.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,217.85
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Coal
Variable O&M	(M/kWh)	4.06
Fixed O&M	($/kW-Yr)	24.36
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	8.844

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	289.70	7.75	-	297.45
2	2002	25.00%	296.99	7.94	15.91	618.30
3	2003	25.00%	304.46	8.14	33.08	963.99
4	2004	25.00%	312.12	8.35	51.57	1,336.03
5		0.00%	-	-	-	1,336.03

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,336.03	90.41	71.48	18.93	44.53	25.60	141.61	17.96	$16.82	8.844	1.39	12.28	4.27	16.55	$21.89	34.51	$38.71
2	2006	1,317.10	90.41	70.46	19.94	44.53	26.25	141.24	17.92		8.844	1.42	12.53	4.37	16.90		34.82	
3	2007	1,297.16	90.41	69.40	21.01	44.53	26.91	140.84	17.86		8.844	1.43	12.62	4.48	17.11		34.97	
4	2008	1,276.15	90.41	68.27	22.13	44.53	27.58	140.39	17.81		8.844	1.46	12.88	4.60	17.48		35.28	
5	2009	1,254.01	90.41	67.09	23.32	44.53	28.28	139.90	17.74		8.844	1.47	13.01	4.71	17.72		35.47	
6	2010	1,230.69	90.41	65.84	24.57	44.53	28.99	139.36	17.68		8.844	1.51	13.31	4.83	18.14		35.82	
7	2011	1,206.13	90.41	64.53	25.88	44.53	29.72	138.78	17.60		8.844	1.53	13.50	4.95	18.45		36.06	
8	2012	1,180.25	90.41	63.14	27.27	44.53	30.46	138.14	17.52		8.844	1.55	13.72	5.08	18.80		36.32	
9	2013	1,152.98	90.41	61.68	28.72	44.53	31.23	137.45	17.43		8.844	1.58	13.98	5.21	19.18		36.62	
10	2014	1,124.26	90.41	60.15	30.26	44.53	32.02	136.70	17.34		8.844	1.62	14.29	5.34	19.63		36.97	
11	2015	1,093.99	90.41	58.53	31.88	44.53	32.82	135.89	17.24		8.844	1.66	14.66	5.47	20.13		37.37	
12	2016	1,062.11	90.41	56.82	33.59	44.53	33.65	135.01	17.12		8.844	1.69	14.95	5.61	20.56		37.68	
13	2017	1,028.53	90.41	55.03	35.38	44.53	34.49	134.06	17.00		8.844	1.75	15.44	5.75	21.19		38.19	
14	2018	993.15	90.41	53.13	37.28	44.53	35.36	133.03	16.87		8.844	1.81	16.04	5.89	21.93		38.80	
15	2019	955.87	90.41	51.14	39.27	44.53	36.25	131.93	16.73		8.844	1.88	16.58	6.04	22.63		39.36	
16	2020	916.60	90.41	49.04	41.37	44.53	37.16	130.74	16.58		8.844	1.94	17.16	6.19	23.35		39.94	
17	2021	875.23	90.41	46.82	43.58	44.53	38.10	129.46	16.42		8.844	2.02	17.85	6.35	24.20		40.62	
18	2022	831.65	90.41	44.49	45.92	44.53	39.06	128.09	16.25		8.844	2.09	18.50	6.51	25.01		41.26	
19	2023	785.73	90.41	42.04	48.37	44.53	40.04	126.61	16.06		8.844	2.17	19.17	6.67	25.85		41.91	
20	2024	737.36	90.41	39.45	50.96	44.53	41.05	125.03	15.86		8.844	2.25	19.87	6.84	26.71		42.57	
21	2025	686.40	90.41	36.72	53.69	44.53	42.08	123.34	15.64		8.844	2.33	20.59	7.01	27.61		43.25	
22	2026	632.71	90.41	33.85	56.56	44.53	43.14	121.52	15.41		8.844	2.41	21.34	7.19	28.53		43.95	
23	2027	576.15	90.41	30.82	59.58	44.53	44.22	119.58	15.17		8.844	2.50	22.12	7.37	29.49		44.66	
24	2028	516.57	90.41	27.64	62.77	44.53	45.34	117.51	14.90		8.844	2.59	22.92	7.56	30.48		45.39	
25	2029	453.80	90.41	24.28	66.13	44.53	46.48	115.29	14.62		8.844	2.69	23.76	7.75	31.50		46.13	
26	2030	387.66	90.41	20.74	69.67	44.53	47.65	112.92	14.32		8.844	2.78	24.62	7.94	32.56		46.89	
27	2031	318.00	90.41	17.01	73.40	44.53	48.85	110.39	14.00		8.844	2.89	25.52	8.14	33.66		47.66	
28	2032	244.60	90.41	13.09	77.32	44.53	50.08	107.70	13.66		8.844	2.99	26.45	8.35	34.79		48.45	
29	2033	167.28	90.41	8.95	81.46	44.53	51.33	104.82	13.30		8.844	3.10	27.41	8.56	35.96		49.26	
30	2034	85.82	90.41	4.59	85.82	44.53	52.63	101.75	12.91		8.844	3.21	28.41	8.77	37.18		50.08	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Coal Gasification CC
Capital Cost		1,402.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,407.61
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Coal
Variable O&M	(M/kWh)	2.58
Fixed O&M	($/kW-Yr)	34.21
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	8.309

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	334.84	8.96	-	343.80
2	2002	25.00%	343.27	9.18	18.39	714.64
3	2003	25.00%	351.90	9.41	38.23	1,114.19
4	2004	25.00%	360.76	9.65	59.61	1,544.20
5		0.00%	-	-	-	1,544.20

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,544.20	104.50	82.61	21.88	51.47	35.95	170.04	21.57	$20.52	8.309	1.39	11.54	2.71	14.25	$18.83	35.82	$39.35
2	2006	1,522.32	104.50	81.44	23.05	51.47	36.86	169.78	21.53		8.309	1.42	11.77	2.78	14.55		36.08	
3	2007	1,499.27	104.50	80.21	24.28	51.47	37.78	169.47	21.50		8.309	1.43	11.86	2.85	14.71		36.21	
4	2008	1,474.99	104.50	78.91	25.58	51.47	38.74	169.12	21.45		8.309	1.46	12.10	2.92	15.02		36.47	
5	2009	1,449.40	104.50	77.54	26.95	51.47	39.71	168.73	21.40		8.309	1.47	12.22	2.99	15.22		36.62	
6	2010	1,422.45	104.50	76.10	28.39	51.47	40.71	168.28	21.34		8.309	1.51	12.51	3.07	15.58		36.92	
7	2011	1,394.06	104.50	74.58	29.91	51.47	41.73	167.79	21.28		8.309	1.53	12.68	3.15	15.83		37.11	
8	2012	1,364.14	104.50	72.98	31.51	51.47	42.78	167.24	21.21		8.309	1.55	12.89	3.23	16.12		37.33	
9	2013	1,332.63	104.50	71.30	33.20	51.47	43.86	166.63	21.14		8.309	1.58	13.13	3.31	16.44		37.58	
10	2014	1,299.43	104.50	69.52	34.98	51.47	44.96	165.96	21.05		8.309	1.62	13.43	3.39	16.82		37.87	
11	2015	1,264.45	104.50	67.65	36.85	51.47	46.09	165.22	20.96		8.309	1.66	13.78	3.48	17.25		38.21	
12	2016	1,227.60	104.50	65.68	38.82	51.47	47.25	164.40	20.85		8.309	1.69	14.05	3.56	17.61		38.46	
13	2017	1,188.79	104.50	63.60	40.90	51.47	48.44	163.52	20.74		8.309	1.75	14.51	3.65	18.16		38.90	
14	2018	1,147.89	104.50	61.41	43.08	51.47	49.66	162.55	20.62		8.309	1.81	15.07	3.75	18.81		39.43	
15	2019	1,104.81	104.50	59.11	45.39	51.47	50.91	161.49	20.48		8.309	1.88	15.58	3.84	19.42		39.90	
16	2020	1,059.42	104.50	56.68	47.82	51.47	52.19	160.34	20.34		8.309	1.94	16.12	3.94	20.06		40.39	
17	2021	1,011.60	104.50	54.12	50.37	51.47	53.50	159.10	20.18		8.309	2.02	16.77	4.04	20.80		40.98	
18	2022	961.23	104.50	51.43	53.07	51.47	54.85	157.75	20.01		8.309	2.09	17.38	4.14	21.52		41.53	
19	2023	908.16	104.50	48.59	55.91	51.47	56.23	156.29	19.82		8.309	2.17	18.01	4.24	22.25		42.08	
20	2024	852.25	104.50	45.60	58.90	51.47	57.65	154.71	19.62		8.309	2.25	18.67	4.35	23.02		42.64	
21	2025	793.35	104.50	42.44	62.05	51.47	59.10	153.01	19.41		8.309	2.33	19.35	4.46	23.80		43.21	
22	2026	731.30	104.50	39.12	65.37	51.47	60.58	151.18	19.18		8.309	2.41	20.05	4.57	24.62		43.80	
23	2027	665.92	104.50	35.63	68.87	51.47	62.11	149.21	18.93		8.309	2.50	20.78	4.68	25.47		44.39	
24	2028	597.06	104.50	31.94	72.55	51.47	63.67	147.09	18.66		8.309	2.59	21.54	4.80	26.34		45.00	
25	2029	524.50	104.50	28.06	76.43	51.47	65.27	144.81	18.37		8.309	2.69	22.32	4.92	27.24		45.61	
26	2030	448.07	104.50	23.97	80.52	51.47	66.91	142.36	18.06		8.309	2.78	23.13	5.05	28.18		46.24	
27	2031	367.54	104.50	19.66	84.83	51.47	68.60	139.73	17.72		8.309	2.89	23.97	5.17	29.15		46.87	
28	2032	282.71	104.50	15.13	89.37	51.47	70.32	136.92	17.37		8.309	2.99	24.85	5.30	30.15		47.52	
29	2033	193.34	104.50	10.34	94.15	51.47	72.09	133.91	16.98		8.309	3.10	25.75	5.44	31.19		48.17	
30	2034	99.19	104.50	5.31	99.19	51.47	73.91	130.69	16.58		8.309	3.21	26.69	5.57	32.26		48.84	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Conv CC
Capital Cost		567.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	569.27
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2000
Primary Fuel		Gas
Variable O&M	(M/kWh)	1.83
Fixed O&M	($/kW-Yr)	11.04
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	7.196

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	185.10	4.95	-	190.05
2	2003	33.33%	189.76	5.08	10.17	395.05
3	2004	33.33%	194.53	5.20	21.14	615.92
4		0.00%	-	-	-	615.92
5		0.00%	-	-	-	615.92

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	615.92	41.68	32.95	8.73	20.53	12.50	65.98	9.42	$8.86	7.196	8.42	60.61	2.07	62.68	$63.96	72.10	$72.82
2	2006	607.19	41.68	32.48	9.19	20.53	12.81	65.83	9.39		7.196	10.31	74.20	2.12	76.33		85.72	
3	2007	598.00	41.68	31.99	9.69	20.53	13.14	65.66	9.37		7.196	9.10	65.49	2.18	67.67		77.04	
4	2008	588.31	41.68	31.47	10.20	20.53	13.47	65.47	9.34		7.196	8.43	60.67	2.23	62.91		72.25	
5	2009	578.11	41.68	30.93	10.75	20.53	13.81	65.27	9.31		7.196	7.94	57.12	2.29	59.40		68.72	
6	2010	567.36	41.68	30.35	11.33	20.53	14.15	65.04	9.28		7.196	7.53	54.20	2.35	56.55		65.83	
7	2011	556.03	41.68	29.75	11.93	20.53	14.51	64.79	9.24		7.196	7.29	52.47	2.41	54.87		64.12	
8	2012	544.10	41.68	29.11	12.57	20.53	14.88	64.52	9.21		7.196	7.05	50.74	2.47	53.20		62.41	
9	2013	531.53	41.68	28.44	13.24	20.53	15.25	64.22	9.16		7.196	6.81	49.01	2.53	51.53		60.70	
10	2014	518.29	41.68	27.73	13.95	20.53	15.63	63.89	9.12		7.196	6.57	47.27	2.59	49.87		58.98	
11	2015	504.34	41.68	26.98	14.70	20.53	16.03	63.54	9.07		7.196	6.33	45.54	2.66	48.20		57.27	
12	2016	489.64	41.68	26.20	15.48	20.53	16.43	63.16	9.01		7.196	6.49	46.69	2.72	49.41		58.42	
13	2017	474.16	41.68	25.37	16.31	20.53	16.84	62.74	8.95		7.196	6.81	48.99	2.79	51.78		60.74	
14	2018	457.85	41.68	24.49	17.18	20.53	17.27	62.29	8.89		7.196	7.24	52.08	2.86	54.94		63.83	
15	2019	440.66	41.68	23.58	18.10	20.53	17.70	61.81	8.82		7.196	7.69	55.34	2.93	58.28		67.10	
16	2020	422.56	41.68	22.61	19.07	20.53	18.15	61.28	8.74		7.196	8.06	57.98	3.01	60.99		69.73	
17	2021	403.49	41.68	21.59	20.09	20.53	18.60	60.72	8.66		7.196	8.40	60.41	3.08	63.50		72.16	
18	2022	383.39	41.68	20.51	21.17	20.53	19.07	60.11	8.58		7.196	8.66	62.29	3.16	65.45		74.03	
19	2023	362.23	41.68	19.38	22.30	20.53	19.55	59.46	8.48		7.196	8.86	63.76	3.24	67.00		75.48	
20	2024	339.93	41.68	18.19	23.49	20.53	20.04	58.76	8.38		7.196	9.21	66.27	3.32	69.59		77.98	
21	2025	316.43	41.68	16.93	24.75	20.53	20.55	58.01	8.28		7.196	9.61	69.14	3.41	72.55		80.83	
22	2026	291.68	41.68	15.61	26.07	20.53	21.06	57.20	8.16		7.196	9.95	71.62	3.49	75.11		83.28	
23	2027	265.61	41.68	14.21	27.47	20.53	21.59	56.33	8.04		7.196	10.30	74.10	3.58	77.68		85.72	
24	2028	238.14	41.68	12.74	28.94	20.53	22.14	55.41	7.91		7.196	10.66	76.72	3.67	80.39		88.30	
25	2029	209.20	41.68	11.19	30.49	20.53	22.69	54.42	7.76		7.196	11.06	79.61	3.76	83.37		91.14	
26	2030	178.72	41.68	9.56	32.12	20.53	23.27	53.36	7.61		7.196	11.48	82.59	3.86	86.44		94.06	
27	2031	146.60	41.68	7.84	33.84	20.53	23.85	52.22	7.45		7.196	11.89	85.58	3.95	89.53		96.98	
28	2032	112.76	41.68	6.03	35.65	20.53	24.45	51.01	7.28		7.196	12.32	88.68	4.05	92.73		100.01	
29	2033	77.12	41.68	4.13	37.55	20.53	25.07	49.72	7.10		7.196	12.77	91.92	4.15	96.07		103.17	
30	2034	39.56	41.68	2.12	39.56	20.53	25.70	48.34	6.90		7.196	13.24	95.30	4.26	99.56		106.46	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Adv CC
Capital Cost		558.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	560.23
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	1.77
Fixed O&M	($/kW-Yr)	10.35
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	6.752

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	182.16	4.87	-	187.03
2	2003	33.33%	186.74	5.00	10.01	388.78
3	2004	33.33%	191.44	5.12	20.80	606.14
4		0.00%	-	-	-	606.14
5		0.00%	-	-	-	606.14

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	606.14	41.02	32.43	8.59	20.20	10.88	63.51	9.06	$8.45	6.752	8.42	56.87	1.86	58.73	$59.90	67.80	$68.35
2	2006	597.55	41.02	31.97	9.05	20.20	11.15	63.32	9.04		6.752	10.31	69.62	1.91	71.53		80.57	
3	2007	588.51	41.02	31.49	9.53	20.20	11.43	63.12	9.01		6.752	9.10	61.45	1.95	63.40		72.41	
4	2008	578.97	41.02	30.98	10.04	20.20	11.72	62.90	8.98		6.752	8.43	56.93	2.00	58.94		67.91	
5	2009	568.93	41.02	30.44	10.58	20.20	12.01	62.66	8.94		6.752	7.94	53.59	2.05	55.65		64.59	
6	2010	558.35	41.02	29.87	11.15	20.20	12.32	62.39	8.90		6.752	7.53	50.86	2.11	52.96		61.87	
7	2011	547.21	41.02	29.28	11.74	20.20	12.63	62.11	8.86		6.752	7.29	49.23	2.16	51.39		60.25	
8	2012	535.46	41.02	28.65	12.37	20.20	12.94	61.80	8.82		6.752	7.05	47.61	2.21	49.82		58.64	
9	2013	523.09	41.02	27.99	13.03	20.20	13.27	61.46	8.77		6.752	6.81	45.98	2.27	48.25		57.02	
10	2014	510.06	41.02	27.29	13.73	20.20	13.60	61.10	8.72		6.752	6.57	44.36	2.33	46.68		55.40	
11	2015	496.33	41.02	26.55	14.46	20.20	13.95	60.70	8.66		6.752	6.33	42.73	2.38	45.12		53.78	
12	2016	481.87	41.02	25.78	15.24	20.20	14.30	60.28	8.60		6.752	6.49	43.81	2.44	46.25		54.86	
13	2017	466.63	41.02	24.96	16.05	20.20	14.66	59.83	8.54		6.752	6.81	45.97	2.51	48.48		57.01	
14	2018	450.58	41.02	24.11	16.91	20.20	15.02	59.34	8.47		6.752	7.24	48.87	2.57	51.44		59.90	
15	2019	433.67	41.02	23.20	17.82	20.20	15.40	58.81	8.39		6.752	7.69	51.93	2.63	54.56		62.96	
16	2020	415.85	41.02	22.25	18.77	20.20	15.79	58.24	8.31		6.752	8.06	54.40	2.70	57.10		65.41	
17	2021	397.08	41.02	21.24	19.77	20.20	16.19	57.64	8.22		6.752	8.40	56.69	2.77	59.45		67.68	
18	2022	377.31	41.02	20.19	20.83	20.20	16.59	56.99	8.13		6.752	8.66	58.45	2.84	61.29		69.42	
19	2023	356.48	41.02	19.07	21.95	20.20	17.01	56.29	8.03		6.752	8.86	59.82	2.91	62.73		70.77	
20	2024	334.53	41.02	17.90	23.12	20.20	17.44	55.54	7.93		6.752	9.21	62.18	2.98	65.16		73.09	
21	2025	311.41	41.02	16.66	24.36	20.20	17.88	54.74	7.81		6.752	9.61	64.88	3.06	67.93		75.75	
22	2026	287.05	41.02	15.36	25.66	20.20	18.33	53.89	7.69		6.752	9.95	67.20	3.13	70.34		78.03	
23	2027	261.39	41.02	13.98	27.03	20.20	18.79	52.98	7.56		6.752	10.30	69.53	3.21	72.74		80.30	
24	2028	234.36	41.02	12.54	28.48	20.20	19.26	52.01	7.42		6.752	10.66	71.99	3.29	75.28		82.70	
25	2029	205.88	41.02	11.01	30.00	20.20	19.75	50.97	7.27		6.752	11.06	74.70	3.38	78.08		85.35	
26	2030	175.88	41.02	9.41	31.61	20.20	20.24	49.86	7.11		6.752	11.48	77.49	3.46	80.95		88.07	
27	2031	144.27	41.02	7.72	33.30	20.20	20.75	48.68	6.95		6.752	11.89	80.30	3.55	83.84		90.79	
28	2032	110.97	41.02	5.94	35.08	20.20	21.28	47.42	6.77		6.752	12.32	83.21	3.64	86.84		93.61	
29	2033	75.89	41.02	4.06	36.96	20.20	21.81	46.08	6.57		6.752	12.77	86.25	3.73	89.98		96.55	
30	2034	38.93	41.02	2.08	38.93	20.20	22.36	44.65	6.37		6.752	13.24	89.42	3.82	93.25		99.62	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Conv CT
Capital Cost		395.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	396.58
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	3.16
Fixed O&M	($/kW-Yr)	10.72
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	10.817

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	198.29	5.30	-	203.59
2	2004	50.00%	203.28	5.44	10.89	423.20
3		0.00%	-	-	-	423.20
4		0.00%	-	-	-	423.20
5		0.00%	-	-	-	423.20

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	423.20	28.64	22.64	6.00	14.11	11.27	48.01	21.92	$21.10	10.817	8.42	91.11	3.32	94.43	$96.42	116.36	$117.53
2	2006	417.21	28.64	22.32	6.32	14.11	11.55	47.98	21.91		10.817	10.31	111.54	3.40	114.95		136.85	
3	2007	410.89	28.64	21.98	6.66	14.11	11.84	47.93	21.89		10.817	9.10	98.45	3.49	101.94		123.82	
4	2008	404.23	28.64	21.63	7.01	14.11	12.14	47.87	21.86		10.817	8.43	91.21	3.58	94.78		116.64	
5	2009	397.22	28.64	21.25	7.39	14.11	12.44	47.80	21.83		10.817	7.94	85.86	3.67	89.52		111.35	
6	2010	389.84	28.64	20.86	7.78	14.11	12.76	47.72	21.79		10.817	7.53	81.47	3.76	85.23		107.02	
7	2011	382.05	28.64	20.44	8.20	14.11	13.08	47.62	21.75		10.817	7.29	78.87	3.85	82.73		104.47	
8	2012	373.86	28.64	20.00	8.64	14.11	13.41	47.51	21.70		10.817	7.05	76.27	3.95	80.22		101.92	
9	2013	365.22	28.64	19.54	9.10	14.11	13.74	47.39	21.64		10.817	6.81	73.67	4.05	77.72		99.36	
10	2014	356.12	28.64	19.05	9.59	14.11	14.09	47.25	21.57		10.817	6.57	71.06	4.15	75.22		96.79	
11	2015	346.53	28.64	18.54	10.10	14.11	14.44	47.09	21.50		10.817	6.33	68.46	4.26	72.72		94.22	
12	2016	336.44	28.64	18.00	10.64	14.11	14.81	46.91	21.42		10.817	6.49	70.18	4.36	74.55		95.97	
13	2017	325.80	28.64	17.43	11.21	14.11	15.18	46.72	21.33		10.817	6.81	73.65	4.47	78.12		99.45	
14	2018	314.59	28.64	16.83	11.81	14.11	15.56	46.50	21.23		10.817	7.24	78.29	4.59	82.87		104.11	
15	2019	302.78	28.64	16.20	12.44	14.11	15.95	46.26	21.12		10.817	7.69	83.19	4.70	87.90		109.02	
16	2020	290.34	28.64	15.53	13.10	14.11	16.35	45.99	21.00		10.817	8.06	87.16	4.82	91.98		112.98	
17	2021	277.24	28.64	14.83	13.81	14.11	16.77	45.71	20.87		10.817	8.40	90.81	4.94	95.75		116.62	
18	2022	263.43	28.64	14.09	14.54	14.11	17.19	45.39	20.73		10.817	8.66	93.64	5.07	98.70		119.43	
19	2023	248.89	28.64	13.32	15.32	14.11	17.62	45.04	20.57		10.817	8.86	95.84	5.19	101.04		121.60	
20	2024	233.57	28.64	12.50	16.14	14.11	18.06	44.67	20.40		10.817	9.21	99.62	5.32	104.94		125.34	
21	2025	217.42	28.64	11.63	17.01	14.11	18.52	44.26	20.21		10.817	9.61	103.94	5.46	109.40		129.60	
22	2026	200.42	28.64	10.72	17.92	14.11	18.98	43.81	20.01		10.817	9.95	107.66	5.60	113.26		133.26	
23	2027	182.50	28.64	9.76	18.87	14.11	19.46	43.33	19.79		10.817	10.30	111.39	5.74	117.13		136.91	
24	2028	163.63	28.64	8.75	19.88	14.11	19.95	42.81	19.55		10.817	10.66	115.33	5.88	121.21		140.76	
25	2029	143.74	28.64	7.69	20.95	14.11	20.45	42.25	19.29		10.817	11.06	119.67	6.03	125.70		145.00	
26	2030	122.80	28.64	6.57	22.07	14.11	20.97	41.64	19.02		10.817	11.48	124.15	6.18	130.33		149.34	
27	2031	100.73	28.64	5.39	23.25	14.11	21.50	40.99	18.72		10.817	11.89	128.64	6.34	134.97		153.69	
28	2032	77.48	28.64	4.15	24.49	14.11	22.04	40.29	18.40		10.817	12.32	133.30	6.50	139.79		158.19	
29	2033	52.99	28.64	2.83	25.80	14.11	22.59	39.53	18.05		10.817	12.77	138.17	6.66	144.83		162.88	
30	2034	27.18	28.64	1.45	27.18	14.11	23.16	38.72	17.68		10.817	13.24	143.26	6.83	150.09		167.77	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Adv CT
Capital Cost		374.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	375.50
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	2.80
Fixed O&M	($/kW-Yr)	9.31
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	9.183

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	187.75	5.02	-	192.77
2	2004	50.00%	192.47	5.15	10.31	400.70
3		0.00%	-	-	-	400.70
4		0.00%	-	-	-	400.70
5		0.00%	-	-	-	400.70

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	400.70	27.12	21.44	5.68	13.36	9.78	44.58	20.36	$19.44	9.183	8.42	77.35	2.94	80.29	$82.02	100.65	$101.47
2	2006	395.03	27.12	21.13	5.98	13.36	10.03	44.52	20.33		9.183	10.31	94.69	3.02	97.71		118.04	
3	2007	389.04	27.12	20.81	6.30	13.36	10.28	44.45	20.30		9.183	9.10	83.57	3.09	86.67		106.97	
4	2008	382.74	27.12	20.48	6.64	13.36	10.54	44.38	20.26		9.183	8.43	77.43	3.17	80.60		100.86	
5	2009	376.10	27.12	20.12	6.99	13.36	10.81	44.29	20.22		9.183	7.94	72.89	3.25	76.14		96.36	
6	2010	369.11	27.12	19.75	7.37	13.36	11.08	44.18	20.17		9.183	7.53	69.17	3.33	72.50		92.67	
7	2011	361.74	27.12	19.35	7.76	13.36	11.36	44.07	20.12		9.183	7.29	66.96	3.42	70.37		90.49	
8	2012	353.98	27.12	18.94	8.18	13.36	11.64	43.94	20.06		9.183	7.05	64.75	3.50	68.25		88.31	
9	2013	345.80	27.12	18.50	8.62	13.36	11.94	43.79	20.00		9.183	6.81	62.54	3.59	66.13		86.12	
10	2014	337.19	27.12	18.04	9.08	13.36	12.24	43.63	19.92		9.183	6.57	60.33	3.68	64.01		83.93	
11	2015	328.11	27.12	17.55	9.56	13.36	12.54	43.45	19.84		9.183	6.33	58.12	3.77	61.89		81.73	
12	2016	318.55	27.12	17.04	10.07	13.36	12.86	43.26	19.75		9.183	6.49	59.58	3.87	63.45		83.20	
13	2017	308.48	27.12	16.50	10.61	13.36	13.18	43.04	19.65		9.183	6.81	62.52	3.96	66.49		86.14	
14	2018	297.86	27.12	15.94	11.18	13.36	13.52	42.81	19.55		9.183	7.24	66.46	4.06	70.52		90.07	
15	2019	286.69	27.12	15.34	11.78	13.36	13.86	42.55	19.43		9.183	7.69	70.63	4.17	74.79		94.22	
16	2020	274.91	27.12	14.71	12.41	13.36	14.20	42.27	19.30		9.183	8.06	73.99	4.27	78.26		97.56	
17	2021	262.50	27.12	14.04	13.07	13.36	14.56	41.96	19.16		9.183	8.40	77.09	4.38	81.47		100.63	
18	2022	249.43	27.12	13.34	13.77	13.36	14.93	41.63	19.01		9.183	8.66	79.49	4.49	83.98		102.99	
19	2023	235.66	27.12	12.61	14.51	13.36	15.30	41.27	18.84		9.183	8.86	81.36	4.60	85.97		104.81	
20	2024	221.15	27.12	11.83	15.28	13.36	15.69	40.88	18.66		9.183	9.21	84.57	4.72	89.29		107.95	
21	2025	205.86	27.12	11.01	16.10	13.36	16.08	40.45	18.47		9.183	9.61	88.24	4.84	93.07		111.54	
22	2026	189.76	27.12	10.15	16.96	13.36	16.49	40.00	18.26		9.183	9.95	91.40	4.96	96.36		114.62	
23	2027	172.80	27.12	9.24	17.87	13.36	16.90	39.50	18.04		9.183	10.30	94.56	5.08	99.65		117.68	
24	2028	154.93	27.12	8.29	18.83	13.36	17.33	38.97	17.80		9.183	10.66	97.90	5.21	103.12		120.91	
25	2029	136.10	27.12	7.28	19.83	13.36	17.76	38.40	17.53		9.183	11.06	101.60	5.34	106.94		124.47	
26	2030	116.27	27.12	6.22	20.90	13.36	18.21	37.79	17.25		9.183	11.48	105.39	5.48	110.87		128.12	
27	2031	95.37	27.12	5.10	22.01	13.36	18.67	37.13	16.95		9.183	11.89	109.21	5.61	114.82		131.77	
28	2032	73.36	27.12	3.92	23.19	13.36	19.14	36.42	16.63		9.183	12.32	113.16	5.76	118.92		135.55	
29	2033	50.17	27.12	2.68	24.43	13.36	19.62	35.66	16.28		9.183	12.77	117.30	5.90	123.20		139.48	
30	2034	25.74	27.12	1.38	25.74	13.36	20.11	34.85	15.91		9.183	13.24	121.62	6.05	127.67		143.58	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Fuel Cells
Capital Cost		4,250.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	4,267.00
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	42.40
Fixed O&M	($/kW-Yr)	5.00
Capacity Factor	(%)	70.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	7.93

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	1,387.43	37.11	-	1,424.54
2	2003	33.33%	1,422.33	38.05	76.21	2,961.13
3	2004	33.33%	1,458.12	39.00	158.42	4,616.68
4		0.00%	-	-	-	4,616.68
5		0.00%	-	-	-	4,616.68

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	4,616.68	312.41	246.99	65.42	153.89	5.25	406.14	66.23	$56.63	7.93	8.42	66.79	44.56	111.36	$126.89	177.59	$183.52
2	2006	4,551.26	312.41	243.49	68.92	153.89	5.39	402.77	65.68		7.93	10.31	81.77	45.68	127.45		193.14	
3	2007	4,482.34	312.41	239.81	72.60	153.89	5.52	399.22	65.10		7.93	9.10	72.17	46.83	119.00		184.11	
4	2008	4,409.74	312.41	235.92	76.49	153.89	5.66	395.47	64.49		7.93	8.43	66.86	48.01	114.87		179.37	
5	2009	4,333.25	312.41	231.83	80.58	153.89	5.80	391.52	63.85		7.93	7.94	62.94	49.22	112.16		176.01	
6	2010	4,252.67	312.41	227.52	84.89	153.89	5.95	387.36	63.17		7.93	7.53	59.73	50.45	110.18		173.35	
7	2011	4,167.78	312.41	222.98	89.43	153.89	6.10	382.97	62.45		7.93	7.29	57.82	51.72	109.55		172.00	
8	2012	4,078.35	312.41	218.19	94.22	153.89	6.25	378.33	61.70		7.93	7.05	55.91	53.03	108.94		170.64	
9	2013	3,984.13	312.41	213.15	99.26	153.89	6.41	373.45	60.90		7.93	6.81	54.00	54.36	108.36		169.27	
10	2014	3,884.88	312.41	207.84	104.57	153.89	6.57	368.30	60.06		7.93	6.57	52.10	55.73	107.82		167.89	
11	2015	3,780.31	312.41	202.25	110.16	153.89	6.74	362.87	59.18		7.93	6.33	50.19	57.13	107.32		166.50	
12	2016	3,670.15	312.41	196.35	116.06	153.89	6.91	357.15	58.24		7.93	6.49	51.45	58.57	110.02		168.26	
13	2017	3,554.09	312.41	190.14	122.26	153.89	7.08	351.11	57.26		7.93	6.81	53.99	60.04	114.03		171.29	
14	2018	3,431.83	312.41	183.60	128.81	153.89	7.26	344.75	56.22		7.93	7.24	57.39	61.55	118.94		175.16	
15	2019	3,303.02	312.41	176.71	135.70	153.89	7.44	338.04	55.13		7.93	7.69	60.99	63.10	124.09		179.22	
16	2020	3,167.32	312.41	169.45	142.96	153.89	7.63	330.97	53.97		7.93	8.06	63.89	64.69	128.58		182.55	
17	2021	3,024.37	312.41	161.80	150.61	153.89	7.82	323.51	52.76		7.93	8.40	66.58	66.31	132.89		185.65	
18	2022	2,873.76	312.41	153.75	158.66	153.89	8.02	315.65	51.48		7.93	8.66	68.65	67.98	136.63		188.10	
19	2023	2,715.10	312.41	145.26	167.15	153.89	8.22	307.37	50.12		7.93	8.86	70.26	69.69	139.96		190.08	
20	2024	2,547.95	312.41	136.32	176.09	153.89	8.43	298.63	48.70		7.93	9.21	73.03	71.45	144.48		193.18	
21	2025	2,371.86	312.41	126.89	185.51	153.89	8.64	289.42	47.20		7.93	9.61	76.20	73.24	149.44		196.64	
22	2026	2,186.34	312.41	116.97	195.44	153.89	8.85	279.71	45.62		7.93	9.95	78.93	75.09	154.01		199.63	
23	2027	1,990.90	312.41	106.51	205.90	153.89	9.08	269.48	43.95		7.93	10.30	81.66	76.98	158.64		202.58	
24	2028	1,785.01	312.41	95.50	216.91	153.89	9.31	258.69	42.19		7.93	10.66	84.55	78.91	163.46		205.65	
25	2029	1,568.10	312.41	83.89	228.52	153.89	9.54	247.32	40.33		7.93	11.06	87.73	80.90	168.63		208.96	
26	2030	1,339.58	312.41	71.67	240.74	153.89	9.78	235.34	38.38		7.93	11.48	91.01	82.93	173.94		212.32	
27	2031	1,098.84	312.41	58.79	253.62	153.89	10.03	222.70	36.32		7.93	11.89	94.30	85.02	179.32		215.64	
28	2032	845.22	312.41	45.22	267.19	153.89	10.28	209.39	34.15		7.93	12.32	97.72	87.16	184.88		219.03	
29	2033	578.03	312.41	30.92	281.48	153.89	10.54	195.35	31.86		7.93	12.77	101.30	89.35	190.65		222.50	
30	2034	296.54	312.41	15.87	296.54	153.89	10.80	180.56	29.44		7.93	13.24	105.02	91.60	196.62		226.07	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Base Distributed
Capital Cost		807.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	810.23
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	6.30
Fixed O&M	($/kW-Yr)	14.18
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	9.95

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	263.45	7.05	-	270.50
2	2003	33.33%	270.08	7.22	14.47	562.27
3	2004	33.33%	276.87	7.41	30.08	876.63
4		0.00%	-	-	-	876.63
5		0.00%	-	-	-	876.63

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	876.63	59.32	46.90	12.42	29.22	14.90	91.02	11.55	$10.72	9.95	8.42	83.81	6.62	90.43	$93.45	101.98	$104.17
2	2006	864.20	59.32	46.23	13.09	29.22	15.28	90.73	11.51		9.95	10.31	102.60	6.79	109.39		120.90	
3	2007	851.12	59.32	45.53	13.79	29.22	15.66	90.42	11.47		9.95	9.10	90.55	6.96	97.51		108.98	
4	2008	837.33	59.32	44.80	14.52	29.22	16.06	90.07	11.42		9.95	8.43	83.90	7.13	91.03		102.45	
5	2009	822.81	59.32	44.02	15.30	29.22	16.46	89.70	11.38		9.95	7.94	78.97	7.31	86.29		97.67	
6	2010	807.51	59.32	43.20	16.12	29.22	16.87	89.30	11.33		9.95	7.53	74.94	7.50	82.44		93.77	
7	2011	791.39	59.32	42.34	16.98	29.22	17.30	88.86	11.27		9.95	7.29	72.55	7.69	80.23		91.51	
8	2012	774.41	59.32	41.43	17.89	29.22	17.73	88.39	11.21		9.95	7.05	70.16	7.88	78.03		89.24	
9	2013	756.52	59.32	40.47	18.85	29.22	18.18	87.87	11.15		9.95	6.81	67.76	8.08	75.84		86.98	
10	2014	737.67	59.32	39.47	19.86	29.22	18.64	87.32	11.08		9.95	6.57	65.37	8.28	73.65		84.72	
11	2015	717.81	59.32	38.40	20.92	29.22	19.11	86.73	11.00		9.95	6.33	62.97	8.49	71.46		82.46	
12	2016	696.90	59.32	37.28	22.04	29.22	19.59	86.09	10.92		9.95	6.49	64.56	8.70	73.26		84.18	
13	2017	674.86	59.32	36.10	23.22	29.22	20.08	85.41	10.83		9.95	6.81	67.74	8.92	76.66		87.50	
14	2018	651.64	59.32	34.86	24.46	29.22	20.58	84.67	10.74		9.95	7.24	72.01	9.15	81.16		91.90	
15	2019	627.19	59.32	33.55	25.77	29.22	21.10	83.88	10.64		9.95	7.69	76.53	9.38	85.90		96.54	
16	2020	601.42	59.32	32.18	27.14	29.22	21.63	83.03	10.53		9.95	8.06	80.17	9.61	89.78		100.31	
17	2021	574.27	59.32	30.72	28.60	29.22	22.18	82.12	10.42		9.95	8.40	83.53	9.85	93.39		103.80	
18	2022	545.68	59.32	29.19	30.13	29.22	22.74	81.15	10.29		9.95	8.66	86.13	10.10	96.23		106.53	
19	2023	515.55	59.32	27.58	31.74	29.22	23.31	80.11	10.16		9.95	8.86	88.16	10.36	98.52		108.68	
20	2024	483.81	59.32	25.88	33.44	29.22	23.89	79.00	10.02		9.95	9.21	91.63	10.62	102.25		112.27	
21	2025	450.37	59.32	24.09	35.23	29.22	24.50	77.81	9.87		9.95	9.61	95.61	10.88	106.49		116.36	
22	2026	415.15	59.32	22.21	37.11	29.22	25.11	76.54	9.71		9.95	9.95	99.03	11.16	110.19		119.90	
23	2027	378.04	59.32	20.22	39.10	29.22	25.74	75.19	9.54		9.95	10.30	102.46	11.44	113.90		123.44	
24	2028	338.94	59.32	18.13	41.19	29.22	26.39	73.75	9.35		9.95	10.66	106.08	11.73	117.81		127.16	
25	2029	297.75	59.32	15.93	43.39	29.22	27.05	72.21	9.16		9.95	11.06	110.08	12.02	122.10		131.26	
26	2030	254.36	59.32	13.61	45.71	29.22	27.74	70.56	8.95		9.95	11.48	114.20	12.32	126.52		135.47	
27	2031	208.65	59.32	11.16	48.16	29.22	28.43	68.82	8.73		9.95	11.89	118.33	12.63	130.96		139.69	
28	2032	160.49	59.32	8.59	50.73	29.22	29.15	66.96	8.49		9.95	12.32	122.61	12.95	135.57		144.06	
29	2033	109.76	59.32	5.87	53.45	29.22	29.88	64.97	8.24		9.95	12.77	127.10	13.28	140.37		148.62	
30	2034	56.31	59.32	3.01	56.31	29.22	30.63	62.87	7.97		9.95	13.24	131.78	13.61	145.39		153.36	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Peak Distributed
Capital Cost		970.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	973.88
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	6.30
Fixed O&M	($/kW-Yr)	14.18
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	11.2

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	486.94	13.03	-	499.97
2	2004	50.00%	499.19	13.35	26.75	1,039.26
3		0.00%	-	-	-	1,039.26
4		0.00%	-	-	-	1,039.26
5		0.00%	-	-	-	1,039.26

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,039.26	70.33	55.60	14.73	34.64	14.90	105.14	48.01	$44.05	11.2	8.42	94.34	6.62	100.96	$104.08	148.97	$148.13
2	2006	1,024.53	70.33	54.81	15.51	34.64	15.28	104.73	47.82		11.2	10.31	115.49	6.79	122.28		170.10	
3	2007	1,009.02	70.33	53.98	16.34	34.64	15.66	104.29	47.62		11.2	9.10	101.93	6.96	108.89		156.51	
4	2008	992.67	70.33	53.11	17.22	34.64	16.06	103.81	47.40		11.2	8.43	94.44	7.13	101.57		148.97	
5	2009	975.46	70.33	52.19	18.14	34.64	16.46	103.29	47.16		11.2	7.94	88.90	7.31	96.21		143.37	
6	2010	957.32	70.33	51.22	19.11	34.64	16.87	102.73	46.91		11.2	7.53	84.36	7.50	91.86		138.76	
7	2011	938.21	70.33	50.19	20.13	34.64	17.30	102.13	46.64		11.2	7.29	81.66	7.69	89.35		135.99	
8	2012	918.08	70.33	49.12	21.21	34.64	17.73	101.49	46.34		11.2	7.05	78.97	7.88	86.85		133.19	
9	2013	896.87	70.33	47.98	22.34	34.64	18.18	100.80	46.03		11.2	6.81	76.27	8.08	84.35		130.38	
10	2014	874.52	70.33	46.79	23.54	34.64	18.64	100.07	45.69		11.2	6.57	73.58	8.28	81.86		127.55	
11	2015	850.98	70.33	45.53	24.80	34.64	19.11	99.28	45.33		11.2	6.33	70.88	8.49	79.37		124.70	
12	2016	826.19	70.33	44.20	26.13	34.64	19.59	98.43	44.94		11.2	6.49	72.67	8.70	81.37		126.32	
13	2017	800.06	70.33	42.80	27.52	34.64	20.08	97.52	44.53		11.2	6.81	76.25	8.92	85.17		129.71	
14	2018	772.54	70.33	41.33	29.00	34.64	20.58	96.56	44.09		11.2	7.24	81.06	9.15	90.20		134.29	
15	2019	743.54	70.33	39.78	30.55	34.64	21.10	95.52	43.62		11.2	7.69	86.14	9.38	95.52		139.13	
16	2020	712.99	70.33	38.15	32.18	34.64	21.63	94.42	43.11		11.2	8.06	90.24	9.61	99.85		142.97	
17	2021	680.81	70.33	36.42	33.90	34.64	22.18	93.24	42.58		11.2	8.40	94.03	9.85	103.88		146.46	
18	2022	646.91	70.33	34.61	35.72	34.64	22.74	91.99	42.00		11.2	8.66	96.95	10.10	107.05		149.06	
19	2023	611.19	70.33	32.70	37.63	34.64	23.31	90.65	41.39		11.2	8.86	99.24	10.36	109.59		150.98	
20	2024	573.57	70.33	30.69	39.64	34.64	23.89	89.22	40.74		11.2	9.21	103.14	10.62	113.76		154.50	
21	2025	533.93	70.33	28.57	41.76	34.64	24.50	87.70	40.05		11.2	9.61	107.62	10.88	118.50		158.55	
22	2026	492.17	70.33	26.33	44.00	34.64	25.11	86.08	39.31		11.2	9.95	111.47	11.16	122.63		161.94	
23	2027	448.17	70.33	23.98	46.35	34.64	25.74	84.36	38.52		11.2	10.30	115.33	11.44	126.77		165.29	
24	2028	401.82	70.33	21.50	48.83	34.64	26.39	82.53	37.69		11.2	10.66	119.41	11.73	131.13		168.82	
25	2029	352.99	70.33	18.89	51.44	34.64	27.05	80.58	36.80		11.2	11.06	123.91	12.02	135.93		172.73	
26	2030	301.55	70.33	16.13	54.19	34.64	27.74	78.51	35.85		11.2	11.48	128.54	12.32	140.86		176.71	
27	2031	247.36	70.33	13.23	57.09	34.64	28.43	76.31	34.84		11.2	11.89	133.19	12.63	145.82		180.67	
28	2032	190.27	70.33	10.18	60.15	34.64	29.15	73.97	33.78		11.2	12.32	138.02	12.95	150.97		184.75	
29	2033	130.12	70.33	6.96	63.36	34.64	29.88	71.49	32.64		11.2	12.77	143.06	13.28	156.34		188.98	
30	2034	66.75	70.33	3.57	66.75	34.64	30.63	68.85	31.44		11.2	13.24	148.33	13.61	161.94		193.38	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Biomass
Capital Cost		1,757.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,764.03
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	2.96
Fixed O&M	($/kW-Yr)	47.18
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	419.63	11.23	-	430.85
2	2002	25.00%	430.18	11.51	23.05	895.59
3	2003	25.00%	441.01	11.80	47.91	1,396.31
4	2004	25.00%	452.10	12.09	74.70	1,935.21
5		0.00%	-	-	-	1,935.21

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,935.21	130.95	103.53	27.42	64.51	49.58	217.62	31.05	$29.79	0	-	-	3.11	3.11	$4.15	34.16	$33.94
2	2006	1,907.79	130.95	102.07	28.89	64.51	50.83	217.41	31.02		0	-	-	3.19	3.19		34.21	
3	2007	1,878.90	130.95	100.52	30.43	64.51	52.11	217.14	30.98		0	-	-	3.27	3.27		34.25	
4	2008	1,848.47	130.95	98.89	32.06	64.51	53.42	216.82	30.94		0	-	-	3.35	3.35		34.29	
5	2009	1,816.41	130.95	97.18	33.78	64.51	54.77	216.45	30.89		0	-	-	3.44	3.44		34.32	
6	2010	1,782.63	130.95	95.37	35.58	64.51	56.14	216.02	30.82		0	-	-	3.52	3.52		34.35	
7	2011	1,747.04	130.95	93.47	37.49	64.51	57.56	215.53	30.75		0	-	-	3.61	3.61		34.37	
8	2012	1,709.56	130.95	91.46	39.49	64.51	59.00	214.97	30.68		0	-	-	3.70	3.70		34.38	
9	2013	1,670.06	130.95	89.35	41.61	64.51	60.49	214.34	30.59		0	-	-	3.79	3.79		34.38	
10	2014	1,628.46	130.95	87.12	43.83	64.51	62.01	213.64	30.49		0	-	-	3.89	3.89		34.38	
11	2015	1,584.62	130.95	84.78	46.18	64.51	63.57	212.85	30.37		0	-	-	3.99	3.99		34.36	
12	2016	1,538.45	130.95	82.31	48.65	64.51	65.17	211.98	30.25		0	-	-	4.09	4.09		34.34	
13	2017	1,489.80	130.95	79.70	51.25	64.51	66.81	211.02	30.11		0	-	-	4.19	4.19		34.30	
14	2018	1,438.55	130.95	76.96	53.99	64.51	68.49	209.96	29.96		0	-	-	4.30	4.30		34.26	
15	2019	1,384.55	130.95	74.07	56.88	64.51	70.21	208.79	29.79		0	-	-	4.41	4.41		34.20	
16	2020	1,327.67	130.95	71.03	59.92	64.51	71.98	207.52	29.61		0	-	-	4.52	4.52		34.13	
17	2021	1,267.75	130.95	67.82	63.13	64.51	73.79	206.12	29.41		0	-	-	4.63	4.63		34.04	
18	2022	1,204.62	130.95	64.45	66.51	64.51	75.65	204.60	29.20		0	-	-	4.75	4.75		33.94	
19	2023	1,138.11	130.95	60.89	70.07	64.51	77.55	202.95	28.96		0	-	-	4.87	4.87		33.82	
20	2024	1,068.04	130.95	57.14	73.81	64.51	79.50	201.15	28.70		0	-	-	4.99	4.99		33.69	
21	2025	994.23	130.95	53.19	77.76	64.51	81.50	199.20	28.42		0	-	-	5.11	5.11		33.54	
22	2026	916.47	130.95	49.03	81.92	64.51	83.55	197.09	28.12		0	-	-	5.24	5.24		33.37	
23	2027	834.54	130.95	44.65	86.31	64.51	85.65	194.81	27.80		0	-	-	5.37	5.37		33.17	
24	2028	748.24	130.95	40.03	90.92	64.51	87.81	192.35	27.45		0	-	-	5.51	5.51		32.96	
25	2029	657.31	130.95	35.17	95.79	64.51	90.02	189.69	27.07		0	-	-	5.65	5.65		32.72	
26	2030	561.52	130.95	30.04	100.91	64.51	92.28	186.83	26.66		0	-	-	5.79	5.79		32.45	
27	2031	460.61	130.95	24.64	106.31	64.51	94.60	183.75	26.22		0	-	-	5.94	5.94		32.16	
28	2032	354.30	130.95	18.95	112.00	64.51	96.98	180.45	25.75		0	-	-	6.08	6.08		31.83	
29	2033	242.30	130.95	12.96	117.99	64.51	99.42	176.89	25.24		0	-	-	6.24	6.24		31.48	
30	2034	124.30	130.95	6.65	124.30	64.51	101.93	173.08	24.70		0	-	-	6.39	6.39		31.09	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Landfill Gas
Capital Cost		1,500.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,506.00
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	0.01
Fixed O&M	($/kW-Yr)	101.07
Capacity Factor	(%)	98.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	489.68	13.10	-	502.78
2	2003	33.33%	502.00	13.43	26.90	1,045.11
3	2004	33.33%	514.63	13.77	55.91	1,629.42
4		0.00%	-	-	-	1,629.42
5		0.00%	-	-	-	1,629.42

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,629.42	110.26	87.17	23.09	54.31	106.22	247.71	28.85	$30.49	0	-	-	0.01	0.01	$0.01	28.86	$30.51
2	2006	1,606.33	110.26	85.94	24.32	54.31	108.89	249.14	29.02		0	-	-	0.01	0.01		29.03	
3	2007	1,582.00	110.26	84.64	25.62	54.31	111.63	250.58	29.19		0	-	-	0.01	0.01		29.20	
4	2008	1,556.38	110.26	83.27	27.00	54.31	114.44	252.02	29.36		0	-	-	0.01	0.01		29.37	
5	2009	1,529.38	110.26	81.82	28.44	54.31	117.32	253.46	29.52		0	-	-	0.01	0.01		29.54	
6	2010	1,500.94	110.26	80.30	29.96	54.31	120.27	254.89	29.69		0	-	-	0.01	0.01		29.70	
7	2011	1,470.98	110.26	78.70	31.56	54.31	123.30	256.31	29.86		0	-	-	0.01	0.01		29.87	
8	2012	1,439.42	110.26	77.01	33.25	54.31	126.40	257.72	30.02		0	-	-	0.01	0.01		30.03	
9	2013	1,406.17	110.26	75.23	35.03	54.31	129.58	259.12	30.18		0	-	-	0.01	0.01		30.20	
10	2014	1,371.13	110.26	73.36	36.91	54.31	132.84	260.51	30.35		0	-	-	0.01	0.01		30.36	
11	2015	1,334.23	110.26	71.38	38.88	54.31	136.18	261.88	30.50		0	-	-	0.01	0.01		30.52	
12	2016	1,295.35	110.26	69.30	40.96	54.31	139.61	263.22	30.66		0	-	-	0.01	0.01		30.68	
13	2017	1,254.39	110.26	67.11	43.15	54.31	143.12	264.54	30.82		0	-	-	0.01	0.01		30.83	
14	2018	1,211.23	110.26	64.80	45.46	54.31	146.72	265.83	30.97		0	-	-	0.01	0.01		30.98	
15	2019	1,165.77	110.26	62.37	47.89	54.31	150.41	267.09	31.11		0	-	-	0.01	0.01		31.13	
16	2020	1,117.88	110.26	59.81	50.46	54.31	154.20	268.32	31.25		0	-	-	0.02	0.02		31.27	
17	2021	1,067.42	110.26	57.11	53.15	54.31	158.08	269.50	31.39		0	-	-	0.02	0.02		31.41	
18	2022	1,014.27	110.26	54.26	56.00	54.31	162.05	270.63	31.52		0	-	-	0.02	0.02		31.54	
19	2023	958.27	110.26	51.27	58.99	54.31	166.13	271.71	31.65		0	-	-	0.02	0.02		31.67	
20	2024	899.28	110.26	48.11	62.15	54.31	170.31	272.73	31.77		0	-	-	0.02	0.02		31.79	
21	2025	837.13	110.26	44.79	65.48	54.31	174.59	273.69	31.88		0	-	-	0.02	0.02		31.90	
22	2026	771.65	110.26	41.28	68.98	54.31	178.99	274.58	31.98		0	-	-	0.02	0.02		32.00	
23	2027	702.67	110.26	37.59	72.67	54.31	183.49	275.40	32.08		0	-	-	0.02	0.02		32.10	
24	2028	630.00	110.26	33.71	76.56	54.31	188.11	276.12	32.16		0	-	-	0.02	0.02		32.18	
25	2029	553.45	110.26	29.61	80.65	54.31	192.84	276.76	32.24		0	-	-	0.02	0.02		32.26	
26	2030	472.79	110.26	25.29	84.97	54.31	197.69	277.30	32.30		0	-	-	0.02	0.02		32.32	
27	2031	387.83	110.26	20.75	89.51	54.31	202.66	277.73	32.35		0	-	-	0.02	0.02		32.37	
28	2032	298.31	110.26	15.96	94.30	54.31	207.76	278.04	32.39		0	-	-	0.02	0.02		32.41	
29	2033	204.01	110.26	10.91	99.35	54.31	212.99	278.22	32.41		0	-	-	0.02	0.02		32.43	
30	2034	104.66	110.26	5.60	104.66	54.31	218.35	278.26	32.41		0	-	-	0.02	0.02		32.43	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Geothermal
Capital Cost		3,108.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	3,120.43
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	104.98
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	742.29	19.86	-	762.14
2	2002	25.00%	760.96	20.36	40.77	1,584.24
3	2003	25.00%	780.11	20.87	84.76	2,469.97
4	2004	25.00%	799.73	21.39	132.14	3,423.24
5		0.00%	-	-	-	3,423.24

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	3,423.24	231.65	183.14	48.51	114.11	110.33	407.58	93.05	$91.20	0	-	-	-	-	$0.00	93.05	$91.20
2	2006	3,374.74	231.65	180.55	51.10	114.11	113.10	407.76	93.10		0	-	-	-	-		93.10	
3	2007	3,323.63	231.65	177.81	53.83	114.11	115.95	407.87	93.12		0	-	-	-	-		93.12	
4	2008	3,269.80	231.65	174.93	56.72	114.11	118.87	407.91	93.13		0	-	-	-	-		93.13	
5	2009	3,213.08	231.65	171.90	59.75	114.11	121.86	407.87	93.12		0	-	-	-	-		93.12	
6	2010	3,153.33	231.65	168.70	62.95	114.11	124.92	407.74	93.09		0	-	-	-	-		93.09	
7	2011	3,090.39	231.65	165.34	66.31	114.11	128.07	407.51	93.04		0	-	-	-	-		93.04	
8	2012	3,024.08	231.65	161.79	69.86	114.11	131.29	407.18	92.96		0	-	-	-	-		92.96	
9	2013	2,954.21	231.65	158.05	73.60	114.11	134.59	406.75	92.87		0	-	-	-	-		92.87	
10	2014	2,880.62	231.65	154.11	77.54	114.11	137.98	406.20	92.74		0	-	-	-	-		92.74	
11	2015	2,803.08	231.65	149.96	81.68	114.11	141.45	405.52	92.58		0	-	-	-	-		92.58	
12	2016	2,721.39	231.65	145.59	86.05	114.11	145.01	404.71	92.40		0	-	-	-	-		92.40	
13	2017	2,635.34	231.65	140.99	90.66	114.11	148.66	403.75	92.18		0	-	-	-	-		92.18	
14	2018	2,544.68	231.65	136.14	95.51	114.11	152.40	402.64	91.93		0	-	-	-	-		91.93	
15	2019	2,449.17	231.65	131.03	100.62	114.11	156.23	401.37	91.64		0	-	-	-	-		91.64	
16	2020	2,348.55	231.65	125.65	106.00	114.11	160.16	399.92	91.31		0	-	-	-	-		91.31	
17	2021	2,242.55	231.65	119.98	111.67	114.11	164.19	398.27	90.93		0	-	-	-	-		90.93	
18	2022	2,130.88	231.65	114.00	117.65	114.11	168.32	396.43	90.51		0	-	-	-	-		90.51	
19	2023	2,013.23	231.65	107.71	123.94	114.11	172.56	394.37	90.04		0	-	-	-	-		90.04	
20	2024	1,889.29	231.65	101.08	130.57	114.11	176.90	392.08	89.52		0	-	-	-	-		89.52	
21	2025	1,758.72	231.65	94.09	137.56	114.11	181.35	389.55	88.94		0	-	-	-	-		88.94	
22	2026	1,621.16	231.65	86.73	144.92	114.11	185.91	386.75	88.30		0	-	-	-	-		88.30	
23	2027	1,476.24	231.65	78.98	152.67	114.11	190.59	383.67	87.60		0	-	-	-	-		87.60	
24	2028	1,323.57	231.65	70.81	160.84	114.11	195.38	380.30	86.83		0	-	-	-	-		86.83	
25	2029	1,162.73	231.65	62.21	169.44	114.11	200.30	376.61	85.98		0	-	-	-	-		85.98	
26	2030	993.29	231.65	53.14	178.51	114.11	205.34	372.59	85.07		0	-	-	-	-		85.07	
27	2031	814.78	231.65	43.59	188.06	114.11	210.50	368.20	84.06		0	-	-	-	-		84.06	
28	2032	626.72	231.65	33.53	198.12	114.11	215.80	363.44	82.98		0	-	-	-	-		82.98	
29	2033	428.60	231.65	22.93	208.72	114.11	221.23	358.27	81.80		0	-	-	-	-		81.80	
30	2034	219.89	231.65	11.76	219.89	114.11	226.79	352.67	80.52		0	-	-	-	-		80.52	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Wind
Capital Cost		1,134.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,138.54
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	26.81
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	370.20	9.90	-	380.10
2	2003	33.33%	379.51	10.15	20.34	790.10
3	2004	33.33%	389.06	10.41	42.27	1,231.84
4		0.00%	-	-	-	1,231.84
5		0.00%	-	-	-	1,231.84

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,231.84	83.36	65.90	17.45	41.06	28.18	135.14	30.85	$29.31	0	-	-	-	-	$0.00	30.85	$29.31
2	2006	1,214.38	83.36	64.97	18.39	41.06	28.88	134.92	30.80		0	-	-	-	-		30.80	
3	2007	1,196.00	83.36	63.99	19.37	41.06	29.61	134.66	30.74		0	-	-	-	-		30.74	
4	2008	1,176.62	83.36	62.95	20.41	41.06	30.36	134.37	30.68		0	-	-	-	-		30.68	
5	2009	1,156.21	83.36	61.86	21.50	41.06	31.12	134.04	30.60		0	-	-	-	-		30.60	
6	2010	1,134.71	83.36	60.71	22.65	41.06	31.90	133.67	30.52		0	-	-	-	-		30.52	
7	2011	1,112.06	83.36	59.50	23.86	41.06	32.71	133.26	30.43		0	-	-	-	-		30.43	
8	2012	1,088.20	83.36	58.22	25.14	41.06	33.53	132.81	30.32		0	-	-	-	-		30.32	
9	2013	1,063.06	83.36	56.87	26.48	41.06	34.37	132.31	30.21		0	-	-	-	-		30.21	
10	2014	1,036.58	83.36	55.46	27.90	41.06	35.24	131.76	30.08		0	-	-	-	-		30.08	
11	2015	1,008.68	83.36	53.96	29.39	41.06	36.12	131.15	29.94		0	-	-	-	-		29.94	
12	2016	979.28	83.36	52.39	30.97	41.06	37.03	130.49	29.79		0	-	-	-	-		29.79	
13	2017	948.32	83.36	50.73	32.62	41.06	37.96	129.76	29.63		0	-	-	-	-		29.63	
14	2018	915.69	83.36	48.99	34.37	41.06	38.92	128.97	29.45		0	-	-	-	-		29.45	
15	2019	881.32	83.36	47.15	36.21	41.06	39.90	128.11	29.25		0	-	-	-	-		29.25	
16	2020	845.12	83.36	45.21	38.14	41.06	40.90	127.18	29.04		0	-	-	-	-		29.04	
17	2021	806.97	83.36	43.17	40.18	41.06	41.93	126.17	28.80		0	-	-	-	-		28.80	
18	2022	766.79	83.36	41.02	42.33	41.06	42.99	125.07	28.55		0	-	-	-	-		28.55	
19	2023	724.45	83.36	38.76	44.60	41.06	44.07	123.89	28.28		0	-	-	-	-		28.28	
20	2024	679.85	83.36	36.37	46.99	41.06	45.18	122.61	27.99		0	-	-	-	-		27.99	
21	2025	632.87	83.36	33.86	49.50	41.06	46.31	121.23	27.68		0	-	-	-	-		27.68	
22	2026	583.37	83.36	31.21	52.15	41.06	47.48	119.75	27.34		0	-	-	-	-		27.34	
23	2027	531.22	83.36	28.42	54.94	41.06	48.67	118.15	26.98		0	-	-	-	-		26.98	
24	2028	476.28	83.36	25.48	57.88	41.06	49.90	116.44	26.58		0	-	-	-	-		26.58	
25	2029	418.40	83.36	22.38	60.97	41.06	51.15	114.60	26.16		0	-	-	-	-		26.16	
26	2030	357.43	83.36	19.12	64.24	41.06	52.44	112.62	25.71		0	-	-	-	-		25.71	
27	2031	293.20	83.36	15.69	67.67	41.06	53.76	110.51	25.23		0	-	-	-	-		25.23	
28	2032	225.52	83.36	12.07	71.29	41.06	55.11	108.24	24.71		0	-	-	-	-		24.71	
29	2033	154.23	83.36	8.25	75.11	41.06	56.50	105.81	24.16		0	-	-	-	-		24.16	
30	2034	79.12	83.36	4.23	79.12	41.06	57.92	103.21	23.56		0	-	-	-	-		23.56	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Solar Thermal
Capital Cost		2,960.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	2,971.84
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	50.23
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	966.30	25.85	-	992.15
2	2003	33.33%	990.61	26.50	53.08	2,062.34
3	2004	33.33%	1,015.54	27.17	110.34	3,215.38
4		0.00%	-	-	-	3,215.38
5		0.00%	-	-	-	3,215.38

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	3,215.38	217.58	172.02	45.56	107.18	52.79	331.99	75.80	$70.18	0	-	-	-	-	$0.00	75.80	$70.18
2	2006	3,169.82	217.58	169.59	48.00	107.18	54.12	330.88	75.54		0	-	-	-	-		75.54	
3	2007	3,121.82	217.58	167.02	50.57	107.18	55.48	329.68	75.27		0	-	-	-	-		75.27	
4	2008	3,071.26	217.58	164.31	53.27	107.18	56.87	328.37	74.97		0	-	-	-	-		74.97	
5	2009	3,017.98	217.58	161.46	56.12	107.18	58.31	326.95	74.65		0	-	-	-	-		74.65	
6	2010	2,961.86	217.58	158.46	59.12	107.18	59.77	325.41	74.29		0	-	-	-	-		74.29	
7	2011	2,902.74	217.58	155.30	62.29	107.18	61.28	323.75	73.92		0	-	-	-	-		73.92	
8	2012	2,840.45	217.58	151.96	65.62	107.18	62.82	321.96	73.51		0	-	-	-	-		73.51	
9	2013	2,774.83	217.58	148.45	69.13	107.18	64.40	320.03	73.07		0	-	-	-	-		73.07	
10	2014	2,705.70	217.58	144.76	72.83	107.18	66.02	317.95	72.59		0	-	-	-	-		72.59	
11	2015	2,632.87	217.58	140.86	76.72	107.18	67.68	315.72	72.08		0	-	-	-	-		72.08	
12	2016	2,556.15	217.58	136.75	80.83	107.18	69.38	313.32	71.53		0	-	-	-	-		71.53	
13	2017	2,475.32	217.58	132.43	85.15	107.18	71.13	310.74	70.94		0	-	-	-	-		70.94	
14	2018	2,390.17	217.58	127.87	89.71	107.18	72.92	307.97	70.31		0	-	-	-	-		70.31	
15	2019	2,300.46	217.58	123.07	94.51	107.18	74.75	305.01	69.64		0	-	-	-	-		69.64	
16	2020	2,205.95	217.58	118.02	99.57	107.18	76.63	301.83	68.91		0	-	-	-	-		68.91	
17	2021	2,106.38	217.58	112.69	104.89	107.18	78.56	298.43	68.14		0	-	-	-	-		68.14	
18	2022	2,001.49	217.58	107.08	110.50	107.18	80.54	294.80	67.31		0	-	-	-	-		67.31	
19	2023	1,890.99	217.58	101.17	116.42	107.18	82.56	290.91	66.42		0	-	-	-	-		66.42	
20	2024	1,774.57	217.58	94.94	122.64	107.18	84.64	286.76	65.47		0	-	-	-	-		65.47	
21	2025	1,651.93	217.58	88.38	129.21	107.18	86.77	282.33	64.46		0	-	-	-	-		64.46	
22	2026	1,522.72	217.58	81.47	136.12	107.18	88.95	277.60	63.38		0	-	-	-	-		63.38	
23	2027	1,386.60	217.58	74.18	143.40	107.18	91.19	272.55	62.23		0	-	-	-	-		62.23	
24	2028	1,243.20	217.58	66.51	151.07	107.18	93.49	267.18	61.00		0	-	-	-	-		61.00	
25	2029	1,092.13	217.58	58.43	159.15	107.18	95.84	261.45	59.69		0	-	-	-	-		59.69	
26	2030	932.98	217.58	49.91	167.67	107.18	98.25	255.34	58.30		0	-	-	-	-		58.30	
27	2031	765.31	217.58	40.94	176.64	107.18	100.72	248.84	56.81		0	-	-	-	-		56.81	
28	2032	588.67	217.58	31.49	186.09	107.18	103.25	241.93	55.23		0	-	-	-	-		55.23	
29	2033	402.58	217.58	21.54	196.05	107.18	105.85	234.57	53.55		0	-	-	-	-		53.55	
30	2034	206.53	217.58	11.05	206.53	107.18	108.51	226.74	51.77		0	-	-	-	-		51.77	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Solar Photovoltaic
Capital Cost		4,467.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	4,484.87
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	10.34
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	2,242.43	59.99	-	2,302.42
2	2004	50.00%	2,298.85	61.49	123.18	4,785.94
3		0.00%	-	-	-	4,785.94
4		0.00%	-	-	-	4,785.94
5		0.00%	-	-	-	4,785.94

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	4,785.94	323.86	256.05	67.81	159.53	10.87	426.45	97.36	$83.84	0	-	-	-	-	$0.00	97.36	$83.84
2	2006	4,718.13	323.86	252.42	71.44	159.53	11.14	423.09	96.60		0	-	-	-	-		96.60	
3	2007	4,646.69	323.86	248.60	75.27	159.53	11.42	419.55	95.79		0	-	-	-	-		95.79	
4	2008	4,571.42	323.86	244.57	79.29	159.53	11.71	415.81	94.93		0	-	-	-	-		94.93	
5	2009	4,492.13	323.86	240.33	83.53	159.53	12.00	411.86	94.03		0	-	-	-	-		94.03	
6	2010	4,408.60	323.86	235.86	88.00	159.53	12.30	407.70	93.08		0	-	-	-	-		93.08	
7	2011	4,320.59	323.86	231.15	92.71	159.53	12.61	403.30	92.08		0	-	-	-	-		92.08	
8	2012	4,227.88	323.86	226.19	97.67	159.53	12.93	398.65	91.02		0	-	-	-	-		91.02	
9	2013	4,130.21	323.86	220.97	102.90	159.53	13.26	393.75	89.90		0	-	-	-	-		89.90	
10	2014	4,027.31	323.86	215.46	108.40	159.53	13.59	388.58	88.72		0	-	-	-	-		88.72	
11	2015	3,918.91	323.86	209.66	114.20	159.53	13.93	383.13	87.47		0	-	-	-	-		87.47	
12	2016	3,804.71	323.86	203.55	120.31	159.53	14.28	377.37	86.16		0	-	-	-	-		86.16	
13	2017	3,684.40	323.86	197.12	126.75	159.53	14.64	371.29	84.77		0	-	-	-	-		84.77	
14	2018	3,557.65	323.86	190.33	133.53	159.53	15.01	364.88	83.31		0	-	-	-	-		83.31	
15	2019	3,424.12	323.86	183.19	140.67	159.53	15.39	358.11	81.76		0	-	-	-	-		81.76	
16	2020	3,283.45	323.86	175.66	148.20	159.53	15.78	350.97	80.13		0	-	-	-	-		80.13	
17	2021	3,135.25	323.86	167.74	156.13	159.53	16.17	343.44	78.41		0	-	-	-	-		78.41	
18	2022	2,979.13	323.86	159.38	164.48	159.53	16.58	335.49	76.60		0	-	-	-	-		76.60	
19	2023	2,814.65	323.86	150.58	173.28	159.53	17.00	327.11	74.68		0	-	-	-	-		74.68	
20	2024	2,641.37	323.86	141.31	182.55	159.53	17.42	318.27	72.66		0	-	-	-	-		72.66	
21	2025	2,458.82	323.86	131.55	192.32	159.53	17.86	308.94	70.53		0	-	-	-	-		70.53	
22	2026	2,266.50	323.86	121.26	202.61	159.53	18.31	299.10	68.29		0	-	-	-	-		68.29	
23	2027	2,063.90	323.86	110.42	213.44	159.53	18.77	288.72	65.92		0	-	-	-	-		65.92	
24	2028	1,850.45	323.86	99.00	224.86	159.53	19.24	277.77	63.42		0	-	-	-	-		63.42	
25	2029	1,625.59	323.86	86.97	236.89	159.53	19.73	266.23	60.78		0	-	-	-	-		60.78	
26	2030	1,388.69	323.86	74.30	249.57	159.53	20.22	254.05	58.00		0	-	-	-	-		58.00	
27	2031	1,139.13	323.86	60.94	262.92	159.53	20.73	241.21	55.07		0	-	-	-	-		55.07	
28	2032	876.21	323.86	46.88	276.99	159.53	21.26	227.66	51.98		0	-	-	-	-		51.98	
29	2033	599.22	323.86	32.06	291.80	159.53	21.79	213.38	48.72		0	-	-	-	-		48.72	
30	2034	307.42	323.86	16.45	307.42	159.53	22.34	198.32	45.28		0	-	-	-	-		45.28	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Hydro
Capital Cost		1,451.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,456.80
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	4.60
Fixed O&M	($/kW-Yr)	12.35
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	346.54	9.27	-	355.81
2	2002	25.00%	355.26	9.50	19.04	739.62
3	2003	25.00%	364.20	9.74	39.57	1,153.13
4	2004	25.00%	373.36	9.99	61.69	1,598.17
5		0.00%	-	-	-	1,598.17

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,598.17	108.15	85.50	22.65	53.27	12.98	151.75	34.65	$30.84	0	-	-	4.83	4.83	$6.45	39.48	$37.29
2	2006	1,575.53	108.15	84.29	23.86	53.27	13.31	150.87	34.44		0	-	-	4.96	4.96		39.40	
3	2007	1,551.67	108.15	83.01	25.13	53.27	13.64	149.93	34.23		0	-	-	5.08	5.08		39.31	
4	2008	1,526.54	108.15	81.67	26.48	53.27	13.98	148.93	34.00		0	-	-	5.21	5.21		39.21	
5	2009	1,500.06	108.15	80.25	27.89	53.27	14.34	147.86	33.76		0	-	-	5.34	5.34		39.10	
6	2010	1,472.17	108.15	78.76	29.39	53.27	14.70	146.73	33.50		0	-	-	5.47	5.47		38.97	
7	2011	1,442.78	108.15	77.19	30.96	53.27	15.07	145.53	33.23		0	-	-	5.61	5.61		38.84	
8	2012	1,411.82	108.15	75.53	32.62	53.27	15.44	144.25	32.93		0	-	-	5.75	5.75		38.69	
9	2013	1,379.20	108.15	73.79	34.36	53.27	15.83	142.89	32.62		0	-	-	5.90	5.90		38.52	
10	2014	1,344.84	108.15	71.95	36.20	53.27	16.23	141.45	32.30		0	-	-	6.05	6.05		38.34	
11	2015	1,308.64	108.15	70.01	38.14	53.27	16.64	139.93	31.95		0	-	-	6.20	6.20		38.14	
12	2016	1,270.51	108.15	67.97	40.18	53.27	17.06	138.30	31.58		0	-	-	6.35	6.35		37.93	
13	2017	1,230.33	108.15	65.82	42.32	53.27	17.49	136.58	31.18		0	-	-	6.51	6.51		37.70	
14	2018	1,188.01	108.15	63.56	44.59	53.27	17.93	134.76	30.77		0	-	-	6.68	6.68		37.44	
15	2019	1,143.42	108.15	61.17	46.97	53.27	18.38	132.82	30.33		0	-	-	6.85	6.85		37.17	
16	2020	1,096.44	108.15	58.66	49.49	53.27	18.84	130.77	29.86		0	-	-	7.02	7.02		36.87	
17	2021	1,046.96	108.15	56.01	52.14	53.27	19.32	128.60	29.36		0	-	-	7.19	7.19		36.56	
18	2022	994.82	108.15	53.22	54.92	53.27	19.80	126.30	28.83		0	-	-	7.38	7.38		36.21	
19	2023	939.90	108.15	50.28	57.86	53.27	20.30	123.86	28.28		0	-	-	7.56	7.56		35.84	
20	2024	882.03	108.15	47.19	60.96	53.27	20.81	121.27	27.69		0	-	-	7.75	7.75		35.44	
21	2025	821.07	108.15	43.93	64.22	53.27	21.33	118.53	27.06		0	-	-	7.95	7.95		35.01	
22	2026	756.85	108.15	40.49	67.66	53.27	21.87	115.63	26.40		0	-	-	8.15	8.15		34.55	
23	2027	689.20	108.15	36.87	71.28	53.27	22.42	112.57	25.70		0	-	-	8.35	8.35		34.05	
24	2028	617.92	108.15	33.06	75.09	53.27	22.99	109.32	24.96		0	-	-	8.56	8.56		33.52	
25	2029	542.83	108.15	29.04	79.11	53.27	23.56	105.88	24.17		0	-	-	8.78	8.78		32.95	
26	2030	463.73	108.15	24.81	83.34	53.27	24.16	102.24	23.34		0	-	-	9.00	9.00		32.34	
27	2031	380.39	108.15	20.35	87.80	53.27	24.76	98.39	22.46		0	-	-	9.22	9.22		31.69	
28	2032	292.59	108.15	15.65	92.49	53.27	25.39	94.31	21.53		0	-	-	9.46	9.46		30.99	
29	2033	200.10	108.15	10.71	97.44	53.27	26.03	90.00	20.55		0	-	-	9.69	9.69		30.24	
30	2034	102.66	108.15	5.49	102.66	53.27	26.68	85.44	19.51		0	-	-	9.94	9.94		29.45	

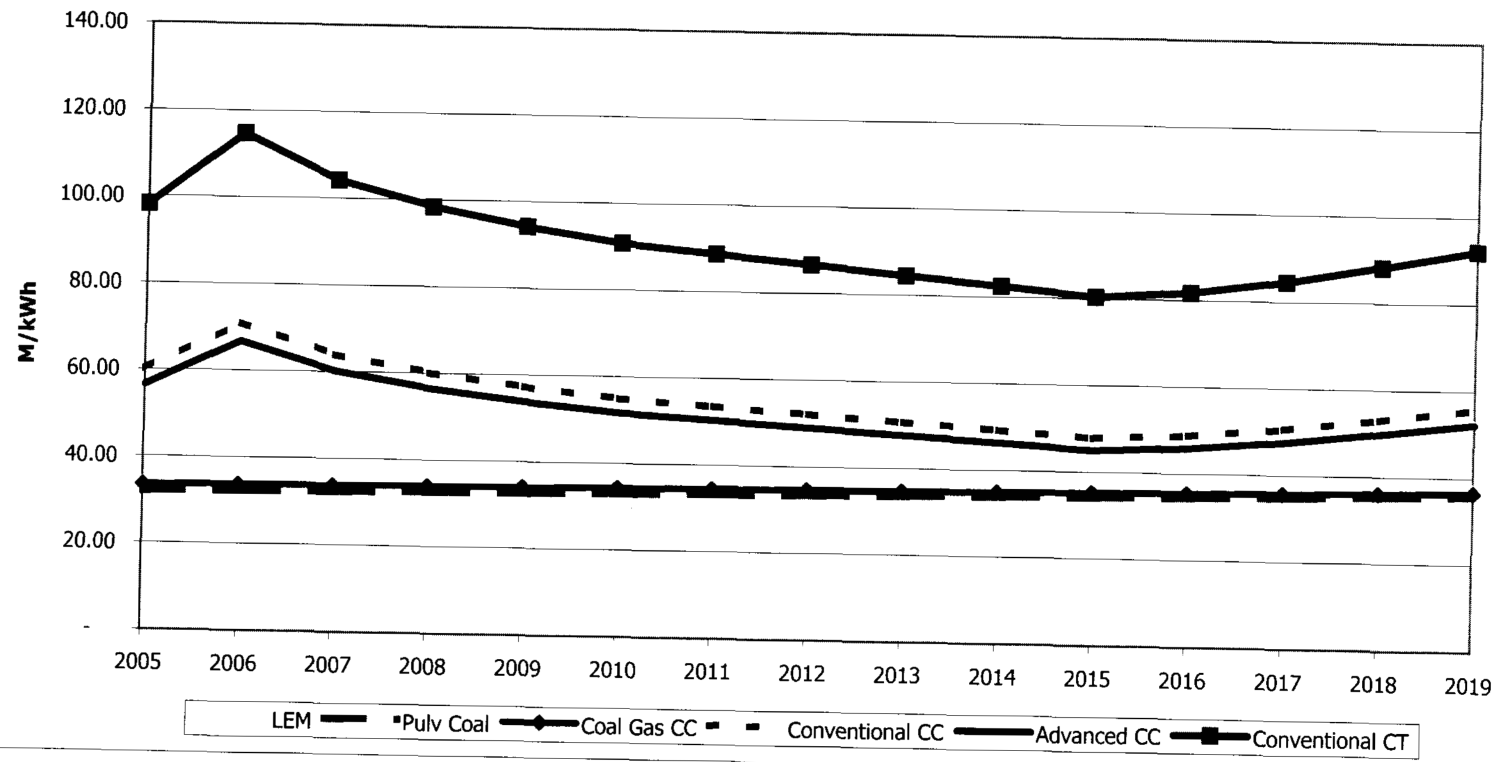
Appendix D
Supply Side Resource Alternatives

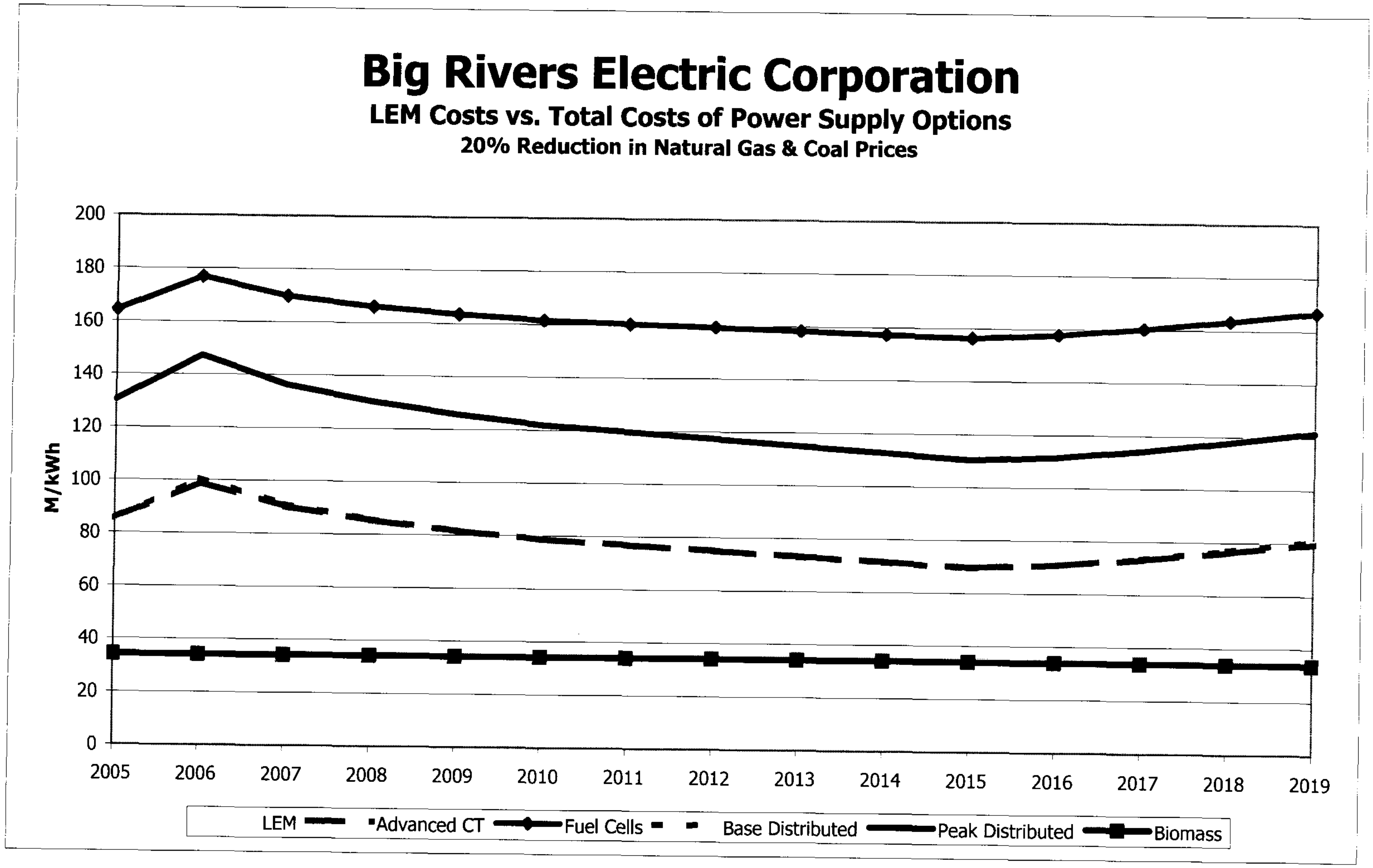
Reduced Fuel Prices

Big Rivers Electric Corporation

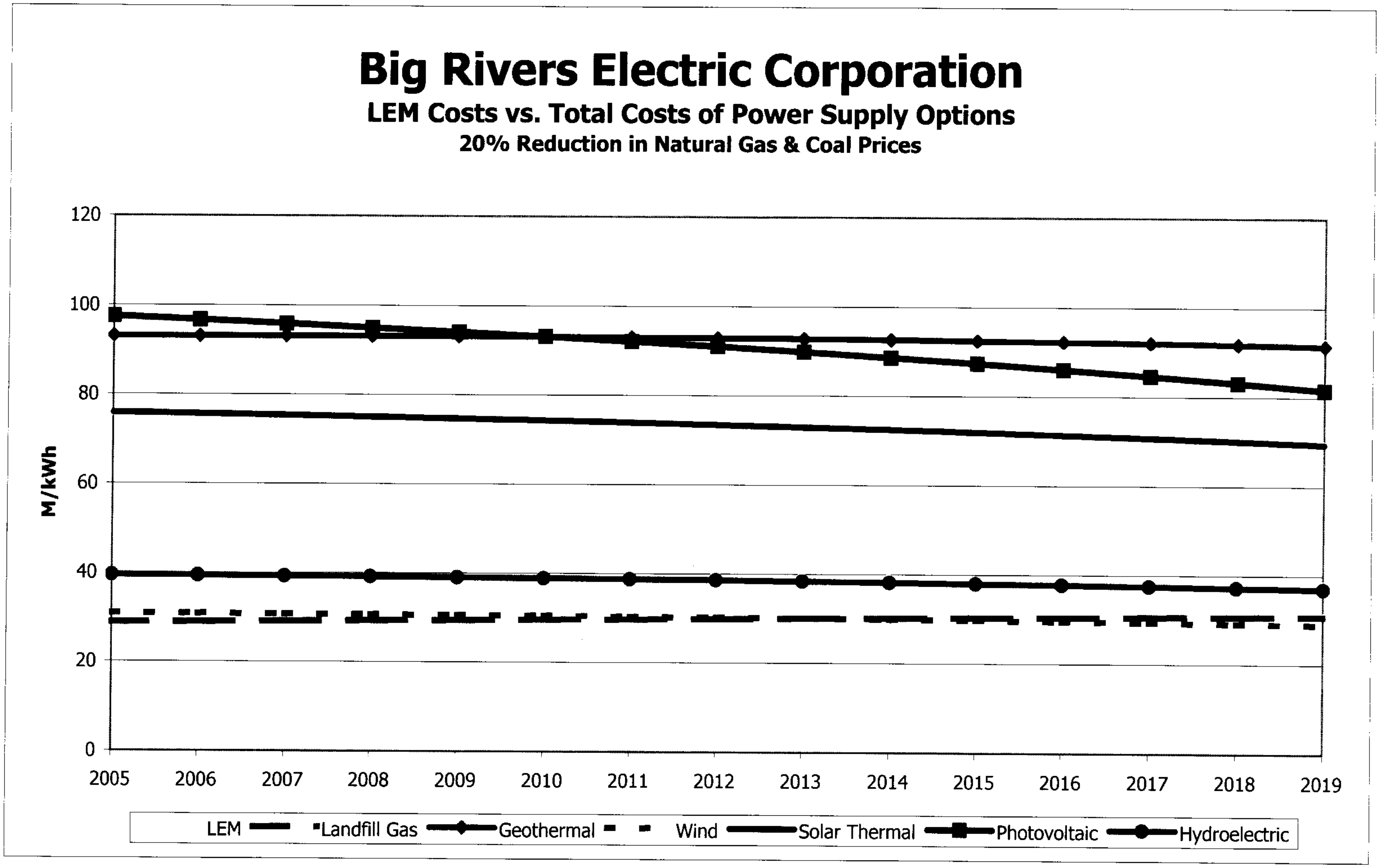
LEM Costs vs. Total Costs of Power Supply Options

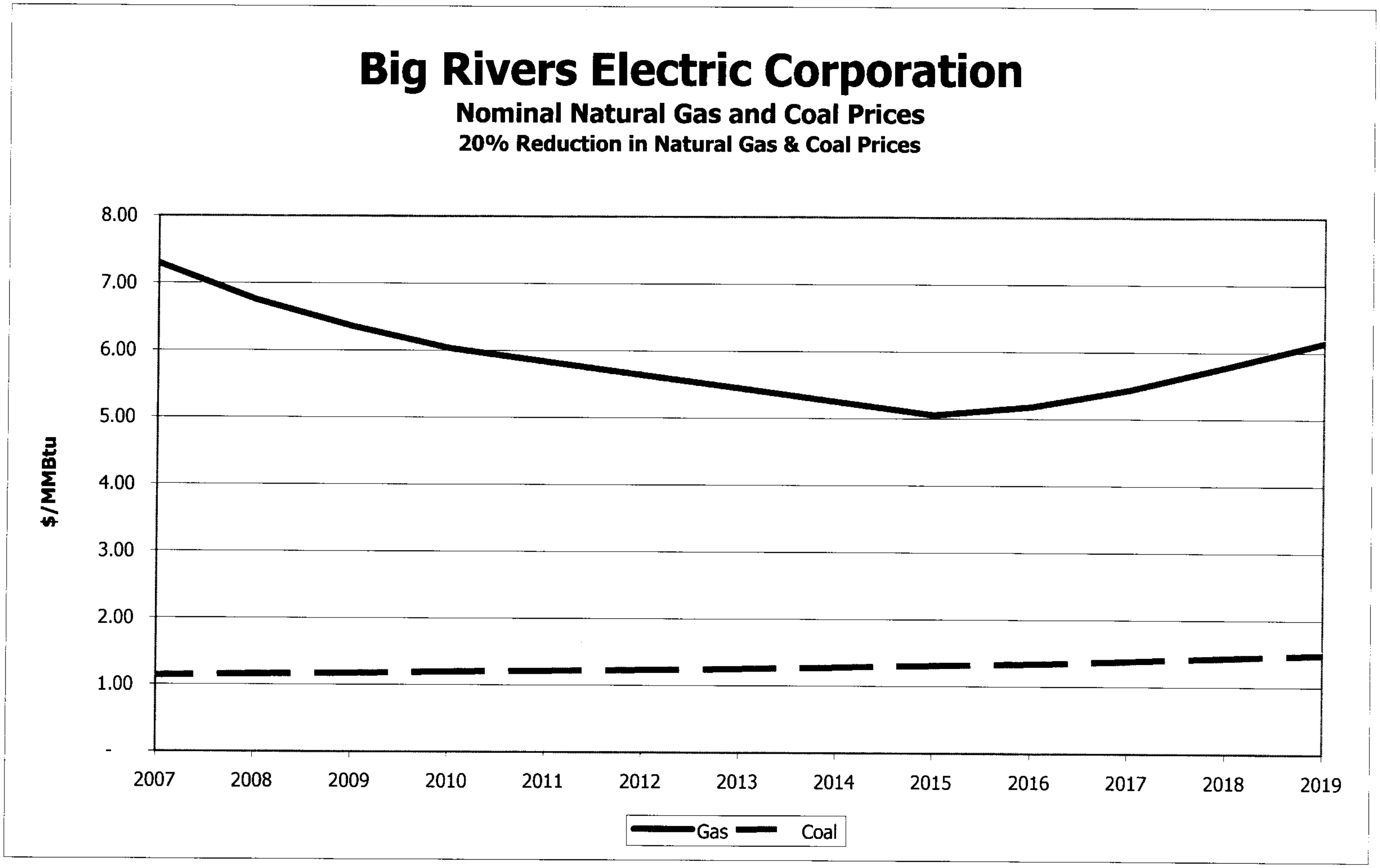
20% Reduction in Natural Gas & Coal Prices





Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
20% Reduction in Natural Gas & Coal Prices
M/kWh
200
180
160
140
120
100
80
60
40
20
0
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Advanced CT
Fuel Cells
Base Distributed
Peak Distributed
Biomass


Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
20% Reduction in Natural Gas & Coal Prices
M/kWh
0
20
40
60
80
100
120
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Landfill Gas
Geothermal
Wind
Solar Thermal
Photovoltaic
Hydroelectric


Big Rivers Electric Corporation
Nominal Natural Gas and Coal Prices
20% Reduction in Natural Gas & Coal Prices
$/MMBtu
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Gas
Coal

Big Rivers Electric Corporation
Comparison of LEM Contract Costs to Power Supply Options

20% Reduction in Natural Gas & Coal Prices

Resource:	LEM	Pulv Coal	Coal Gas CC	Conventional CC	Advanced CC	Conventional CT	Advanced CT	Fuel Cells	Base Distributed	Peak Distributed	Biomass	Landfill Gas	Geothermal	Wind	Solar Thermal	Photovoltaic	Hydroelectric
Capacity Factor:		90.00%	90.00%	80.00%	80.00%	25.00%	25.00%	70.00%	90.00%	25.00%	80.00%	98.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Levelized Rate:	[REDACTED]	$34.14	$35.23	$57.23	$53.76	$94.11	$81.66	$165.21	$82.21	$124.78	$34.24	$30.13	$92.44	$30.04	$72.60	$89.11	$38.30
Annual Rates:																	
2005	[REDACTED]	32.06	33.51	59.98	56.42	98.14	85.18	164.23	85.21	130.10	34.16	28.86	93.05	30.85	75.80	97.36	39.48
2006	[REDACTED]	32.31	33.73	70.88	66.64	114.54	99.10	176.78	100.38	147.00	34.21	29.03	93.10	30.80	75.54	96.60	39.40
2007	[REDACTED]	32.45	33.83	63.94	60.12	104.13	90.25	169.67	90.87	136.12	34.25	29.20	93.12	30.74	75.27	95.79	39.31
2008	[REDACTED]	32.71	34.05	60.11	56.52	98.40	85.38	165.99	85.68	130.08	34.29	29.37	93.13	30.68	74.97	94.93	39.21
2009	[REDACTED]	32.86	34.17	57.29	53.87	94.18	81.78	163.42	81.87	125.59	34.32	29.54	93.12	30.60	74.65	94.03	39.10
2010	[REDACTED]	33.16	34.42	54.99	51.69	90.73	78.84	161.41	78.78	121.89	34.35	29.70	93.09	30.52	74.29	93.08	38.97
2011	[REDACTED]	33.36	34.58	53.63	50.41	88.70	77.10	160.43	77.00	119.65	34.37	29.87	93.04	30.43	73.92	92.08	38.84
2012	[REDACTED]	33.58	34.75	52.26	49.12	86.66	75.36	159.45	75.21	117.40	34.38	30.03	92.96	30.32	73.51	91.02	38.69
2013	[REDACTED]	33.82	34.95	50.90	47.83	84.62	73.62	158.47	73.43	115.13	34.38	30.20	92.87	30.21	73.07	89.90	38.52
2014	[REDACTED]	34.11	35.18	49.53	46.53	82.58	71.87	157.47	71.65	112.84	34.38	30.36	92.74	30.08	72.59	88.72	38.34
2015	[REDACTED]	34.44	35.45	48.16	45.23	80.53	70.11	156.46	69.87	110.53	34.36	30.52	92.58	29.94	72.08	87.47	38.14
2016	[REDACTED]	34.69	35.65	49.09	46.09	81.93	71.29	157.97	71.27	111.78	34.34	30.68	92.40	29.79	71.53	86.16	37.93
2017	[REDACTED]	35.10	36.00	50.94	47.82	84.72	73.64	160.49	73.95	114.45	34.30	30.83	92.18	29.63	70.94	84.77	37.70
2018	[REDACTED]	35.60	36.42	53.41	50.13	88.45	76.78	163.69	77.49	118.08	34.26	30.98	91.93	29.45	70.31	83.31	37.44
2019	[REDACTED]	36.04	36.79	56.03	52.57	92.38	80.10	167.02	81.24	121.91	34.20	31.13	91.64	29.25	69.64	81.76	37.17
2020	[REDACTED]	36.50	37.17	58.14	54.53	95.55	82.76	169.78	84.28	124.92	34.13	31.27	91.31	29.04	68.91	80.13	36.87
2021	[REDACTED]	37.05	37.63	60.08	56.34	98.46	85.22	172.33	87.10	127.65	34.04	31.41	90.93	28.80	68.14	78.41	36.56
2022	[REDACTED]	37.56	38.05	61.57	57.73	100.70	87.09	174.38	89.30	129.67	33.94	31.54	90.51	28.55	67.31	76.60	36.21
2023	[REDACTED]	38.07	38.48	62.73	58.80	102.44	88.54	176.03	91.04	131.14	33.82	31.67	90.04	28.28	66.42	74.68	35.84
2024	[REDACTED]	38.60	38.91	64.72	60.65	105.41	91.04	178.57	93.94	133.87	33.69	31.79	89.52	27.99	65.47	72.66	35.44

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Pulv Coal
Capital Cost		1,213.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,217.85
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Coal
Variable O&M	(M/kWh)	4.06
Fixed O&M	($/kW-Yr)	24.36
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	8.844

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	289.70	7.75	-	297.45
2	2002	25.00%	296.99	7.94	15.91	618.30
3	2003	25.00%	304.46	8.14	33.08	963.99
4	2004	25.00%	312.12	8.35	51.57	1,336.03
5		0.00%	-	-	-	1,336.03

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,336.03	90.41	71.48	18.93	44.53	25.60	141.61	17.96	$16.82	8.844	1.11	9.83	4.27	14.09	$18.65	32.06	$35.47
2	2006	1,317.10	90.41	70.46	19.94	44.53	26.25	141.24	17.92		8.844	1.13	10.02	4.37	14.40		32.31	
3	2007	1,297.16	90.41	69.40	21.01	44.53	26.91	140.84	17.86		8.844	1.14	10.10	4.48	14.58		32.45	
4	2008	1,276.15	90.41	68.27	22.13	44.53	27.58	140.39	17.81		8.844	1.17	10.30	4.60	14.90		32.71	
5	2009	1,254.01	90.41	67.09	23.32	44.53	28.28	139.90	17.74		8.844	1.18	10.41	4.71	15.12		32.86	
6	2010	1,230.69	90.41	65.84	24.57	44.53	28.99	139.36	17.68		8.844	1.20	10.65	4.83	15.48		33.16	
7	2011	1,206.13	90.41	64.53	25.88	44.53	29.72	138.78	17.60		8.844	1.22	10.80	4.95	15.75		33.36	
8	2012	1,180.25	90.41	63.14	27.27	44.53	30.46	138.14	17.52		8.844	1.24	10.98	5.08	16.05		33.58	
9	2013	1,152.98	90.41	61.68	28.72	44.53	31.23	137.45	17.43		8.844	1.26	11.18	5.21	16.39		33.82	
10	2014	1,124.26	90.41	60.15	30.26	44.53	32.02	136.70	17.34		8.844	1.29	11.43	5.34	16.77		34.11	
11	2015	1,093.99	90.41	58.53	31.88	44.53	32.82	135.89	17.24		8.844	1.33	11.73	5.47	17.20		34.44	
12	2016	1,062.11	90.41	56.82	33.59	44.53	33.65	135.01	17.12		8.844	1.35	11.96	5.61	17.57		34.69	
13	2017	1,028.53	90.41	55.03	35.38	44.53	34.49	134.06	17.00		8.844	1.40	12.35	5.75	18.10		35.10	
14	2018	993.15	90.41	53.13	37.28	44.53	35.36	133.03	16.87		8.844	1.45	12.83	5.89	18.72		35.60	
15	2019	955.87	90.41	51.14	39.27	44.53	36.25	131.93	16.73		8.844	1.50	13.27	6.04	19.31		36.04	
16	2020	916.60	90.41	49.04	41.37	44.53	37.16	130.74	16.58		8.844	1.55	13.73	6.19	19.92		36.50	
17	2021	875.23	90.41	46.82	43.58	44.53	38.10	129.46	16.42		8.844	1.61	14.28	6.35	20.63		37.05	
18	2022	831.65	90.41	44.49	45.92	44.53	39.06	128.09	16.25		8.844	1.67	14.80	6.51	21.31		37.56	
19	2023	785.73	90.41	42.04	48.37	44.53	40.04	126.61	16.06		8.844	1.73	15.34	6.67	22.01		38.07	
20	2024	737.36	90.41	39.45	50.96	44.53	41.05	125.03	15.86		8.844	1.80	15.90	6.84	22.74		38.60	
21	2025	686.40	90.41	36.72	53.69	44.53	42.08	123.34	15.64		8.844	1.86	16.48	7.01	23.49		39.13	
22	2026	632.71	90.41	33.85	56.56	44.53	43.14	121.52	15.41		8.844	1.93	17.07	7.19	24.26		39.68	
23	2027	576.15	90.41	30.82	59.58	44.53	44.22	119.58	15.17		8.844	2.00	17.70	7.37	25.07		40.23	
24	2028	516.57	90.41	27.64	62.77	44.53	45.34	117.51	14.90		8.844	2.07	18.34	7.56	25.90		40.80	
25	2029	453.80	90.41	24.28	66.13	44.53	46.48	115.29	14.62		8.844	2.15	19.01	7.75	26.75		41.38	
26	2030	387.66	90.41	20.74	69.67	44.53	47.65	112.92	14.32		8.844	2.23	19.70	7.94	27.64		41.96	
27	2031	318.00	90.41	17.01	73.40	44.53	48.85	110.39	14.00		8.844	2.31	20.41	8.14	28.56		42.56	
28	2032	244.60	90.41	13.09	77.32	44.53	50.08	107.70	13.66		8.844	2.39	21.16	8.35	29.50		43.16	
29	2033	167.28	90.41	8.95	81.46	44.53	51.33	104.82	13.30		8.844	2.48	21.93	8.56	30.48		43.78	
30	2034	85.82	90.41	4.59	85.82	44.53	52.63	101.75	12.91		8.844	2.57	22.72	8.77	31.50		44.40	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Coal Gasification CC
Capital Cost		1,402.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,407.61
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Coal
Variable O&M	(M/kWh)	2.58
Fixed O&M	($/kW-Yr)	34.21
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	8.309

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	334.84	8.96	-	343.80
2	2002	25.00%	343.27	9.18	18.39	714.64
3	2003	25.00%	351.90	9.41	38.23	1,114.19
4	2004	25.00%	360.76	9.65	59.61	1,544.20
5		0.00%	-	-	-	1,544.20

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,544.20	104.50	82.61	21.88	51.47	35.95	170.04	21.57	$20.52	8.309	1.11	9.23	2.71	11.94	$15.79	33.51	$36.31
2	2006	1,522.32	104.50	81.44	23.05	51.47	36.86	169.78	21.53		8.309	1.13	9.42	2.78	12.19		33.73	
3	2007	1,499.27	104.50	80.21	24.28	51.47	37.78	169.47	21.50		8.309	1.14	9.49	2.85	12.34		33.83	
4	2008	1,474.99	104.50	78.91	25.58	51.47	38.74	169.12	21.45		8.309	1.17	9.68	2.92	12.60		34.05	
5	2009	1,449.40	104.50	77.54	26.95	51.47	39.71	168.73	21.40		8.309	1.18	9.78	2.99	12.77		34.17	
6	2010	1,422.45	104.50	76.10	28.39	51.47	40.71	168.28	21.34		8.309	1.20	10.01	3.07	13.08		34.42	
7	2011	1,394.06	104.50	74.58	29.91	51.47	41.73	167.79	21.28		8.309	1.22	10.15	3.15	13.29		34.58	
8	2012	1,364.14	104.50	72.98	31.51	51.47	42.78	167.24	21.21		8.309	1.24	10.31	3.23	13.54		34.75	
9	2013	1,332.63	104.50	71.30	33.20	51.47	43.86	166.63	21.14		8.309	1.26	10.51	3.31	13.81		34.95	
10	2014	1,299.43	104.50	69.52	34.98	51.47	44.96	165.96	21.05		8.309	1.29	10.74	3.39	14.13		35.18	
11	2015	1,264.45	104.50	67.65	36.85	51.47	46.09	165.22	20.96		8.309	1.33	11.02	3.48	14.50		35.45	
12	2016	1,227.60	104.50	65.68	38.82	51.47	47.25	164.40	20.85		8.309	1.35	11.24	3.56	14.80		35.65	
13	2017	1,188.79	104.50	63.60	40.90	51.47	48.44	163.52	20.74		8.309	1.40	11.60	3.65	15.26		36.00	
14	2018	1,147.89	104.50	61.41	43.08	51.47	49.66	162.55	20.62		8.309	1.45	12.05	3.75	15.80		36.42	
15	2019	1,104.81	104.50	59.11	45.39	51.47	50.91	161.49	20.48		8.309	1.50	12.46	3.84	16.30		36.79	
16	2020	1,059.42	104.50	56.68	47.82	51.47	52.19	160.34	20.34		8.309	1.55	12.90	3.94	16.83		37.17	
17	2021	1,011.60	104.50	54.12	50.37	51.47	53.50	159.10	20.18		8.309	1.61	13.41	4.04	17.45		37.63	
18	2022	961.23	104.50	51.43	53.07	51.47	54.85	157.75	20.01		8.309	1.67	13.90	4.14	18.04		38.05	
19	2023	908.16	104.50	48.59	55.91	51.47	56.23	156.29	19.82		8.309	1.73	14.41	4.24	18.65		38.48	
20	2024	852.25	104.50	45.60	58.90	51.47	57.65	154.71	19.62		8.309	1.80	14.94	4.35	19.28		38.91	
21	2025	793.35	104.50	42.44	62.05	51.47	59.10	153.01	19.41		8.309	1.86	15.48	4.46	19.94		39.34	
22	2026	731.30	104.50	39.12	65.37	51.47	60.58	151.18	19.18		8.309	1.93	16.04	4.57	20.61		39.79	
23	2027	665.92	104.50	35.63	68.87	51.47	62.11	149.21	18.93		8.309	2.00	16.63	4.68	21.31		40.23	
24	2028	597.06	104.50	31.94	72.55	51.47	63.67	147.09	18.66		8.309	2.07	17.23	4.80	22.03		40.69	
25	2029	524.50	104.50	28.06	76.43	51.47	65.27	144.81	18.37		8.309	2.15	17.86	4.92	22.78		41.15	
26	2030	448.07	104.50	23.97	80.52	51.47	66.91	142.36	18.06		8.309	2.23	18.51	5.05	23.55		41.61	
27	2031	367.54	104.50	19.66	84.83	51.47	68.60	139.73	17.72		8.309	2.31	19.18	5.17	24.35		42.08	
28	2032	282.71	104.50	15.13	89.37	51.47	70.32	136.92	17.37		8.309	2.39	19.88	5.30	25.18		42.55	
29	2033	193.34	104.50	10.34	94.15	51.47	72.09	133.91	16.98		8.309	2.48	20.60	5.44	26.04		43.02	
30	2034	99.19	104.50	5.31	99.19	51.47	73.91	130.69	16.58		8.309	2.57	21.35	5.57	26.92		43.50	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Conv CC
Capital Cost		567.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	569.27
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2000
Primary Fuel		Gas
Variable O&M	(M/kWh)	1.83
Fixed O&M	($/kW-Yr)	11.04
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	7.196

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	185.10	4.95	-	190.05
2	2003	33.33%	189.76	5.08	10.17	395.05
3	2004	33.33%	194.53	5.20	21.14	615.92
4		0.00%	-	-	-	615.92
5		0.00%	-	-	-	615.92

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	615.92	41.68	32.95	8.73	20.53	12.50	65.98	9.42	$8.86	7.196	6.74	48.49	2.07	50.56	$51.72	59.98	$60.58
2	2006	607.19	41.68	32.48	9.19	20.53	12.81	65.83	9.39		7.196	8.25	59.36	2.12	61.49		70.88	
3	2007	598.00	41.68	31.99	9.69	20.53	13.14	65.66	9.37		7.196	7.28	52.39	2.18	54.57		63.94	
4	2008	588.31	41.68	31.47	10.20	20.53	13.47	65.47	9.34		7.196	6.75	48.54	2.23	50.77		60.11	
5	2009	578.11	41.68	30.93	10.75	20.53	13.81	65.27	9.31		7.196	6.35	45.69	2.29	47.98		57.29	
6	2010	567.36	41.68	30.35	11.33	20.53	14.15	65.04	9.28		7.196	6.03	43.36	2.35	45.71		54.99	
7	2011	556.03	41.68	29.75	11.93	20.53	14.51	64.79	9.24		7.196	5.83	41.98	2.41	44.38		53.63	
8	2012	544.10	41.68	29.11	12.57	20.53	14.88	64.52	9.21		7.196	5.64	40.59	2.47	43.06		52.26	
9	2013	531.53	41.68	28.44	13.24	20.53	15.25	64.22	9.16		7.196	5.45	39.20	2.53	41.73		50.90	
10	2014	518.29	41.68	27.73	13.95	20.53	15.63	63.89	9.12		7.196	5.26	37.82	2.59	40.41		49.53	
11	2015	504.34	41.68	26.98	14.70	20.53	16.03	63.54	9.07		7.196	5.06	36.43	2.66	39.09		48.16	
12	2016	489.64	41.68	26.20	15.48	20.53	16.43	63.16	9.01		7.196	5.19	37.35	2.72	40.08		49.09	
13	2017	474.16	41.68	25.37	16.31	20.53	16.84	62.74	8.95		7.196	5.45	39.19	2.79	41.99		50.94	
14	2018	457.85	41.68	24.49	17.18	20.53	17.27	62.29	8.89		7.196	5.79	41.66	2.86	44.53		53.41	
15	2019	440.66	41.68	23.58	18.10	20.53	17.70	61.81	8.82		7.196	6.15	44.28	2.93	47.21		56.03	
16	2020	422.56	41.68	22.61	19.07	20.53	18.15	61.28	8.74		7.196	6.45	46.38	3.01	49.39		58.14	
17	2021	403.49	41.68	21.59	20.09	20.53	18.60	60.72	8.66		7.196	6.72	48.33	3.08	51.41		60.08	
18	2022	383.39	41.68	20.51	21.17	20.53	19.07	60.11	8.58		7.196	6.93	49.83	3.16	52.99		61.57	
19	2023	362.23	41.68	19.38	22.30	20.53	19.55	59.46	8.48		7.196	7.09	51.01	3.24	54.25		62.73	
20	2024	339.93	41.68	18.19	23.49	20.53	20.04	58.76	8.38		7.196	7.37	53.02	3.32	56.34		64.72	
21	2025	316.43	41.68	16.93	24.75	20.53	20.55	58.01	8.28		7.196	7.69	55.31	3.41	58.72		67.00	
22	2026	291.68	41.68	15.61	26.07	20.53	21.06	57.20	8.16		7.196	7.96	57.30	3.49	60.79		68.95	
23	2027	265.61	41.68	14.21	27.47	20.53	21.59	56.33	8.04		7.196	8.24	59.28	3.58	62.86		70.90	
24	2028	238.14	41.68	12.74	28.94	20.53	22.14	55.41	7.91		7.196	8.53	61.38	3.67	65.05		72.95	
25	2029	209.20	41.68	11.19	30.49	20.53	22.69	54.42	7.76		7.196	8.85	63.69	3.76	67.45		75.22	
26	2030	178.72	41.68	9.56	32.12	20.53	23.27	53.36	7.61		7.196	9.18	66.07	3.86	69.93		77.54	
27	2031	146.60	41.68	7.84	33.84	20.53	23.85	52.22	7.45		7.196	9.51	68.46	3.95	72.41		79.87	
28	2032	112.76	41.68	6.03	35.65	20.53	24.45	51.01	7.28		7.196	9.86	70.94	4.05	74.99		82.27	
29	2033	77.12	41.68	4.13	37.55	20.53	25.07	49.72	7.10		7.196	10.22	73.54	4.15	77.69		84.79	
30	2034	39.56	41.68	2.12	39.56	20.53	25.70	48.34	6.90		7.196	10.60	76.24	4.26	80.50		87.40	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Adv CC
Capital Cost		558.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	560.23
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	1.77
Fixed O&M	($/kW-Yr)	10.35
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	6.752

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	182.16	4.87	-	187.03
2	2003	33.33%	186.74	5.00	10.01	388.78
3	2004	33.33%	191.44	5.12	20.80	606.14
4		0.00%	-	-	-	606.14
5		0.00%	-	-	-	606.14

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	606.14	41.02	32.43	8.59	20.20	10.88	63.51	9.06	$8.45	6.752	6.74	45.50	1.86	47.36	$48.42	56.42	$56.86
2	2006	597.55	41.02	31.97	9.05	20.20	11.15	63.32	9.04		6.752	8.25	55.70	1.91	57.61		66.64	
3	2007	588.51	41.02	31.49	9.53	20.20	11.43	63.12	9.01		6.752	7.28	49.16	1.95	51.11		60.12	
4	2008	578.97	41.02	30.98	10.04	20.20	11.72	62.90	8.98		6.752	6.75	45.54	2.00	47.55		56.52	
5	2009	568.93	41.02	30.44	10.58	20.20	12.01	62.66	8.94		6.752	6.35	42.87	2.05	44.93		53.87	
6	2010	558.35	41.02	29.87	11.15	20.20	12.32	62.39	8.90		6.752	6.03	40.68	2.11	42.79		51.69	
7	2011	547.21	41.02	29.28	11.74	20.20	12.63	62.11	8.86		6.752	5.83	39.39	2.16	41.54		50.41	
8	2012	535.46	41.02	28.65	12.37	20.20	12.94	61.80	8.82		6.752	5.64	38.09	2.21	40.30		49.12	
9	2013	523.09	41.02	27.99	13.03	20.20	13.27	61.46	8.77		6.752	5.45	36.79	2.27	39.06		47.83	
10	2014	510.06	41.02	27.29	13.73	20.20	13.60	61.10	8.72		6.752	5.26	35.49	2.33	37.81		46.53	
11	2015	496.33	41.02	26.55	14.46	20.20	13.95	60.70	8.66		6.752	5.06	34.19	2.38	36.57		45.23	
12	2016	481.87	41.02	25.78	15.24	20.20	14.30	60.28	8.60		6.752	5.19	35.05	2.44	37.49		46.09	
13	2017	466.63	41.02	24.96	16.05	20.20	14.66	59.83	8.54		6.752	5.45	36.78	2.51	39.28		47.82	
14	2018	450.58	41.02	24.11	16.91	20.20	15.02	59.34	8.47		6.752	5.79	39.09	2.57	41.66		50.13	
15	2019	433.67	41.02	23.20	17.82	20.20	15.40	58.81	8.39		6.752	6.15	41.54	2.63	44.18		52.57	
16	2020	415.85	41.02	22.25	18.77	20.20	15.79	58.24	8.31		6.752	6.45	43.52	2.70	46.22		54.53	
17	2021	397.08	41.02	21.24	19.77	20.20	16.19	57.64	8.22		6.752	6.72	45.35	2.77	48.12		56.34	
18	2022	377.31	41.02	20.19	20.83	20.20	16.59	56.99	8.13		6.752	6.93	46.76	2.84	49.60		57.73	
19	2023	356.48	41.02	19.07	21.95	20.20	17.01	56.29	8.03		6.752	7.09	47.86	2.91	50.77		58.80	
20	2024	334.53	41.02	17.90	23.12	20.20	17.44	55.54	7.93		6.752	7.37	49.74	2.98	52.73		60.65	
21	2025	311.41	41.02	16.66	24.36	20.20	17.88	54.74	7.81		6.752	7.69	51.90	3.06	54.96		62.77	
22	2026	287.05	41.02	15.36	25.66	20.20	18.33	53.89	7.69		6.752	7.96	53.76	3.13	56.90		64.59	
23	2027	261.39	41.02	13.98	27.03	20.20	18.79	52.98	7.56		6.752	8.24	55.62	3.21	58.84		66.40	
24	2028	234.36	41.02	12.54	28.48	20.20	19.26	52.01	7.42		6.752	8.53	57.59	3.29	60.88		68.30	
25	2029	205.88	41.02	11.01	30.00	20.20	19.75	50.97	7.27		6.752	8.85	59.76	3.38	63.14		70.41	
26	2030	175.88	41.02	9.41	31.61	20.20	20.24	49.86	7.11		6.752	9.18	61.99	3.46	65.46		72.57	
27	2031	144.27	41.02	7.72	33.30	20.20	20.75	48.68	6.95		6.752	9.51	64.24	3.55	67.79		74.73	
28	2032	110.97	41.02	5.94	35.08	20.20	21.28	47.42	6.77		6.752	9.86	66.56	3.64	70.20		76.97	
29	2033	75.89	41.02	4.06	36.96	20.20	21.81	46.08	6.57		6.752	10.22	69.00	3.73	72.73		79.30	
30	2034	38.93	41.02	2.08	38.93	20.20	22.36	44.65	6.37		6.752	10.60	71.54	3.82	75.36		81.73	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Conv CT
Capital Cost		395.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	396.58
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	3.16
Fixed O&M	($/kW-Yr)	10.72
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	10.817

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	198.29	5.30	-	203.59
2	2004	50.00%	203.28	5.44	10.89	423.20
3		0.00%	-	-	-	423.20
4		0.00%	-	-	-	423.20
5		0.00%	-	-	-	423.20

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	423.20	28.64	22.64	6.00	14.11	11.27	48.01	21.92	$21.10	10.817	6.74	72.89	3.32	76.21	$78.02	98.14	$99.13
2	2006	417.21	28.64	22.32	6.32	14.11	11.55	47.98	21.91		10.817	8.25	89.23	3.40	92.64		114.54	
3	2007	410.89	28.64	21.98	6.66	14.11	11.84	47.93	21.89		10.817	7.28	78.76	3.49	82.25		104.13	
4	2008	404.23	28.64	21.63	7.01	14.11	12.14	47.87	21.86		10.817	6.75	72.96	3.58	76.54		98.40	
5	2009	397.22	28.64	21.25	7.39	14.11	12.44	47.80	21.83		10.817	6.35	68.69	3.67	72.35		94.18	
6	2010	389.84	28.64	20.86	7.78	14.11	12.76	47.72	21.79		10.817	6.03	65.18	3.76	68.94		90.73	
7	2011	382.05	28.64	20.44	8.20	14.11	13.08	47.62	21.75		10.817	5.83	63.10	3.85	66.95		88.70	
8	2012	373.86	28.64	20.00	8.64	14.11	13.41	47.51	21.70		10.817	5.64	61.01	3.95	64.97		86.66	
9	2013	365.22	28.64	19.54	9.10	14.11	13.74	47.39	21.64		10.817	5.45	58.93	4.05	62.98		84.62	
10	2014	356.12	28.64	19.05	9.59	14.11	14.09	47.25	21.57		10.817	5.26	56.85	4.15	61.00		82.58	
11	2015	346.53	28.64	18.54	10.10	14.11	14.44	47.09	21.50		10.817	5.06	54.77	4.26	59.03		80.53	
12	2016	336.44	28.64	18.00	10.64	14.11	14.81	46.91	21.42		10.817	5.19	56.15	4.36	60.51		81.93	
13	2017	325.80	28.64	17.43	11.21	14.11	15.18	46.72	21.33		10.817	5.45	58.92	4.47	63.39		84.72	
14	2018	314.59	28.64	16.83	11.81	14.11	15.56	46.50	21.23		10.817	5.79	62.63	4.59	67.22		88.45	
15	2019	302.78	28.64	16.20	12.44	14.11	15.95	46.26	21.12		10.817	6.15	66.56	4.70	71.26		92.38	
16	2020	290.34	28.64	15.53	13.10	14.11	16.35	45.99	21.00		10.817	6.45	69.72	4.82	74.55		95.55	
17	2021	277.24	28.64	14.83	13.81	14.11	16.77	45.71	20.87		10.817	6.72	72.65	4.94	77.59		98.46	
18	2022	263.43	28.64	14.09	14.54	14.11	17.19	45.39	20.73		10.817	6.93	74.91	5.07	79.98		100.70	
19	2023	248.89	28.64	13.32	15.32	14.11	17.62	45.04	20.57		10.817	7.09	76.67	5.19	81.87		102.44	
20	2024	233.57	28.64	12.50	16.14	14.11	18.06	44.67	20.40		10.817	7.37	79.69	5.32	85.02		105.41	
21	2025	217.42	28.64	11.63	17.01	14.11	18.52	44.26	20.21		10.817	7.69	83.15	5.46	88.61		108.82	
22	2026	200.42	28.64	10.72	17.92	14.11	18.98	43.81	20.01		10.817	7.96	86.13	5.60	91.73		111.73	
23	2027	182.50	28.64	9.76	18.87	14.11	19.46	43.33	19.79		10.817	8.24	89.11	5.74	94.85		114.64	
24	2028	163.63	28.64	8.75	19.88	14.11	19.95	42.81	19.55		10.817	8.53	92.26	5.88	98.14		117.69	
25	2029	143.74	28.64	7.69	20.95	14.11	20.45	42.25	19.29		10.817	8.85	95.74	6.03	101.77		121.06	
26	2030	122.80	28.64	6.57	22.07	14.11	20.97	41.64	19.02		10.817	9.18	99.32	6.18	105.50		124.51	
27	2031	100.73	28.64	5.39	23.25	14.11	21.50	40.99	18.72		10.817	9.51	102.91	6.34	109.25		127.96	
28	2032	77.48	28.64	4.15	24.49	14.11	22.04	40.29	18.40		10.817	9.86	106.64	6.50	113.13		131.53	
29	2033	52.99	28.64	2.83	25.80	14.11	22.59	39.53	18.05		10.817	10.22	110.54	6.66	117.20		135.25	
30	2034	27.18	28.64	1.45	27.18	14.11	23.16	38.72	17.68		10.817	10.60	114.61	6.83	121.43		139.11	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Adv CT
Capital Cost		374.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	375.50
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	2.80
Fixed O&M	($/kW-Yr)	9.31
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	9.183

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	187.75	5.02	-	192.77
2	2004	50.00%	192.47	5.15	10.31	400.70
3		0.00%	-	-	-	400.70
4		0.00%	-	-	-	400.70
5		0.00%	-	-	-	400.70

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	400.70	27.12	21.44	5.68	13.36	9.78	44.58	20.36	$19.44	9.183	6.74	61.88	2.94	64.82	$66.40	85.18	$85.85
2	2006	395.03	27.12	21.13	5.98	13.36	10.03	44.52	20.33		9.183	8.25	75.75	3.02	78.77		99.10	
3	2007	389.04	27.12	20.81	6.30	13.36	10.28	44.45	20.30		9.183	7.28	66.86	3.09	69.95		90.25	
4	2008	382.74	27.12	20.48	6.64	13.36	10.54	44.38	20.26		9.183	6.75	61.94	3.17	65.11		85.38	
5	2009	376.10	27.12	20.12	6.99	13.36	10.81	44.29	20.22		9.183	6.35	58.31	3.25	61.56		81.78	
6	2010	369.11	27.12	19.75	7.37	13.36	11.08	44.18	20.17		9.183	6.03	55.33	3.33	58.67		78.84	
7	2011	361.74	27.12	19.35	7.76	13.36	11.36	44.07	20.12		9.183	5.83	53.57	3.42	56.98		77.10	
8	2012	353.98	27.12	18.94	8.18	13.36	11.64	43.94	20.06		9.183	5.64	51.80	3.50	55.30		75.36	
9	2013	345.80	27.12	18.50	8.62	13.36	11.94	43.79	20.00		9.183	5.45	50.03	3.59	53.62		73.62	
10	2014	337.19	27.12	18.04	9.08	13.36	12.24	43.63	19.92		9.183	5.26	48.26	3.68	51.94		71.87	
11	2015	328.11	27.12	17.55	9.56	13.36	12.54	43.45	19.84		9.183	5.06	46.50	3.77	50.27		70.11	
12	2016	318.55	27.12	17.04	10.07	13.36	12.86	43.26	19.75		9.183	5.19	47.67	3.87	51.53		71.29	
13	2017	308.48	27.12	16.50	10.61	13.36	13.18	43.04	19.65		9.183	5.45	50.02	3.96	53.98		73.64	
14	2018	297.86	27.12	15.94	11.18	13.36	13.52	42.81	19.55		9.183	5.79	53.17	4.06	57.23		76.78	
15	2019	286.69	27.12	15.34	11.78	13.36	13.86	42.55	19.43		9.183	6.15	56.50	4.17	60.67		80.10	
16	2020	274.91	27.12	14.71	12.41	13.36	14.20	42.27	19.30		9.183	6.45	59.19	4.27	63.46		82.76	
17	2021	262.50	27.12	14.04	13.07	13.36	14.56	41.96	19.16		9.183	6.72	61.68	4.38	66.05		85.22	
18	2022	249.43	27.12	13.34	13.77	13.36	14.93	41.63	19.01		9.183	6.93	63.59	4.49	68.08		87.09	
19	2023	235.66	27.12	12.61	14.51	13.36	15.30	41.27	18.84		9.183	7.09	65.09	4.60	69.69		88.54	
20	2024	221.15	27.12	11.83	15.28	13.36	15.69	40.88	18.66		9.183	7.37	67.66	4.72	72.37		91.04	
21	2025	205.86	27.12	11.01	16.10	13.36	16.08	40.45	18.47		9.183	7.69	70.59	4.84	75.43		93.90	
22	2026	189.76	27.12	10.15	16.96	13.36	16.49	40.00	18.26		9.183	7.96	73.12	4.96	78.08		96.34	
23	2027	172.80	27.12	9.24	17.87	13.36	16.90	39.50	18.04		9.183	8.24	75.65	5.08	80.73		98.77	
24	2028	154.93	27.12	8.29	18.83	13.36	17.33	38.97	17.80		9.183	8.53	78.32	5.21	83.53		101.33	
25	2029	136.10	27.12	7.28	19.83	13.36	17.76	38.40	17.53		9.183	8.85	81.28	5.34	86.62		104.15	
26	2030	116.27	27.12	6.22	20.90	13.36	18.21	37.79	17.25		9.183	9.18	84.31	5.48	89.79		107.05	
27	2031	95.37	27.12	5.10	22.01	13.36	18.67	37.13	16.95		9.183	9.51	87.36	5.61	92.98		109.93	
28	2032	73.36	27.12	3.92	23.19	13.36	19.14	36.42	16.63		9.183	9.86	90.53	5.76	96.29		112.92	
29	2033	50.17	27.12	2.68	24.43	13.36	19.62	35.66	16.28		9.183	10.22	93.84	5.90	99.74		116.02	
30	2034	25.74	27.12	1.38	25.74	13.36	20.11	34.85	15.91		9.183	10.60	97.29	6.05	103.34		119.26	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Fuel Cells
Capital Cost		4,250.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	4,267.00
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	42.40
Fixed O&M	($/kW-Yr)	5.00
Capacity Factor	(%)	70.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	7.93

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	1,387.43	37.11	-	1,424.54
2	2003	33.33%	1,422.33	38.05	76.21	2,961.13
3	2004	33.33%	1,458.12	39.00	158.42	4,616.68
4		0.00%	-	-	-	4,616.68
5		0.00%	-	-	-	4,616.68

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	4,616.68	312.41	246.99	65.42	153.89	5.25	406.14	66.23	$56.63	7.93	6.74	53.44	44.56	98.00	$113.40	164.23	$170.03
2	2006	4,551.26	312.41	243.49	68.92	153.89	5.39	402.77	65.68		7.93	8.25	65.42	45.68	111.10		176.78	
3	2007	4,482.34	312.41	239.81	72.60	153.89	5.52	399.22	65.10		7.93	7.28	57.74	46.83	104.57		169.67	
4	2008	4,409.74	312.41	235.92	76.49	153.89	5.66	395.47	64.49		7.93	6.75	53.49	48.01	101.50		165.99	
5	2009	4,333.25	312.41	231.83	80.58	153.89	5.80	391.52	63.85		7.93	6.35	50.35	49.22	99.57		163.42	
6	2010	4,252.67	312.41	227.52	84.89	153.89	5.95	387.36	63.17		7.93	6.03	47.78	50.45	98.24		161.41	
7	2011	4,167.78	312.41	222.98	89.43	153.89	6.10	382.97	62.45		7.93	5.83	46.26	51.72	97.98		160.43	
8	2012	4,078.35	312.41	218.19	94.22	153.89	6.25	378.33	61.70		7.93	5.64	44.73	53.03	97.76		159.45	
9	2013	3,984.13	312.41	213.15	99.26	153.89	6.41	373.45	60.90		7.93	5.45	43.20	54.36	97.56		158.47	
10	2014	3,884.88	312.41	207.84	104.57	153.89	6.57	368.30	60.06		7.93	5.26	41.68	55.73	97.40		157.47	
11	2015	3,780.31	312.41	202.25	110.16	153.89	6.74	362.87	59.18		7.93	5.06	40.15	57.13	97.28		156.46	
12	2016	3,670.15	312.41	196.35	116.06	153.89	6.91	357.15	58.24		7.93	5.19	41.16	58.57	99.73		157.97	
13	2017	3,554.09	312.41	190.14	122.26	153.89	7.08	351.11	57.26		7.93	5.45	43.19	60.04	103.23		160.49	
14	2018	3,431.83	312.41	183.60	128.81	153.89	7.26	344.75	56.22		7.93	5.79	45.91	61.55	107.46		163.69	
15	2019	3,303.02	312.41	176.71	135.70	153.89	7.44	338.04	55.13		7.93	6.15	48.79	63.10	111.89		167.02	
16	2020	3,167.32	312.41	169.45	142.96	153.89	7.63	330.97	53.97		7.93	6.45	51.12	64.69	115.80		169.78	
17	2021	3,024.37	312.41	161.80	150.61	153.89	7.82	323.51	52.76		7.93	6.72	53.26	66.31	119.57		172.33	
18	2022	2,873.76	312.41	153.75	158.66	153.89	8.02	315.65	51.48		7.93	6.93	54.92	67.98	122.90		174.38	
19	2023	2,715.10	312.41	145.26	167.15	153.89	8.22	307.37	50.12		7.93	7.09	56.21	69.69	125.90		176.03	
20	2024	2,547.95	312.41	136.32	176.09	153.89	8.43	298.63	48.70		7.93	7.37	58.42	71.45	129.87		178.57	
21	2025	2,371.86	312.41	126.89	185.51	153.89	8.64	289.42	47.20		7.93	7.69	60.96	73.24	134.20		181.40	
22	2026	2,186.34	312.41	116.97	195.44	153.89	8.85	279.71	45.62		7.93	7.96	63.14	75.09	138.23		183.84	
23	2027	1,990.90	312.41	106.51	205.90	153.89	9.08	269.48	43.95		7.93	8.24	65.33	76.98	142.30		186.25	
24	2028	1,785.01	312.41	95.50	216.91	153.89	9.31	258.69	42.19		7.93	8.53	67.64	78.91	146.55		188.74	
25	2029	1,568.10	312.41	83.89	228.52	153.89	9.54	247.32	40.33		7.93	8.85	70.19	80.90	151.08		191.42	
26	2030	1,339.58	312.41	71.67	240.74	153.89	9.78	235.34	38.38		7.93	9.18	72.81	82.93	155.74		194.12	
27	2031	1,098.84	312.41	58.79	253.62	153.89	10.03	222.70	36.32		7.93	9.51	75.44	85.02	160.46		196.78	
28	2032	845.22	312.41	45.22	267.19	153.89	10.28	209.39	34.15		7.93	9.86	78.18	87.16	165.34		199.48	
29	2033	578.03	312.41	30.92	281.48	153.89	10.54	195.35	31.86		7.93	10.22	81.04	89.35	170.39		202.24	
30	2034	296.54	312.41	15.87	296.54	153.89	10.80	180.56	29.44		7.93	10.60	84.02	91.60	175.62		205.06	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Base Distributed
Capital Cost		807.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	810.23
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	6.30
Fixed O&M	($/kW-Yr)	14.18
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	9.95

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	263.45	7.05	-	270.50
2	2003	33.33%	270.08	7.22	14.47	562.27
3	2004	33.33%	276.87	7.41	30.08	876.63
4		0.00%	-	-	-	876.63
5		0.00%	-	-	-	876.63

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	876.63	59.32	46.90	12.42	29.22	14.90	91.02	11.55	$10.72	9.95	6.74	67.05	6.62	73.67	$76.53	85.21	$87.24
2	2006	864.20	59.32	46.23	13.09	29.22	15.28	90.73	11.51		9.95	8.25	82.08	6.79	88.87		100.38	
3	2007	851.12	59.32	45.53	13.79	29.22	15.66	90.42	11.47		9.95	7.28	72.44	6.96	79.40		90.87	
4	2008	837.33	59.32	44.80	14.52	29.22	16.06	90.07	11.42		9.95	6.75	67.12	7.13	74.25		85.68	
5	2009	822.81	59.32	44.02	15.30	29.22	16.46	89.70	11.38		9.95	6.35	63.18	7.31	70.49		81.87	
6	2010	807.51	59.32	43.20	16.12	29.22	16.87	89.30	11.33		9.95	6.03	59.95	7.50	67.45		78.78	
7	2011	791.39	59.32	42.34	16.98	29.22	17.30	88.86	11.27		9.95	5.83	58.04	7.69	65.73		77.00	
8	2012	774.41	59.32	41.43	17.89	29.22	17.73	88.39	11.21		9.95	5.64	56.12	7.88	64.00		75.21	
9	2013	756.52	59.32	40.47	18.85	29.22	18.18	87.87	11.15		9.95	5.45	54.21	8.08	62.29		73.43	
10	2014	737.67	59.32	39.47	19.86	29.22	18.64	87.32	11.08		9.95	5.26	52.29	8.28	60.57		71.65	
11	2015	717.81	59.32	38.40	20.92	29.22	19.11	86.73	11.00		9.95	5.06	50.38	8.49	58.87		69.87	
12	2016	696.90	59.32	37.28	22.04	29.22	19.59	86.09	10.92		9.95	5.19	51.65	8.70	60.35		71.27	
13	2017	674.86	59.32	36.10	23.22	29.22	20.08	85.41	10.83		9.95	5.45	54.19	8.92	63.11		73.95	
14	2018	651.64	59.32	34.86	24.46	29.22	20.58	84.67	10.74		9.95	5.79	57.61	9.15	66.75		77.49	
15	2019	627.19	59.32	33.55	25.77	29.22	21.10	83.88	10.64		9.95	6.15	61.22	9.38	70.60		81.24	
16	2020	601.42	59.32	32.18	27.14	29.22	21.63	83.03	10.53		9.95	6.45	64.14	9.61	73.75		84.28	
17	2021	574.27	59.32	30.72	28.60	29.22	22.18	82.12	10.42		9.95	6.72	66.83	9.85	76.68		87.10	
18	2022	545.68	59.32	29.19	30.13	29.22	22.74	81.15	10.29		9.95	6.93	68.91	10.10	79.01		89.30	
19	2023	515.55	59.32	27.58	31.74	29.22	23.31	80.11	10.16		9.95	7.09	70.53	10.36	80.88		91.04	
20	2024	483.81	59.32	25.88	33.44	29.22	23.89	79.00	10.02		9.95	7.37	73.31	10.62	83.92		93.94	
21	2025	450.37	59.32	24.09	35.23	29.22	24.50	77.81	9.87		9.95	7.69	76.48	10.88	87.37		97.24	
22	2026	415.15	59.32	22.21	37.11	29.22	25.11	76.54	9.71		9.95	7.96	79.23	11.16	90.38		100.09	
23	2027	378.04	59.32	20.22	39.10	29.22	25.74	75.19	9.54		9.95	8.24	81.97	11.44	93.41		102.94	
24	2028	338.94	59.32	18.13	41.19	29.22	26.39	73.75	9.35		9.95	8.53	84.87	11.73	96.59		105.94	
25	2029	297.75	59.32	15.93	43.39	29.22	27.05	72.21	9.16		9.95	8.85	88.07	12.02	100.09		109.24	
26	2030	254.36	59.32	13.61	45.71	29.22	27.74	70.56	8.95		9.95	9.18	91.36	12.32	103.68		112.63	
27	2031	208.65	59.32	11.16	48.16	29.22	28.43	68.82	8.73		9.95	9.51	94.66	12.63	107.29		116.02	
28	2032	160.49	59.32	8.59	50.73	29.22	29.15	66.96	8.49		9.95	9.86	98.09	12.95	111.04		119.53	
29	2033	109.76	59.32	5.87	53.45	29.22	29.88	64.97	8.24		9.95	10.22	101.68	13.28	114.95		123.20	
30	2034	56.31	59.32	3.01	56.31	29.22	30.63	62.87	7.97		9.95	10.60	105.42	13.61	119.03		127.01	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Peak Distributed
Capital Cost		970.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	973.88
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	6.30
Fixed O&M	($/kW-Yr)	14.18
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	11.2

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	486.94	13.03	-	499.97
2	2004	50.00%	499.19	13.35	26.75	1,039.26
3		0.00%	-	-	-	1,039.26
4		0.00%	-	-	-	1,039.26
5		0.00%	-	-	-	1,039.26

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,039.26	70.33	55.60	14.73	34.64	14.90	105.14	48.01	$44.05	11.2	6.74	75.47	6.62	82.09	$85.03	130.10	$129.08
2	2006	1,024.53	70.33	54.81	15.51	34.64	15.28	104.73	47.82		11.2	8.25	92.39	6.79	99.18		147.00	
3	2007	1,009.02	70.33	53.98	16.34	34.64	15.66	104.29	47.62		11.2	7.28	81.54	6.96	88.50		136.12	
4	2008	992.67	70.33	53.11	17.22	34.64	16.06	103.81	47.40		11.2	6.75	75.55	7.13	82.68		130.08	
5	2009	975.46	70.33	52.19	18.14	34.64	16.46	103.29	47.16		11.2	6.35	71.12	7.31	78.43		125.59	
6	2010	957.32	70.33	51.22	19.11	34.64	16.87	102.73	46.91		11.2	6.03	67.49	7.50	74.98		121.89	
7	2011	938.21	70.33	50.19	20.13	34.64	17.30	102.13	46.64		11.2	5.83	65.33	7.69	73.02		119.65	
8	2012	918.08	70.33	49.12	21.21	34.64	17.73	101.49	46.34		11.2	5.64	63.18	7.88	71.05		117.40	
9	2013	896.87	70.33	47.98	22.34	34.64	18.18	100.80	46.03		11.2	5.45	61.02	8.08	69.10		115.13	
10	2014	874.52	70.33	46.79	23.54	34.64	18.64	100.07	45.69		11.2	5.26	58.86	8.28	67.14		112.84	
11	2015	850.98	70.33	45.53	24.80	34.64	19.11	99.28	45.33		11.2	5.06	56.71	8.49	65.20		110.53	
12	2016	826.19	70.33	44.20	26.13	34.64	19.59	98.43	44.94		11.2	5.19	58.13	8.70	66.84		111.78	
13	2017	800.06	70.33	42.80	27.52	34.64	20.08	97.52	44.53		11.2	5.45	61.00	8.92	69.92		114.45	
14	2018	772.54	70.33	41.33	29.00	34.64	20.58	96.56	44.09		11.2	5.79	64.85	9.15	73.99		118.08	
15	2019	743.54	70.33	39.78	30.55	34.64	21.10	95.52	43.62		11.2	6.15	68.91	9.38	78.29		121.91	
16	2020	712.99	70.33	38.15	32.18	34.64	21.63	94.42	43.11		11.2	6.45	72.19	9.61	81.80		124.92	
17	2021	680.81	70.33	36.42	33.90	34.64	22.18	93.24	42.58		11.2	6.72	75.22	9.85	85.08		127.65	
18	2022	646.91	70.33	34.61	35.72	34.64	22.74	91.99	42.00		11.2	6.93	77.56	10.10	87.66		129.67	
19	2023	611.19	70.33	32.70	37.63	34.64	23.31	90.65	41.39		11.2	7.09	79.39	10.36	89.74		131.14	
20	2024	573.57	70.33	30.69	39.64	34.64	23.89	89.22	40.74		11.2	7.37	82.52	10.62	93.13		133.87	
21	2025	533.93	70.33	28.57	41.76	34.64	24.50	87.70	40.05		11.2	7.69	86.09	10.88	96.98		137.02	
22	2026	492.17	70.33	26.33	44.00	34.64	25.11	86.08	39.31		11.2	7.96	89.18	11.16	100.34		139.64	
23	2027	448.17	70.33	23.98	46.35	34.64	25.74	84.36	38.52		11.2	8.24	92.27	11.44	103.70		142.23	
24	2028	401.82	70.33	21.50	48.83	34.64	26.39	82.53	37.69		11.2	8.53	95.53	11.73	107.25		144.94	
25	2029	352.99	70.33	18.89	51.44	34.64	27.05	80.58	36.80		11.2	8.85	99.13	12.02	111.15		147.94	
26	2030	301.55	70.33	16.13	54.19	34.64	27.74	78.51	35.85		11.2	9.18	102.83	12.32	115.16		151.01	
27	2031	247.36	70.33	13.23	57.09	34.64	28.43	76.31	34.84		11.2	9.51	106.55	12.63	119.19		154.03	
28	2032	190.27	70.33	10.18	60.15	34.64	29.15	73.97	33.78		11.2	9.86	110.41	12.95	123.37		157.14	
29	2033	130.12	70.33	6.96	63.36	34.64	29.88	71.49	32.64		11.2	10.22	114.45	13.28	127.73		160.37	
30	2034	66.75	70.33	3.57	66.75	34.64	30.63	68.85	31.44		11.2	10.60	118.66	13.61	132.28		163.71	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Biomass
Capital Cost		1,757.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,764.03
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	2.96
Fixed O&M	($/kW-Yr)	47.18
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	419.63	11.23	-	430.85
2	2002	25.00%	430.18	11.51	23.05	895.59
3	2003	25.00%	441.01	11.80	47.91	1,396.31
4	2004	25.00%	452.10	12.09	74.70	1,935.21
5		0.00%	-	-	-	1,935.21

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,935.21	130.95	103.53	27.42	64.51	49.58	217.62	31.05	$29.79	0	-	-	3.11	3.11	$4.15	34.16	$33.94
2	2006	1,907.79	130.95	102.07	28.89	64.51	50.83	217.41	31.02		0	-	-	3.19	3.19		34.21	
3	2007	1,878.90	130.95	100.52	30.43	64.51	52.11	217.14	30.98		0	-	-	3.27	3.27		34.25	
4	2008	1,848.47	130.95	98.89	32.06	64.51	53.42	216.82	30.94		0	-	-	3.35	3.35		34.29	
5	2009	1,816.41	130.95	97.18	33.78	64.51	54.77	216.45	30.89		0	-	-	3.44	3.44		34.32	
6	2010	1,782.63	130.95	95.37	35.58	64.51	56.14	216.02	30.82		0	-	-	3.52	3.52		34.35	
7	2011	1,747.04	130.95	93.47	37.49	64.51	57.56	215.53	30.75		0	-	-	3.61	3.61		34.37	
8	2012	1,709.56	130.95	91.46	39.49	64.51	59.00	214.97	30.68		0	-	-	3.70	3.70		34.38	
9	2013	1,670.06	130.95	89.35	41.61	64.51	60.49	214.34	30.59		0	-	-	3.79	3.79		34.38	
10	2014	1,628.46	130.95	87.12	43.83	64.51	62.01	213.64	30.49		0	-	-	3.89	3.89		34.38	
11	2015	1,584.62	130.95	84.78	46.18	64.51	63.57	212.85	30.37		0	-	-	3.99	3.99		34.36	
12	2016	1,538.45	130.95	82.31	48.65	64.51	65.17	211.98	30.25		0	-	-	4.09	4.09		34.34	
13	2017	1,489.80	130.95	79.70	51.25	64.51	66.81	211.02	30.11		0	-	-	4.19	4.19		34.30	
14	2018	1,438.55	130.95	76.96	53.99	64.51	68.49	209.96	29.96		0	-	-	4.30	4.30		34.26	
15	2019	1,384.55	130.95	74.07	56.88	64.51	70.21	208.79	29.79		0	-	-	4.41	4.41		34.20	
16	2020	1,327.67	130.95	71.03	59.92	64.51	71.98	207.52	29.61		0	-	-	4.52	4.52		34.13	
17	2021	1,267.75	130.95	67.82	63.13	64.51	73.79	206.12	29.41		0	-	-	4.63	4.63		34.04	
18	2022	1,204.62	130.95	64.45	66.51	64.51	75.65	204.60	29.20		0	-	-	4.75	4.75		33.94	
19	2023	1,138.11	130.95	60.89	70.07	64.51	77.55	202.95	28.96		0	-	-	4.87	4.87		33.82	
20	2024	1,068.04	130.95	57.14	73.81	64.51	79.50	201.15	28.70		0	-	-	4.99	4.99		33.69	
21	2025	994.23	130.95	53.19	77.76	64.51	81.50	199.20	28.42		0	-	-	5.11	5.11		33.54	
22	2026	916.47	130.95	49.03	81.92	64.51	83.55	197.09	28.12		0	-	-	5.24	5.24		33.37	
23	2027	834.54	130.95	44.65	86.31	64.51	85.65	194.81	27.80		0	-	-	5.37	5.37		33.17	
24	2028	748.24	130.95	40.03	90.92	64.51	87.81	192.35	27.45		0	-	-	5.51	5.51		32.96	
25	2029	657.31	130.95	35.17	95.79	64.51	90.02	189.69	27.07		0	-	-	5.65	5.65		32.72	
26	2030	561.52	130.95	30.04	100.91	64.51	92.28	186.83	26.66		0	-	-	5.79	5.79		32.45	
27	2031	460.61	130.95	24.64	106.31	64.51	94.60	183.75	26.22		0	-	-	5.94	5.94		32.16	
28	2032	354.30	130.95	18.95	112.00	64.51	96.98	180.45	25.75		0	-	-	6.08	6.08		31.83	
29	2033	242.30	130.95	12.96	117.99	64.51	99.42	176.89	25.24		0	-	-	6.24	6.24		31.48	
30	2034	124.30	130.95	6.65	124.30	64.51	101.93	173.08	24.70		0	-	-	6.39	6.39		31.09	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Landfill Gas
Capital Cost		1,500.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,506.00
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	0.01
Fixed O&M	($/kW-Yr)	101.07
Capacity Factor	(%)	98.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	489.68	13.10	-	502.78
2	2003	33.33%	502.00	13.43	26.90	1,045.11
3	2004	33.33%	514.63	13.77	55.91	1,629.42
4		0.00%	-	-	-	1,629.42
5		0.00%	-	-	-	1,629.42

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,629.42	110.26	87.17	23.09	54.31	106.22	247.71	28.85	$30.49	0	-	-	0.01	0.01	$0.01	28.86	$30.51
2	2006	1,606.33	110.26	85.94	24.32	54.31	108.89	249.14	29.02		0	-	-	0.01	0.01		29.03	
3	2007	1,582.00	110.26	84.64	25.62	54.31	111.63	250.58	29.19		0	-	-	0.01	0.01		29.20	
4	2008	1,556.38	110.26	83.27	27.00	54.31	114.44	252.02	29.36		0	-	-	0.01	0.01		29.37	
5	2009	1,529.38	110.26	81.82	28.44	54.31	117.32	253.46	29.52		0	-	-	0.01	0.01		29.54	
6	2010	1,500.94	110.26	80.30	29.96	54.31	120.27	254.89	29.69		0	-	-	0.01	0.01		29.70	
7	2011	1,470.98	110.26	78.70	31.56	54.31	123.30	256.31	29.86		0	-	-	0.01	0.01		29.87	
8	2012	1,439.42	110.26	77.01	33.25	54.31	126.40	257.72	30.02		0	-	-	0.01	0.01		30.03	
9	2013	1,406.17	110.26	75.23	35.03	54.31	129.58	259.12	30.18		0	-	-	0.01	0.01		30.20	
10	2014	1,371.13	110.26	73.36	36.91	54.31	132.84	260.51	30.35		0	-	-	0.01	0.01		30.36	
11	2015	1,334.23	110.26	71.38	38.88	54.31	136.18	261.88	30.50		0	-	-	0.01	0.01		30.52	
12	2016	1,295.35	110.26	69.30	40.96	54.31	139.61	263.22	30.66		0	-	-	0.01	0.01		30.68	
13	2017	1,254.39	110.26	67.11	43.15	54.31	143.12	264.54	30.82		0	-	-	0.01	0.01		30.83	
14	2018	1,211.23	110.26	64.80	45.46	54.31	146.72	265.83	30.97		0	-	-	0.01	0.01		30.98	
15	2019	1,165.77	110.26	62.37	47.89	54.31	150.41	267.09	31.11		0	-	-	0.01	0.01		31.13	
16	2020	1,117.88	110.26	59.81	50.46	54.31	154.20	268.32	31.25		0	-	-	0.02	0.02		31.27	
17	2021	1,067.42	110.26	57.11	53.15	54.31	158.08	269.50	31.39		0	-	-	0.02	0.02		31.41	
18	2022	1,014.27	110.26	54.26	56.00	54.31	162.05	270.63	31.52		0	-	-	0.02	0.02		31.54	
19	2023	958.27	110.26	51.27	58.99	54.31	166.13	271.71	31.65		0	-	-	0.02	0.02		31.67	
20	2024	899.28	110.26	48.11	62.15	54.31	170.31	272.73	31.77		0	-	-	0.02	0.02		31.79	
21	2025	837.13	110.26	44.79	65.48	54.31	174.59	273.69	31.88		0	-	-	0.02	0.02		31.90	
22	2026	771.65	110.26	41.28	68.98	54.31	178.99	274.58	31.98		0	-	-	0.02	0.02		32.00	
23	2027	702.67	110.26	37.59	72.67	54.31	183.49	275.40	32.08		0	-	-	0.02	0.02		32.10	
24	2028	630.00	110.26	33.71	76.56	54.31	188.11	276.12	32.16		0	-	-	0.02	0.02		32.18	
25	2029	553.45	110.26	29.61	80.65	54.31	192.84	276.76	32.24		0	-	-	0.02	0.02		32.26	
26	2030	472.79	110.26	25.29	84.97	54.31	197.69	277.30	32.30		0	-	-	0.02	0.02		32.32	
27	2031	387.83	110.26	20.75	89.51	54.31	202.66	277.73	32.35		0	-	-	0.02	0.02		32.37	
28	2032	298.31	110.26	15.96	94.30	54.31	207.76	278.04	32.39		0	-	-	0.02	0.02		32.41	
29	2033	204.01	110.26	10.91	99.35	54.31	212.99	278.22	32.41		0	-	-	0.02	0.02		32.43	
30	2034	104.66	110.26	5.60	104.66	54.31	218.35	278.26	32.41		0	-	-	0.02	0.02		32.43	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Geothermal
Capital Cost		3,108.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	3,120.43
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	104.98
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	742.29	19.86	-	762.14
2	2002	25.00%	760.96	20.36	40.77	1,584.24
3	2003	25.00%	780.11	20.87	84.76	2,469.97
4	2004	25.00%	799.73	21.39	132.14	3,423.24
5		0.00%	-	-	-	3,423.24

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	3,423.24	231.65	183.14	48.51	114.11	110.33	407.58	93.05	$91.20	0	-	-	-	-	$0.00	93.05	$91.20
2	2006	3,374.74	231.65	180.55	51.10	114.11	113.10	407.76	93.10		0	-	-	-	-		93.10	
3	2007	3,323.63	231.65	177.81	53.83	114.11	115.95	407.87	93.12		0	-	-	-	-		93.12	
4	2008	3,269.80	231.65	174.93	56.72	114.11	118.87	407.91	93.13		0	-	-	-	-		93.13	
5	2009	3,213.08	231.65	171.90	59.75	114.11	121.86	407.87	93.12		0	-	-	-	-		93.12	
6	2010	3,153.33	231.65	168.70	62.95	114.11	124.92	407.74	93.09		0	-	-	-	-		93.09	
7	2011	3,090.39	231.65	165.34	66.31	114.11	128.07	407.51	93.04		0	-	-	-	-		93.04	
8	2012	3,024.08	231.65	161.79	69.86	114.11	131.29	407.18	92.96		0	-	-	-	-		92.96	
9	2013	2,954.21	231.65	158.05	73.60	114.11	134.59	406.75	92.87		0	-	-	-	-		92.87	
10	2014	2,880.62	231.65	154.11	77.54	114.11	137.98	406.20	92.74		0	-	-	-	-		92.74	
11	2015	2,803.08	231.65	149.96	81.68	114.11	141.45	405.52	92.58		0	-	-	-	-		92.58	
12	2016	2,721.39	231.65	145.59	86.05	114.11	145.01	404.71	92.40		0	-	-	-	-		92.40	
13	2017	2,635.34	231.65	140.99	90.66	114.11	148.66	403.75	92.18		0	-	-	-	-		92.18	
14	2018	2,544.68	231.65	136.14	95.51	114.11	152.40	402.64	91.93		0	-	-	-	-		91.93	
15	2019	2,449.17	231.65	131.03	100.62	114.11	156.23	401.37	91.64		0	-	-	-	-		91.64	
16	2020	2,348.55	231.65	125.65	106.00	114.11	160.16	399.92	91.31		0	-	-	-	-		91.31	
17	2021	2,242.55	231.65	119.98	111.67	114.11	164.19	398.27	90.93		0	-	-	-	-		90.93	
18	2022	2,130.88	231.65	114.00	117.65	114.11	168.32	396.43	90.51		0	-	-	-	-		90.51	
19	2023	2,013.23	231.65	107.71	123.94	114.11	172.56	394.37	90.04		0	-	-	-	-		90.04	
20	2024	1,889.29	231.65	101.08	130.57	114.11	176.90	392.08	89.52		0	-	-	-	-		89.52	
21	2025	1,758.72	231.65	94.09	137.56	114.11	181.35	389.55	88.94		0	-	-	-	-		88.94	
22	2026	1,621.16	231.65	86.73	144.92	114.11	185.91	386.75	88.30		0	-	-	-	-		88.30	
23	2027	1,476.24	231.65	78.98	152.67	114.11	190.59	383.67	87.60		0	-	-	-	-		87.60	
24	2028	1,323.57	231.65	70.81	160.84	114.11	195.38	380.30	86.83		0	-	-	-	-		86.83	
25	2029	1,162.73	231.65	62.21	169.44	114.11	200.30	376.61	85.98		0	-	-	-	-		85.98	
26	2030	993.29	231.65	53.14	178.51	114.11	205.34	372.59	85.07		0	-	-	-	-		85.07	
27	2031	814.78	231.65	43.59	188.06	114.11	210.50	368.20	84.06		0	-	-	-	-		84.06	
28	2032	626.72	231.65	33.53	198.12	114.11	215.80	363.44	82.98		0	-	-	-	-		82.98	
29	2033	428.60	231.65	22.93	208.72	114.11	221.23	358.27	81.80		0	-	-	-	-		81.80	
30	2034	219.89	231.65	11.76	219.89	114.11	226.79	352.67	80.52		0	-	-	-	-		80.52	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Wind
Capital Cost		1,134.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,138.54
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	26.81
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	370.20	9.90	-	380.10
2	2003	33.33%	379.51	10.15	20.34	790.10
3	2004	33.33%	389.06	10.41	42.27	1,231.84
4		0.00%	-	-	-	1,231.84
5		0.00%	-	-	-	1,231.84

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,231.84	83.36	65.90	17.45	41.06	28.18	135.14	30.85	$29.31	0	-	-	-	-	$0.00	30.85	$29.31
2	2006	1,214.38	83.36	64.97	18.39	41.06	28.88	134.92	30.80		0	-	-	-	-		30.80	
3	2007	1,196.00	83.36	63.99	19.37	41.06	29.61	134.66	30.74		0	-	-	-	-		30.74	
4	2008	1,176.62	83.36	62.95	20.41	41.06	30.36	134.37	30.68		0	-	-	-	-		30.68	
5	2009	1,156.21	83.36	61.86	21.50	41.06	31.12	134.04	30.60		0	-	-	-	-		30.60	
6	2010	1,134.71	83.36	60.71	22.65	41.06	31.90	133.67	30.52		0	-	-	-	-		30.52	
7	2011	1,112.06	83.36	59.50	23.86	41.06	32.71	133.26	30.43		0	-	-	-	-		30.43	
8	2012	1,088.20	83.36	58.22	25.14	41.06	33.53	132.81	30.32		0	-	-	-	-		30.32	
9	2013	1,063.06	83.36	56.87	26.48	41.06	34.37	132.31	30.21		0	-	-	-	-		30.21	
10	2014	1,036.58	83.36	55.46	27.90	41.06	35.24	131.76	30.08		0	-	-	-	-		30.08	
11	2015	1,008.68	83.36	53.96	29.39	41.06	36.12	131.15	29.94		0	-	-	-	-		29.94	
12	2016	979.28	83.36	52.39	30.97	41.06	37.03	130.49	29.79		0	-	-	-	-		29.79	
13	2017	948.32	83.36	50.73	32.62	41.06	37.96	129.76	29.63		0	-	-	-	-		29.63	
14	2018	915.69	83.36	48.99	34.37	41.06	38.92	128.97	29.45		0	-	-	-	-		29.45	
15	2019	881.32	83.36	47.15	36.21	41.06	39.90	128.11	29.25		0	-	-	-	-		29.25	
16	2020	845.12	83.36	45.21	38.14	41.06	40.90	127.18	29.04		0	-	-	-	-		29.04	
17	2021	806.97	83.36	43.17	40.18	41.06	41.93	126.17	28.80		0	-	-	-	-		28.80	
18	2022	766.79	83.36	41.02	42.33	41.06	42.99	125.07	28.55		0	-	-	-	-		28.55	
19	2023	724.45	83.36	38.76	44.60	41.06	44.07	123.89	28.28		0	-	-	-	-		28.28	
20	2024	679.85	83.36	36.37	46.99	41.06	45.18	122.61	27.99		0	-	-	-	-		27.99	
21	2025	632.87	83.36	33.86	49.50	41.06	46.31	121.23	27.68		0	-	-	-	-		27.68	
22	2026	583.37	83.36	31.21	52.15	41.06	47.48	119.75	27.34		0	-	-	-	-		27.34	
23	2027	531.22	83.36	28.42	54.94	41.06	48.67	118.15	26.98		0	-	-	-	-		26.98	
24	2028	476.28	83.36	25.48	57.88	41.06	49.90	116.44	26.58		0	-	-	-	-		26.58	
25	2029	418.40	83.36	22.38	60.97	41.06	51.15	114.60	26.16		0	-	-	-	-		26.16	
26	2030	357.43	83.36	19.12	64.24	41.06	52.44	112.62	25.71		0	-	-	-	-		25.71	
27	2031	293.20	83.36	15.69	67.67	41.06	53.76	110.51	25.23		0	-	-	-	-		25.23	
28	2032	225.52	83.36	12.07	71.29	41.06	55.11	108.24	24.71		0	-	-	-	-		24.71	
29	2033	154.23	83.36	8.25	75.11	41.06	56.50	105.81	24.16		0	-	-	-	-		24.16	
30	2034	79.12	83.36	4.23	79.12	41.06	57.92	103.21	23.56		0	-	-	-	-		23.56	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Solar Thermal
Capital Cost		2,960.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	2,971.84
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	50.23
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	966.30	25.85	-	992.15
2	2003	33.33%	990.61	26.50	53.08	2,062.34
3	2004	33.33%	1,015.54	27.17	110.34	3,215.38
4		0.00%	-	-	-	3,215.38
5		0.00%	-	-	-	3,215.38

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	3,215.38	217.58	172.02	45.56	107.18	52.79	331.99	75.80	$70.18	0	-	-	-	-	$0.00	75.80	$70.18
2	2006	3,169.82	217.58	169.59	48.00	107.18	54.12	330.88	75.54		0	-	-	-	-		75.54	
3	2007	3,121.82	217.58	167.02	50.57	107.18	55.48	329.68	75.27		0	-	-	-	-		75.27	
4	2008	3,071.26	217.58	164.31	53.27	107.18	56.87	328.37	74.97		0	-	-	-	-		74.97	
5	2009	3,017.98	217.58	161.46	56.12	107.18	58.31	326.95	74.65		0	-	-	-	-		74.65	
6	2010	2,961.86	217.58	158.46	59.12	107.18	59.77	325.41	74.29		0	-	-	-	-		74.29	
7	2011	2,902.74	217.58	155.30	62.29	107.18	61.28	323.75	73.92		0	-	-	-	-		73.92	
8	2012	2,840.45	217.58	151.96	65.62	107.18	62.82	321.96	73.51		0	-	-	-	-		73.51	
9	2013	2,774.83	217.58	148.45	69.13	107.18	64.40	320.03	73.07		0	-	-	-	-		73.07	
10	2014	2,705.70	217.58	144.76	72.83	107.18	66.02	317.95	72.59		0	-	-	-	-		72.59	
11	2015	2,632.87	217.58	140.86	76.72	107.18	67.68	315.72	72.08		0	-	-	-	-		72.08	
12	2016	2,556.15	217.58	136.75	80.83	107.18	69.38	313.32	71.53		0	-	-	-	-		71.53	
13	2017	2,475.32	217.58	132.43	85.15	107.18	71.13	310.74	70.94		0	-	-	-	-		70.94	
14	2018	2,390.17	217.58	127.87	89.71	107.18	72.92	307.97	70.31		0	-	-	-	-		70.31	
15	2019	2,300.46	217.58	123.07	94.51	107.18	74.75	305.01	69.64		0	-	-	-	-		69.64	
16	2020	2,205.95	217.58	118.02	99.57	107.18	76.63	301.83	68.91		0	-	-	-	-		68.91	
17	2021	2,106.38	217.58	112.69	104.89	107.18	78.56	298.43	68.14		0	-	-	-	-		68.14	
18	2022	2,001.49	217.58	107.08	110.50	107.18	80.54	294.80	67.31		0	-	-	-	-		67.31	
19	2023	1,890.99	217.58	101.17	116.42	107.18	82.56	290.91	66.42		0	-	-	-	-		66.42	
20	2024	1,774.57	217.58	94.94	122.64	107.18	84.64	286.76	65.47		0	-	-	-	-		65.47	
21	2025	1,651.93	217.58	88.38	129.21	107.18	86.77	282.33	64.46		0	-	-	-	-		64.46	
22	2026	1,522.72	217.58	81.47	136.12	107.18	88.95	277.60	63.38		0	-	-	-	-		63.38	
23	2027	1,386.60	217.58	74.18	143.40	107.18	91.19	272.55	62.23		0	-	-	-	-		62.23	
24	2028	1,243.20	217.58	66.51	151.07	107.18	93.49	267.18	61.00		0	-	-	-	-		61.00	
25	2029	1,092.13	217.58	58.43	159.15	107.18	95.84	261.45	59.69		0	-	-	-	-		59.69	
26	2030	932.98	217.58	49.91	167.67	107.18	98.25	255.34	58.30		0	-	-	-	-		58.30	
27	2031	765.31	217.58	40.94	176.64	107.18	100.72	248.84	56.81		0	-	-	-	-		56.81	
28	2032	588.67	217.58	31.49	186.09	107.18	103.25	241.93	55.23		0	-	-	-	-		55.23	
29	2033	402.58	217.58	21.54	196.05	107.18	105.85	234.57	53.55		0	-	-	-	-		53.55	
30	2034	206.53	217.58	11.05	206.53	107.18	108.51	226.74	51.77		0	-	-	-	-		51.77	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Solar Photovoltaic
Capital Cost		4,467.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	4,484.87
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	10.34
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	2,242.43	59.99	-	2,302.42
2	2004	50.00%	2,298.85	61.49	123.18	4,785.94
3		0.00%	-	-	-	4,785.94
4		0.00%	-	-	-	4,785.94
5		0.00%	-	-	-	4,785.94

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	4,785.94	323.86	256.05	67.81	159.53	10.87	426.45	97.36	$83.84	0	-	-	-	-	$0.00	97.36	$83.84
2	2006	4,718.13	323.86	252.42	71.44	159.53	11.14	423.09	96.60		0	-	-	-	-		96.60	
3	2007	4,646.69	323.86	248.60	75.27	159.53	11.42	419.55	95.79		0	-	-	-	-		95.79	
4	2008	4,571.42	323.86	244.57	79.29	159.53	11.71	415.81	94.93		0	-	-	-	-		94.93	
5	2009	4,492.13	323.86	240.33	83.53	159.53	12.00	411.86	94.03		0	-	-	-	-		94.03	
6	2010	4,408.60	323.86	235.86	88.00	159.53	12.30	407.70	93.08		0	-	-	-	-		93.08	
7	2011	4,320.59	323.86	231.15	92.71	159.53	12.61	403.30	92.08		0	-	-	-	-		92.08	
8	2012	4,227.88	323.86	226.19	97.67	159.53	12.93	398.65	91.02		0	-	-	-	-		91.02	
9	2013	4,130.21	323.86	220.97	102.90	159.53	13.26	393.75	89.90		0	-	-	-	-		89.90	
10	2014	4,027.31	323.86	215.46	108.40	159.53	13.59	388.58	88.72		0	-	-	-	-		88.72	
11	2015	3,918.91	323.86	209.66	114.20	159.53	13.93	383.13	87.47		0	-	-	-	-		87.47	
12	2016	3,804.71	323.86	203.55	120.31	159.53	14.28	377.37	86.16		0	-	-	-	-		86.16	
13	2017	3,684.40	323.86	197.12	126.75	159.53	14.64	371.29	84.77		0	-	-	-	-		84.77	
14	2018	3,557.65	323.86	190.33	133.53	159.53	15.01	364.88	83.31		0	-	-	-	-		83.31	
15	2019	3,424.12	323.86	183.19	140.67	159.53	15.39	358.11	81.76		0	-	-	-	-		81.76	
16	2020	3,283.45	323.86	175.66	148.20	159.53	15.78	350.97	80.13		0	-	-	-	-		80.13	
17	2021	3,135.25	323.86	167.74	156.13	159.53	16.17	343.44	78.41		0	-	-	-	-		78.41	
18	2022	2,979.13	323.86	159.38	164.48	159.53	16.58	335.49	76.60		0	-	-	-	-		76.60	
19	2023	2,814.65	323.86	150.58	173.28	159.53	17.00	327.11	74.68		0	-	-	-	-		74.68	
20	2024	2,641.37	323.86	141.31	182.55	159.53	17.42	318.27	72.66		0	-	-	-	-		72.66	
21	2025	2,458.82	323.86	131.55	192.32	159.53	17.86	308.94	70.53		0	-	-	-	-		70.53	
22	2026	2,266.50	323.86	121.26	202.61	159.53	18.31	299.10	68.29		0	-	-	-	-		68.29	
23	2027	2,063.90	323.86	110.42	213.44	159.53	18.77	288.72	65.92		0	-	-	-	-		65.92	
24	2028	1,850.45	323.86	99.00	224.86	159.53	19.24	277.77	63.42		0	-	-	-	-		63.42	
25	2029	1,625.59	323.86	86.97	236.89	159.53	19.73	266.23	60.78		0	-	-	-	-		60.78	
26	2030	1,388.69	323.86	74.30	249.57	159.53	20.22	254.05	58.00		0	-	-	-	-		58.00	
27	2031	1,139.13	323.86	60.94	262.92	159.53	20.73	241.21	55.07		0	-	-	-	-		55.07	
28	2032	876.21	323.86	46.88	276.99	159.53	21.26	227.66	51.98		0	-	-	-	-		51.98	
29	2033	599.22	323.86	32.06	291.80	159.53	21.79	213.38	48.72		0	-	-	-	-		48.72	
30	2034	307.42	323.86	16.45	307.42	159.53	22.34	198.32	45.28		0	-	-	-	-		45.28	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Hydro
Capital Cost		1,451.00
Regional Multiplier		1.004
Adjusted Capital Cost	($/kW)	1,456.80
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	4.60
Fixed O&M	($/kW-Yr)	12.35
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	346.54	9.27	-	355.81
2	2002	25.00%	355.26	9.50	19.04	739.62
3	2003	25.00%	364.20	9.74	39.57	1,153.13
4	2004	25.00%	373.36	9.99	61.69	1,598.17
5		0.00%	-	-	-	1,598.17

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,598.17	108.15	85.50	22.65	53.27	12.98	151.75	34.65	$30.84	0	-	-	4.83	4.83	$6.45	39.48	$37.29
2	2006	1,575.53	108.15	84.29	23.86	53.27	13.31	150.87	34.44		0	-	-	4.96	4.96		39.40	
3	2007	1,551.67	108.15	83.01	25.13	53.27	13.64	149.93	34.23		0	-	-	5.08	5.08		39.31	
4	2008	1,526.54	108.15	81.67	26.48	53.27	13.98	148.93	34.00		0	-	-	5.21	5.21		39.21	
5	2009	1,500.06	108.15	80.25	27.89	53.27	14.34	147.86	33.76		0	-	-	5.34	5.34		39.10	
6	2010	1,472.17	108.15	78.76	29.39	53.27	14.70	146.73	33.50		0	-	-	5.47	5.47		38.97	
7	2011	1,442.78	108.15	77.19	30.96	53.27	15.07	145.53	33.23		0	-	-	5.61	5.61		38.84	
8	2012	1,411.82	108.15	75.53	32.62	53.27	15.44	144.25	32.93		0	-	-	5.75	5.75		38.69	
9	2013	1,379.20	108.15	73.79	34.36	53.27	15.83	142.89	32.62		0	-	-	5.90	5.90		38.52	
10	2014	1,344.84	108.15	71.95	36.20	53.27	16.23	141.45	32.30		0	-	-	6.05	6.05		38.34	
11	2015	1,308.64	108.15	70.01	38.14	53.27	16.64	139.93	31.95		0	-	-	6.20	6.20		38.14	
12	2016	1,270.51	108.15	67.97	40.18	53.27	17.06	138.30	31.58		0	-	-	6.35	6.35		37.93	
13	2017	1,230.33	108.15	65.82	42.32	53.27	17.49	136.58	31.18		0	-	-	6.51	6.51		37.70	
14	2018	1,188.01	108.15	63.56	44.59	53.27	17.93	134.76	30.77		0	-	-	6.68	6.68		37.44	
15	2019	1,143.42	108.15	61.17	46.97	53.27	18.38	132.82	30.33		0	-	-	6.85	6.85		37.17	
16	2020	1,096.44	108.15	58.66	49.49	53.27	18.84	130.77	29.86		0	-	-	7.02	7.02		36.87	
17	2021	1,046.96	108.15	56.01	52.14	53.27	19.32	128.60	29.36		0	-	-	7.19	7.19		36.56	
18	2022	994.82	108.15	53.22	54.92	53.27	19.80	126.30	28.83		0	-	-	7.38	7.38		36.21	
19	2023	939.90	108.15	50.28	57.86	53.27	20.30	123.86	28.28		0	-	-	7.56	7.56		35.84	
20	2024	882.03	108.15	47.19	60.96	53.27	20.81	121.27	27.69		0	-	-	7.75	7.75		35.44	
21	2025	821.07	108.15	43.93	64.22	53.27	21.33	118.53	27.06		0	-	-	7.95	7.95		35.01	
22	2026	756.85	108.15	40.49	67.66	53.27	21.87	115.63	26.40		0	-	-	8.15	8.15		34.55	
23	2027	689.20	108.15	36.87	71.28	53.27	22.42	112.57	25.70		0	-	-	8.35	8.35		34.05	
24	2028	617.92	108.15	33.06	75.09	53.27	22.99	109.32	24.96		0	-	-	8.56	8.56		33.52	
25	2029	542.83	108.15	29.04	79.11	53.27	23.56	105.88	24.17		0	-	-	8.78	8.78		32.95	
26	2030	463.73	108.15	24.81	83.34	53.27	24.16	102.24	23.34		0	-	-	9.00	9.00		32.34	
27	2031	380.39	108.15	20.35	87.80	53.27	24.76	98.39	22.46		0	-	-	9.22	9.22		31.69	
28	2032	292.59	108.15	15.65	92.49	53.27	25.39	94.31	21.53		0	-	-	9.46	9.46		30.99	
29	2033	200.10	108.15	10.71	97.44	53.27	26.03	90.00	20.55		0	-	-	9.69	9.69		30.24	
30	2034	102.66	108.15	5.49	102.66	53.27	26.68	85.44	19.51		0	-	-	9.94	9.94		29.45	

Appendix E

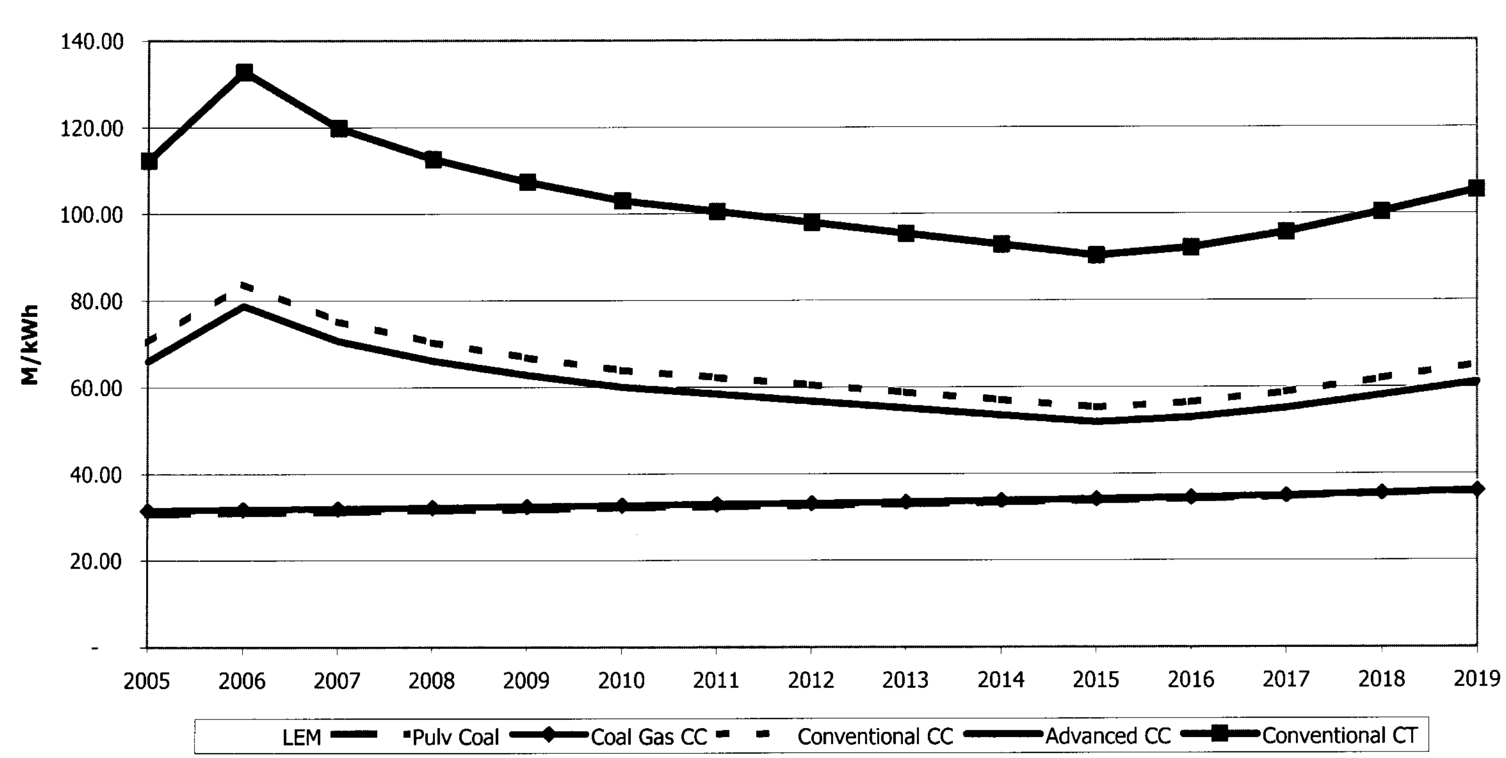
Supply Side Resource Alternatives

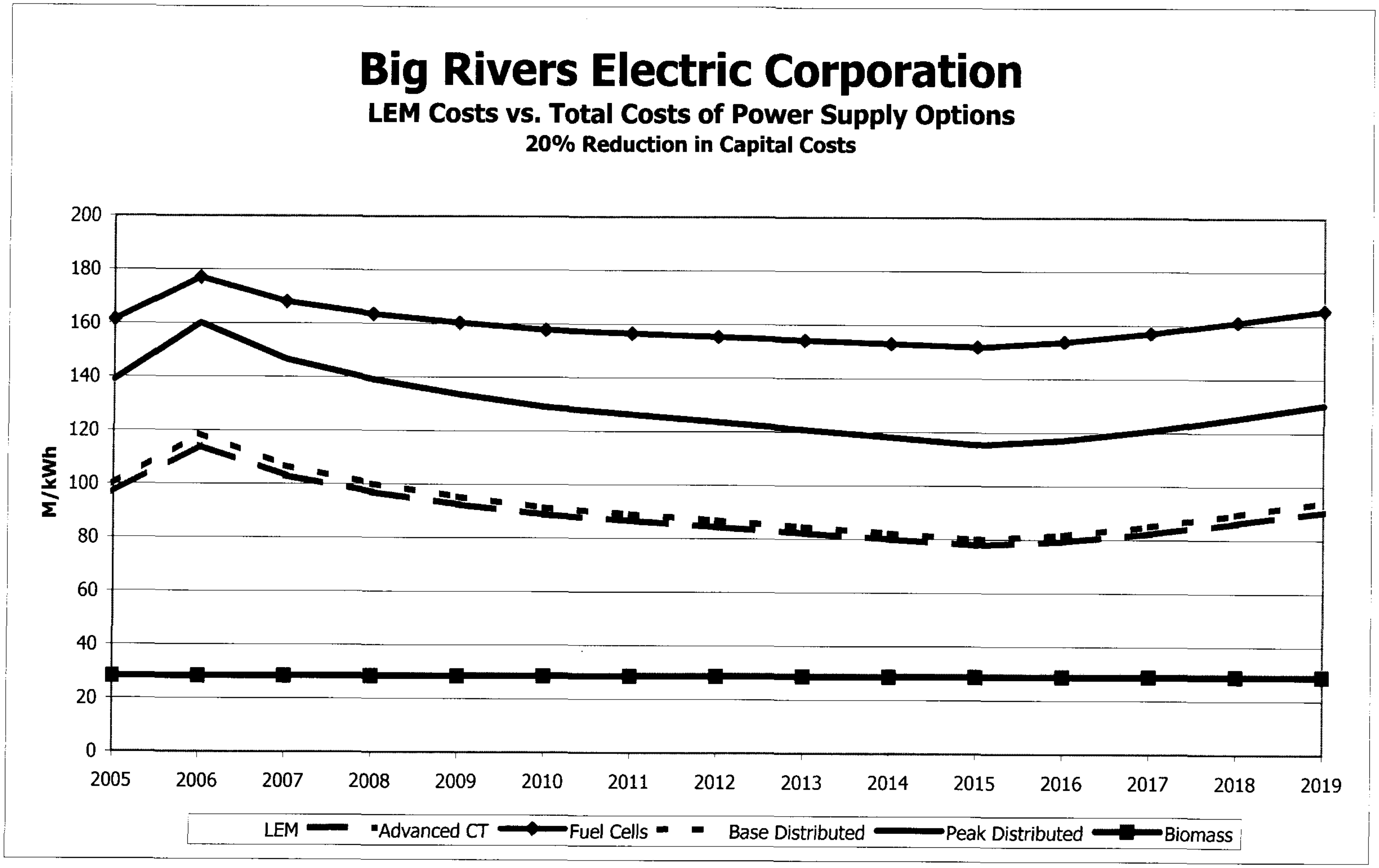
Reduced Capital Costs

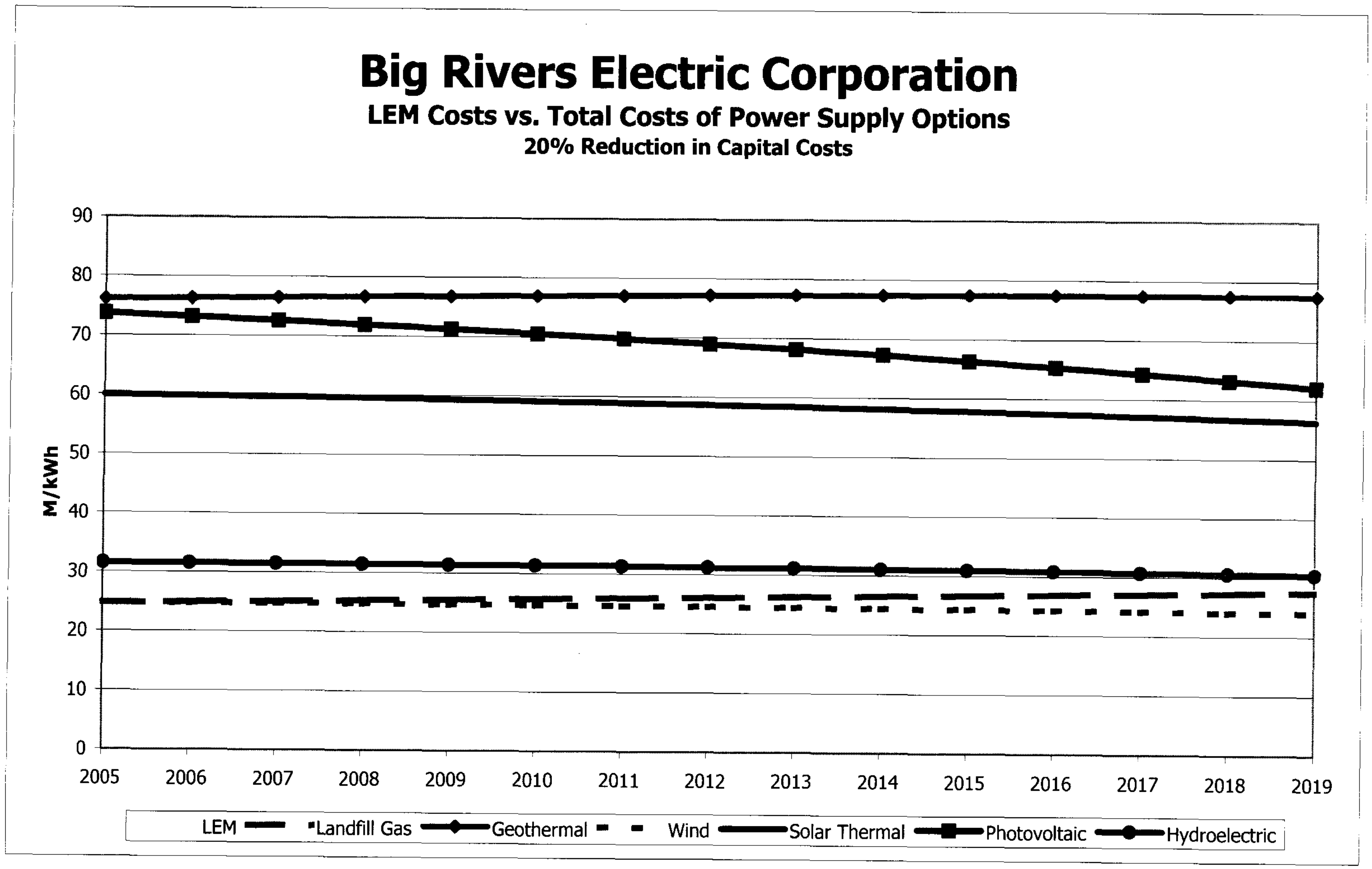
Big Rivers Electric Corporation

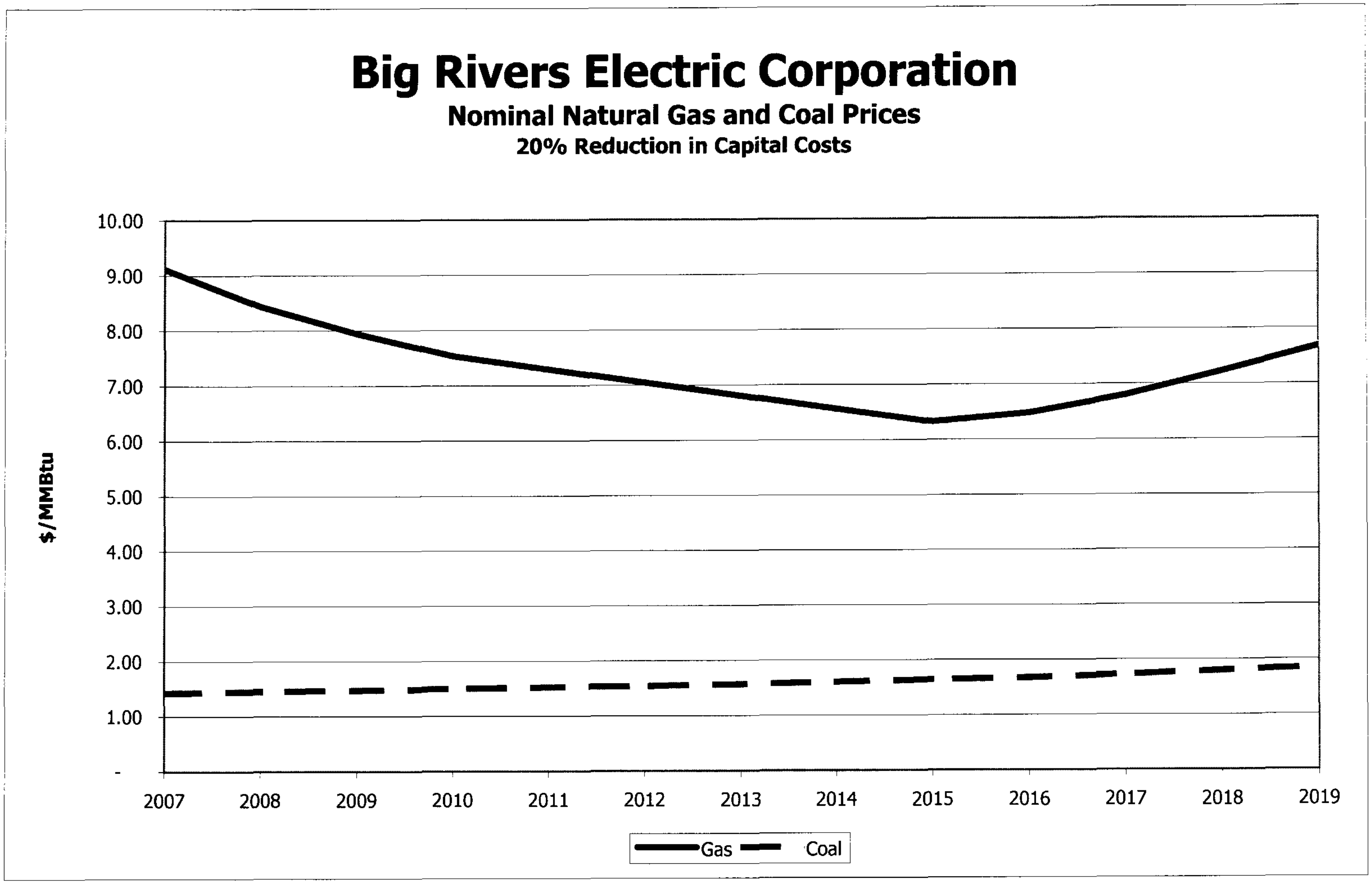
LEM Costs vs. Total Costs of Power Supply Options

20% Reduction in Capital Costs




Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
20% Reduction in Capital Costs
M/kWh
200
180
160
140
120
100
80
60
40
20
0
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Advanced CT
Fuel Cells
Base Distributed
Peak Distributed
Biomass


Big Rivers Electric Corporation
LEM Costs vs. Total Costs of Power Supply Options
20% Reduction in Capital Costs
M/kWh
90
80
70
60
50
40
30
20
10
0
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
LEM
Landfill Gas
Geothermal
Wind
Solar Thermal
Photovoltaic
Hydroelectric



Big Rivers Electric Corporation
Nominal Natural Gas and Coal Prices
20% Reduction in Capital Costs
$/MMBtu
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
-
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
Gas
Coal

Big Rivers Electric Corporation
Comparison of LEM Contract Costs to Power Supply Options

20% Reduction in Capital Costs

Resource:	LEM	Pulv Coal	Coal Gas CC	Conventional CC	Advanced CC	Conventional CT	Advanced CT	Fuel Cells	Base Distributed	Peak Distributed	Biomass	Landfill Gas	Geothermal	Wind	Solar Thermal	Photovoltaic	Hydroelectric
Capacity Factor:		90.00%	90.00%	80.00%	80.00%	25.00%	25.00%	70.00%	90.00%	25.00%	80.00%	98.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Levelized Rate:	[REDACTED]	$33.70	$34.09	$66.89	$62.75	$107.44	$92.60	$162.94	$95.78	$133.17	$28.80	$26.39	$77.05	$24.50	$58.14	$67.60	$31.12
Annual Rates:																	
2005	[REDACTED]	30.83	31.57	70.19	65.92	112.16	96.68	161.24	99.56	138.67	28.17	24.74	76.09	24.75	59.86	73.64	31.56
2006	[REDACTED]	31.17	31.87	83.83	78.71	132.69	114.10	176.93	118.50	159.89	28.27	24.95	76.28	24.75	59.75	73.08	31.55
2007	[REDACTED]	31.36	32.03	75.16	70.57	119.70	103.06	168.05	106.61	146.39	28.37	25.15	76.46	24.75	59.62	72.49	31.53
2008	[REDACTED]	31.71	32.34	70.39	66.08	112.56	97.00	163.47	100.11	138.95	28.46	25.36	76.63	24.74	59.47	71.87	31.51
2009	[REDACTED]	31.93	32.53	66.88	62.78	107.32	92.54	160.28	95.34	133.46	28.55	25.57	76.80	24.73	59.31	71.21	31.48
2010	[REDACTED]	32.32	32.88	64.01	60.08	103.03	88.89	157.80	91.47	128.96	28.64	25.78	76.95	24.71	59.13	70.51	31.44
2011	[REDACTED]	32.60	33.12	62.33	58.49	100.53	86.76	156.63	89.24	126.30	28.73	25.99	77.09	24.69	58.93	69.78	31.39
2012	[REDACTED]	32.91	33.38	60.64	56.90	98.02	84.63	155.47	87.00	123.63	28.81	26.21	77.22	24.65	58.72	69.00	31.33
2013	[REDACTED]	33.25	33.68	58.95	55.30	95.52	82.49	154.30	84.77	120.95	28.89	26.42	77.33	24.62	58.48	68.18	31.27
2014	[REDACTED]	33.65	34.03	57.26	53.71	93.01	80.35	153.14	82.55	118.26	28.97	26.64	77.43	24.57	58.21	67.31	31.19
2015	[REDACTED]	34.10	34.43	55.57	52.11	90.49	78.21	151.98	80.32	115.55	29.04	26.86	77.51	24.52	57.92	66.40	31.11
2016	[REDACTED]	34.47	34.75	56.76	53.22	92.31	79.73	153.98	82.07	117.32	29.10	27.08	77.58	24.46	57.61	65.43	31.01
2017	[REDACTED]	35.04	35.25	59.10	55.40	95.85	82.73	157.26	85.42	120.86	29.16	27.29	77.62	24.39	57.27	64.41	30.90
2018	[REDACTED]	35.71	35.85	62.22	58.32	100.57	86.73	161.40	89.86	125.62	29.21	27.51	77.64	24.31	56.90	63.34	30.78
2019	[REDACTED]	36.33	36.40	65.53	61.41	105.56	90.95	165.74	94.55	130.64	29.25	27.73	77.64	24.21	56.49	62.20	30.64
2020	[REDACTED]	36.97	36.97	68.19	63.90	109.59	94.36	169.37	98.37	134.66	29.29	27.95	77.62	24.11	56.06	61.00	30.49
2021	[REDACTED]	37.72	37.64	70.66	66.20	113.32	97.51	172.78	101.90	138.35	29.32	28.16	77.57	24.00	55.59	59.73	30.32
2022	[REDACTED]	38.43	38.26	72.57	67.98	116.21	99.94	175.56	104.67	141.15	29.34	28.38	77.49	23.87	55.08	58.39	30.13
2023	[REDACTED]	39.16	38.91	74.06	69.36	118.47	101.85	177.88	106.88	143.30	29.35	28.59	77.38	23.73	54.53	56.98	29.93
2024	[REDACTED]	39.91	39.56	76.60	71.73	122.30	105.08	181.34	110.52	147.04	29.35	28.80	77.23	23.57	53.93	55.49	29.70

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Pulv Coal
Capital Cost		1,213.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	913.39
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Coal
Variable O&M	(M/kWh)	4.06
Fixed O&M	($/kW-Yr)	24.36
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	8.844

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	217.28	5.81	-	223.09
2	2002	25.00%	222.74	5.96	11.94	463.73
3	2003	25.00%	228.35	6.11	24.81	722.99
4	2004	25.00%	234.09	6.26	38.68	1,002.02
5		0.00%	-	-	-	1,002.02

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,002.02	67.81	53.61	14.20	33.40	25.60	112.61	14.28	$13.70	8.844	1.39	12.28	4.27	16.55	$21.89	30.83	$35.59
2	2006	987.83	67.81	52.85	14.96	33.40	26.25	112.49	14.27		8.844	1.42	12.53	4.37	16.90		31.17	
3	2007	972.87	67.81	52.05	15.76	33.40	26.91	112.35	14.25		8.844	1.43	12.62	4.48	17.11		31.36	
4	2008	957.11	67.81	51.21	16.60	33.40	27.58	112.19	14.23		8.844	1.46	12.88	4.60	17.48		31.71	
5	2009	940.51	67.81	50.32	17.49	33.40	28.28	111.99	14.21		8.844	1.47	13.01	4.71	17.72		31.93	
6	2010	923.02	67.81	49.38	18.43	33.40	28.99	111.77	14.18		8.844	1.51	13.31	4.83	18.14		32.32	
7	2011	904.60	67.81	48.40	19.41	33.40	29.72	111.51	14.14		8.844	1.53	13.50	4.95	18.45		32.60	
8	2012	885.18	67.81	47.36	20.45	33.40	30.46	111.22	14.11		8.844	1.55	13.72	5.08	18.80		32.91	
9	2013	864.73	67.81	46.26	21.54	33.40	31.23	110.90	14.07		8.844	1.58	13.98	5.21	19.18		33.25	
10	2014	843.19	67.81	45.11	22.70	33.40	32.02	110.53	14.02		8.844	1.62	14.29	5.34	19.63		33.65	
11	2015	820.50	67.81	43.90	23.91	33.40	32.82	110.12	13.97		8.844	1.66	14.66	5.47	20.13		34.10	
12	2016	796.59	67.81	42.62	25.19	33.40	33.65	109.67	13.91		8.844	1.69	14.95	5.61	20.56		34.47	
13	2017	771.40	67.81	41.27	26.54	33.40	34.49	109.17	13.85		8.844	1.75	15.44	5.75	21.19		35.04	
14	2018	744.86	67.81	39.85	27.96	33.40	35.36	108.61	13.78		8.844	1.81	16.04	5.89	21.93		35.71	
15	2019	716.90	67.81	38.35	29.45	33.40	36.25	108.01	13.70		8.844	1.88	16.58	6.04	22.63		36.33	
16	2020	687.45	67.81	36.78	31.03	33.40	37.16	107.34	13.62		8.844	1.94	17.16	6.19	23.35		36.97	
17	2021	656.42	67.81	35.12	32.69	33.40	38.10	106.62	13.52		8.844	2.02	17.85	6.35	24.20		37.72	
18	2022	623.73	67.81	33.37	34.44	33.40	39.06	105.83	13.42		8.844	2.09	18.50	6.51	25.01		38.43	
19	2023	589.30	67.81	31.53	36.28	33.40	40.04	104.97	13.31		8.844	2.17	19.17	6.67	25.85		39.16	
20	2024	553.02	67.81	29.59	38.22	33.40	41.05	104.04	13.20		8.844	2.25	19.87	6.84	26.71		39.91	
21	2025	514.80	67.81	27.54	40.26	33.40	42.08	103.02	13.07		8.844	2.33	20.59	7.01	27.61		40.67	
22	2026	474.53	67.81	25.39	42.42	33.40	43.14	101.93	12.93		8.844	2.41	21.34	7.19	28.53		41.46	
23	2027	432.11	67.81	23.12	44.69	33.40	44.22	100.74	12.78		8.844	2.50	22.12	7.37	29.49		42.27	
24	2028	387.43	67.81	20.73	47.08	33.40	45.34	99.47	12.62		8.844	2.59	22.92	7.56	30.48		43.10	
25	2029	340.35	67.81	18.21	49.60	33.40	46.48	98.09	12.44		8.844	2.69	23.76	7.75	31.50		43.95	
26	2030	290.75	67.81	15.56	52.25	33.40	47.65	96.60	12.25		8.844	2.78	24.62	7.94	32.56		44.82	
27	2031	238.50	67.81	12.76	55.05	33.40	48.85	95.01	12.05		8.844	2.89	25.52	8.14	33.66		45.71	
28	2032	183.45	67.81	9.81	57.99	33.40	50.08	93.29	11.83		8.844	2.99	26.45	8.35	34.79		46.63	
29	2033	125.46	67.81	6.71	61.09	33.40	51.33	91.45	11.60		8.844	3.10	27.41	8.56	35.96		47.56	
30	2034	64.36	67.81	3.44	64.36	33.40	52.63	89.47	11.35		8.844	3.21	28.41	8.77	37.18		48.53	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Coal Gasification CC
Capital Cost		1,402.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	1,055.71
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Coal
Variable O&M	(M/kWh)	2.58
Fixed O&M	($/kW-Yr)	34.21
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	8.309

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	251.13	6.72	-	257.85
2	2002	25.00%	257.45	6.89	13.79	535.98
3	2003	25.00%	263.93	7.06	28.67	835.64
4	2004	25.00%	270.57	7.24	44.71	1,158.15
5		0.00%	-	-	-	1,158.15

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,158.15	78.37	61.96	16.41	38.61	35.95	136.52	17.32	$16.91	8.309	1.39	11.54	2.71	14.25	$18.83	31.57	$35.74
2	2006	1,141.74	78.37	61.08	17.29	38.61	36.86	136.55	17.32		8.309	1.42	11.77	2.78	14.55		31.87	
3	2007	1,124.45	78.37	60.16	18.21	38.61	37.78	136.55	17.32		8.309	1.43	11.86	2.85	14.71		32.03	
4	2008	1,106.24	78.37	59.18	19.19	38.61	38.74	136.52	17.32		8.309	1.46	12.10	2.92	15.02		32.34	
5	2009	1,087.05	78.37	58.16	20.21	38.61	39.71	136.47	17.31		8.309	1.47	12.22	2.99	15.22		32.53	
6	2010	1,066.84	78.37	57.08	21.30	38.61	40.71	136.39	17.30		8.309	1.51	12.51	3.07	15.58		32.88	
7	2011	1,045.54	78.37	55.94	22.44	38.61	41.73	136.27	17.28		8.309	1.53	12.68	3.15	15.83		33.12	
8	2012	1,023.11	78.37	54.74	23.64	38.61	42.78	136.12	17.27		8.309	1.55	12.89	3.23	16.12		33.38	
9	2013	999.47	78.37	53.47	24.90	38.61	43.86	135.94	17.24		8.309	1.58	13.13	3.31	16.44		33.68	
10	2014	974.57	78.37	52.14	26.23	38.61	44.96	135.71	17.21		8.309	1.62	13.43	3.39	16.82		34.03	
11	2015	948.34	78.37	50.74	27.64	38.61	46.09	135.44	17.18		8.309	1.66	13.78	3.48	17.25		34.43	
12	2016	920.70	78.37	49.26	29.11	38.61	47.25	135.12	17.14		8.309	1.69	14.05	3.56	17.61		34.75	
13	2017	891.59	78.37	47.70	30.67	38.61	48.44	134.75	17.09		8.309	1.75	14.51	3.65	18.16		35.25	
14	2018	860.92	78.37	46.06	32.31	38.61	49.66	134.33	17.04		8.309	1.81	15.07	3.75	18.81		35.85	
15	2019	828.60	78.37	44.33	34.04	38.61	50.91	133.85	16.98		8.309	1.88	15.58	3.84	19.42		36.40	
16	2020	794.56	78.37	42.51	35.86	38.61	52.19	133.31	16.91		8.309	1.94	16.12	3.94	20.06		36.97	
17	2021	758.70	78.37	40.59	37.78	38.61	53.50	132.70	16.83		8.309	2.02	16.77	4.04	20.80		37.64	
18	2022	720.92	78.37	38.57	39.80	38.61	54.85	132.03	16.75		8.309	2.09	17.38	4.14	21.52		38.26	
19	2023	681.12	78.37	36.44	41.93	38.61	56.23	131.28	16.65		8.309	2.17	18.01	4.24	22.25		38.91	
20	2024	639.19	78.37	34.20	44.18	38.61	57.65	130.45	16.55		8.309	2.25	18.67	4.35	23.02		39.56	
21	2025	595.01	78.37	31.83	46.54	38.61	59.10	129.53	16.43		8.309	2.33	19.35	4.46	23.80		40.23	
22	2026	548.47	78.37	29.34	49.03	38.61	60.58	128.53	16.30		8.309	2.41	20.05	4.57	24.62		40.92	
23	2027	499.44	78.37	26.72	51.65	38.61	62.11	127.43	16.16		8.309	2.50	20.78	4.68	25.47		41.63	
24	2028	447.79	78.37	23.96	54.41	38.61	63.67	126.23	16.01		8.309	2.59	21.54	4.80	26.34		42.35	
25	2029	393.38	78.37	21.05	57.33	38.61	65.27	124.92	15.85		8.309	2.69	22.32	4.92	27.24		43.09	
26	2030	336.05	78.37	17.98	60.39	38.61	66.91	123.50	15.66		8.309	2.78	23.13	5.05	28.18		43.84	
27	2031	275.66	78.37	14.75	63.62	38.61	68.60	121.95	15.47		8.309	2.89	23.97	5.17	29.15		44.62	
28	2032	212.03	78.37	11.34	67.03	38.61	70.32	120.27	15.26		8.309	2.99	24.85	5.30	30.15		45.41	
29	2033	145.01	78.37	7.76	70.61	38.61	72.09	118.46	15.02		8.309	3.10	25.75	5.44	31.19		46.21	
30	2034	74.39	78.37	3.98	74.39	38.61	73.91	116.49	14.78		8.309	3.21	26.69	5.57	32.26		47.04	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Conv CC
Capital Cost		567.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	426.95
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2000
Primary Fuel		Gas
Variable O&M	(M/kWh)	1.83
Fixed O&M	($/kW-Yr)	11.04
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	7.196

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	138.82	3.71	-	142.54
2	2003	33.33%	142.32	3.81	7.63	296.29
3	2004	33.33%	145.90	3.90	15.85	461.94
4		0.00%	-	-	-	461.94
5		0.00%	-	-	-	461.94

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	461.94	31.26	24.71	6.55	15.40	12.50	52.61	7.51	$7.24	7.196	8.42	60.61	2.07	62.68	$63.96	70.19	$71.20
2	2006	455.39	31.26	24.36	6.90	15.40	12.81	52.58	7.50		7.196	10.31	74.20	2.12	76.33		83.83	
3	2007	448.50	31.26	23.99	7.26	15.40	13.14	52.53	7.50		7.196	9.10	65.49	2.18	67.67		75.16	
4	2008	441.23	31.26	23.61	7.65	15.40	13.47	52.47	7.49		7.196	8.43	60.67	2.23	62.91		70.39	
5	2009	433.58	31.26	23.20	8.06	15.40	13.81	52.40	7.48		7.196	7.94	57.12	2.29	59.40		66.88	
6	2010	425.52	31.26	22.77	8.49	15.40	14.15	52.32	7.47		7.196	7.53	54.20	2.35	56.55		64.01	
7	2011	417.02	31.26	22.31	8.95	15.40	14.51	52.22	7.45		7.196	7.29	52.47	2.41	54.87		62.33	
8	2012	408.08	31.26	21.83	9.43	15.40	14.88	52.11	7.44		7.196	7.05	50.74	2.47	53.20		60.64	
9	2013	398.65	31.26	21.33	9.93	15.40	15.25	51.98	7.42		7.196	6.81	49.01	2.53	51.53		58.95	
10	2014	388.72	31.26	20.80	10.46	15.40	15.63	51.83	7.40		7.196	6.57	47.27	2.59	49.87		57.26	
11	2015	378.25	31.26	20.24	11.02	15.40	16.03	51.66	7.37		7.196	6.33	45.54	2.66	48.20		55.57	
12	2016	367.23	31.26	19.65	11.61	15.40	16.43	51.47	7.35		7.196	6.49	46.69	2.72	49.41		56.76	
13	2017	355.62	31.26	19.03	12.23	15.40	16.84	51.27	7.32		7.196	6.81	48.99	2.79	51.78		59.10	
14	2018	343.38	31.26	18.37	12.89	15.40	17.27	51.04	7.28		7.196	7.24	52.08	2.86	54.94		62.22	
15	2019	330.50	31.26	17.68	13.58	15.40	17.70	50.78	7.25		7.196	7.69	55.34	2.93	58.28		65.53	
16	2020	316.92	31.26	16.96	14.30	15.40	18.15	50.50	7.21		7.196	8.06	57.98	3.01	60.99		68.19	
17	2021	302.61	31.26	16.19	15.07	15.40	18.60	50.19	7.16		7.196	8.40	60.41	3.08	63.50		70.66	
18	2022	287.55	31.26	15.38	15.88	15.40	19.07	49.85	7.11		7.196	8.66	62.29	3.16	65.45		72.57	
19	2023	271.67	31.26	14.53	16.72	15.40	19.55	49.48	7.06		7.196	8.86	63.76	3.24	67.00		74.06	
20	2024	254.94	31.26	13.64	17.62	15.40	20.04	49.08	7.00		7.196	9.21	66.27	3.32	69.59		76.60	
21	2025	237.33	31.26	12.70	18.56	15.40	20.55	48.64	6.94		7.196	9.61	69.14	3.41	72.55		79.49	
22	2026	218.76	31.26	11.70	19.56	15.40	21.06	48.17	6.87		7.196	9.95	71.62	3.49	75.11		81.99	
23	2027	199.21	31.26	10.66	20.60	15.40	21.59	47.65	6.80		7.196	10.30	74.10	3.58	77.68		84.48	
24	2028	178.61	31.26	9.56	21.70	15.40	22.14	47.09	6.72		7.196	10.66	76.72	3.67	80.39		87.11	
25	2029	156.90	31.26	8.39	22.87	15.40	22.69	46.49	6.63		7.196	11.06	79.61	3.76	83.37		90.01	
26	2030	134.04	31.26	7.17	24.09	15.40	23.27	45.83	6.54		7.196	11.48	82.59	3.86	86.44		92.98	
27	2031	109.95	31.26	5.88	25.38	15.40	23.85	45.13	6.44		7.196	11.89	85.58	3.95	89.53		95.97	
28	2032	84.57	31.26	4.52	26.73	15.40	24.45	44.37	6.33		7.196	12.32	88.68	4.05	92.73		99.06	
29	2033	57.84	31.26	3.09	28.16	15.40	25.07	43.56	6.22		7.196	12.77	91.92	4.15	96.07		102.29	
30	2034	29.67	31.26	1.59	29.67	15.40	25.70	42.68	6.09		7.196	13.24	95.30	4.26	99.56		105.65	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Adv CC
Capital Cost		558.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	420.17
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	1.77
Fixed O&M	($/kW-Yr)	10.35
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	6.752

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	136.62	3.65	-	140.28
2	2003	33.33%	140.06	3.75	7.50	291.58
3	2004	33.33%	143.58	3.84	15.60	454.61
4		0.00%	-	-	-	454.61
5		0.00%	-	-	-	454.61

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	454.61	30.76	24.32	6.44	15.15	10.88	50.35	7.18	$6.85	6.752	8.42	56.87	1.86	58.73	$59.90	65.92	$66.75
2	2006	448.17	30.76	23.98	6.79	15.15	11.15	50.28	7.17		6.752	10.31	69.62	1.91	71.53		78.71	
3	2007	441.38	30.76	23.61	7.15	15.15	11.43	50.20	7.16		6.752	9.10	61.45	1.95	63.40		70.57	
4	2008	434.23	30.76	23.23	7.53	15.15	11.72	50.10	7.15		6.752	8.43	56.93	2.00	58.94		66.08	
5	2009	426.70	30.76	22.83	7.93	15.15	12.01	50.00	7.13		6.752	7.94	53.59	2.05	55.65		62.78	
6	2010	418.76	30.76	22.40	8.36	15.15	12.32	49.87	7.12		6.752	7.53	50.86	2.11	52.96		60.08	
7	2011	410.40	30.76	21.96	8.81	15.15	12.63	49.74	7.10		6.752	7.29	49.23	2.16	51.39		58.49	
8	2012	401.60	30.76	21.49	9.28	15.15	12.94	49.58	7.08		6.752	7.05	47.61	2.21	49.82		56.90	
9	2013	392.32	30.76	20.99	9.77	15.15	13.27	49.41	7.05		6.752	6.81	45.98	2.27	48.25		55.30	
10	2014	382.55	30.76	20.47	10.30	15.15	13.60	49.22	7.02		6.752	6.57	44.36	2.33	46.68		53.71	
11	2015	372.25	30.76	19.92	10.85	15.15	13.95	49.01	6.99		6.752	6.33	42.73	2.38	45.12		52.11	
12	2016	361.40	30.76	19.33	11.43	15.15	14.30	48.78	6.96		6.752	6.49	43.81	2.44	46.25		53.22	
13	2017	349.97	30.76	18.72	12.04	15.15	14.66	48.53	6.93		6.752	6.81	45.97	2.51	48.48		55.40	
14	2018	337.93	30.76	18.08	12.68	15.15	15.02	48.26	6.89		6.752	7.24	48.87	2.57	51.44		58.32	
15	2019	325.25	30.76	17.40	13.36	15.15	15.40	47.96	6.84		6.752	7.69	51.93	2.63	54.56		61.41	
16	2020	311.89	30.76	16.69	14.08	15.15	15.79	47.63	6.80		6.752	8.06	54.40	2.70	57.10		63.90	
17	2021	297.81	30.76	15.93	14.83	15.15	16.19	47.27	6.75		6.752	8.40	56.69	2.77	59.45		66.20	
18	2022	282.98	30.76	15.14	15.62	15.15	16.59	46.89	6.69		6.752	8.66	58.45	2.84	61.29		67.98	
19	2023	267.36	30.76	14.30	16.46	15.15	17.01	46.47	6.63		6.752	8.86	59.82	2.91	62.73		69.36	
20	2024	250.90	30.76	13.42	17.34	15.15	17.44	46.02	6.57		6.752	9.21	62.18	2.98	65.16		71.73	
21	2025	233.56	30.76	12.50	18.27	15.15	17.88	45.53	6.50		6.752	9.61	64.88	3.06	67.93		74.43	
22	2026	215.29	30.76	11.52	19.25	15.15	18.33	45.00	6.42		6.752	9.95	67.20	3.13	70.34		76.76	
23	2027	196.05	30.76	10.49	20.27	15.15	18.79	44.43	6.34		6.752	10.30	69.53	3.21	72.74		79.08	
24	2028	175.77	30.76	9.40	21.36	15.15	19.26	43.82	6.25		6.752	10.66	71.99	3.29	75.28		81.53	
25	2029	154.41	30.76	8.26	22.50	15.15	19.75	43.16	6.16		6.752	11.06	74.70	3.38	78.08		84.24	
26	2030	131.91	30.76	7.06	23.71	15.15	20.24	42.45	6.06		6.752	11.48	77.49	3.46	80.95		87.01	
27	2031	108.20	30.76	5.79	24.97	15.15	20.75	41.70	5.95		6.752	11.89	80.30	3.55	83.84		89.79	
28	2032	83.23	30.76	4.45	26.31	15.15	21.28	40.88	5.83		6.752	12.32	83.21	3.64	86.84		92.68	
29	2033	56.92	30.76	3.05	27.72	15.15	21.81	40.01	5.71		6.752	12.77	86.25	3.73	89.98		95.69	
30	2034	29.20	30.76	1.56	29.20	15.15	22.36	39.08	5.58		6.752	13.24	89.42	3.82	93.25		98.82	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Conv CT
Capital Cost		395.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	297.44
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	3.16
Fixed O&M	($/kW-Yr)	10.72
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	10.817

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	148.72	3.98	-	152.70
2	2004	50.00%	152.46	4.08	8.17	317.40
3		0.00%	-	-	-	317.40
4		0.00%	-	-	-	317.40
5		0.00%	-	-	-	317.40

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	317.40	21.48	16.98	4.50	10.58	11.27	38.83	17.73	$17.54	10.817	8.42	91.11	3.32	94.43	$96.42	112.16	$113.97
2	2006	312.90	21.48	16.74	4.74	10.58	11.55	38.87	17.75		10.817	10.31	111.54	3.40	114.95		132.69	
3	2007	308.17	21.48	16.49	4.99	10.58	11.84	38.91	17.77		10.817	9.10	98.45	3.49	101.94		119.70	
4	2008	303.18	21.48	16.22	5.26	10.58	12.14	38.94	17.78		10.817	8.43	91.21	3.58	94.78		112.56	
5	2009	297.92	21.48	15.94	5.54	10.58	12.44	38.96	17.79		10.817	7.94	85.86	3.67	89.52		107.32	
6	2010	292.38	21.48	15.64	5.84	10.58	12.76	38.98	17.80		10.817	7.53	81.47	3.76	85.23		103.03	
7	2011	286.54	21.48	15.33	6.15	10.58	13.08	38.99	17.80		10.817	7.29	78.87	3.85	82.73		100.53	
8	2012	280.39	21.48	15.00	6.48	10.58	13.41	38.99	17.80		10.817	7.05	76.27	3.95	80.22		98.02	
9	2013	273.91	21.48	14.65	6.82	10.58	13.74	38.98	17.80		10.817	6.81	73.67	4.05	77.72		95.52	
10	2014	267.09	21.48	14.29	7.19	10.58	14.09	38.96	17.79		10.817	6.57	71.06	4.15	75.22		93.01	
11	2015	259.90	21.48	13.90	7.57	10.58	14.44	38.93	17.78		10.817	6.33	68.46	4.26	72.72		90.49	
12	2016	252.33	21.48	13.50	7.98	10.58	14.81	38.89	17.76		10.817	6.49	70.18	4.36	74.55		92.31	
13	2017	244.35	21.48	13.07	8.41	10.58	15.18	38.83	17.73		10.817	6.81	73.65	4.47	78.12		95.85	
14	2018	235.94	21.48	12.62	8.86	10.58	15.56	38.76	17.70		10.817	7.24	78.29	4.59	82.87		100.57	
15	2019	227.09	21.48	12.15	9.33	10.58	15.95	38.68	17.66		10.817	7.69	83.19	4.70	87.90		105.56	
16	2020	217.76	21.48	11.65	9.83	10.58	16.35	38.58	17.62		10.817	8.06	87.16	4.82	91.98		109.59	
17	2021	207.93	21.48	11.12	10.35	10.58	16.77	38.47	17.57		10.817	8.40	90.81	4.94	95.75		113.32	
18	2022	197.57	21.48	10.57	10.91	10.58	17.19	38.34	17.51		10.817	8.66	93.64	5.07	98.70		116.21	
19	2023	186.67	21.48	9.99	11.49	10.58	17.62	38.19	17.44		10.817	8.86	95.84	5.19	101.04		118.47	
20	2024	175.17	21.48	9.37	12.11	10.58	18.06	38.02	17.36		10.817	9.21	99.62	5.32	104.94		122.30	
21	2025	163.07	21.48	8.72	12.75	10.58	18.52	37.82	17.27		10.817	9.61	103.94	5.46	109.40		126.67	
22	2026	150.31	21.48	8.04	13.44	10.58	18.98	37.61	17.17		10.817	9.95	107.66	5.60	113.26		130.43	
23	2027	136.88	21.48	7.32	14.16	10.58	19.46	37.36	17.06		10.817	10.30	111.39	5.74	117.13		134.19	
24	2028	122.72	21.48	6.57	14.91	10.58	19.95	37.10	16.94		10.817	10.66	115.33	5.88	121.21		138.15	
25	2029	107.81	21.48	5.77	15.71	10.58	20.45	36.80	16.80		10.817	11.06	119.67	6.03	125.70		142.51	
26	2030	92.10	21.48	4.93	16.55	10.58	20.97	36.48	16.66		10.817	11.48	124.15	6.18	130.33		146.98	
27	2031	75.55	21.48	4.04	17.44	10.58	21.50	36.12	16.49		10.817	11.89	128.64	6.34	134.97		151.47	
28	2032	58.11	21.48	3.11	18.37	10.58	22.04	35.73	16.31		10.817	12.32	133.30	6.50	139.79		156.11	
29	2033	39.74	21.48	2.13	19.35	10.58	22.59	35.30	16.12		10.817	12.77	138.17	6.66	144.83		160.95	
30	2034	20.39	21.48	1.09	20.39	10.58	23.16	34.83	15.90		10.817	13.24	143.26	6.83	150.09		165.99	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Adv CT
Capital Cost		374.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	281.62
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	2.80
Fixed O&M	($/kW-Yr)	9.31
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	9.183

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	140.81	3.77	-	144.58
2	2004	50.00%	144.35	3.86	7.73	300.53
3		0.00%	-	-	-	300.53
4		0.00%	-	-	-	300.53
5		0.00%	-	-	-	300.53

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	300.53	20.34	16.08	4.26	10.02	9.78	35.88	16.38	$16.07	9.183	8.42	77.35	2.94	80.29	$82.02	96.68	$98.09
2	2006	296.27	20.34	15.85	4.49	10.02	10.03	35.90	16.39		9.183	10.31	94.69	3.02	97.71		114.10	
3	2007	291.78	20.34	15.61	4.73	10.02	10.28	35.91	16.40		9.183	9.10	83.57	3.09	86.67		103.06	
4	2008	287.06	20.34	15.36	4.98	10.02	10.54	35.92	16.40		9.183	8.43	77.43	3.17	80.60		97.00	
5	2009	282.08	20.34	15.09	5.25	10.02	10.81	35.92	16.40		9.183	7.94	72.89	3.25	76.14		92.54	
6	2010	276.83	20.34	14.81	5.53	10.02	11.08	35.91	16.40		9.183	7.53	69.17	3.33	72.50		88.89	
7	2011	271.31	20.34	14.51	5.82	10.02	11.36	35.89	16.39		9.183	7.29	66.96	3.42	70.37		86.76	
8	2012	265.48	20.34	14.20	6.13	10.02	11.64	35.86	16.38		9.183	7.05	64.75	3.50	68.25		84.63	
9	2013	259.35	20.34	13.88	6.46	10.02	11.94	35.83	16.36		9.183	6.81	62.54	3.59	66.13		82.49	
10	2014	252.89	20.34	13.53	6.81	10.02	12.24	35.78	16.34		9.183	6.57	60.33	3.68	64.01		80.35	
11	2015	246.08	20.34	13.17	7.17	10.02	12.54	35.73	16.31		9.183	6.33	58.12	3.77	61.89		78.21	
12	2016	238.91	20.34	12.78	7.55	10.02	12.86	35.66	16.28		9.183	6.49	59.58	3.87	63.45		79.73	
13	2017	231.36	20.34	12.38	7.96	10.02	13.18	35.58	16.25		9.183	6.81	62.52	3.96	66.49		82.73	
14	2018	223.40	20.34	11.95	8.38	10.02	13.52	35.48	16.20		9.183	7.24	66.46	4.06	70.52		86.73	
15	2019	215.01	20.34	11.50	8.83	10.02	13.86	35.38	16.15		9.183	7.69	70.63	4.17	74.79		90.95	
16	2020	206.18	20.34	11.03	9.31	10.02	14.20	35.25	16.10		9.183	8.06	73.99	4.27	78.26		94.36	
17	2021	196.87	20.34	10.53	9.80	10.02	14.56	35.11	16.03		9.183	8.40	77.09	4.38	81.47		97.51	
18	2022	187.07	20.34	10.01	10.33	10.02	14.93	34.95	15.96		9.183	8.66	79.49	4.49	83.98		99.94	
19	2023	176.74	20.34	9.46	10.88	10.02	15.30	34.78	15.88		9.183	8.86	81.36	4.60	85.97		101.85	
20	2024	165.86	20.34	8.87	11.46	10.02	15.69	34.58	15.79		9.183	9.21	84.57	4.72	89.29		105.08	
21	2025	154.40	20.34	8.26	12.08	10.02	16.08	34.36	15.69		9.183	9.61	88.24	4.84	93.07		108.76	
22	2026	142.32	20.34	7.61	12.72	10.02	16.49	34.12	15.58		9.183	9.95	91.40	4.96	96.36		111.94	
23	2027	129.60	20.34	6.93	13.40	10.02	16.90	33.85	15.46		9.183	10.30	94.56	5.08	99.65		115.10	
24	2028	116.20	20.34	6.22	14.12	10.02	17.33	33.56	15.32		9.183	10.66	97.90	5.21	103.12		118.44	
25	2029	102.08	20.34	5.46	14.88	10.02	17.76	33.24	15.18		9.183	11.06	101.60	5.34	106.94		122.12	
26	2030	87.20	20.34	4.67	15.67	10.02	18.21	32.89	15.02		9.183	11.48	105.39	5.48	110.87		125.89	
27	2031	71.53	20.34	3.83	16.51	10.02	18.67	32.51	14.85		9.183	11.89	109.21	5.61	114.82		129.67	
28	2032	55.02	20.34	2.94	17.39	10.02	19.14	32.10	14.66		9.183	12.32	113.16	5.76	118.92		133.58	
29	2033	37.63	20.34	2.01	18.32	10.02	19.62	31.65	14.45		9.183	12.77	117.30	5.90	123.20		137.65	
30	2034	19.30	20.34	1.03	19.30	10.02	20.11	31.16	14.23		9.183	13.24	121.62	6.05	127.67		141.90	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Fuel Cells
Capital Cost		4,250.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	3,200.25
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	42.40
Fixed O&M	($/kW-Yr)	5.00
Capacity Factor	(%)	70.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	7.93

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	1,040.57	27.84	-	1,068.41
2	2003	33.33%	1,066.75	28.54	57.16	2,220.85
3	2004	33.33%	1,093.59	29.25	118.82	3,462.51
4		0.00%	-	-	-	3,462.51
5		0.00%	-	-	-	3,462.51

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	3,462.51	234.31	185.24	49.06	115.42	5.25	305.92	49.89	$42.76	7.93	8.42	66.79	44.56	111.36	$126.89	161.24	$169.64
2	2006	3,413.45	234.31	182.62	51.69	115.42	5.39	303.42	49.48		7.93	10.31	81.77	45.68	127.45		176.93	
3	2007	3,361.76	234.31	179.85	54.45	115.42	5.52	300.79	49.05		7.93	9.10	72.17	46.83	119.00		168.05	
4	2008	3,307.31	234.31	176.94	57.37	115.42	5.66	298.02	48.60		7.93	8.43	66.86	48.01	114.87		163.47	
5	2009	3,249.94	234.31	173.87	60.43	115.42	5.80	295.09	48.12		7.93	7.94	62.94	49.22	112.16		160.28	
6	2010	3,189.51	234.31	170.64	63.67	115.42	5.95	292.01	47.62		7.93	7.53	59.73	50.45	110.18		157.80	
7	2011	3,125.84	234.31	167.23	67.07	115.42	6.10	288.75	47.09		7.93	7.29	57.82	51.72	109.55		156.63	
8	2012	3,058.76	234.31	163.64	70.66	115.42	6.25	285.31	46.53		7.93	7.05	55.91	53.03	108.94		155.47	
9	2013	2,988.10	234.31	159.86	74.44	115.42	6.41	281.69	45.94		7.93	6.81	54.00	54.36	108.36		154.30	
10	2014	2,913.66	234.31	155.88	78.43	115.42	6.57	277.87	45.31		7.93	6.57	52.10	55.73	107.82		153.14	
11	2015	2,835.23	234.31	151.68	82.62	115.42	6.74	273.84	44.66		7.93	6.33	50.19	57.13	107.32		151.98	
12	2016	2,752.61	234.31	147.26	87.04	115.42	6.91	269.59	43.96		7.93	6.49	51.45	58.57	110.02		153.98	
13	2017	2,665.57	234.31	142.61	91.70	115.42	7.08	265.11	43.23		7.93	6.81	53.99	60.04	114.03		157.26	
14	2018	2,573.87	234.31	137.70	96.60	115.42	7.26	260.38	42.46		7.93	7.24	57.39	61.55	118.94		161.40	
15	2019	2,477.27	234.31	132.53	101.77	115.42	7.44	255.39	41.65		7.93	7.69	60.99	63.10	124.09		165.74	
16	2020	2,375.49	234.31	127.09	107.22	115.42	7.63	250.13	40.79		7.93	8.06	63.89	64.69	128.58		169.37	
17	2021	2,268.28	234.31	121.35	112.95	115.42	7.82	244.59	39.89		7.93	8.40	66.58	66.31	132.89		172.78	
18	2022	2,155.32	234.31	115.31	119.00	115.42	8.02	238.74	38.93		7.93	8.66	68.65	67.98	136.63		175.56	
19	2023	2,036.32	234.31	108.94	125.36	115.42	8.22	232.58	37.93		7.93	8.86	70.26	69.69	139.96		177.88	
20	2024	1,910.96	234.31	102.24	132.07	115.42	8.43	226.08	36.87		7.93	9.21	73.03	71.45	144.48		181.34	
21	2025	1,778.89	234.31	95.17	139.14	115.42	8.64	219.22	35.75		7.93	9.61	76.20	73.24	149.44		185.19	
22	2026	1,639.76	234.31	87.73	146.58	115.42	8.85	212.00	34.57		7.93	9.95	78.93	75.09	154.01		188.59	
23	2027	1,493.18	234.31	79.88	154.42	115.42	9.08	204.38	33.33		7.93	10.30	81.66	76.98	158.64		191.97	
24	2028	1,338.75	234.31	71.62	162.68	115.42	9.31	196.35	32.02		7.93	10.66	84.55	78.91	163.46		195.48	
25	2029	1,176.07	234.31	62.92	171.39	115.42	9.54	187.88	30.64		7.93	11.06	87.73	80.90	168.63		199.27	
26	2030	1,004.68	234.31	53.75	180.56	115.42	9.78	178.95	29.18		7.93	11.48	91.01	82.93	173.94		203.13	
27	2031	824.13	234.31	44.09	190.22	115.42	10.03	169.53	27.65		7.93	11.89	94.30	85.02	179.32		206.97	
28	2032	633.91	234.31	33.91	200.39	115.42	10.28	159.61	26.03		7.93	12.32	97.72	87.16	184.88		210.91	
29	2033	433.52	234.31	23.19	211.11	115.42	10.54	149.15	24.32		7.93	12.77	101.30	89.35	190.65		214.97	
30	2034	222.41	234.31	11.90	222.41	115.42	10.80	138.12	22.52		7.93	13.24	105.02	91.60	196.62		219.15	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Base Distributed
Capital Cost		807.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	607.67
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	6.30
Fixed O&M	($/kW-Yr)	14.18
Capacity Factor	(%)	90.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	9.95

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	197.59	5.29	-	202.87
2	2003	33.33%	202.56	5.42	10.85	421.70
3	2004	33.33%	207.65	5.55	22.56	657.47
4		0.00%	-	-	-	657.47
5		0.00%	-	-	-	657.47

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	657.47	44.49	35.17	9.32	21.92	14.90	71.99	9.13	$8.67	9.95	8.42	83.81	6.62	90.43	$93.45	99.56	$102.12
2	2006	648.15	44.49	34.68	9.81	21.92	15.28	71.87	9.12		9.95	10.31	102.60	6.79	109.39		118.50	
3	2007	638.34	44.49	34.15	10.34	21.92	15.66	71.73	9.10		9.95	9.10	90.55	6.96	97.51		106.61	
4	2008	628.00	44.49	33.60	10.89	21.92	16.06	71.57	9.08		9.95	8.43	83.90	7.13	91.03		100.11	
5	2009	617.11	44.49	33.02	11.48	21.92	16.46	71.39	9.06		9.95	7.94	78.97	7.31	86.29		95.34	
6	2010	605.63	44.49	32.40	12.09	21.92	16.87	71.19	9.03		9.95	7.53	74.94	7.50	82.44		91.47	
7	2011	593.54	44.49	31.75	12.74	21.92	17.30	70.97	9.00		9.95	7.29	72.55	7.69	80.23		89.24	
8	2012	580.81	44.49	31.07	13.42	21.92	17.73	70.72	8.97		9.95	7.05	70.16	7.88	78.03		87.00	
9	2013	567.39	44.49	30.36	14.14	21.92	18.18	70.45	8.94		9.95	6.81	67.76	8.08	75.84		84.77	
10	2014	553.25	44.49	29.60	14.89	21.92	18.64	70.15	8.90		9.95	6.57	65.37	8.28	73.65		82.55	
11	2015	538.36	44.49	28.80	15.69	21.92	19.11	69.82	8.86		9.95	6.33	62.97	8.49	71.46		80.32	
12	2016	522.67	44.49	27.96	16.53	21.92	19.59	69.47	8.81		9.95	6.49	64.56	8.70	73.26		82.07	
13	2017	506.14	44.49	27.08	17.41	21.92	20.08	69.07	8.76		9.95	6.81	67.74	8.92	76.66		85.42	
14	2018	488.73	44.49	26.15	18.34	21.92	20.58	68.65	8.71		9.95	7.24	72.01	9.15	81.16		89.86	
15	2019	470.39	44.49	25.17	19.32	21.92	21.10	68.18	8.65		9.95	7.69	76.53	9.38	85.90		94.55	
16	2020	451.06	44.49	24.13	20.36	21.92	21.63	67.68	8.58		9.95	8.06	80.17	9.61	89.78		98.37	
17	2021	430.71	44.49	23.04	21.45	21.92	22.18	67.14	8.52		9.95	8.40	83.53	9.85	93.39		101.90	
18	2022	409.26	44.49	21.90	22.60	21.92	22.74	66.55	8.44		9.95	8.66	86.13	10.10	96.23		104.67	
19	2023	386.66	44.49	20.69	23.80	21.92	23.31	65.91	8.36		9.95	8.86	88.16	10.36	98.52		106.88	
20	2024	362.86	44.49	19.41	25.08	21.92	23.89	65.22	8.27		9.95	9.21	91.63	10.62	102.25		110.52	
21	2025	337.78	44.49	18.07	26.42	21.92	24.50	64.48	8.18		9.95	9.61	95.61	10.88	106.49		114.67	
22	2026	311.36	44.49	16.66	27.83	21.92	25.11	63.68	8.08		9.95	9.95	99.03	11.16	110.19		118.27	
23	2027	283.53	44.49	15.17	29.32	21.92	25.74	62.83	7.97		9.95	10.30	102.46	11.44	113.90		121.87	
24	2028	254.21	44.49	13.60	30.89	21.92	26.39	61.91	7.85		9.95	10.66	106.08	11.73	117.81		125.66	
25	2029	223.32	44.49	11.95	32.54	21.92	27.05	60.92	7.73		9.95	11.06	110.08	12.02	122.10		129.83	
26	2030	190.77	44.49	10.21	34.28	21.92	27.74	59.86	7.59		9.95	11.48	114.20	12.32	126.52		134.11	
27	2031	156.49	44.49	8.37	36.12	21.92	28.43	58.72	7.45		9.95	11.89	118.33	12.63	130.96		138.41	
28	2032	120.37	44.49	6.44	38.05	21.92	29.15	57.50	7.29		9.95	12.32	122.61	12.95	135.57		142.86	
29	2033	82.32	44.49	4.40	40.09	21.92	29.88	56.20	7.13		9.95	12.77	127.10	13.28	140.37		147.50	
30	2034	42.23	44.49	2.26	42.23	21.92	30.63	54.81	6.95		9.95	13.24	131.78	13.61	145.39		152.34	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Peak Distributed
Capital Cost		970.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	730.41
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		Gas
Variable O&M	(M/kWh)	6.30
Fixed O&M	($/kW-Yr)	14.18
Capacity Factor	(%)	25.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	11.2

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	365.21	9.77	-	374.97
2	2004	50.00%	374.39	10.02	20.06	779.44
3		0.00%	-	-	-	779.44
4		0.00%	-	-	-	779.44
5		0.00%	-	-	-	779.44

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	779.44	52.74	41.70	11.04	25.98	14.90	82.58	37.71	$35.31	11.2	8.42	94.34	6.62	100.96	$104.08	138.67	$139.39
2	2006	768.40	52.74	41.11	11.64	25.98	15.28	82.37	37.61		11.2	10.31	115.49	6.79	122.28		159.89	
3	2007	756.76	52.74	40.49	12.26	25.98	15.66	82.13	37.50		11.2	9.10	101.93	6.96	108.89		146.39	
4	2008	744.51	52.74	39.83	12.91	25.98	16.06	81.87	37.38		11.2	8.43	94.44	7.13	101.57		138.95	
5	2009	731.59	52.74	39.14	13.60	25.98	16.46	81.58	37.25		11.2	7.94	88.90	7.31	96.21		133.46	
6	2010	717.99	52.74	38.41	14.33	25.98	16.87	81.27	37.11		11.2	7.53	84.36	7.50	91.86		128.96	
7	2011	703.66	52.74	37.65	15.10	25.98	17.30	80.93	36.95		11.2	7.29	81.66	7.69	89.35		126.30	
8	2012	688.56	52.74	36.84	15.91	25.98	17.73	80.55	36.78		11.2	7.05	78.97	7.88	86.85		123.63	
9	2013	672.65	52.74	35.99	16.76	25.98	18.18	80.15	36.60		11.2	6.81	76.27	8.08	84.35		120.95	
10	2014	655.89	52.74	35.09	17.65	25.98	18.64	79.71	36.40		11.2	6.57	73.58	8.28	81.86		118.26	
11	2015	638.24	52.74	34.15	18.60	25.98	19.11	79.23	36.18		11.2	6.33	70.88	8.49	79.37		115.55	
12	2016	619.64	52.74	33.15	19.59	25.98	19.59	78.72	35.94		11.2	6.49	72.67	8.70	81.37		117.32	
13	2017	600.04	52.74	32.10	20.64	25.98	20.08	78.16	35.69		11.2	6.81	76.25	8.92	85.17		120.86	
14	2018	579.40	52.74	31.00	21.75	25.98	20.58	77.56	35.42		11.2	7.24	81.06	9.15	90.20		125.62	
15	2019	557.66	52.74	29.83	22.91	25.98	21.10	76.92	35.12		11.2	7.69	86.14	9.38	95.52		130.64	
16	2020	534.75	52.74	28.61	24.14	25.98	21.63	76.22	34.81		11.2	8.06	90.24	9.61	99.85		134.66	
17	2021	510.61	52.74	27.32	25.43	25.98	22.18	75.48	34.46		11.2	8.40	94.03	9.85	103.88		138.35	
18	2022	485.18	52.74	25.96	26.79	25.98	22.74	74.67	34.10		11.2	8.66	96.95	10.10	107.05		141.15	
19	2023	458.40	52.74	24.52	28.22	25.98	23.31	73.81	33.70		11.2	8.86	99.24	10.36	109.59		143.30	
20	2024	430.18	52.74	23.01	29.73	25.98	23.89	72.89	33.28		11.2	9.21	103.14	10.62	113.76		147.04	
21	2025	400.45	52.74	21.42	31.32	25.98	24.50	71.90	32.83		11.2	9.61	107.62	10.88	118.50		151.33	
22	2026	369.12	52.74	19.75	33.00	25.98	25.11	70.84	32.35		11.2	9.95	111.47	11.16	122.63		154.98	
23	2027	336.13	52.74	17.98	34.76	25.98	25.74	69.71	31.83		11.2	10.30	115.33	11.44	126.77		158.60	
24	2028	301.37	52.74	16.12	36.62	25.98	26.39	68.50	31.28		11.2	10.66	119.41	11.73	131.13		162.41	
25	2029	264.74	52.74	14.16	38.58	25.98	27.05	67.20	30.69		11.2	11.06	123.91	12.02	135.93		166.62	
26	2030	226.16	52.74	12.10	40.64	25.98	27.74	65.82	30.05		11.2	11.48	128.54	12.32	140.86		170.92	
27	2031	185.52	52.74	9.93	42.82	25.98	28.43	64.34	29.38		11.2	11.89	133.19	12.63	145.82		175.20	
28	2032	142.70	52.74	7.63	45.11	25.98	29.15	62.76	28.66		11.2	12.32	138.02	12.95	150.97		179.63	
29	2033	97.59	52.74	5.22	47.52	25.98	29.88	61.08	27.89		11.2	12.77	143.06	13.28	156.34		184.23	
30	2034	50.07	52.74	2.68	50.07	25.98	30.63	59.29	27.07		11.2	13.24	148.33	13.61	161.94		189.02	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Biomass
Capital Cost		1,757.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	1,323.02
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	2.96
Fixed O&M	($/kW-Yr)	47.18
Capacity Factor	(%)	80.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	314.72	8.42	-	323.14
2	2002	25.00%	322.64	8.63	17.29	671.70
3	2003	25.00%	330.76	8.85	35.94	1,047.23
4	2004	25.00%	339.08	9.07	56.03	1,451.41
5		0.00%	-	-	-	1,451.41

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,451.41	98.22	77.65	20.57	48.38	49.58	175.61	25.06	$24.70	0	-	-	3.11	3.11	$4.15	28.17	$28.85
2	2006	1,430.84	98.22	76.55	21.67	48.38	50.83	175.76	25.08		0	-	-	3.19	3.19		28.27	
3	2007	1,409.18	98.22	75.39	22.83	48.38	52.11	175.88	25.10		0	-	-	3.27	3.27		28.37	
4	2008	1,386.35	98.22	74.17	24.05	48.38	53.42	175.97	25.11		0	-	-	3.35	3.35		28.46	
5	2009	1,362.30	98.22	72.88	25.33	48.38	54.77	176.03	25.12		0	-	-	3.44	3.44		28.55	
6	2010	1,336.97	98.22	71.53	26.69	48.38	56.14	176.05	25.12		0	-	-	3.52	3.52		28.64	
7	2011	1,310.28	98.22	70.10	28.12	48.38	57.56	176.04	25.12		0	-	-	3.61	3.61		28.73	
8	2012	1,282.17	98.22	68.60	29.62	48.38	59.00	175.98	25.11		0	-	-	3.70	3.70		28.81	
9	2013	1,252.55	98.22	67.01	31.20	48.38	60.49	175.88	25.10		0	-	-	3.79	3.79		28.89	
10	2014	1,221.34	98.22	65.34	32.87	48.38	62.01	175.73	25.08		0	-	-	3.89	3.89		28.97	
11	2015	1,188.47	98.22	63.58	34.63	48.38	63.57	175.53	25.05		0	-	-	3.99	3.99		29.04	
12	2016	1,153.83	98.22	61.73	36.49	48.38	65.17	175.28	25.01		0	-	-	4.09	4.09		29.10	
13	2017	1,117.35	98.22	59.78	38.44	48.38	66.81	174.97	24.97		0	-	-	4.19	4.19		29.16	
14	2018	1,078.91	98.22	57.72	40.49	48.38	68.49	174.59	24.91		0	-	-	4.30	4.30		29.21	
15	2019	1,038.42	98.22	55.56	42.66	48.38	70.21	174.15	24.85		0	-	-	4.41	4.41		29.25	
16	2020	995.75	98.22	53.27	44.94	48.38	71.98	173.63	24.78		0	-	-	4.52	4.52		29.29	
17	2021	950.81	98.22	50.87	47.35	48.38	73.79	173.04	24.69		0	-	-	4.63	4.63		29.32	
18	2022	903.46	98.22	48.34	49.88	48.38	75.65	172.36	24.60		0	-	-	4.75	4.75		29.34	
19	2023	853.58	98.22	45.67	52.55	48.38	77.55	171.60	24.49		0	-	-	4.87	4.87		29.35	
20	2024	801.03	98.22	42.86	55.36	48.38	79.50	170.74	24.36		0	-	-	4.99	4.99		29.35	
21	2025	745.67	98.22	39.89	58.32	48.38	81.50	169.77	24.23		0	-	-	5.11	5.11		29.34	
22	2026	687.35	98.22	36.77	61.44	48.38	83.55	168.71	24.07		0	-	-	5.24	5.24		29.32	
23	2027	625.91	98.22	33.49	64.73	48.38	85.65	167.52	23.90		0	-	-	5.37	5.37		29.28	
24	2028	561.18	98.22	30.02	68.19	48.38	87.81	166.21	23.72		0	-	-	5.51	5.51		29.23	
25	2029	492.98	98.22	26.37	71.84	48.38	90.02	164.77	23.51		0	-	-	5.65	5.65		29.16	
26	2030	421.14	98.22	22.53	75.69	48.38	92.28	163.19	23.29		0	-	-	5.79	5.79		29.08	
27	2031	345.46	98.22	18.48	79.73	48.38	94.60	161.47	23.04		0	-	-	5.94	5.94		28.98	
28	2032	265.72	98.22	14.22	84.00	48.38	96.98	159.58	22.77		0	-	-	6.08	6.08		28.86	
29	2033	181.72	98.22	9.72	88.49	48.38	99.42	157.53	22.48		0	-	-	6.24	6.24		28.72	
30	2034	93.23	98.22	4.99	93.23	48.38	101.93	155.29	22.16		0	-	-	6.39	6.39		28.55	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Landfill Gas
Capital Cost		1,500.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	1,129.50
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	0.01
Fixed O&M	($/kW-Yr)	101.07
Capacity Factor	(%)	98.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	367.26	9.82	-	377.08
2	2003	33.33%	376.50	10.07	20.17	783.83
3	2004	33.33%	385.97	10.32	41.93	1,222.06
4		0.00%	-	-	-	1,222.06
5		0.00%	-	-	-	1,222.06

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,222.06	82.70	65.38	17.32	40.74	106.22	212.34	24.73	$27.00	0	-	-	0.01	0.01	$0.01	24.74	$27.01
2	2006	1,204.75	82.70	64.45	18.24	40.74	108.89	214.08	24.94		0	-	-	0.01	0.01		24.95	
3	2007	1,186.50	82.70	63.48	19.22	40.74	111.63	215.84	25.14		0	-	-	0.01	0.01		25.15	
4	2008	1,167.28	82.70	62.45	20.25	40.74	114.44	217.63	25.35		0	-	-	0.01	0.01		25.36	
5	2009	1,147.04	82.70	61.37	21.33	40.74	117.32	219.42	25.56		0	-	-	0.01	0.01		25.57	
6	2010	1,125.71	82.70	60.23	22.47	40.74	120.27	221.23	25.77		0	-	-	0.01	0.01		25.78	
7	2011	1,103.24	82.70	59.02	23.67	40.74	123.30	223.06	25.98		0	-	-	0.01	0.01		25.99	
8	2012	1,079.56	82.70	57.76	24.94	40.74	126.40	224.89	26.20		0	-	-	0.01	0.01		26.21	
9	2013	1,054.62	82.70	56.42	26.27	40.74	129.58	226.74	26.41		0	-	-	0.01	0.01		26.42	
10	2014	1,028.35	82.70	55.02	27.68	40.74	132.84	228.59	26.63		0	-	-	0.01	0.01		26.64	
11	2015	1,000.67	82.70	53.54	29.16	40.74	136.18	230.45	26.84		0	-	-	0.01	0.01		26.86	
12	2016	971.51	82.70	51.98	30.72	40.74	139.61	232.32	27.06		0	-	-	0.01	0.01		27.08	
13	2017	940.79	82.70	50.33	32.36	40.74	143.12	234.19	27.28		0	-	-	0.01	0.01		27.29	
14	2018	908.42	82.70	48.60	34.10	40.74	146.72	236.06	27.50		0	-	-	0.01	0.01		27.51	
15	2019	874.33	82.70	46.78	35.92	40.74	150.41	237.92	27.71		0	-	-	0.01	0.01		27.73	
16	2020	838.41	82.70	44.85	37.84	40.74	154.20	239.79	27.93		0	-	-	0.02	0.02		27.95	
17	2021	800.57	82.70	42.83	39.87	40.74	158.08	241.64	28.15		0	-	-	0.02	0.02		28.16	
18	2022	760.70	82.70	40.70	42.00	40.74	162.05	243.48	28.36		0	-	-	0.02	0.02		28.38	
19	2023	718.70	82.70	38.45	44.25	40.74	166.13	245.32	28.58		0	-	-	0.02	0.02		28.59	
20	2024	674.46	82.70	36.08	46.61	40.74	170.31	247.13	28.79		0	-	-	0.02	0.02		28.80	
21	2025	627.84	82.70	33.59	49.11	40.74	174.59	248.92	29.00		0	-	-	0.02	0.02		29.01	
22	2026	578.74	82.70	30.96	51.73	40.74	178.99	250.68	29.20		0	-	-	0.02	0.02		29.22	
23	2027	527.00	82.70	28.19	54.50	40.74	183.49	252.42	29.40		0	-	-	0.02	0.02		29.42	
24	2028	472.50	82.70	25.28	57.42	40.74	188.11	254.12	29.60		0	-	-	0.02	0.02		29.62	
25	2029	415.08	82.70	22.21	60.49	40.74	192.84	255.78	29.79		0	-	-	0.02	0.02		29.81	
26	2030	354.59	82.70	18.97	63.73	40.74	197.69	257.40	29.98		0	-	-	0.02	0.02		30.00	
27	2031	290.87	82.70	15.56	67.13	40.74	202.66	258.96	30.16		0	-	-	0.02	0.02		30.19	
28	2032	223.73	82.70	11.97	70.73	40.74	207.76	260.47	30.34		0	-	-	0.02	0.02		30.36	
29	2033	153.01	82.70	8.19	74.51	40.74	212.99	261.91	30.51		0	-	-	0.02	0.02		30.53	
30	2034	78.50	82.70	4.20	78.50	40.74	218.35	263.28	30.67		0	-	-	0.02	0.02		30.69	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Geothermal
Capital Cost		3,108.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	2,340.32
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	104.98
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	556.72	14.89	-	571.61
2	2002	25.00%	570.72	15.27	30.58	1,188.18
3	2003	25.00%	585.08	15.65	63.57	1,852.48
4	2004	25.00%	599.80	16.04	99.11	2,567.43
5		0.00%	-	-	-	2,567.43

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	2,567.43	173.74	137.36	36.38	85.58	110.33	333.27	76.09	$76.80	0	-	-	-	-	$0.00	76.09	$76.80
2	2006	2,531.05	173.74	135.41	38.33	85.58	113.10	334.10	76.28		0	-	-	-	-		76.28	
3	2007	2,492.73	173.74	133.36	40.38	85.58	115.95	334.89	76.46		0	-	-	-	-		76.46	
4	2008	2,452.35	173.74	131.20	42.54	85.58	118.87	335.65	76.63		0	-	-	-	-		76.63	
5	2009	2,409.81	173.74	128.93	44.81	85.58	121.86	336.36	76.80		0	-	-	-	-		76.80	
6	2010	2,365.00	173.74	126.53	47.21	85.58	124.92	337.03	76.95		0	-	-	-	-		76.95	
7	2011	2,317.79	173.74	124.00	49.74	85.58	128.07	337.65	77.09		0	-	-	-	-		77.09	
8	2012	2,268.06	173.74	121.34	52.40	85.58	131.29	338.21	77.22		0	-	-	-	-		77.22	
9	2013	2,215.66	173.74	118.54	55.20	85.58	134.59	338.71	77.33		0	-	-	-	-		77.33	
10	2014	2,160.46	173.74	115.58	58.15	85.58	137.98	339.14	77.43		0	-	-	-	-		77.43	
11	2015	2,102.31	173.74	112.47	61.26	85.58	141.45	339.50	77.51		0	-	-	-	-		77.51	
12	2016	2,041.05	173.74	109.20	64.54	85.58	145.01	339.78	77.58		0	-	-	-	-		77.58	
13	2017	1,976.50	173.74	105.74	67.99	85.58	148.66	339.98	77.62		0	-	-	-	-		77.62	
14	2018	1,908.51	173.74	102.11	71.63	85.58	152.40	340.08	77.64		0	-	-	-	-		77.64	
15	2019	1,836.88	173.74	98.27	75.46	85.58	156.23	340.08	77.64		0	-	-	-	-		77.64	
16	2020	1,761.42	173.74	94.24	79.50	85.58	160.16	339.98	77.62		0	-	-	-	-		77.62	
17	2021	1,681.91	173.74	89.98	83.75	85.58	164.19	339.75	77.57		0	-	-	-	-		77.57	
18	2022	1,598.16	173.74	85.50	88.24	85.58	168.32	339.40	77.49		0	-	-	-	-		77.49	
19	2023	1,509.92	173.74	80.78	92.96	85.58	172.56	338.92	77.38		0	-	-	-	-		77.38	
20	2024	1,416.97	173.74	75.81	97.93	85.58	176.90	338.29	77.23		0	-	-	-	-		77.23	
21	2025	1,319.04	173.74	70.57	103.17	85.58	181.35	337.50	77.05		0	-	-	-	-		77.05	
22	2026	1,215.87	173.74	65.05	108.69	85.58	185.91	336.54	76.84		0	-	-	-	-		76.84	
23	2027	1,107.18	173.74	59.23	114.50	85.58	190.59	335.40	76.58		0	-	-	-	-		76.58	
24	2028	992.68	173.74	53.11	120.63	85.58	195.38	334.07	76.27		0	-	-	-	-		76.27	
25	2029	872.05	173.74	46.65	127.08	85.58	200.30	332.53	75.92		0	-	-	-	-		75.92	
26	2030	744.97	173.74	39.86	133.88	85.58	205.34	330.77	75.52		0	-	-	-	-		75.52	
27	2031	611.09	173.74	32.69	141.04	85.58	210.50	328.78	75.06		0	-	-	-	-		75.06	
28	2032	470.04	173.74	25.15	148.59	85.58	215.80	326.53	74.55		0	-	-	-	-		74.55	
29	2033	321.45	173.74	17.20	156.54	85.58	221.23	324.01	73.97		0	-	-	-	-		73.97	
30	2034	164.91	173.74	8.82	164.91	85.58	226.79	321.20	73.33		0	-	-	-	-		73.33	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Wind
Capital Cost		1,134.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	853.90
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	26.81
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	277.65	7.43	-	285.08
2	2003	33.33%	284.63	7.61	15.25	592.58
3	2004	33.33%	291.80	7.81	31.70	923.88
4		0.00%	-	-	-	923.88
5		0.00%	-	-	-	923.88

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	923.88	62.52	49.43	13.09	30.80	28.18	108.40	24.75	$24.13	0	-	-	-	-	$0.00	24.75	$24.13
2	2006	910.79	62.52	48.73	13.79	30.80	28.88	108.41	24.75		0	-	-	-	-		24.75	
3	2007	897.00	62.52	47.99	14.53	30.80	29.61	108.40	24.75		0	-	-	-	-		24.75	
4	2008	882.47	62.52	47.21	15.31	30.80	30.36	108.36	24.74		0	-	-	-	-		24.74	
5	2009	867.16	62.52	46.39	16.13	30.80	31.12	108.31	24.73		0	-	-	-	-		24.73	
6	2010	851.04	62.52	45.53	16.99	30.80	31.90	108.23	24.71		0	-	-	-	-		24.71	
7	2011	834.05	62.52	44.62	17.90	30.80	32.71	108.12	24.69		0	-	-	-	-		24.69	
8	2012	816.15	62.52	43.66	18.85	30.80	33.53	107.99	24.65		0	-	-	-	-		24.65	
9	2013	797.30	62.52	42.66	19.86	30.80	34.37	107.82	24.62		0	-	-	-	-		24.62	
10	2014	777.43	62.52	41.59	20.93	30.80	35.24	107.63	24.57		0	-	-	-	-		24.57	
11	2015	756.51	62.52	40.47	22.05	30.80	36.12	107.39	24.52		0	-	-	-	-		24.52	
12	2016	734.46	62.52	39.29	23.22	30.80	37.03	107.12	24.46		0	-	-	-	-		24.46	
13	2017	711.24	62.52	38.05	24.47	30.80	37.96	106.81	24.39		0	-	-	-	-		24.39	
14	2018	686.77	62.52	36.74	25.78	30.80	38.92	106.46	24.31		0	-	-	-	-		24.31	
15	2019	660.99	62.52	35.36	27.16	30.80	39.90	106.06	24.21		0	-	-	-	-		24.21	
16	2020	633.84	62.52	33.91	28.61	30.80	40.90	105.61	24.11		0	-	-	-	-		24.11	
17	2021	605.23	62.52	32.38	30.14	30.80	41.93	105.11	24.00		0	-	-	-	-		24.00	
18	2022	575.09	62.52	30.77	31.75	30.80	42.99	104.55	23.87		0	-	-	-	-		23.87	
19	2023	543.34	62.52	29.07	33.45	30.80	44.07	103.93	23.73		0	-	-	-	-		23.73	
20	2024	509.89	62.52	27.28	35.24	30.80	45.18	103.25	23.57		0	-	-	-	-		23.57	
21	2025	474.65	62.52	25.39	37.12	30.80	46.31	102.50	23.40		0	-	-	-	-		23.40	
22	2026	437.53	62.52	23.41	39.11	30.80	47.48	101.68	23.22		0	-	-	-	-		23.22	
23	2027	398.41	62.52	21.32	41.20	30.80	48.67	100.78	23.01		0	-	-	-	-		23.01	
24	2028	357.21	62.52	19.11	43.41	30.80	49.90	99.80	22.79		0	-	-	-	-		22.79	
25	2029	313.80	62.52	16.79	45.73	30.80	51.15	98.74	22.54		0	-	-	-	-		22.54	
26	2030	268.07	62.52	14.34	48.18	30.80	52.44	97.58	22.28		0	-	-	-	-		22.28	
27	2031	219.90	62.52	11.76	50.75	30.80	53.76	96.32	21.99		0	-	-	-	-		21.99	
28	2032	169.14	62.52	9.05	53.47	30.80	55.11	94.96	21.68		0	-	-	-	-		21.68	
29	2033	115.67	62.52	6.19	56.33	30.80	56.50	93.48	21.34		0	-	-	-	-		21.34	
30	2034	59.34	62.52	3.17	59.34	30.80	57.92	91.89	20.98		0	-	-	-	-		20.98	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Solar Thermal
Capital Cost		2,960.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	2,228.88
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	3
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	50.23
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2002	33.33%	724.73	19.39	-	744.11
2	2003	33.33%	742.96	19.87	39.81	1,546.76
3	2004	33.33%	761.65	20.37	82.75	2,411.54
4		0.00%	-	-	-	2,411.54
5		0.00%	-	-	-	2,411.54

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	2,411.54	163.19	129.02	34.17	80.38	52.79	262.19	59.86	$56.66	0	-	-	-	-	$0.00	59.86	$56.66
2	2006	2,377.36	163.19	127.19	36.00	80.38	54.12	261.69	59.75		0	-	-	-	-		59.75	
3	2007	2,341.37	163.19	125.26	37.92	80.38	55.48	261.13	59.62		0	-	-	-	-		59.62	
4	2008	2,303.44	163.19	123.23	39.95	80.38	56.87	260.49	59.47		0	-	-	-	-		59.47	
5	2009	2,263.49	163.19	121.10	42.09	80.38	58.31	259.79	59.31		0	-	-	-	-		59.31	
6	2010	2,221.40	163.19	118.84	44.34	80.38	59.77	259.00	59.13		0	-	-	-	-		59.13	
7	2011	2,177.05	163.19	116.47	46.72	80.38	61.28	258.13	58.93		0	-	-	-	-		58.93	
8	2012	2,130.34	163.19	113.97	49.21	80.38	62.82	257.18	58.72		0	-	-	-	-		58.72	
9	2013	2,081.12	163.19	111.34	51.85	80.38	64.40	256.12	58.48		0	-	-	-	-		58.48	
10	2014	2,029.28	163.19	108.57	54.62	80.38	66.02	254.97	58.21		0	-	-	-	-		58.21	
11	2015	1,974.66	163.19	105.64	57.54	80.38	67.68	253.71	57.92		0	-	-	-	-		57.92	
12	2016	1,917.11	163.19	102.57	60.62	80.38	69.38	252.33	57.61		0	-	-	-	-		57.61	
13	2017	1,856.49	163.19	99.32	63.87	80.38	71.13	250.83	57.27		0	-	-	-	-		57.27	
14	2018	1,792.62	163.19	95.91	67.28	80.38	72.92	249.21	56.90		0	-	-	-	-		56.90	
15	2019	1,725.34	163.19	92.31	70.88	80.38	74.75	247.44	56.49		0	-	-	-	-		56.49	
16	2020	1,654.46	163.19	88.51	74.67	80.38	76.63	245.53	56.06		0	-	-	-	-		56.06	
17	2021	1,579.79	163.19	84.52	78.67	80.38	78.56	243.46	55.59		0	-	-	-	-		55.59	
18	2022	1,501.12	163.19	80.31	82.88	80.38	80.54	241.23	55.08		0	-	-	-	-		55.08	
19	2023	1,418.24	163.19	75.88	87.31	80.38	82.56	238.82	54.53		0	-	-	-	-		54.53	
20	2024	1,330.93	163.19	71.20	91.98	80.38	84.64	236.23	53.93		0	-	-	-	-		53.93	
21	2025	1,238.95	163.19	66.28	96.90	80.38	86.77	233.44	53.30		0	-	-	-	-		53.30	
22	2026	1,142.04	163.19	61.10	102.09	80.38	88.95	230.44	52.61		0	-	-	-	-		52.61	
23	2027	1,039.95	163.19	55.64	107.55	80.38	91.19	227.21	51.88		0	-	-	-	-		51.88	
24	2028	932.40	163.19	49.88	113.30	80.38	93.49	223.75	51.09		0	-	-	-	-		51.09	
25	2029	819.10	163.19	43.82	119.37	80.38	95.84	220.04	50.24		0	-	-	-	-		50.24	
26	2030	699.73	163.19	37.44	125.75	80.38	98.25	216.07	49.33		0	-	-	-	-		49.33	
27	2031	573.98	163.19	30.71	132.48	80.38	100.72	211.81	48.36		0	-	-	-	-		48.36	
28	2032	441.50	163.19	23.62	139.57	80.38	103.25	207.26	47.32		0	-	-	-	-		47.32	
29	2033	301.93	163.19	16.15	147.03	80.38	105.85	202.39	46.21		0	-	-	-	-		46.21	
30	2034	154.90	163.19	8.29	154.90	80.38	108.51	197.19	45.02		0	-	-	-	-		45.02	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Solar Photovoltaic
Capital Cost		4,467.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	3,363.65
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	2
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	-
Fixed O&M	($/kW-Yr)	10.34
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2003	50.00%	1,681.83	44.99	-	1,726.81
2	2004	50.00%	1,724.14	46.12	92.38	3,589.46
3		0.00%	-	-	-	3,589.46
4		0.00%	-	-	-	3,589.46
5		0.00%	-	-	-	3,589.46

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	3,589.46	242.90	192.04	50.86	119.65	10.87	322.55	73.64	$63.71	0	-	-	-	-	$0.00	73.64	$63.71
2	2006	3,538.60	242.90	189.31	53.58	119.65	11.14	320.10	73.08		0	-	-	-	-		73.08	
3	2007	3,485.01	242.90	186.45	56.45	119.65	11.42	317.52	72.49		0	-	-	-	-		72.49	
4	2008	3,428.57	242.90	183.43	59.47	119.65	11.71	314.78	71.87		0	-	-	-	-		71.87	
5	2009	3,369.10	242.90	180.25	62.65	119.65	12.00	311.90	71.21		0	-	-	-	-		71.21	
6	2010	3,306.45	242.90	176.89	66.00	119.65	12.30	308.85	70.51		0	-	-	-	-		70.51	
7	2011	3,240.44	242.90	173.36	69.53	119.65	12.61	305.63	69.78		0	-	-	-	-		69.78	
8	2012	3,170.91	242.90	169.64	73.25	119.65	12.93	302.22	69.00		0	-	-	-	-		69.00	
9	2013	3,097.66	242.90	165.72	77.17	119.65	13.26	298.63	68.18		0	-	-	-	-		68.18	
10	2014	3,020.48	242.90	161.60	81.30	119.65	13.59	294.83	67.31		0	-	-	-	-		67.31	
11	2015	2,939.18	242.90	157.25	85.65	119.65	13.93	290.83	66.40		0	-	-	-	-		66.40	
12	2016	2,853.53	242.90	152.66	90.23	119.65	14.28	286.60	65.43		0	-	-	-	-		65.43	
13	2017	2,763.30	242.90	147.84	95.06	119.65	14.64	282.13	64.41		0	-	-	-	-		64.41	
14	2018	2,668.24	242.90	142.75	100.15	119.65	15.01	277.41	63.34		0	-	-	-	-		63.34	
15	2019	2,568.09	242.90	137.39	105.50	119.65	15.39	272.43	62.20		0	-	-	-	-		62.20	
16	2020	2,462.59	242.90	131.75	111.15	119.65	15.78	267.17	61.00		0	-	-	-	-		61.00	
17	2021	2,351.44	242.90	125.80	117.10	119.65	16.17	261.62	59.73		0	-	-	-	-		59.73	
18	2022	2,234.34	242.90	119.54	123.36	119.65	16.58	255.76	58.39		0	-	-	-	-		58.39	
19	2023	2,110.98	242.90	112.94	129.96	119.65	17.00	249.58	56.98		0	-	-	-	-		56.98	
20	2024	1,981.03	242.90	105.98	136.91	119.65	17.42	243.06	55.49		0	-	-	-	-		55.49	
21	2025	1,844.11	242.90	98.66	144.24	119.65	17.86	236.17	53.92		0	-	-	-	-		53.92	
22	2026	1,699.88	242.90	90.94	151.95	119.65	18.31	228.90	52.26		0	-	-	-	-		52.26	
23	2027	1,547.92	242.90	82.81	160.08	119.65	18.77	221.23	50.51		0	-	-	-	-		50.51	
24	2028	1,387.84	242.90	74.25	168.65	119.65	19.24	213.14	48.66		0	-	-	-	-		48.66	
25	2029	1,219.19	242.90	65.23	177.67	119.65	19.73	204.60	46.71		0	-	-	-	-		46.71	
26	2030	1,041.52	242.90	55.72	187.18	119.65	20.22	195.59	44.66		0	-	-	-	-		44.66	
27	2031	854.34	242.90	45.71	197.19	119.65	20.73	186.09	42.49		0	-	-	-	-		42.49	
28	2032	657.15	242.90	35.16	207.74	119.65	21.26	176.06	40.20		0	-	-	-	-		40.20	
29	2033	449.42	242.90	24.04	218.85	119.65	21.79	165.48	37.78		0	-	-	-	-		37.78	
30	2034	230.56	242.90	12.34	230.56	119.65	22.34	154.32	35.23		0	-	-	-	-		35.23	

Big Rivers Electric Corporation
Supply-Side Resource Alternatives
Cost Projection

Resource		Hydro
Capital Cost		1,451.00
Regional Multiplier		0.753
Adjusted Capital Cost	($/kW)	1,092.60
Capital Cost Year		2003
COD Date		2005
Construction Period	(Years)	4
Construction Escl	(%)	2.52%
Cost of Debt	(%)	5.35%
Service Life	(Years)	30
Operating Cost Year		2003
Primary Fuel		None
Variable O&M	(M/kWh)	4.60
Fixed O&M	($/kW-Yr)	12.35
Capacity Factor	(%)	50.00%
O&M Escalation	(%)	2.52%
Heat Rate	(MMBtu/MWh)	

Construction Period

Ordinal Year	Calendar Year	Expenditure Percentage (%)	Expenditure ($/kW)	Interest on Current Yr Expenditure ($/kW)	Interest on Previous Yr Ending Bal ($/kW)	Ending Balance ($/kW)
1	2001	25.00%	259.91	6.95	-	266.86
2	2002	25.00%	266.45	7.13	14.28	554.71
3	2003	25.00%	273.15	7.31	29.68	864.85
4	2004	25.00%	280.02	7.49	46.27	1,198.63
5		0.00%	-	-	-	1,198.63

Service Period

Ordinal Year	Calendar Year	Loan Bal ($/kW)	Payment ($/kW)	Interest ($/kW)	Principal ($/kW)	Straight-Line Depreciation ($/kW)	Fixed O&M ($/kW)	Total Fixed Cost Annual ($/kW)	Total Fixed Cost Annual (M/kWh)	Total Fixed Cost Levelized (M/kWh)	Heat Rate (MMBtu/MWh)	Fuel Cost ($/MMBtu)	Fuel Cost (M/kWh)	Variable O&M (M/kWh)	Total Variable Cost Annual (M/kWh)	Total Variable Cost Levelized (M/kWh)	Total Cost Annual (M/kWh)	Total Cost Levelized (M/kWh)
1	2005	1,198.63	81.11	64.13	16.98	39.95	12.98	117.06	26.73	$24.12	0	-	-	4.83	4.83	$6.45	31.56	$30.57
2	2006	1,181.65	81.11	63.22	17.89	39.95	13.31	116.48	26.59		0	-	-	4.96	4.96		31.55	
3	2007	1,163.75	81.11	62.26	18.85	39.95	13.64	115.86	26.45		0	-	-	5.08	5.08		31.53	
4	2008	1,144.90	81.11	61.25	19.86	39.95	13.98	115.19	26.30		0	-	-	5.21	5.21		31.51	
5	2009	1,125.04	81.11	60.19	20.92	39.95	14.34	114.48	26.14		0	-	-	5.34	5.34		31.48	
6	2010	1,104.12	81.11	59.07	22.04	39.95	14.70	113.72	25.96		0	-	-	5.47	5.47		31.44	
7	2011	1,082.08	81.11	57.89	23.22	39.95	15.07	112.91	25.78		0	-	-	5.61	5.61		31.39	
8	2012	1,058.86	81.11	56.65	24.46	39.95	15.44	112.05	25.58		0	-	-	5.75	5.75		31.33	
9	2013	1,034.40	81.11	55.34	25.77	39.95	15.83	111.13	25.37		0	-	-	5.90	5.90		31.27	
10	2014	1,008.63	81.11	53.96	27.15	39.95	16.23	110.15	25.15		0	-	-	6.05	6.05		31.19	
11	2015	981.48	81.11	52.51	28.60	39.95	16.64	109.10	24.91		0	-	-	6.20	6.20		31.11	
12	2016	952.88	81.11	50.98	30.13	39.95	17.06	107.99	24.66		0	-	-	6.35	6.35		31.01	
13	2017	922.75	81.11	49.37	31.74	39.95	17.49	106.81	24.39		0	-	-	6.51	6.51		30.90	
14	2018	891.01	81.11	47.67	33.44	39.95	17.93	105.55	24.10		0	-	-	6.68	6.68		30.78	
15	2019	857.56	81.11	45.88	35.23	39.95	18.38	104.21	23.79		0	-	-	6.85	6.85		30.64	
16	2020	822.33	81.11	43.99	37.12	39.95	18.84	102.79	23.47		0	-	-	7.02	7.02		30.49	
17	2021	785.22	81.11	42.01	39.10	39.95	19.32	101.28	23.12		0	-	-	7.19	7.19		30.32	
18	2022	746.12	81.11	39.92	41.19	39.95	19.80	99.67	22.76		0	-	-	7.38	7.38		30.13	
19	2023	704.92	81.11	37.71	43.40	39.95	20.30	97.97	22.37		0	-	-	7.56	7.56		29.93	
20	2024	661.53	81.11	35.39	45.72	39.95	20.81	96.16	21.95		0	-	-	7.75	7.75		29.70	
21	2025	615.81	81.11	32.95	48.17	39.95	21.33	94.23	21.51		0	-	-	7.95	7.95		29.46	
22	2026	567.64	81.11	30.37	50.74	39.95	21.87	92.19	21.05		0	-	-	8.15	8.15		29.20	
23	2027	516.90	81.11	27.65	53.46	39.95	22.42	90.03	20.55		0	-	-	8.35	8.35		28.91	
24	2028	463.44	81.11	24.79	56.32	39.95	22.99	87.73	20.03		0	-	-	8.56	8.56		28.59	
25	2029	407.13	81.11	21.78	59.33	39.95	23.56	85.30	19.47		0	-	-	8.78	8.78		28.25	
26	2030	347.80	81.11	18.61	62.50	39.95	24.16	82.72	18.89		0	-	-	9.00	9.00		27.88	
27	2031	285.29	81.11	15.26	65.85	39.95	24.76	79.98	18.26		0	-	-	9.22	9.22		27.48	
28	2032	219.44	81.11	11.74	69.37	39.95	25.39	77.08	17.60		0	-	-	9.46	9.46		27.05	
29	2033	150.07	81.11	8.03	73.08	39.95	26.03	74.01	16.90		0	-	-	9.69	9.69		26.59	
30	2034	76.99	81.11	4.12	76.99	39.95	26.68	70.75	16.15		0	-	-	9.94	9.94		26.09	

Appendix F

Planned Transmission Improvements

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2014

Year: 2005

Project Description	Notes
Meade Co. 161kV Line (18 miles)	Up-grading infrastructure to meet system load growth
Possum Trot 69 kV Tap/Metering	Member Substation tap line and metering
Madisonville 69 kV Line (5 miles)	Member Substation tap line and metering
Reid, Coleman, & Wilson EHV RTU	Equipment replacement
Meade Co. 161kV Line Terminal	Up-grading infrastructure to meet system load growth
6 GHz Digital Microwave System	Equipment replacement
EHV Static Relaying Replacement	Equipment replacement
Hardinsburg-Cloverport (LGEE) PLC	Equipment replacement
Salem/Hartford RCS Radios	Equipment replacement
LGEE 345kV Interconnection	Up-grading infrastructure to meet system needs
Cumberland Resources 69kV Line (8 miles)	Member Substation tap line and metering
Doe Valley tap & KB Alloys Line Switching	Up-grading infrastructure to meet system load growth
Henderson Co., Skillman, & Hardinsburg Block Carriers	Equipment replacement
Hardinsburg #1 RCS	Up-grading infrastructure to meet system load growth

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2014

Project Description	Notes
Year: 2006	
McDaniels-Falls of Rough 69kV Line (5 miles)	Up-grading infrastructure to meet system load growth
LGEE 345kV Interconnection	Up-grading infrastructure to meet system needs
McCracken Co.-Olivet Church Rd. 69kV Line (4 miles)	Up-grading infrastructure to meet system load growth
McCracken Co. 69kV Line Terminal	Up-grading infrastructure to meet system load growth
Olivet Church Rd. tap Switching	Up-grading infrastructure to meet system load growth
Livingston Co. to Grand Rivers(TVA) Microwave Tie	Up-grading infrastructure to meet system needs
Reid, Daviess Co., Hardinsburg & Meade Co. Block Carriers	Equipment Replacement
Year: 2007	
Hardinsburg 161kV Station Modifications	Up-grading infrastructure to meet system load growth
Reconductor Reid-Onton Jct. 69kV Line (10 miles)	Up-grading infrastructure to meet system load growth
Jackson Purchase HQ Microwave	Up-grading infrastructure to meet system needs
Meade Co. HQ Microwave	Up-grading infrastructure to meet system needs

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2014

Project Description	Notes
Year: 2008	
Re-sag Livingston Co.-Smithland (5 miles)	Up-grading infrastructure to meet system load growth
Re-sag Livingston Co.-Dover Jct.(3 miles)	Up-grading infrastructure to meet system load growth
Relaying PLC at Reid (2), Henderson & Daviess Co.	Equipment replacement
Reconductor Hopkins Co.-South Hanson tap (14 miles)	Up-grading infrastructure to meet system load growth
Reconductor Hancock.-Lewisport 69kV Line (3 miles)	Up-grading infrastructure to meet system load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2009	
East Owensboro Substation (50 MVA)	New Substation to meet system load growth
East Owensboro 69 kV and 161 kV Lines (5 miles)	Transmission lines to connect new Substation
Relaying PLC at Coleman, Hardinsburg(2), & Skillman	Equipment replacement
Reconductor Meade Co. – Garrett (8.5 miles)	Up-grading infrastructure to meet system load growth
Reconductor Reid-Niagara 69kV Line (6 miles)	Up-grading infrastructure to meet system load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2014

Project Description	Notes
Year: 2010	
Hardinsburg Transformer Upgrades (100 MVA)	Up-grading infrastructure to meet system load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2011	
Corydon 161/69 kV Substation (50 MVA)	New Substation to meet system load growth
HMP&L #4 161 kV Line Terminal	Transmission Line to connect new Substation
Corydon-HMP&L #4 161 kV Line (9 miles)	Transmission Line to connect new Substation
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2012	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2013	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2014

Project Description	Notes
Year: 2014	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering

BIG RIVERS ELECTRIC TRANSMISSION SYSTEM ADDITIONS (2003 – 2005)

Project Description	Year
Meade Co.-Doe Valley tap 69kV Line	2003
Strawberry Hill-Olivet Church Rd. 69kV Line	2003
Garrett #2 Tap & Metering	2003
Steamport Tap & Metering	2003
Centertown-Ky. Utilities 69kV Tie Line	2004
Daviess Co.-Horse Fork tap 69kV Line	2004
Caldwell Co. 161/69kV Substation (20 MVA)	2004
Caldwell Co. 161 & 69kV Lines	2004
Adams Lane 69kV Tap Line	2004
Bryan Road 161/69kV Transformer Addition (50 MVA)	2004
Steamport #2 & #3 Metering	2004
Draffenville 69kV Tap Line	2005
Madisonville 69kV Tap Line	2005

Appendix G
Environmental Equipment Installations

Big Rivers Units' Environmental Equipment

Unit	Firing System	NOx Reduction	SO2 Reduction	Particulate Reduction
Coleman 1	Front Wall Fired	low-Nox burners & advanced over-fire air	wet limestone FGD, forced oxidation	ESP
Coleman 2	Front Wall Fired	low-Nox burners & advanced over-fire air	wet limestone FGD, forced oxidation	ESP
Coleman 3	Rear Wall Fired	low-Nox burners & advanced over-fire air	wet limestone FGD, forced oxidation	ESP
Henderson 1	Rear Wall Fired	low-Nox burners & selective catalytic reduction	wet mag-lime FGD, natural oxidation	ESP
Henderson 2	Rear Wall Fired	low-Nox burners & selective catalytic reduction	wet mag-lime FGD, natural oxidation	ESP
Green 1	Opposed Wall Fired	low-Nox burners & coal Re-burn	wet mag-lime FGD, natural oxidation	ESP
Green 2	Opposed Wall Fired	low-Nox burners & coal Re-burn	wet mag-lime FGD, natural oxidation	ESP
Wilson 1	Opposed Wall Fired	low-Nox burners & selective catalytic reduction	wet limestone FGD, inhibited oxidation	ESP
Reid 1	Front Wall Fired	convert to 50% Gas-Fired		ESP
Reid CT	Oil Fired	convert to natural gas or fuel oil		

Over time considerable investment has been made in these units to control emissions. All of the coal-fired-only units listed above are equipped with low-Nox burners and either Selective Catalytic Reduction (SCR) equipment, coal re-burn, or advanced over-fire air combustion technology for Nox control; and scrubbers to control SO2. All of the units, except for the Reid combustion turbine, have precipitators to control particulate. The Reid #1 unit has been retro-fitted to burn natural gas as well as coal to better control Nox and SO2 emissions. The Reid combustion turbine has been retro-fitted to burn natural gas as well as fuel oil, also to better control emissions. Continuous emissions monitors are in place on each of the respective units' stacks.

System Outage summary

	2002 scheduled	2002 unscheduled	2003 scheduled	2003 unscheduled	2004 scheduled	2004 unscheduled
C-1	1	15	1	11	1	21
C-2	0	10	1	17	1	10
C-3	1	16	1	21	1	16
G-1	1	15	1	13	1	14
G-2	1	6	1	6	1	12
H-1	1	12	1	23	1	11
H-2	1	13	1	14	1	15
R-1	0	17	0	22	1	20
W-1	2	23	1	16	1	14
System FOR		4.6%		5.2%		3.7%

Western Kentucky Energy (WKE) scheduled unit outages are generally 3- to 4-week duration every 24 months, with a 1-week "pitstop" outage approximately 12 months after each of the 3- to 4-week outages. WKE schedules unit turbine/generator overhaul outages (6 to 8 weeks duration) generally every 9 years.