FN 82

Clean Air Interstate Rule

On December 17, 2003, The EPA proposed the "Interstate Air Quality Rule" that subsequently received a name change to the "Clean Air Interstate Rule" ("CAIR"). CAIR is a multi-pollutant strategy rule that would require significant additional reduction of SO_2 and/or NO_x emissions to further reduce levels of ozone and $PM_{2.5}$ in the atmosphere. The rule would generally apply to the eastern 25-28 states (including Kentucky) and the District of Columbia. The electric power generation sector is the only industry affected by this rule.

Implementation of the rule would be based on a "cap-and-trade" allowance program similar to the NO_x SIP Call regulation. In the case of NO_x, the EPA would allocate a predetermined amount of allowances to each state and the states would determine how to allocate these to individual units. For SO_2, current allocations under the Acid Rain Program would be used.

As proposed, CAIR would target annual SO_2 reductions of 3.6 million tons during Phase I (from 2010-2014) and an additional 2 million tons during Phase II (from 2015 and later). Because the Companies (and all other utilities impacted by CAIR) have already received their SO_2 allowances for 2010 through 2034, the EPA proposes utilities surrender allowances at a greater rate than is currently required: on a 2-for-1 and 3-for-1 basis, during Phases I and II, respectively. However, pre-2010 Acid Rain Program SO_2 allowances (i.e., banked allowances) would retain their full value. This means, to meet forecasted generation needs, additional SO_2 controls need to be investigated by KU.

For NO_x, targeted reductions for 2010 are 1.5 million tons and an additional 1.8 million tons by 2015. Additionally, emissions would begin to be counted on a year-round basis in 2010, instead of just during the ozone season. This means that controls, currently considered to be

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2003

INTEGRATED RESOURCE PLAN

VOLUME I

April 1, 2004

By: The Union Light, Heat and Power Company.
Gregory C. Ficke, President
139 East Fourth Street
Cincinnati, OH 45202

1. EXECUTIVE SUMMARY

A. SYSTEM DESCRIPTION

ULH&P is a wholly owned subsidiary of CG&E that provides electric and gas service in the Northern Kentucky area contiguous to the Southwestern Ohio area served by CG&E. ULH&P serves approximately 128,000 customers in its 500 square mile service territory. ULH&P's service territory includes the cities of Covington and Newport, Kentucky.

ULH&P currently owns no generation resources, and has historically relied on its parent company, CG&E, to provide it with its full requirements of electric power. Until January 1, 2002, ULH&P received its full requirements of electric power from CG&E under a cost-of-service-based wholesale power tariff approved by the Federal Energy Regulatory Commission (FERC). Since January 1, 2002, ULH&P has received its full requirements of electric power to serve its retail customers from CG&E pursuant to a market-based, fixed price Power Sales Agreement, which expires on December 31, 2006.

ULH&P owns an electric transmission system and an electric distribution system in portions of Kenton, Campbell, Boone, Grant, and Pendleton counties of Northern Kentucky. ULH&P also owns a gas distribution system, which serves either all or parts of Kenton, Campbell, Boone, Grant, Gallatin, and Pendleton counties in Northern Kentucky. ULH&P contracts separately with the Midwest Independent

Transmission System Operator, Inc. (MISO) through Cinergy Services, Inc. for bulk transmission service to transport electric power from CG&E's plants and from outside the Cinergy system through the Cinergy transmission system to ULH&P's transmission and distribution system for ultimate delivery to ULH&P's distribution system and end-use retail customers.

The Cinergy Control Area is directly interconnected with twelve other control areas (American Electric Power, LGE Energy, Ameren, Hoosier Energy, Indianapolis Power & Light, Northern Indiana Public Service Co., Southern Indiana Gas & Electric Co., Dayton Power & Light, East Kentucky Power Cooperative, Ohio Valley Electric Corporation, Allegheny Power Wheatland, and Duke Energy Vermillion).

B. PLANNING OBJECTIVES AND CRITERIA

An integrated resource planning process generally encompasses an assessment of a variety of supply-side, demand-side, and emission compliance alternatives leading to the formation of a diversified, long-term cost-effective portfolio of options intended to satisfy reliably the electricity demands of customers located within a franchised service territory. The purpose of this Integrated Resource Plan (IRP) is to outline a strategy to furnish electric energy services in a reliable, efficient, and economic manner while factoring in environmental considerations.

The major objectives of the IRP presented in this filing are:

- Provide adequate, reliable, and economical service to customers while meeting all environmental requirements
- Maintain the flexibility and ability to alter the plan in the future as circumstances change
- Choose a near-term plan that is robust over a wide variety of possible futures
- Minimize risks (such as wholesale market risks, reliability risks, etc.)

The reliability constraints utilized for this IRP are:

1. Minimum reserve margin of fifteen percent (15%);
2. Annual loss of load hours (LOLH) less than 175; and
3. Expected unserved energy (EUE) less than 0.18 percent.

The reserve margin criterion represents a balance that must be struck between reliability needs and costs. Lower reserves may help restrain rates, but using a reserve level that is too low can result in additional costs to customers. ULH&P is continuing to examine the appropriate level of reserves for long-term planning.

C. PLANNING PROCESS

The injection of customer choice into various segments of the electric utility industry has resulted in the electric utility business shortening its planning horizon. The analysis performed to prepare this IRP covered the period 2003-2023, although the primary focus was on the first ten years. This technique was used in order to concentrate on the near-term while recognizing the fact that course corrections may be made along the way. While Kentucky IRP rules only require analysis of a 15-year timeframe, the unique circumstances of the expiration of ULH&P's contract with CG&E at the end of 2006 necessitated using a longer planning period to encompass a minimum of 15 years beyond the contract expiration date.

The major Base Case assumption concerning new laws and regulations is that no environmental compliance changes beyond the NO_x SIP call will be required to be implemented throughout the 2003-2012 time period. Risks associated with potential changes to environmental regulations are discussed further in Chapter 8, Section E. Risks associated with other changes to the Base Case assumptions are addressed through sensitivity analyses and qualitative reasoning in various sections of Chapters 5, 6, and 8.

The process utilized to develop the IRP consisted of two major components. One was organizational/structural, while the other was analytical.

The organizational process involved the formation of an IRP Team with representatives from key functional areas of Cinergy. The Team approach facilitated the high level of communication necessary across the functional areas required to develop an IRP. The Team also was responsible for examining the IRP requirements contained within the Kentucky rules and conducting the necessary analyses to comply with them. In addition, it was important to select the best way to conduct the integration while incorporating interrelationships with other planning areas, e.g., fuel planning and procurement and, to the extent allowable considering the standards of conduct in FERC Order 889, transmission/distribution planning.

The analytical process involved the following specific steps:

1. Develop planning objectives and assumptions.
2. Prepare the electric load forecast.
3. Identify and screen potential electric demand-side resource options.
4. Identify, screen, and perform sensitivity analysis around the cost-effectiveness of potential electric supply-side resource options.
5. Identify, screen, and perform sensitivity analysis around the cost-effectiveness of potential environmental compliance options.
6. Integrate the demand-side, supply-side, and environmental compliance options.
7. Perform final sensitivity analyses on the integrated resource alternatives, and select the plan.
8. Determine the best way to implement the chosen plan.

The resource plan presented herein represents the results of this extensive business planning process.

D. LOAD FORECAST

The electric energy and peak demand forecasts of the ULH&P franchised service territory are prepared each year as part of the planning process.

The general framework of the Electric Energy and Peak Load Forecast involves a national economic forecast, a service area economic forecast, and the electric load forecast.

The national economic forecast provides information about the prospective growth of the national economy. This involves projections of numerous national economic and demographic concepts such as population, employment, industrial production, inflation, wage rates, and income. The national economic forecast is obtained from Economy.com, a national economic consulting firm.

Similarly, the history and forecast of key economic and demographic concepts for the service area economy is obtained from Economy.com. The service area economic forecast is used along with the energy and peak models to produce the electric load forecast.

Energy sales projections are prepared for the residential, commercial, industrial, and other sectors. Those components plus electric system losses are aggregated to produce a forecast of net energy.

Table 1-1 provides information on the ULH&P System annual growth rates (before implementation of any new, or incremental, demand-side management programs) in energy for the major customer classes as well as net energy and peak demand.

TABLE 1-1

ULH&P System

ELECTRIC ENERGY AND PEAK LOAD

FORECAST: ANNUAL GROWTH RATES

	2003-2023
Residential MWH	1.3%
Commercial MWH	1.4%
Industrial MWH	3.3%
Net Energy MWH	1.9%
Summer Peak MW	1.4%
Winter Peak MW	1.5%

The forecast of energy is graphically depicted on Figure 1-1, and the summer and winter peak forecasts are shown on Figure 1-2. These forecasts of energy and peak demand provide the starting point for the development of the Integrated Resource Plan.

E. DEMAND-SIDE MANAGEMENT RESOURCES

ULH&P's demand-side programs, which are expected to help reduce demand on the ULH&P system during times of peak load, fall into three categories: traditional regulated DSM, customer-specific contract options, and innovative pricing programs.

DSM Programs

As a result of the Kentucky Public Service Commission's Order in Case No. 2002-00358 dated December 17, 2002, the Commission approved the continuation of and cost recovery for three current programs: the Residential Conservation and Energy Education, Residential Home Energy House Call, and Residential Comprehensive Energy Education programs for a 3-year period, through December 31, 2005. In addition, the Commission approved the implementation of a revised low-income home energy assistance program (Payment Plus) as a pilot through May 31, 2004.

On September 26, 2003, ULH&P, with the approval of the DSM Collaborative, made an application to the Commission for approval to implement a direct load control program (Power Manager) in the utility's service area. The Power Manager program subsequently received Commission approval for implementation on November 20, 2003. The incremental impacts of the DSM resource programs, including direct load control, are incorporated into the IRP analysis. The above-mentioned DSM programs were screened during this IRP process before proceeding to the integration/optimization process.

Pricing Programs

In addition to the traditional regulated DSM programs, ULH&P has two pricing programs: customer-specific contract options, and innovative pricing programs.

ULH&P has contracted with an industrial customer to reduce demand for electricity during times of peak system demand. By the term of the contract, ULH&P assumes no obligation to plan for or build to serve the customers' non-firm loads, and ULH&P can interrupt the customer at times of system peak or during times of system emergencies (up to a certain number of hours per year).

We currently expect and plan for a 3 MW reduction in our load forecasts for this "as available" load at any given point in time.

ULH&P's innovative pricing programs fall into two categories: PowerShare® and Real Time Pricing (RTP). Both programs provide customers with a market price-based incentive to alter their usage patterns. The PowerShare® program is a market-based program that provides financial incentives in the form of bill credits to our industrial and commercial customers to reduce their electric demand during periods of peak load on the ULH&P system. Customers may choose to participate in either CallOption (a contractual obligation to reduce load if requested) or QuoteOption (a pure pricing program with no contractual obligation to reduce load). With the reduction of up-front premiums under CallOption due to the drop in market prices, the amount of CallOption load reduction for summer 2003 was estimated at about 100 kW. Estimated peak reduction impacts from these programs vary based on expected market prices.

ULH&P's RTP program (Rate RTP) consists of a two-part rate: an access charge for the customer's historic or usual load, billed at standard tariff rates; and an energy charge, for the customer's incremental or decremental energy usage, billed at a real time price. The RTP rate sends price signals to participating customers that encourage usage during low cost periods and discourage consumption in high cost periods. Currently, 25 ULH&P customers participate in RTP with the estimated peak load reduction for summer 2003 at about 2 MW. While this program is scheduled to end in 2004, it was assumed to continue throughout the IRP planning horizon.

The expected impacts of the customer-specific contract options and innovative pricing programs are incorporated into the IRP analysis.

F. SUPPLY-SIDE RESOURCES

A wide variety of supply-side resource options were considered in the screening process. These generally included existing or potential purchases from other utilities, non-utility generation, and new utility-built generating units (conventional, advanced technologies, and renewables).

Because customers make cogeneration decisions based on their particular economic situations, ULH&P does not attempt to forecast specific Megawatt levels of cogeneration activity in its service area. Cogeneration facilities built to affect customer energy and demand served by the utility are captured in the load forecast. Cogeneration built to provide supply to the electric network represent additional regional supply capability. As purchase contracts are signed, the resulting energy and capacity supply will be reflected in future plans.

Over one hundred supply-side technologies from the Electric Power Research Institute (EPRI) Technical Assessment Guide® (TAG®) and other sources were screened using a set of relative dollar per kilowatt-year versus capacity factor screening curves. Sensitivity analyses were performed to determine what data input and/or assumption changes would be necessary to make a technology that is not economical under base case conditions become economical. As a result of the screening process, the following supply technologies were selected to be utilized as candidate supply-side resources in the STRATEGIST® dynamic integration computer runs: 1) 156 MW 7FA Simple Cycle Combustion Turbine (CT) units for the 2007-2023 time period, 2) 477 MW Combined Cycle (CC) units for the 2007-2023 time period, 3) 467 MW Pulverized Coal (PC) units for the 2007-2012 time period, 4) 350 MW Pressurized Circulating Fluidized Bed (PCFB) units for the 2013-2023 time period, and 5) 25 MW Fuel Cells for the 2013-2023 period. These units could represent potential non-utility generating units, purchases, or utility-constructed units. Due to the relatively small size of ULH&P's system, the larger units above (i.e., CT, CC, PC, and PCFB) were limited in size to 70 MW blocks so that no single unit would constitute more than 8% of ULH&P's load so that the 15% reserve margin criterion would be adequate.

In this IRP, ULH&P also considered the acquisition of CG&E's ownership of East Bend 2, Miami Fort 6, and Woodsdale 1-6, in conjunction with a Back-up Power Sales Agreement (PSA) for East Bend 2 and Miami Fort 6, as potential supply-side resources.

G. ENVIRONMENTAL COMPLIANCE

CAAA Phase I & Phase II Compliance

A detailed description of Cinergy's Phase I and Phase II compliance planning processes can be found in the Cinergy 1995, 1997, and 1999 IRPs.

NO_x Compliance Planning

NO_x State Implementation Plan (SIP) Call Compliance Planning must include requirements set forth by the following: 1) Federal NO_x SIP Call, 2) Kentucky NO_x SIP, and 3) Section 126 Petitions. These requirements are described in detail in Chapter 6.

A large number of potential NO_x reduction projects were considered. They include Combustion Controls, such as Low NO_x burners and combustion tuning, and post Combustion NO_x Controls, such as Selective Non-catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Sensitivity analyses were performed to evaluate a number of emerging technologies.

Cinergy used a marginal cost based model that ranks each potential NO_x reduction project using the potential NO_x tons removed, the capital cost, and the O&M costs (both fixed and variable). After ranking the projects from lowest to highest marginal cost per ton of NO_x reduced, the model continues to select projects until enough tons have been removed so that estimated emissions are less than the expected NO_x allowance allocation.

The compliance plan that was developed assumes that trading will be permitted across state lines. This decision ultimately rested with the individual States when they developed their State Implementation Plans (SIP). Initially, it was assumed that because of the stringency of EPA's NO_x SIP Call and the lack of a fluid market, that trading will comprise a relatively small amount of overall compliance. The Cinergy compliance plan therefore assumes that compliance will be accomplished on system in the near term. However, the plan is structured to utilize trading should allowance prices fall below the highest marginal cost reduction projects.

USEPA is implementing a new, more restrictive 8-hour ozone standard. This new standard is expected to create many additional non-attainment areas. In preparation of the SIPs, states have the ability to target specific areas for reductions. As a result, Cinergy could be required to make reductions targeted at specific generating plants.

These reductions may not result in the lowest cost plan based on marginal cost per ton removed.

H. ELECTRIC TRANSMISSION FORECAST

In compliance with the standards of conduct in FERC Order 889, the relevant transmission information is located in the Transmission Volume of this report, which was prepared independently.

I. SELECTION AND IMPLEMENTATION OF THE PLAN

Once the screening processes were completed, the demand-side, supply-side, and environmental compliance options were integrated into a set of resource plans, or strategies, using a consistent method of evaluation. STRATEGIST® (formerly named PROSCREEN II®) was the model utilized in this final integration process. From the optimized plans, five significantly different types of plans were selected. The sensitivity analysis methodology used in this IRP performs more detailed analysis at the front-end, or screening stage, and less detailed analysis at the back-end, or final integration stage. The sensitivities addressed at the integration stage were higher and lower gas price forecasts, a lower power market price forecast, and higher and lower load levels (based on extreme and mild weather conditions). Environmental risks, market volatility risks, and transmission risks were also considered.

Based upon both the quantitative and qualitative results of the screening analyses and sensitivity analyses, the plan selected to be the 2003 IRP is shown in Figure 1-3, assuming the transfer of the plants to ULH&P occurs on 7/1/04. The details of the plan including yearly capacity, purchases, capacity additions, retirements/derates, cogeneration, load, DSM, interruptible load, firm sales, and reserve margins are shown in Figure 1-4.

This IRP is the plan with the lowest Present Value Revenue Requirements (PVRR), over $640 million lower than the next lowest PVRR plan without the Plants. It contains the DSM bundle and DLC/RTP/CallOption programs. The supply-side resources consist of East Bend, Miami Fort 6, and Woodsdale, along with a Back-up Power Sale Agreement (PSA) for East Bend and Miami Fort 6. In addition, the plan contains small amounts of summer purchases (*i.e.*, 25-50 MW per year) in 2011-2012. Later on in the plan, there are PCFB units in 2013, 2018, and 2023, and Fuel Cell units in 2015 and 2017, which all currently act as "placeholders" for whatever capacity resources are the most economical at the time decisions for adding capacity need to be made. Of course, as the time approaches when final commitments have to be made for capacity in the last ten years of the plan, the plan may be adjusted – to levelize the reserve margins, or to substitute purchases for some of the new plant construction beginning in 2013 in the plan, if the economics and reliability of power purchases improve.

East Bend, Miami Fort 6, and Woodsdale are currently dispatched economically along with CG&E's other units and with PSI's generating units under a Joint Generation Dispatch Agreement (JGDA) between CG&E and PSI. Once all regulatory approvals are received, after ULH&P acquires these plants, they will continue to be dispatched economically with the other Cinergy system units under a Purchase, Sales and Operation Agreement between ULH&P and CG&E. This agreement will also allow energy transfers between ULH&P and CG&E at market price.

The IRP includes the projected SO_2 and NO_x compliance options described in past IRPs and in Chapter 6 associated with the East Bend, Miami Fort 6, and Woodsdale units. Any shortfalls between the yearly emission allowance allocation from the USEPA and the actual SO_2 and NO_x emitted will be supplied by ULH&P's allowance bank or by allowance purchases from the market.

The relative value for the 2003 Present Value Total Cost obtained from the STRATEGIST® output for the 2003 IRP is $3,313,502,200. The effective after-tax discount rate used was 8.737%.

The plan chosen has a number of distinct advantages due to the inclusion of the East Bend, Miami Fort 6, and Woodsdale as outlined below:

- Because these Plants already exist, there is no risk of construction or siting delay as would be the case with building new capacity.
- Excessive reliance on the wholesale market can pose pricing, scarcity, and non-performance (i.e., supplier credit) risks. The acquisition of these Plants greatly reduces ULH&P's reliance on the wholesale market for its reliability needs.

- Because these Plants are within the Cinergy control area and connected to the Cinergy transmission system, ULH&P can avoid the risks associated with trying to import the large amounts of purchases that would be required without these plants. In addition, ULH&P can avoid the deliverability risks associated with the acquisition of generation distant from the Cinergy transmission system.
- The inclusion of these plants in ULH&P's portfolio will provide source and price stability to Kentucky's electric supply which has been a key factor historically in economic development in the state.

In making decisions concerning what steps to take to begin the implementation of the 2003 IRP, careful consideration must be given to the rapidly changing environment in which utilities operate. Some of the key issues or uncertainties are:

- Environmental Regulatory Climate
- Volatility in the Wholesale Power Market
- Transmission Constraints

On July 21, 2003, ULH&P filed a petition with the Kentucky Public Service Commission to obtain Certificates of Public Convenience and Necessity (CPCN) to acquire the East Bend, Miami Fort 6, and Woodsdale units (Case No. 2003-00252). ULH&P also requested approval of the Back-up PSA for East Bend and Miami Fort 6. On December 5, 2003, the Kentucky Public Service Commission approved ULH&P's acquisition of the Plants and approved the Back-up PSA. Regulatory approvals are also required from the Federal Energy Regulatory Commission (FERC) and the Securities Exchange Commission (SEC).

After 2007, the purchases, fluidized bed units, and Fuel Cells in the plan represent, to a large extent, "placeholders" for capacity and energy needs on the system. These needs can be fulfilled by purchases from the market, cogeneration, repowering, or other capacity that may be economical at the time decisions to acquire new capacity are required. Decisions concerning coordinating the construction and operation of new units with other utilities or entities can also be made at the proper time. Until then, coordination will be achieved through purchases and sales in the bulk power market.

To comply with Phase II of the Acid Rain Program sulfur dioxide emission requirements, Cinergy's current strategy, as described in previous IRPs, includes a combination of switching to lower-sulfur coals and using an emission allowance banking strategy. This cost-effective strategy will allow Cinergy to meet Phase II sulfur dioxide reduction requirements while maintaining optimal flexibility. In the event the market price for emission allowances or lower-sulfur coal increases substantially from the current forecast, Cinergy could be forced to implement high capital cost compliance options. Fuel switches generally can be implemented in two years or less. Therefore, the implementation of a number of these fuel switches has not been finalized at this time.

The NO_x compliance strategy is described in Chapter 6. Cinergy has begun to implement its strategy (specifically by installing and operating an SCR on East Bend, as well as other Cinergy system units) in order to be ready to meet the compliance deadline of May 2004. However, Cinergy continues to study the environmental compliance alternatives and the viability of allowance purchases from the market to meet the requirements in the most cost-effective manner. Whenever possible, Cinergy plans to implement the NO_x compliance controls during regularly scheduled unit outages.

Cinergy will be closely monitoring the SO_2 and NO_x emission allowance markets to determine whether the current SO_2 and NO_x compliance plans continue to be economic. These compliance strategies will be adjusted as needed to ensure that the most economical plans are implemented.

The KY PSC approved ULH&P's current DSM programs through December 31, 2005, in an order dated December 17, 2002. Under this Agreement, ULH&P is implementing several DSM programs and RTP and the PowerShare® load interruption program as discussed in detail in Chapter 4 of this IRP and in the Short-Term Implementation Plan. In addition, ULH&P sought approval to amend its DSM program to add a Direct Load Control program. The Kentucky PSC approved the implementation of the Direct Load Control program on November 20, 2003. The incremental impacts going forward of the Interruptible customer contract and the

DSM, DLC, RTP, and CallOption programs are incorporated into the resource plan for ULH&P.

The 2003 IRP, with its proposed implementation, is consistent with ULH&P's overall planning objectives and goals. The plan that was chosen was the least cost (PVRR), provides reliable service to ULH&P's customers, is robust, and minimizes risks to customers of potential future market price spikes. In addition, monitoring of the SO_2 and NO_x emission allowance markets provide flexibility to ULH&P's environmental compliance strategy.

Figure 1-1

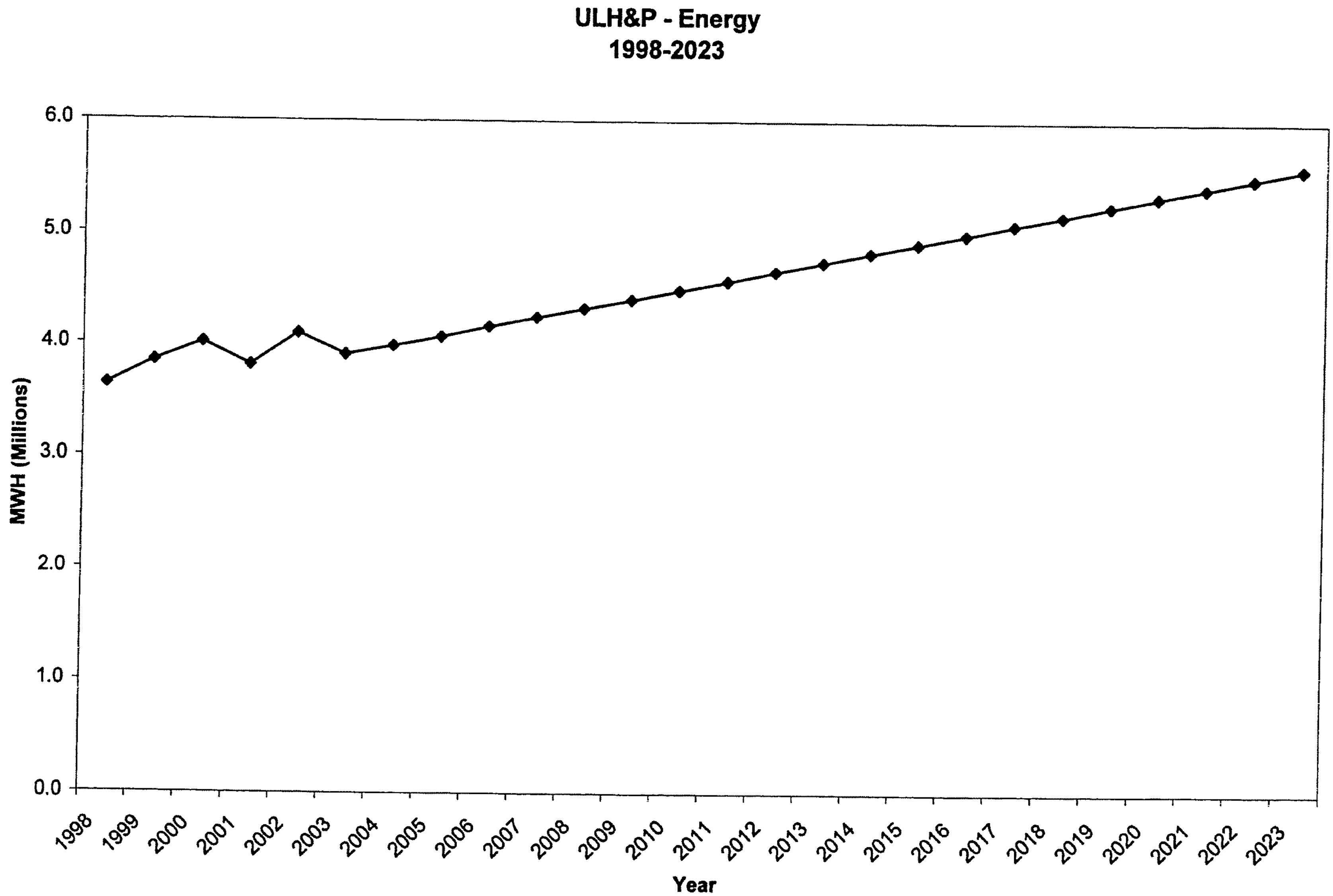
ULH&P - Energy
1998-2023
MWH (Millions)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year

Figure 1-2

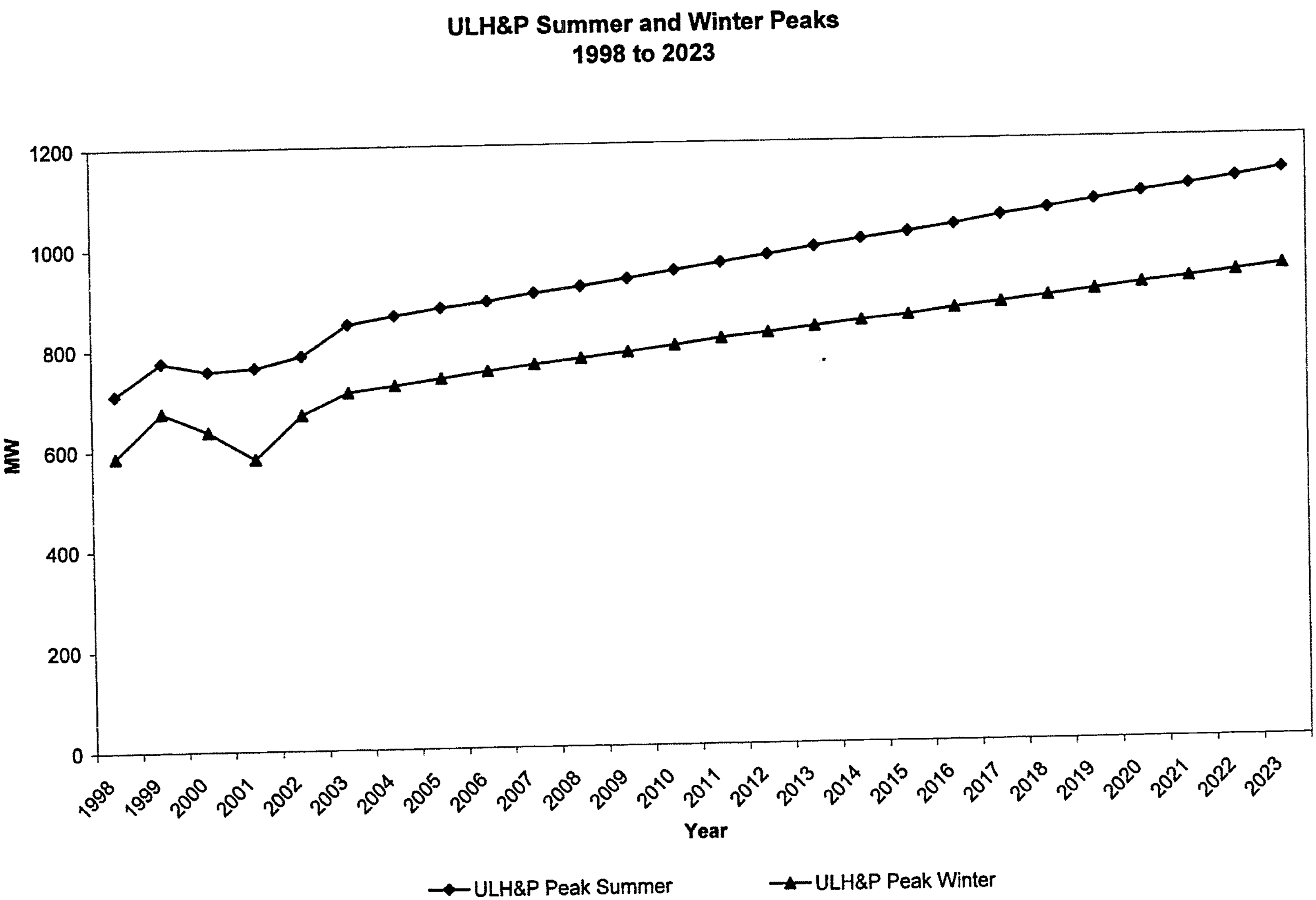
ULH&P Summer and Winter Peaks
1998 to 2023
1200
1000
800
600
400
200
0
MW
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
ULH&P Peak Summer
ULH&P Peak Winter

Figure 1-3

ULH&P INTEGRATED RESOURCE PLAN
2003-2023

Year	Demand-Side[1]	Purchases/Unit Additions[2]
2003	DSM Bundle Interruptible Contracts RTP/DLC/CallOption Programs	
2004		East Bend 2 with Back-up PSA Miami Fort 6 with Back-up PSA Woodsdale 1-6
2005		
2006		
2007		
2008		
2009		
2010		
2011		25 MW Summer Purchase
2012		50 MW Summer Purchase
2013		1-70 MW PCFB Unit
2014		
2015		1-25 MW Fuel Cell
2016		
2017		1-25 MW Fuel Cell
2018		1-70 MW PCFB Unit
2019		
2020		
2021		
2022		
2023		1-70 MW PCFB Unit

[1] The Demand-side resources are assumed to continue throughout the planning period (2003-2023)
[2] Capacity shown denotes summer ratings

Figure 1-4

ULH&P

INTEGRATED RESOURCE PLAN

East Bend/Miami Fort 6/Woodsdale Plan

(Summer Capacity and Loads)

YEAR	INITIAL CAPACITY	SHORT TERM PURCH.	INCR. CAPACITY ADDITIONS	INCR. CAPACITY RETIRE./ DERATES	COGEN. CAPACITY	TOTAL CAPACITY	PEAK LOAD	INCR. DSM[a]	DLC/RTP/ CALLOPTION	INDUSTRIAL INTERRUPTIBLE LOAD	FIRM SALES	NET LOAD	RES. MAR. (%)	RM CRITERION[b] (%)	MW TO ADD TO MEET RM
2003	0	843	0	0	0	843	848	-0.4	-2	-3	0	843	NA	NA	NA
2004	0	0	1077	0	0	1077	864	-0.4	-4	-3	0	857	25.7	16.7	-77
2005	1077	0	0	0	0	1077	879	-0.4	-7	-3	0	869	24.0	16.6	-64
2006	1077	0	0	0	0	1077	890	-0.4	-10	-3	0	877	22.9	16.5	-56
2007	1077	0	0	0	0	1077	905	-0.4	-13	-3	0	889	21.2	16.4	-43
2008	1077	0	0	0	0	1077	917	-0.4	-15	-3	0	899	19.8	16.3	-32
2009	1077	0	0	0	0	1077	931	-0.4	-15	-3	0	913	18.0	16.1	-17
2010	1077	0	0	0	0	1077	946	-0.4	-15	-3	0	928	16.1	16.0	-1
2011	1077	25	0	0	0	1102	960	-0.4	-15	-3	0	942	17.0	15.9	-11
2012	1077	50	0	0	0	1127	974	-0.4	-15	-3	0	956	17.9	15.7	-21
2013	1077	0	70	0	0	1147	989	-0.4	-15	-3	0	971	18.2	15.6	-25
2014	1147	0	0	0	0	1147	1003	-0.4	-15	-3	0	985	16.5	15.5	-10
2015	1147	0	25	0	0	1172	1016	-0.4	-15	-3	0	998	17.5	15.4	-21
2016	1172	0	0	0	0	1172	1030	-0.4	-15	-3	0	1012	15.8	15.2	-6
2017	1172	0	25	0	0	1197	1047	-0.4	-15	-3	0	1029	16.4	15.1	-13
2018	1197	0	70	0	0	1267	1060	-0.4	-15	-3	0	1042	21.6	15.0	-69
2019	1267	0	0	0	0	1267	1075	-0.4	-15	-3	0	1057	19.9	15.0	-52
2020	1267	0	0	0	0	1267	1089	-0.4	-15	-3	0	1071	18.3	15.0	-36
2021	1267	0	0	0	0	1267	1102	-0.4	-15	-3	0	1084	16.9	15.0	-21
2022	1267	0	0	0	0	1267	1116	-0.4	-15	-3	0	1098	15.4	15.0	-5
2023	1267	0	70	0	0	1337	1131	-0.4	-15	-3	0	1113	20.2	15.0	-57

[a] Not included in load forecast

[b] East Bend and Miami Fort 6 have a back-up contract, so Reserve Margin Criterion is the greater of 15% or 7% plus reserving for the loss of the largest unit

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE TO ACQUIRE CERTAIN GENERATION RESOURCES AND RELATED PROPERTY; FOR APPROVAL OF CERTAIN PURCHASE POWER AGREEMENTS; FOR APPROVAL OF CERTAIN ACCOUNTING TREATMENT; AND FOR APPROVAL OF DEVIATION FROM REQUIREMENTS OF KRS 278.2207 AND 278.2213(6)	)	CASE NO. 2003-00252

INDEX

COMMONWEALTH OF KENTUCKY

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INTERIM ORDER

On July 21, 2003, The Union Light, Heat and Power Company ("ULH&P") applied for a certificate of public convenience to acquire 1,105 megawatts ("MW") of generating capacity from its parent company, The Cincinnati Gas and Electric Company ("CG&E"), and approval of: (1) certain purchase power agreements with CG&E; (2) certain accounting and rate-making treatments related to the proposed acquisition, and (3) a request to deviate from certain statutory requirements related to affiliate transactions.

The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("AG"), is the only intervenor in this proceeding. ULH&P responded to two rounds of interrogatories by the AG and Commission Staff. The AG filed testimony of his expert witnesses on September 26, 2003 and responded to one round of interrogatories by ULH&P and Commission Staff. Informal conferences were held at the Commission's offices on October 15, 21, and 24, 2003. On October 29, ULH&P filed an amendment to its application that changed several of the accounting and rate-making treatments proposed in its original application.

A public hearing was held on October 29 and 30, 2003. ULH&P and the AG filed responses to hearing data requests on November 7, 2003. Post-hearing briefs were received on November 19, 2003, and the case now stands submitted for decision.

SUMMARY OF DECISION

Having considered and thoroughly analyzed the evidence, we find that the proposed transfer is in the best interests of ULH&P and its ratepayers and should be approved, with some clarification and modification, subject to the Commission's review and approval of all transaction documents in their final form.[1] While this Commission cannot, in this transfer proceeding, render a decision on certain requests that will be binding on a future Commission in a ULH&P general rate case, we find that the related accounting and rate-making treatments proposed by ULH&P appear, at this time, to be reasonable.[2] We also find that ULH&P's requests to deviate from the Commission's statutory requirements regarding affiliate transactions and from our requirement that it analyze bids for purchased power in conjunction with its next Integrated Resource Plan ("IRP") filing are reasonable and should be granted.

[1] Based on the evidence in this record, it appears that the proposed transaction is in the best interests of ULH&P's customers. The Commission urges that the federal agencies that must approve this transfer, the Federal Energy Regulatory Commission ("FERC") and the Securities and Exchange Commission ("SEC"), will give consideration to our findings in this proceeding when rendering their decisions.

[2] We recognize, however, that a change in law or compelling evidence to the contrary may require Commission consideration in ULH&P's next general rate case.

BACKGROUND

In Case No. 2001-00058, the Commission approved a wholesale power contract under which ULH&P purchases power from CG&E as a full requirements customer.[3] That contract, scheduled to run through 2006, provides for ULH&P to purchase power from CG&E at a fixed price containing a market price component.[4] In its approval Order in that proceeding, the Commission expressed its interest in ULH&P acquiring generation in order to insulate itself from the impacts of market prices for wholesale power on a going-forward basis. The Commission also required ULH&P to file a stand-alone IRP no later than June 30, 2004 as a means of evaluating its future resource supply needs.[5] In its December 21, 2001 Order in Administrative Case No. 387, the Commission reiterated its concern regarding ULH&P's potential exposure to market prices in the future and also expressed concern that ULH&P had no announced plans for meeting its customers' power needs after the termination date of the current wholesale power contract.[6]

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[3] Case No. 2001-00058, The Application of The Union Light, Heat and Power Company for Certain Findings Under 15 U.S.C. § 79Z, final Order dated May 11, 2001, at 17.

[4] ULH&P and CG&E are both part of the Cinergy Corp. ("Cinergy") system. CG&E's rates to ULH&P include a market component due to its generating facilities being deregulated under Ohio's electric industry restructuring and FERC's mandate that wholesale rates be market-based rather than cost-based.

[5] In Case No. 2001-00058 ULH&P also agreed to freeze retail rate components that recover wholesale generation and transmission costs through December 31, 2006.

[6] Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System, final Order dated December 21, 2001, at 39-40.

ULH&P states that this application is its response to the concerns expressed by the Commission in those prior proceedings. Its proposal includes the acquisition of CG&E's 69 percent share of East Bend No. 2,[7] a 648 MW base load, coal-fired generating unit located in Rabbit Hash, Kentucky; Miami Fort No. 6, a 168 MW intermediate load, coal-fired generating unit located in North Bend, Ohio; and the 490 MW Woodsdale Generating Station, consisting of six peak load, gas or propane-fired generating units located in Trenton, Ohio.[8] Along with its application, ULH&P filed an independent due diligence assessment of the subject facilities, which was performed by Burns & McDonnell Engineering Company ("B&McD").[9]

ULH&P'S PROPOSAL

Under the amended application, the specific generating units will be transferred from CG&E to ULH&P at what is commonly referred to as net book value which, from a utility regulatory perspective, is defined as original cost less accumulated depreciation, with the original cost and the accumulated depreciation being carried forward to the accounting records of the acquiring entity. Because FERC and the SEC must rule upon the proposed transaction before it can be consummated, ULH&P and CG&E anticipate that the proposed transaction will not be completed until mid 2004. Although ULH&P

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[7] The Dayton Power and Light Company owns the remaining 31 percent.

[8] Under Ohio's electric industry restructuring plan, all the units proposed to be transferred were deregulated effective January 1, 2001. See Transcript of Evidence ("T.E."), Vol. I, October 29, 2003, at 221-222.

[9] Information on the facilities subject to the proposed transfer and B&McD's due diligence study of the facilities are included in Appendix A to this Order.

will acquire ownership of these units, Cinergy's generation fleet, including these units, will continue to be operated and dispatched on a system-wide, centralized basis.

ULH&P requests approval of a back-up power sale agreement ("PSA") under which CG&E will provide power to ULH&P when ULH&P's generation is not available to meet its system demand. It also requests approval of a purchase, sale and operation agreement ("PSOA") which will govern the terms of energy transfers between ULH&P and CG&E that occur for economic rather than reliability reasons. In addition to these agreements, ULH&P requests approval of assignment from CG&E of existing contracts governing the natural gas supply, propane fuel supply and propane storage at the Woodsdale site. The parties to these contracts are Cinergy Marketing and Trading, LP ("CMT"), Ohio River Valley Propane LLC ("ORVP"), affiliates within Cinergy, and TE Products Pipeline Company ("TEPPCO"), a non-affiliate company.[10]

In conjunction with the proposed acquisition of these generating units, ULH&P proposes specific accounting and rate-making treatments for certain revenues and costs, treatments it claims are necessary to make the transaction acceptable to CG&E and to maintain benefits that CG&E and Cinergy presently realize under the units' deregulated status. These accounting and rate-making treatments, as set forth in the amendment to ULH&P's application, are:

(1) Fixing, for rate-making purposes, the value of the facilities being transferred at original cost less accumulated depreciation;

(2) Deferring until ULH&P's next rate case a maximum of $2.45 million in transaction costs incurred by ULH&P and CG&E related to the transfer of the specific units, with such costs amortized over 5 years without carrying charges;

[10] ULH&P also requests approval of assignment from CG&E of the existing coal supply contracts for East Bend and Miami Fort No. 6.

(3) Including in ULH&P's future base rates the capacity charges set out in the back-up PSA;

(4) Including in ULH&P's future Fuel Adjustment Clause ("FAC") the costs of energy charges assessed under the back-up PSA and the costs of energy transfers from CG&E assessed under the PSOA;

(5) Authorizing ULH&P to record accumulated deferred investment tax credits ("ADITC") and accumulated deferred income taxes ("deferred income taxes") transferred from CG&E "below the line" and to exclude the ADITC and deferred income taxes from retail rate-making in its next general rate case; and

(6) In its next general rate case, permitting ratepayers to retain the first $1 million in profits from off-system sales and 50 percent of profits above $1 million, with ULH&P retaining the other 50 percent of any off-system sales profits in excess of $1 million.[11]

ULH&P also requests approval to modify the IRP that it is required to file by June 30, 2004 to eliminate the requirement that the IRP include an evaluation of purchased power alternatives. In its amendment to its application, ULH&P commits to submit to the Commission for review and approval all final transaction documents prior to closing.

ULH&P requests approval to deviate from the affiliate transaction requirements of KRS 278.2207 through 278.2213 in order to effect the acquisition of the specific units and establish the proposed agreements with CG&E, CMT and OVRP. ULH&P also proposes to continue the rate freeze ordered in Case No. 2001-00058. It will honor its commitment to continue its rate freeze through 2006, and its commitment will apply to base rates, FAC charges, and environmental surcharges.

[11] Off-system sales profits will be calculated by subtracting the incremental costs of such sales, as listed in paragraph 1.10 of the proposed PSOA, from the revenues generated through off-system sales.

THE AG'S POSITION

The AG takes issue with certain aspects of ULH&P's proposal. Those are as follows:

(1) The fact that ULH&P did not issue a Request for Proposals ("RFP") seeking offers of generating assets, purchase power agreements, or combinations thereof, to meet its future needs;

(2) The request to fix the value of the facilities being transferred for future rate-making purposes;

(3) The proposed deferral and recovery of transaction costs;

(4) The proposal to record ADITC and deferred income taxes "below the line" and exclude them for retail rate-making in ULH&P's next general rate case;

(5) ULH&P's proposed sharing of off-system sales profits; and

(6) The FAC treatment of energy transfers made under the proposed PSOA.

The aspects of the proposal which the AG contests, or with which the AG disagrees, are discussed individually in the following paragraphs.

Need for an RFP

The AG commends ULH&P and CG&E for working to provide a means by which ULH&P's rates can remain stable and ratepayers can be sheltered from the impact of market price fluctuations. However, he argues that without an RFP, ULH&P and the Commission cannot be assured that the offer from CG&E represents the least cost alternative for meeting ULH&P's future power supply needs. Among other things, the AG cites KRS 278.2207(2), arguing that ULH&P has not demonstrated that the pricing for the transfer and related agreements is at CG&E's or its other affiliates' fully distributed costs, but in no event greater than market. The AG also contends that ULH&P has not demonstrated that the requested pricing is reasonable.

The AG cites the recent experiences of East Kentucky Power Cooperative, Inc. ("East Kentucky") and Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") in support of his argument. He refers to East Kentucky's recent application for approval to construct two combustion turbines ("CTs") based on the low bid it received in response to an RFP for peaking power. He also cites LG&E/KU's use of an RFP to demonstrate that purchasing CTs from a non-regulated affiliate was the least cost alternative for meeting their need for additional peaking capacity. The AG argues that an RFP is especially warranted when the transaction involves affiliates. He states that the acquisition price of the Woodsdale units exceeds the prices of the CTs acquired recently by East Kentucky and LG&E/KU; therefore, he concludes the price ULH&P is paying exceeds market.

ULH&P states that it did not issue an RFP for several reasons. First, it cites the recent and ongoing financial problems that have resulted in significant downgrades in the credit ratings of numerous electric industry participants, both regulated and non-regulated. Such downgrades have greatly increased credit risk concerns within the industry. Second, ULH&P indicates that the electricity market today focuses primarily on short-term contractual arrangements and that such a focus likely means that it would need to be back in the market for power within three to five years if it entered into a purchase power agreement at this time. Third, while acknowledging that a market exists for peaking generation such as CTs, ULH&P notes that there is not a comparable market for base load capacity.[12] It also notes that there are no recent transactions similar to the proposed transaction, wherein a distribution utility attempted to acquire generation to supply its entire system or where facilities originally regulated, which were later deregulated, would go back under regulation.[13] Although an active market for base load capacity similar to the market for peaking capacity does not exist, ULH&P engaged ICF Consulting ("ICF")[14] to prepare an analysis of the market value of the generating capacity that is the subject of the proposed transaction.[15] ICF's analysis includes a base case scenario that shows the market value of the assets being transferred to be more than twice their book value. It also includes 11 sensitivities to reflect changes in assumptions such as demand levels, fuel prices, environmental regulations, and/or combinations of changes in various assumptions. Under each of the 11 sensitivities, the market value of the generating assets exceeds their book value.[16]

ULH&P points to the advantages of acquiring existing facilities with documented service histories and avoiding the risks inherent with siting and permitting new facilities. It also cites the advantages of acquiring generation facilities that are already integrated into the Cinergy transmission system and that will continue to be dispatched on a centralized basis along with the rest of the generation in the Cinergy system. Finally,

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[12] T.E., Vol. I, October 29, 2003, at 181-182.

[13] Id. at 182.

[14] ICF Consulting is an international consulting firm whose clients include the United States Environmental Protection Agency, Royal Bank of Canada, JP Morgan Securities, Inc., Moody's Investors Service, other government entities and investment firms, along with utilities and regulatory commissions.

[15] Rose Direct Testimony, Attachments JLR-26 and JLR-26a.

[16] Id.

ULH&P states that the offer from CG&E may not remain available after it goes through the 6- to 9-month RFP process described by the AG. This is due to the potential for other parties to make purchase offers for some or all of the capacity or for wholesale power prices to increase to the point where CG&E decides that selling the output of the units in the market is in its best business interests.

The AG's arguments regarding the affiliate nature of the transaction and whether ULH&P has met its burden under KRS 278.2207(2) are not compelling. It is clear that the cost of the generating units to be transferred reflects CG&E's fully distributed costs. The record evidence is also very clear that the cost of the units is no greater than market. While the AG claims that the absence of an RFP leaves the Commission no alternative but to speculate as to the market price of alternatives to the proposed transaction, he ignores other measures of "market" prices. ICF's market analysis of the facilities being transferred, which the AG neither refuted or contested, is one such measure.

The AG's reliance on the recent CT proposals by East Kentucky and LG&E/KU does not consider any differences between those units and the Woodsdale units that could affect their relative costs. Some of those differences include: (1) Woodsdale's cost includes the cost of the land at that location; (2) Woodsdale's cost includes the cost of the pipelines that will be acquired with the generating units; and (3) the design of the Woodsdale units allows them to operate on either natural gas or propane. Furthermore, the AG has not demonstrated, in arguing as to whether prices are "no greater than market," that the Commission is required to review the components of the proposed transaction separately. Therefore, while the per cost kilowatt ("kw") of capacity of the

Woodsdale units may exceed the cost of the East Kentucky and LG&E/KU CTs, the cost of the total package of generating facilities that ULH&P proposes to acquire is substantially below market value as reflected in ICF's market analysis.

The Commission recognizes the AG's concerns and acknowledges that utilities under its jurisdiction typically conduct an RFP as part of the process of selecting new supply resources. We believe that such a process has benefited Kentucky's utilities and its ratepayers and that it will continue to benefit them in the future. However, in this instance, given the uniqueness of the proposed transaction, we are not persuaded that undertaking an RFP process would benefit ULH&P or its ratepayers. Attempting to acquire an entire generation fleet through a single transaction is unprecedented in the electric utility industry. Given the level of uncertainty that exists in the electric industry today, there are several arguments in favor of relying on factors other than the market or the financial strength of the firms that make up that market. Furthermore, based on ICF's market analysis, the facilities included in the transaction are being offered at an attractive price. As noted in the record, the average depreciated cost of the generating units included in the offer to ULH&P is $332 per kw of capacity.[17] This compares to typical installed costs in today's electric industry of roughly $350 to $400 per kw for CTs and $1,000, or more, per kw for base load coal-fired capacity.[18]

As evident both in Case No. 2001-00058 and Administrative Case No. 387, the Commission is on record as favoring ULH&P owning generation to serve the needs of

[17] Id. at 183.

[18] Response to the Commission Staff's Hearing Data Request of October 29, 2003, Item 1.

its customers and to reduce its reliance on wholesale power purchases. Under the unique circumstances of this case, and given that the evidence demonstrates that a market for baseload capacity comparable to the market for peaking capacity does not exist, we find ULH&P's analysis of supply-side resource options to be reasonable. While CG&E's generation offer may not reflect the mix of facilities that ULH&P would seek under ideal circumstances, this "imperfection" does not persuade the Commission that the proposed transaction should be put on hold while ULH&P undertakes the process of issuing an RFP and evaluating the responses it receives thereto.[19]

Considering all relevant factors, we find that requiring ULH&P to conduct an RFP process is not necessary to determine the reasonableness of the proposed transfer of generating facilities. Based on a thorough review and analysis of the evidence of record, the Commission finds that it has other means of determining whether the proposed transfer is reasonable. We also find that ULH&P's acquisition of the facilities being offered by CG&E is in its best interests and the interests of its ratepayers. Having determined that an RFP is not necessary in this instance, we must still make a determination of whether the various conditions proposed by ULH&P are reasonable before ruling on whether to approve the transfer as proposed.

Transaction Costs

In its amended application, ULH&P requests that it be permitted to defer no more than $2.45 million of transaction costs incurred in conjunction with the proposed acquisition. ULH&P also proposes that the deferred costs be amortized over 5 years,

[19] The Commission notes that it has no statutory authority to require that CG&E sell any generation to ULH&P or to require CG&E to hold open its current offer until ULH&P has completed an RFP process.

without carrying charges, beginning on the effective date of the Commission's Order in its next general rate case.[20] ULH&P has estimated that the total transaction costs would be $4.9 million, and would include transaction costs associated with filing preparation, financing, and taxes.[21]

The AG recommends that the transaction costs be deferred and recovered, but does not recommend that amortization begin with the next rate case. The AG suggests that, during the period between the transfer of the units and the next rate case, any profits generated by the units in excess of a reasonable rate of return be applied against the recovery of the deferred transaction costs. The AG believes this approach would reduce or possibly eliminate the deferred balance by the time of the next rate case.[22]

The Commission finds that ULH&P's proposal is reasonable and should be approved. Limiting the deferral provides for a sharing of the transaction costs between ULH&P's shareholders and ratepayers. The 5-year amortization period also represents a reasonable balance between the interests of these two groups. The exclusion of carrying charges on the deferred balance is consistent with the Commission's previous

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[20] Amendment to Application at 2-3.

[21] Steffen Direct Testimony, Attachment JPS-7. ULH&P explained that as a result of becoming "more comfortable" with certain aspects of Kentucky statutes and regulations, it decided to amend the application. The proposal to defer roughly half of the estimated transaction costs was one of the areas in which ULH&P felt comfortable in shifting the "balance more in customers' favor." See T.E., Volume I, October 29, 2003, at 16.

[22] King Direct Testimony at 10-11. The AG's testimony on this issue related to the original application and request to defer all the transaction costs and amortize those costs over 3 years. The AG did not address the treatment of the transaction costs as included in the amended application in testimony or in his brief.

decisions concerning situations in which the unamortized balance of a deferred cost is excluded from the rate base calculations during a general rate case.

ADITC and Deferred Income Taxes

As a result of Ohio's retail unbundling effective January 1, 2001, ADITC and deferred income tax balances associated with the generating units proposed to be transferred to ULH&P were reclassified as "below the line" and have been amortized "below the line" over the remaining lives of the plants. ULH&P proposes that ADITC and deferred income tax balances associated with the generating units be transferred from CG&E's books to ULH&P's books concurrent with the transfer of the units. ULH&P proposes that the transferred ADITC and deferred income tax balances remain "below the line" items on its books, amortized over the remaining lives of the units, and excluded from retail rate-making in ULH&P's future general rate proceedings. Any deferred income taxes generated after ULH&P owns the units would be "above the line" and included for rate-making purposes.[23] ULH&P acknowledges that the amortization expense associated with the "below the line" ADITC and deferred income tax balances would be recorded "below the line" as well.[24] As of March 31, 2003, the ADITC balance was $7,404,258,[25] and the deferred income tax balance was $83,388,148.[26]

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[23] Application at 9-10 and Steffen Direct Testimony at 12-13.

[24] T.E., Volume I, October 29, 2003, at 216-217.

[25] Response to the Commission Staff's First Data Request dated August 21, 2003, Item 51(a).

[26] Id., Item 52(a).

ULH&P argues that the proposed treatment for the ADITC and deferred income tax balances is reasonable. It states that the units included in the proposal were not subject to retail rate-making in Kentucky during the period when they were owned by CG&E, and concludes that ULH&P's ratepayers should not receive the benefit of the rate base reduction generally made by the Commission for ADITC and deferred income taxes.[27] ULH&P notes that the treatment proposed in this case is identical to that proposed and accepted in a recent plant transfer involving Cinergy affiliates in Indiana.[28] ULH&P also contends that the proposed treatment is consistent with Internal Revenue Service ("IRS") tax normalization requirements, and cites several IRS rulings in support of this conclusion.[29]

The AG opposes ULH&P's proposed treatment of the ADITC and deferred income tax balances. The AG argues that ULH&P's proposal will result in an overstated rate base, a distorted capital structure that will produce an overstated cost of equity, and an overstated income tax expense on a going-forward basis. The AG contends that the proposed treatment is at odds with conventional rate-making and that it does not recognize that the ADITC and deferred income tax balances represent customer-supplied capital that was provided while the plants were under regulation. The AG estimates that the revenue requirement impact of ULH&P's proposed treatment would

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[27] Id., Items 51(d)(1) and 52(c)(1).

[28] T.E., Volume I, October 29, 2003, at 222.

[29] Response to the Commission Staff's Hearing Data Request of October 29, 2003, Item 4. ULH&P cites a 1987 IRS General Counsel Memorandum and references several IRS Private Letter Rulings issued between 1987 and 1996.

be approximately $341.9 million over the next 25 years.[30] The AG recommends that the ADITC balance be either subtracted from ULH&P's rate base or treated as zero-cost capital, with the ADITC balance amortized over the remaining lives of the plant "above the line" in order to recognize the source of the ADITC. The AG further recommends that the deferred income tax balance be accounted for "above the line" in accordance with the FERC Uniform System of Accounts ("FERC USoA").

ULH&P's proposed acquisition of generating facilities from CG&E represents an unprecedented transaction to be considered by the Commission. Not only must the Commission consider that the proposed transaction is between affiliated companies, it must also recognize that the generating assets being sold to the regulated entity have been deregulated. Consequently, the Commission must carefully consider the accounting and rate-making treatments authorized in conjunction with the proposed transaction, including the tax normalization impacts.

After reviewing the arguments and evidence, the Commission finds that the treatment of ADITC and deferred income taxes proposed by ULH&P is reasonable and should be approved. The generating units proposed to be transferred to ULH&P have been deregulated since January 1, 2001. When CG&E's regulated generating fleet became deregulated, the ADITC and deferred income tax balances were moved "below the line" for rate-making purposes. The possibility that some units of the deregulated generating fleet may be returning to regulation does not, in and of itself, support an assumption that the associated ADITC and deferred income tax balances will

[30] AG's Response to Hearing Data Request filed November 7, 2003.

automatically move "above the line" for rate-making purposes. No evidence has been presented in this case that supports such an assumption.

ULH&P has provided the results of its research concerning the treatment of the ADITC and deferred income tax balances from a tax perspective. That research indicates that, upon the sale of public utility assets between two public utilities, ADITC cannot be added to the regulated books of the purchasing utility and that it cannot be flowed-through to the customers of either the buyer or seller. ULH&P's research also indicates that, as the result of an asset sale and purchase transaction, any reduction of the purchaser's cost of service for pre-transfer ADITC or deferred income tax balances would result in a tax normalization violation.

In addition, ULH&P's proposal concerning the transfer of the deferred income taxes is consistent with the FERC USoA. In three separate account descriptions, the FERC USoA provides, "When plant is disposed of by transfer to a wholly owned subsidiary the related balance in this account shall also be transferred."[31] However, the Commission notes that the FERC USoA addresses only the accounting treatment, and does not state for rate-making purposes whether the deferred income taxes are to be recorded "above the line" or "below the line."

Concerning the AG's estimated revenue requirement impact of ULH&P's proposed treatment for ADITC and deferred income taxes, the Commission finds the estimate to be of little persuasive value. The AG has not consistently stated the amount

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[31] See FERC USoA, Account No. 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account No. 282, Accumulated Deferred Income Taxes – Other Property; and Account No. 283, Accumulated Deferred Income Taxes – Other.

of the estimated impact.[32] The Commission has examined the calculation of the $341.9 million estimate and notes that the calculation assumes the rate of return on rate base and federal and state income tax rates to be constant over the approximate 25-year time frame covered by the estimate. The calculations include the determination of an annual return resulting from the AG's contention that there will be an excessive equity ratio. This annual return is also assumed to be constant, and is multiplied by 24.75 years to reflect its impact on the AG's revenue requirement. We note that ULH&P expressed similar concerns about the calculations in its brief.[33] The Commission does not believe that these assumptions produce a reasonable estimate of the revenue requirement impact of ULH&P's proposed rate-making treatment for ADITC and deferred income taxes. The Commission must consider all impacts of the proposal submitted rather than focus solely on the revenue requirement impact, as it appears the AG has done. Given the potential tax normalization issues, the lack of documentation supporting the AG's arguments, and the unrealistic assumptions contained in the AG's estimate of the revenue requirements impact, the Commission cannot consider the AG's position to be a reasonable alternative.

Profits from Off-System Sales

The AG argues that ratepayers should receive 90 percent of the profits from off-system sales and that ULH&P should be allowed to retain 10 percent as an incentive to

[32] The AG did not include an estimate of the revenue requirement impact in his prefiled testimony. At the public hearing, the AG's witness stated the estimated impact was approximately $200.0 million. See T.E., Volume II, October 30, 2003 at 43-44. In the AG's response to the hearing data request, the estimated revenue requirement was determined to be $341.9 million. However, the AG's brief states that the impact on ULH&P's revenue requirement is $317.7 million. See AG's Post Hearing Brief at 10.

[33] ULH&P Brief at 43-44.

make such sales. The AG states that ratepayers receive 100 percent of the profits from off-system sales under standard rate-making treatment, but recognizes that ULH&P should be given an incentive, albeit a small one, to make these sales. The AG also argues against ULH&P's proposed treatment of off-system sales profits on the basis that the proposal is not limited to sales made exclusively from the facilities being transferred. He claims the proposal would also apply to off-system sales derived from other assets that ULH&P could acquire while its proposed treatment of off-system sales profits was in place, which would produce an absurd result.

ULH&P acknowledges that the proposal to share off-system sales profits between customers and shareholders departs from typical rate-making treatment. However, it points out that, since Ohio's electric restructuring went into effect, CG&E has retained 100 percent of the profits from off-system sales from the units. ULH&P argues that this aspect of the proposal is critical to making the transaction acceptable to CG&E from an economic perspective.

The Commission finds ULH&P's proposal that ratepayers retain the first $1 million in profits from off-system sales and 50 percent of profits above $1 million to be acceptable. While it represents a departure from standard rate-making treatment, it represents an improvement for ratepayers compared to the current purchased power contract. As the contract is not cost-based, its pricing is not based on ratepayer retention of any off-system sales profits; hence, under ULH&P's proposal, ratepayers will be receiving a benefit from off-system sales that they had not received previously.

In addition, ULH&P forecasts annual off-system sales profits of $4.5 million in the early years after the transfer, with the amount declining to $1.6 million by 2012. Given the uncertainty attendant to forecasting off-system sales, the guarantee of retaining up to the first $1 million in profits from such sales is a significant benefit to ratepayers.

We recognize that this treatment does not comport with conventional rate-making; however, as stated elsewhere in this Order, this is not a conventional proceeding before this Commission. While ULH&P has referred to the sharing of off-system sales profits that has been approved for American Electric Power ("AEP") in the past, this is largely an issue of first impression.[34] It is also, contrary to the AG's brief, an issue applicable only to sales from the facilities that are the subject of the proposed transfer.[35]

For these reasons, and considering all provisions in the transaction as a whole, we find that the treatment of off-system sales profits proposed in the amendment to ULH&P's application is reasonable. We further find no reason, at this time, that such treatment should not be approved in ULH&P's next general rate proceeding.

FAC Treatment of Energy Transfers Under the PSOA

The AG does not disagree with ULH&P's proposal to include the cost of energy transfers from CG&E to ULH&P for recovery through its future FAC. However, he argues that such treatment is appropriate only if credits that occur when ULH&P makes transfers to CG&E are also passed through the FAC. The amendment to ULH&P's

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[34] AEP's sharing of profits from off-system sales has no revenue requirement impact, as does ULH&P's proposal. It involves a monthly comparison of such profits to the level (100%) of profits included in the revenue requirements determination in its prior general rate case.

[35] ULH&P's application and testimony refer to off-system sales from the facilities being transferred and its amended application refers only to its next general rate case. To extend its proposal to include facilities that it might acquire in the future, ULH&P would have to file for and receive Commission approval.

application revised its original proposal, under which it would have retained 100 percent of the profits from off-system sales, such that ratepayers will receive the bulk of the profits from such sales. The proposal in ULH&P's original application would have precluded the AG's proposed treatment of the costs of energy transfers from ULH&P to CG&E. However, recognizing the change to both ULH&P's proposed treatment of off-system sales and its proposed treatment of energy transfers, as set out later in this Order in the section "Other Accounting and Rate-making Treatment Proposals," we conclude that passing through the FAC the credits that occur when ULH&P makes energy transfers to CG&E is entirely consistent with the FAC treatment prescribed in 807 KAR 5:056 and should, therefore, be approved, as proposed by the AG.

OTHER ISSUES

New Agreements and Contracts

ULH&P seeks approval of a form of asset transfer agreement for each of the three generating facilities included in the proposed transfer. A draft of the asset transfer agreement for East Bend was filed with the application.[36] Based on the amendment to ULH&P's application, the final agreements are expected to mirror the draft agreement, except for the deletion of provisions governing a "Regulatory Non-Satisfaction Event" and the "Purchase Option" both of which addressed circumstances that could lead to ULH&P transferring the facilities back to CG&E in the future.

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[36] Turner Direct Testimony, Attachment JLT-1.

In conjunction with the proposed transfer, ULH&P and CG&E will enter into the back-up PSA and PSOA described earlier in this Order.[37] The back-up PSA provides a firm supply of power for ULH&P's native load customers to replace capacity from either East Bend or Miami Fort when outages or deratings of those units occur.[38] Pricing terms under the back-up PSA call for energy to be priced at the average variable cost per MWh during the prior calendar month at the plant for which back-up power is required. The capacity charges ULH&P will pay under the back-up PSA are based on a value of power calculated using forward market prices quoted from Megawatt Daily and the North American Power 10x Report.[39] There are separate capacity charges for East Bend and Miami Fort which, on a combined basis, equal $421,595 per month. The overall price for back-up power included in the PSA is less than the price embedded in ULH&P's existing wholesale purchase power contract with CG&E.

ULH&P and CG&E will also enter into the PSOA, which will allow the units being transferred to be jointly dispatched along with other Cinergy generating units. Energy transferred between ULH&P and CG&E under the PSOA will be priced at the market price for the hour in which the energy transfer takes place but will be capped at the receiving entity's incremental cost of available generation. The PSOA also establishes

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[37] Although the Commission can "approve" the back-up PSA and the PSOA as requested by ULH&P, because they both relate to wholesale transactions between ULH&P and CG&E, those agreements are subject to FERC's jurisdiction. Therefore, any approval thereof by the Commission would constitute an official endorsement of the agreements but would not constitute the final approval necessary.

[38] Woodsdale is not covered by the back-up PSA because it is peaking capacity, which will not operate for most hours of the year and will not be relied upon to meet ULH&P's base load requirements.

[39] McCarthy Direct Testimony, as adopted by M. Stephen Harkness, at 4.

the terms under which off-system purchases and sales will be made and how the costs and revenues associated with such transactions will be treated by ULH&P and CG&E.

For its operation of the Woodsdale station, CG&E presently has a contract with CMT to obtain its natural gas supply and contracts with ORVP to obtain propane and to store propane in a cavern partially owned by ORVP. CG&E also has a contract with TEPPCO to store propane in TEPPCO's pipeline system.[40] CG&E owns the pipelines used to transport propane to Woodsdale from both the ORVP cavern and the TEPPCO pipeline. ULH&P will acquire CG&E's pipelines as part of the proposed transaction.

Other than stating his concerns about the price of the facilities and the affiliate aspects of the proposed transaction, the AG did not oppose the form or content of the amended draft asset transfer agreement or ULH&P's proposal to enter into the back-up PSA and PSOA with CG&E. Likewise, the AG did not oppose CG&E's assignment of the "Woodsdale contracts" or its coal supply contracts to ULH&P. The Commission finds that the subject agreements and contracts are required in conjunction with the proposed transfer and, based on information in this record, appear to be reasonable and should therefore be approved, subject to our review and approval of the final documents.[41]

Several of the transaction documents have been and will be drafted to accomplish the proposed transaction. ULH&P commits to submit to the Commission for

[40] CG&E also has non-affiliate contracts for the coal supply for East Bend and Miami Fort 6, which are to be assigned to ULH&P.

[41] It should be noted, due to their impact on ULH&P's base rates and/or future FAC charges, that both the back-up PSA and the PSOA are subject to periodic audit or review by the Commission.

review and approval the final documents prior to closing. ULH&P refers to 12 transaction documents that will be executed as part of the proposed transaction.[42] The Commission recognizes that the timing of the closing of the proposed transaction will be of significant concern to ULH&P and CG&E. However, the Commission must have adequate time to review the numerous documents related thereto.

Therefore, the Commission finds that a process should be established to address the review and approval of the transaction documents in their final form. ULH&P should submit all the transaction documents in their final form to the Commission no later than 30 days prior to the expected closing date of the transaction. The submitted documents should include all attachments, exhibits, appendices, and schedules that are referenced as part of the particular transaction document. For those documents it has already included in this record, ULH&P should include a detailed explanation for any changes made to the document from the version already existing in the record. For those documents not already included in this record, ULH&P should include a narrative describing the purpose of the document and explaining how the terms and conditions contained in the document are consistent with this Order. ULH&P should file an original and 5 copies of this information with the Commission and a copy with the AG.[43] Upon ULH&P's filing of these documents and explanations, the Commission will complete its review as expeditiously as possible.

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[42] The transaction documents identified in the record are listed in Appendix B of this Order.

[43] This docket will remain open to receive the final documents. The AG, as is his right as an intervenor, will have an opportunity to offer his opinion on those documents.

Request for Deviation Regarding Affiliate Transactions

In 2000, the Kentucky General Assembly enacted guidelines on cost allocations and affiliate transactions, as well as a code of conduct for utilities with nonregulated activities or affiliates. These standards and guidelines are codified in Chapter 278 of the Kentucky Revised Statutes, specifically as KRS 278.2201 through KRS 278.2219. Provided within these statutes is the opportunity for regulated utilities to request from the Commission a waiver or deviation from the requirements thereof.

ULH&P requests permission to deviate from the requirements of KRS 278.2207(1)(b) and requests a waiver from the requirements of KRS 278.2213(6) for its plant acquisition transaction and certain affiliate agreements.[44] These statutes require, respectively, that the services and products provided to the utility by an affiliate be priced at the affiliate's fully distributed cost but in no event greater than market, and that all dealings between a utility and a nonregulated affiliate be conducted at arm's length. The Commission may grant a deviation from KRS 278.2207(1)(b) if it determines that the deviation is in the public interest. It shall grant a waiver or deviation from KRS 278.2207(1)(b) and/or KRS 278.2213 if it finds that compliance with the provisions thereof are impracticable or unreasonable.

The AG argues that ULH&P has failed to demonstrate to the Commission that a waiver or deviation from the provisions of KRS 278.2207 and KRS 278.2213 is

[44] The affiliate agreements for which ULH&P requests deviation and waiver are the contract with CM&T that provides for CG&E to obtain natural gas for Woodsdale (Gas Supply and Management Agreement), the contract with ORVP for propane storage in the Todhunter propane cavern (Commodity Storage Agreement), and the contract CG&E has with ORVP to obtain propane for Woodsdale (Propane Supply and Management Agreement).

appropriate and asserts that ULH&P's request should be denied. The Commission does not agree.

In reviewing ULH&P's arguments justifying the lack of an RFP for the acquisition of the generating facilities and ICF's market analysis of those facilities, the Commission was able to determine that the generating units being transferred from CG&E are priced at CG&E's fully distributed cost and that the cost is below market. Therefore, the Commission finds that no deviation from KRS 278.2207(1)(b) is required for the acquisition of the generating units. The Commission is also satisfied from the evidence presented by ULH&P that the pricing of the products and services provided in the Gas Supply and Management Agreement, Commodity Storage Agreement, and the Propane Supply and Management Agreement is reasonable and that ULH&P's request to deviate from the pricing requirements of KRS 278.2207(1)(b) with regard to these agreements should be granted.

As stated previously, KRS 278.2213(6) requires that all dealings between a utility and its nonregulated affiliate be conducted at arm's length. Thus, a deviation from KRS 278.2213(6) is required for all of the agreements proposed by ULH&P in this proceeding, including the agreements for the generating units that the Commission has determined do not require a deviation from KRS 278.2207(1)(b).

Having reviewed ULH&P's reasons for not issuing an RFP and our previous findings herein that an RFP was not necessary to determine the reasonableness of the transfer of generating units, that the transfer is reasonable and in the public interest, and that the agreements associated with the transfer are in the public interest, the

Commission finds that ULH&P has met its burden under KRS 278.2219. Consequently, ULH&P's request to deviate from KRS 278.2213(6) should be granted.

The Commission finds, however, that the deviations approved herein should apply only to this transaction and the agreements discussed herein. Future transactions or successor agreements will require separate deviation or waiver requests if and when they are proposed by ULH&P.

Other Accounting and Rate-Making Treatment Proposals

In addition to its proposals regarding the value of the facilities being transferred, deferral and recovery of transaction costs, treatment of ADITC and deferred income taxes, and sharing the profits from off-system sales, ULH&P also requested approval of the following provisions related to the back-up PSA and the PSOA, to be effective with its next general rate case:

(1) Inclusion in its future base rates of all monthly capacity charges specified in the back-up PSA; and a commitment to consult with the Commission and the AG prior to filing a successor agreement at FERC;

(2) Inclusion in its future FAC of all energy charges assessed under the back-up PSA in accordance with 807 KAR 5:056 and Commission precedent;

(3) Inclusion in its future FAC of the costs of energy transfers from CG&E under the PSOA in accordance with 807 KAR 5:056 and Commission precedent; and

(4) Inclusion in its future FAC of the cost of the fuel consumed in the facilities in accordance with 807 KAR 5:056 and Commission precedent.

The Commission finds that this request is generally reasonable and should be approved. However, ULH&P did not specify what is meant by "Commission precedent" regarding its requested FAC treatment. Given that application and review of an electric utility's FAC is addressed in its entirety in 807 KAR 5:056, the Commission will limit its decision herein to approving treatment in accordance with that administrative regulation.

Requirement to File a Stand-Alone IRP

In Case No. 2001-00058, the Commission required ULH&P to file a stand-alone IRP by June 30, 2004. Our Order stated that the IRP should include analyses of bids to purchase power from non-affiliated suppliers as well as construction of generation to lock in prices for the long term. In the amendment to its application, ULH&P requests that it be permitted to deviate from the requirement to analyze bids for purchased power. ULH&P states that, should the Commission approve the proposed transfer, such a requirement, which would impose significant costs on ULH&P, would no longer be necessary. Given that ULH&P's load forecast and supply-side analysis show that it will not need additional resources until the 2011-2012 time frame, and that this need is expected to be met with summer season purchases, the Commission finds that the requested deviation is reasonable and should be granted.

ULH&P's Next General Rate Case

Based on the current freeze on ULH&P's retail electric rates, effective through December 31, 2006, many of the accounting or rate-making provisions included in the amendment to its application refer to its next general rate proceeding or contain the phrasing "on or after January 1, 2007." These same references and phrasing were in ULH&P's original application and in numerous of its responses to data requests.

The Commission takes notice of the fact that ULH&P has not filed to increase its retail electric rates since 1991. By the end of the current rate freeze, its customers will have gone 15 years without a base rate increase. The Commission commends ULH&P

for its efficiency and its stewardship of ratepayers' monies, which have contributed to its not requiring a general rate increase for this length of time.

In some of its testimony and exhibits, ULH&P projected the future rate impact of acquiring the facilities that are the subject of the proposed transfer. Its projections show a possible future rate increase going into effect January 1, 2007, concurrent with the end of its current rate freeze. The Commission believes that a general rate proceeding will be necessary for ULH&P within that time frame. Given the numerous changes that have occurred in the electric industry since 1991, we believe that shareholders and ratepayers will both be better served in the long run by ULH&P filing a general rate application to effect a change in rates on January 1, 2007. Such an effective date, of course, would be at the conclusion of the suspension period provided by the statutes and regulations governing changes in rates. Therefore, we find that ULH&P should file a general rate application in 2006 to adjust its retail electric rates, so that, based on the suspension period applicable to ULH&P's choice of test period, the effective date of any eventual rate adjustment ordered by the Commission will be January 1, 2007.

Acceptance of Decision

The decision enunciated herein approves ULH&P's proposal, subject to certain conditions and modifications. Since the proposal was a response to concerns previously expressed by the Commission regarding ULH&P's long-term power supply needs, if any modifications are found to be unacceptable by ULH&P or its affiliates, the Commission wishes to be informed of that finding as soon as is practicable. Therefore, ULH&P should notify the Commission in writing, no later than 30 days from the date of this Order, whether or not it and its affiliates accept this decision, including all modifications.

FINDINGS AND ORDERS

Based on the evidence of record and being otherwise sufficiently advised, the Commission finds that:

1. ULH&P's amendment to its application, which establishes the terms and conditions under which it will acquire CG&E's interests in East Bend Unit No. 2, Miami Fort Unit No. 6, Woodsdale Unit Nos. 1 through 6, and the related property, appurtenances, contracts and agreements, should be approved, subject to Commission review and approval of final drafts of the transaction documents.

2. The termination of ULH&P's current PSA with CG&E, effective on the closing date of the transfer of facilities, is reasonable and should be approved.

3. ULH&P should be granted a waiver, in accordance with KRS 278.2219, from the requirements of KRS 278.2213(6) that its acquisition of the facilities, subject to this transfer, from its affiliate, CG&E, be at arm's length; and ULH&P should be granted a deviation, pursuant to KRS 278.2207, of certain affiliate agreements related to the operation of the facilities being transferred.

4. ULH&P's draft transfer agreements for the three facilities being acquired, with the provisions governing a "Regulatory Non-Satisfaction Event" and the "Purchase Option" deleted, should be approved, subject to Commission review and approval of the agreements in their final form.

5. ULH&P's back-up PSA and its PSOA, which will govern its power transactions with CG&E on a going forward basis subsequent to the consummation of

the proposed transfer of facilities, should be approved, subject to Commission review and approval of the agreements in their final form.

6. The assignment to ULH&P by CG&E of CG&E's interests in the contracts for the supply, delivery, and storage of coal, oil, natural gas and propane used as fuel for electricity generation at East Bend Unit No. 2, Miami Fort Unit No. 6, and Woodsdale Unit Nos. 1 through 6 should be approved, subject to Commission review and approval of the contracts in their final form.

7. The facilities being acquired by ULH&P should be recorded by ULH&P at their original cost less accumulated depreciation. At this time, the Commission knows of no reason why such value should not be used in the future for rate-making purposes.

8. ULH&P should defer no more than $2.45 million of the transaction costs incurred in relation to its acquisition of the subject generating facilities, with the costs to be deferred and amortized over 5 years, without carrying charges, beginning with the effective date of the Commission's Order in ULH&P's next general rate proceeding. At this time, the Commission knows of no reason why the resulting amortization expense should not be recovered through rates beginning with the effective date of the Commission's Order in ULH&P's next general rate proceeding.

9. ULH&P's proposal to record the ADITC and deferred income tax balances associated with the generating facilities being transferred "below the line" is reasonable and should be approved. At this time, the Commission knows of no reason why such treatment should not be reasonable for future rate-making purposes.

10. Based on its approval of the back-up PSA, the monthly capacity charges set out therein are reasonable. The Commission knows of no reason, at this time, why

such charges should not be recovered through rates beginning with the effective date of the our final Order in ULH&P's next general rate proceeding. ULH&P should consult with the Commission and the AG prior to filing any successor agreement with FERC.

11. ULH&P's recovery of energy charges assessed under the Back-Up PSA, from the date that its next FAC goes into effect, on or after January 1, 2007, should be in accordance with 807 KAR 5:056.

12. Treatment of the costs of energy transfers between ULH&P and CG&E under the PSOA, from the date that its next FAC goes into effect, on or after January 1, 2007, should be in accordance with 807 KAR 5:056.

13. ULH&P's proposal to share off-system sales profits with its customers, beginning with the effective date of the Commission's Order in its next general rate proceeding so that customers receive up to $1 million from off-system sales profits annually and 50 percent of such profits above $1 million annually, if any, while ULH&P retains 50 percent of the profits from off-system sales above $1 million annually, if any, is reasonable. The costs attributable to off-system sales should include the incremental costs listed in the PSOA, Paragraph 1.10. ULH&P should implement the necessary processes to allocate appropriately said incremental costs to its off-system sales. The Commission knows of no reason, at this time, why such treatment of off-system sales profits should not be approved in ULH&P's next general rate proceeding.

14. ULH&P should be granted a waiver from the Commission's requirement, imposed in Case No. 2001-00058, that it analyze purchase power alternatives in its stand-alone IRP, which is to be filed by June 30, 2004.

15. ULH&P should file its next general rate application to adjust retail electric rates so that, based on the suspension period applicable to ULH&P's choice of test period, the effective date of any eventual rate adjustment ordered by the Commission will be January 1, 2007.

16. ULH&P should notify the Commission in writing, not later than 30 days from the date of this Order, if this decision, including all conditions and modifications, is acceptable to it and its affiliates.

17. ULH&P should submit the final draft versions of the various transaction documents and accompanying narrative explanations for final Commission review and approval in the manner described herein.

18. Within 10 days of their receipt, ULH&P should file one copy of each of the approval documents issued by the FERC and the SEC.

IT IS THEREFORE ORDERED that:

1. The proposed acquisition of generating facilities by ULH&P, as described in its amended application of October 29, 2003, is approved, subject to the conditions and modifications described in this Order.

2. Findings 2 through 15 shall be implemented as if the same were individually so ordered.

3. ULH&P shall notify the Commission in writing, not later than 30 days from the date of this Order, if this decision, including all conditions and modifications, is acceptable to it and its affiliates.

4. ULH&P shall submit the final draft versions of the various transaction documents and accompanying narrative explanations for final Commission review and approval in the manner described herein.

5. Within 10 days of their receipt, ULH&P shall file with the Commission one copy of each of the approval documents issued by the FERC and the SEC.

Done at Frankfort, Kentucky, this 5th day of December, 2003.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00252 DATED December 5, 2003

DESCRIPTION OF FACILITIES PROPOSED TO BE TRANSFERRED

East Bend No. 2

A 648 MW (nameplate rating) coal-fired base load plant in Boone County, Kentucky. Commissioned in 1981, it is jointly owned by CG&E and Dayton Power and Light, with CG&E owning a 69% interest. The unit's net rating is 600 MW, after allowing for power used to operate the plant machinery. The net rating of CG&E's 69% share is 414 MW.

East Bend is designed to burn low- to high-sulfur eastern bituminous coal. Its recent achieved heat rates have ranged between 10,400 and 10,900 Btu/kWh. It is equipped with a lime-based flue gas desulfurization system (scrubber) along with a selective catalytic reduction (SCR) control system, which is designed to reduce NO_x emissions by 85%. East Bend No. 2 has a 1.2 lbs./MMBTU SO_2 emission limit. The unit's output is directly connected to Cinergy's 345 kV transmission system.

Burns & McDonnell (B&McD) completed its due diligence review of East Bend in June 2003. Its personnel had visited the East Bend Generating Station on May 23, 2003. Its report concludes that the plant is fully capable of providing long-term, reliable service as a base load power facility if it continues to be properly operated and maintained in accordance with good utility practice. B&McD estimates that the unit's remaining useful operating life is at least 38 years.

Miami Fort No. 6

A 168 MW (nameplate rating) coal-fired base or intermediate load plant in Hamilton County, Ohio. Commissioned in 1960, it is one of four coal-fired units at the Miami Fort Generating Station. CG&E owns 100% of the unit, which has a net rating of 163 MW.

Miami Fort 6 is designed to burn low- to medium- sulfur eastern bituminous coal. Its recent heat rates have ranged between 9,900 and 10,200 Btu/kWh. It is equipped with a high efficiency electrostatic precipitator and with a temporary selective non-catalytic reduction (SNCR) system for NO_x reductions. Miami Fort 6 has a 5.0 lbs./MMBTU SO_2 emission limit. The SNCR has not performed as well as expected and will be replaced with second generation low NO_x burners in the future. It is directly connected to Cinergy's 138 kV transmission system.

B&McD visited the Miami Fort Generating Station on May 26, 2003. It shares a 600-foot tall exhaust stack and continuous emissions monitoring system with its sister unit, Miami Fort No. 5 as well as crushed coal conveyors. Miami Fort 6 also shares coal handling and fuel oil storage facilities with the three other units at the site. B&McD's report concludes that the plant is fully capable of providing long-term, reliable service as a base load/intermediate power facility if it continues to be properly operated and maintained in accordance with good utility practice. B&McD estimates that the unit's remaining useful operating life is at least 17 years.

Woodsdale

A 490 MW (nameplate rating) six-unit combustion turbine station located in Butler County, Ohio. Its net summer capacity, including inlet cooling, is 500 MW. It is owned 100% by CG&E. The Woodsdale Generating Station was originally planned for twelve units, but only six units were constructed. It has dual fuel capability (natural gas and propane) and black start capability. Five units were commissioned in 1992 with the sixth unit commissioned in 1993.

Woodsdale is connected to two interstate natural gas transmission pipelines, Texas Eastern Transmission Company and Texas Gas Transmission Company. Its contracts with Ohio River Valley Propane LLC, an affiliate, provide for its propane supply and its propane storage. NO_x emissions are controlled by water injection. Woodsdale's output is directly connected to Cinergy's 345 kV transmission system.

B&McD visited the Woodsdale Station on May 28, 2003. Its report noted that Units 5 and 6 had undergone major overhauls in 2001 and that Units 1-4 will have major overhauls in 2004-2005. B&McD's report concludes that the plant is fully capable of providing long-term, reliable service as a peaking power facility if it continues to be properly operated and maintained in accordance with good utility practice. B&McD indicated that the units' remaining useful operating lives will be dependent on the number of times the units are started and that, based on the number of starts that have occurred since the units were commissioned, they should be able to operate for several more years.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2003-00252 DATED December 5, 2003

TRANSACTION DOCUMENTS

Documents Filed with the Commission as of July 21, 2003:

- Asset Transfer Agreement for Unit 2 of the East Bend Generating Station (See Turner Direct Testimony, Attachment JLT-1)

- Back-up Power Sale Agreement (See McCarthy Direct Testimony, Attachment RCM-1)

- Purchase, Sales and Operation Agreement (See McCarthy Direct Testimony, Attachment RCM-2)

Documents Referenced But Not Flied with the Commission:

- Schedules referenced in Section 7.09 of the Asset Transfer Agreement for Unit 2 of the East Bend Generating Station

- Asset Transfer Agreement for Miami Fort 6

- Asset Transfer Agreement for Woodsdale

- Assignment Document for the Gas Supply and Management Agreement (See Roebel Direct Testimony, Attachment JJR-1 for copy of the current Gas Supply and Management Agreement)

- Assignment of the Commodity Storage Agreement (See Roebel Direct Testimony, Attachment JJR-2 for copy of the current Commodity Storage Agreement)

- Assignment of the Storage and Service Agreement (See Roebel Direct Testimony, Attachment JJR-3 for copy of the current Storage and Service Agreement)

- Assignment of the Propane Supply and Management Agreement (See Roebel Direct Testimony, Attachment JJR-4 for copy of the current Propane Supply and Management Agreement)

- Amendment/Assignment of current Coal Contracts
- Ownership transfer and lease back of shared stack at Miami Fort 5 and 6
- Use of shared coal handling and fuel oil storage facilities associated with Miami Fort 6

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PUBLIC SERVICE
COMMISSION

Big Rivers Electric Corporation

Touchstone Energy

Case 2002-00428

2002 Integrated Resource Plan

Prepared for

Big Rivers Electric Corporation

Henderson, Kentucky

November 2002

GDS Associates, Inc.

Table of Contents

Introduction

Big Rivers' 2002 Integrated Resource Plan (IRP) was completed in November 2002. The report presents Big Rivers' current and future plans regarding the power and resources needed to meet customer demand over the next fifteen years, 2002-2017. The plan supersedes the 1999 IRP and incorporates two recent key inputs: one, Big Rivers' most recent load forecast, which was completed in July 2001, and two, a new demand-side planning study, which was completed in November 2002.

Summary of Results

Big Rivers will be able to meet all of its demand and energy requirements through 2017 through the SEPA and LG&E Energy Marketing, Inc. ("LEM") contracts. In year 2010, the high range forecast approaches total capacity; however, the increase in the LEM contract beginning in 2011 keeps Big Rivers in a surplus mode throughout year 2017. 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. Figure ES-1 illustrates that Big Rivers does not have an incremental need for power during the 2003 through 2017 period under (1) Base Case, (2) Optimistic Economy, and (3) Extreme Weather forecasts.

Figure ES-1
Capacity and Peak Demand Requirements

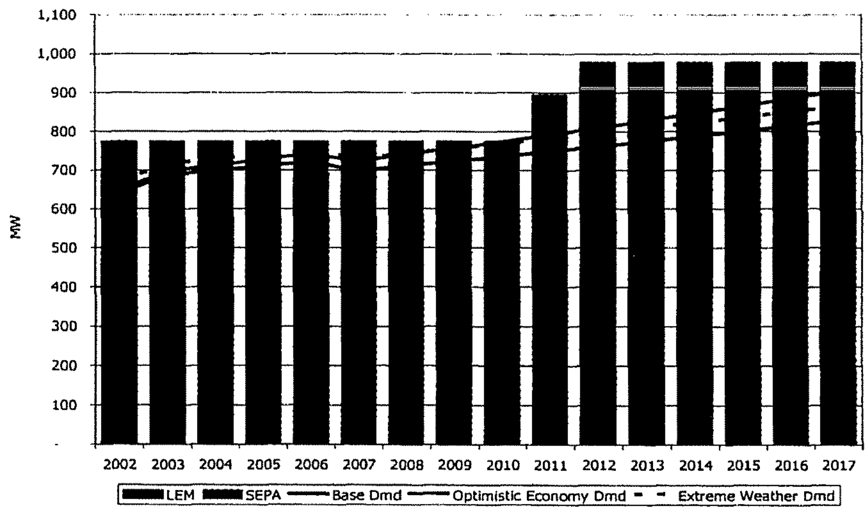


Table ES-1 on the following page lists projected demand and energy amounts through 2017 and the associated LEM and SEPA contract values. Big Rivers' purchases from SEPA and LEM are firm contracts, and the LEM contract includes liquidated damages for non-delivery (LD Firm); therefore, Big Rivers has no need for a planning reserve margin as in the case with generating utilities.

Table ES-1
Load Forecast, Capacity, Peak Demand, and Energy Requirements Summary

Year	System Peak Demand (MW)[1]	Total Energy Requirements for Generation Service (MWh)[2]	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)
2002	641	3,298,001	597	5,327,285	178	267,000	775	134
2003	688	3,625,665	597	5,327,285	178	267,000	775	87
2004	699	3,676,821	597	5,327,285	178	267,000	775	76
2005	711	3,734,545	597	5,327,285	178	267,000	775	64
2006	722	3,783,971	597	5,327,285	178	267,000	775	53
2007	698	3,537,386	597	5,327,285	178	267,000	775	77
2008	711	3,596,195	597	5,327,285	178	267,000	775	64
2009	723	3,650,147	597	5,327,285	178	267,000	775	52
2010	735	3,705,392	597	5,327,285	178	267,000	775	40
2011	749	3,766,818	717	6,321,741	178	267,000	895	146
2012	761	3,823,153	800	7,008,000	178	267,000	978	217
2013	774	3,880,729	800	7,008,000	178	267,000	978	204
2014	788	3,943,476	800	7,008,000	178	267,000	978	190
2015	801	4,002,583	800	7,008,000	178	267,000	978	177
2016	814	4,061,689	800	7,008,000	178	267,000	978	164
2017	827	4,120,796	800	7,008,000	178	267,000	978	151

Load Forecast

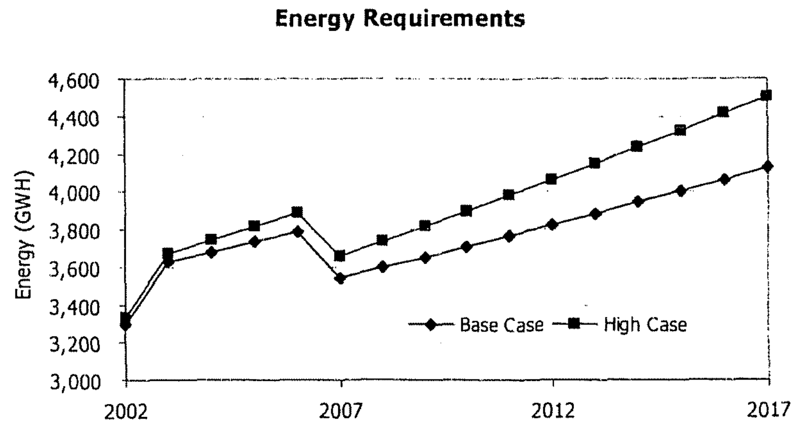
The 2001 load forecast provided key inputs into the IRP, including projections of total system demand and energy requirements, energy sales and number of consumers by rate classification, and assumptions regarding the long-term economic outlook. The forecast was completed in July 2001, approved by the Big Rivers Board of Directors, and filed and approved by the Rural Utilities Services. The complete load forecast report is included in the IRP report in the Appendix.

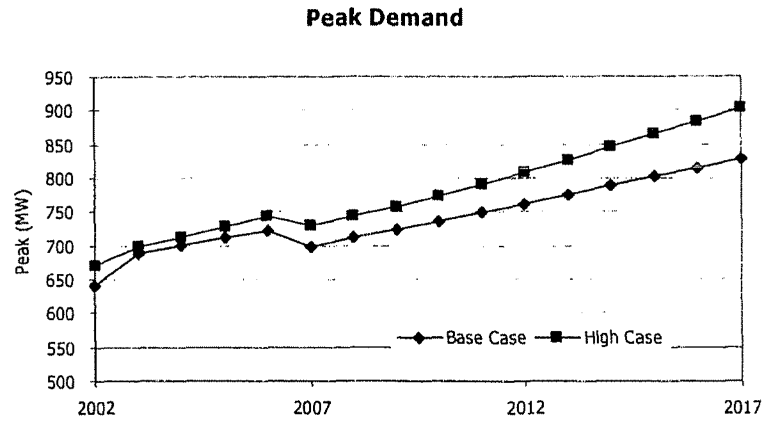
Under the base case, total system energy and peak demand are projected to increase at average compound rates of 0.7 percent and 1.0 percent, respectively, over the 2001-2015 period. Figure ES-2 on the following page presents the base and high case forecasts. Relative to the load forecast contained in the 1999 IRP, the current forecast reflects lower load growth over the long term. Projected energy and peak demand requirements for industrial customers with peak demand in excess of 1 MW have been held constant at current levels, unless Big

[1] System peak demand represents the sum of rural system coincident peak demand plus all non-rural demand, net of smelters, plus transmission losses.
[2] Total energy requirements include transmission losses of 1.39 percent.

Rivers planners were aware of planned expansions or changes in operations; therefore, projected growth in the industrial class is conservative.

Figure ES-2
Projected Energy Requirements and Peak Demand





Power Supply Plan

Big Rivers' power supply plan incorporates both supply-side and demand-side planning efforts. Compared to the 1999 IRP, Big Rivers' current power supply plan reflects more consideration and efforts to secure non-utility generation. With respect to transmission, Big Rivers currently has no plans to build any new transmission.

Supply-Side Plan

Big Rivers currently purchases power from LEM under a Power Purchase Agreement ("PPA") that runs through 2023. This purchase, combined with Big

Rivers' SEPA capacity, will be sufficient to serve expected load through the study period. Big Rivers' SEPA contract expires in 2016; however, for purposes of the analysis completed in the IRP, it was assumed that the contract would be renewed through at least 2017.

Although Big Rivers does not have a need for additional power resources during the study period, comparisons were made of LEM contract prices and the costs associated with alternative sources. The list of resources considered included both traditional fossil-fueled options as well as renewable energy options such as biomass, landfill gas, geothermal, wind, solar thermal, and photovoltaic. Graphs comparing the annual costs associated with each option to annual LEM contract prices are presented in Section 5.2.1.1 of the IRP report.

Based on the analysis, which included development of a supply-side evaluation model to quantify various key factors, it was determined that if Big Rivers had the need and opportunity to access new power resources, the associated costs would exceed the cost of power purchased from LEM. 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' cost of debt. 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.

Demand-Side Plan

Demand-side planning at Big Rivers is a joint planning process among Big Rivers and its three member cooperatives. Prior to this IRP, the latest DSM study was completed in 1995. Based upon planning needs, a new demand-side planning study was completed in November 2002. The study is more comprehensive than the initial study and addresses the recommendations made by the KPSC staff, as well as the AG and DOE, in its evaluation of the 1999 IRP.

The results of the economic screening of the energy efficiency and load management options indicate that a few energy efficiency measures are cost effective before the inclusion of administrative, marketing, evaluation and incentive costs. When these additional costs are included in the cost effectiveness analyses, and given that Big Rivers' avoided cost of generation capacity is zero, few individual measures or programs pass the Total Resource Cost Test; nonetheless, Big Rivers has reviewed a considerable range of technical reports and market research analyses to prepare this report, 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 given that barriers to energy efficiency remain, Big Rivers has developed a 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 the table below is a summary of the key actions included in the three-year plan, along with a proposed budget.

Summary of Three-Year Energy Efficiency Action Plan

Action	Description	Market Barrier Addressed	Proposed Annual Budget
1	Big Rivers and its member cooperatives plan to conduct a consumer attitude survey in 2003 to assess the current penetration of energy efficient products and practices in the residential sector. This baseline information is needed in order to determine where high market penetration already exists, and to determine where significant market barriers to energy efficiency remain.	Lack of market baseline information	$50,000
2	Big Rivers proposes to work with its three member distribution cooperatives to enhance the energy efficiency information provided on its web site and the web sites of its member cooperatives. The enhanced information shall include links to pertinent state, regional and national energy efficiency web sites, including the US EPA ENERGY STAR® programs, the US DOE, the State of Kentucky Department of Energy, and other sites providing financing alternatives for energy efficiency measures.	Lack of information on energy efficiency technologies and building practices by members	$5,000
3	Kenergy currently offers web based software that consumers can use to identify energy saving opportunities in their homes and businesses. Big Rivers will examine the feasibility of offering similar products on the other member cooperative web sites.	Lack of information on costs and benefits of energy efficiency measures	$2,500
4	Big Rivers will develop a brochure for members who are considering building a new home to explain energy efficient equipment and building practices that should be considered during the construction process. This brochure will follow the guidelines of the US EPA's ENERGY STAR Homes Program. Big Rivers will also examine the feasibility of offering the ENERGY STAR Homes program to its three member distribution cooperatives.	Lack of information and lack of awareness of the ENERGY STAR programs	$10,000
5	Big Rivers will examine the feasibility of sponsoring the US EPA "Change a Light" Initiative, and timing the introduction of this program with the major advertising for this national initiative planned for 2003 by the US EPA. Big Rivers will seek co-funding for this research from Federal and State government sources.	Lack of information and lack of awareness	$5,000

Action	Description	Market Barrier Addressed	Proposed Annual Budget
6	For the industrial sector, Big Rivers will examine the feasibility of seeking funding from the US EPA to promote demonstration projects for new, energy efficient technologies in the industrial sector. Big Rivers will work closely with other States that are participating in this national EPA effort to help make industrial organizations in the Big Rivers service area more energy efficient. Big Rivers will seek co-funding for this research from Federal and State government sources as well as private businesses.		$20,000
7	Big Rivers will collect information on resources and programs available to low-income members to assist them with purchasing and installing energy efficiency measures. Big Rivers will develop recommendations for its three member cooperatives on additional web site links that could be added to the cooperative web sites to help members find these resources for low-income households.		$5,000
8	Big Rivers will study the possibility of working with its members, builders (for new installations), and HVAC installers (for replacements) to present the following: Install add-on heat pumps with gas furnaces for auxiliary heat. This would increase the efficiency of Big Rivers by increasing the load factor and help the member cooperative by increasing MWh sales and load factor. The customer could receive the benefit of an up front rebate for the installation as well as a lower rate for their power consumption.		Under Consider-ation, No budget assigned
	TOTAL ANNUAL BUDGET		$97,500

Net Metering

During the development of the IRP, Big Rivers reviewed all existing Net Metering Tariffs approved by the KPSC. These approved tariffs are available on the KPSC website. Big Rivers' has closely examined the pilot net metering project underway by Louisville Gas and Electric. Big Rivers is following the progress and results of the program and at its conclusion will review the findings and recommendations to be provided by LG&E in the final report to the KPSC. After the final report is available, Big Rivers will also review any Commission Order that directs LG&E either to implement a full-scale net metering program or forego such a program. At that time Big Rivers' staff will present recommendations to the Big Rivers Board of Directors on how to proceed with net metering tariffs.

Local Integrated Resource Planning

Big Rivers has taken positive steps since the 1999 IRP with respect to local integrated resource planning. During 2001, an 85 MW generator was installed at Willamette Industries (recently purchased by Weyerhauser Company) which effectively reduced Big Rivers' demand obligations by 50 MW. Big Rivers is currently in the preliminary stages of determining the feasibility of making a capital investment at this site, which would potentially provide for the generation of an additional 20-30 MW. Electricity generated at the Weyerhauser site is renewable energy, as the plant is fueled by waste by-products and gases. Big Rivers has initiated discussion with Weyerhauser and is currently evaluating a potential purchase (1 MW per hour) of this source of renewable resource power for its customers.

Big Rivers is also evaluating the purchase of renewable resource power from neighboring utilities. Big Rivers management met with representatives from Wabash Valley Power Association and from East Kentucky Power Cooperative to discuss the potential purchase of renewable resource power from these utilities. Big Rivers is evaluating the purchase of block power for customers expressing a desire for renewable resource power.

Big Rivers is currently evaluating distributed generation options as a complement to traditional transmission planning. While no economic analysis has been competed to date, Big Rivers staff have recently met with local distributed generation representatives to begin the evaluation process. The evaluation will focus on determining the feasibility of using distributed generation in remote areas in conjunction with existing transmission facilities.

Issues Raised in the Staff Report on Big River's 1999 IRP

In its report titled *Staff Report on the Integrated Resource Plan Report of Big Rivers Electric Corporation, Case No. 99-429, April 2001*, the KPSC staff made recommendations in four areas with respect to Big Rivers 1999 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.

Load Forecast Issues

Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Big Rivers' 1999 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 1999-2001. Refer to Section 5.3.3 of this report.

Provide a comparison of the annual forecast of energy sales with actual results for the period following Big Rivers' 1999 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 1999-2001. Refer to Section 5.3.3 of this report.

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' 2001 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 following two years; therefore, the load forecast did not include any impacts associated with customer choice or any other deregulation issues. Big Rivers will continue to evaluate wholesale and retail competition in future load forecasts.

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.

In development of the 2001 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 were assumed to be insignificant at the time the 2001 load forecast was developed, and projections included in the forecast do not include any environmental impacts. Big Rivers will continue to monitor environmental issues that potentially impact the demand for electricity.

Big Rivers estimates its cost of NOx compliance to approximate the benefit it received from a sale-leaseback transaction it consummated April 18, 2000. The sale-leaseback generated an up-front cash benefit of $64.0 million, which Big Rivers applied to its 5.75% RUS debt, resulting in an annual interest savings of $3.7 million. Big Rivers plans to use this benefit, which is currently serving to reduce its member wholesale rates approximately 3.4%, for its NOx compliance cost. The NOx compliance effective date is May 31, 2004.

Demand-Side Planning Issues

In its next IRP filing due in November 2002, Big Rivers should discuss its progress in implementing Net Metering tariffs that are beneficial to both itself and its members.

Big Rivers is addressing the possible implementation of net metering by evaluating work currently being performed by LG&E. Refer to Section 5.7.4 of this report.

Big Rivers should meet with the DOE and the AG well in advance of the next IRP filing to establish a constructive dialogue relative to DSM and other concerns raised by the parties. In addition, Big Rivers should discuss the results of this dialogue and how it has incorporated the parties' concerns into the 2002 IRP analysis.

In April 2002, representatives of Big Rivers met with the Kentucky Division of Energy (DOE), to discuss DOE input regarding Big Rivers' 2002 IRP. Big Rivers was informed at the meeting that the DOE had raised all of their concerns regarding the 1999 IRP filing that they concluded needed to be addressed in the 2002 IRP. The DOE representative concurred that a new DSM study should be included in the 2002 IRP. Big Rivers indicated at the April 2002 meeting their intention of completing a new demand-side management study prior to filing the 2002 IRP.

A representative of the AG's office reviewed and provided constructive comments on the draft 2002 IRP.

Big Rivers should provide a more extensive discussion of potential improvements to and more efficient utilization of its transmission system in its next IRP filing.

In the 2002 IRP, Big Rivers has provided a more extensive discussion of potential improvements to and more efficient utilization of its transmission system. Refer to Section 5.4.2 of this report.

In its next IRP filing, Big Rivers should report on efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and other initiatives of the type advocated by DOE and the AG.

Since the 1999 IRP was completed, Big Rivers has initiated local integrated resource planning efforts with respect to cogeneration and consideration of distributed generation facilities. Refer to Sections 5.1.3.1 and 5.7.5 of this report.

Big Rivers should perform a new DSM study prior to its next IRP filing and consider expanding its load management programs to include residential and small commercial customers, with a particular emphasis on air conditioning cycling programs.

Big Rivers completed a new DSM study in November 2002. The study, included as Appendix B in this IRP report, expands significantly beyond the analysis completed in the 1995 DSM study. The study included a comprehensive economic screening process and considered, among a number of other options, load management programs for residential and small commercial customers. Results from the study were used to prepare a three-year action plan regarding energy efficiency measures, which is summarized in Table 5.9 on page 26.

Supply-Side Resource Issues

Big Rivers should explore the renewable resource options of hydropower and biomass as suggested by the AG, and report the results in its next IRP filing.

Big Rivers has addressed renewable resource options in its evaluation of supply-side resources. Specifically, Big Rivers has compared the costs associated with alternative renewable resources (biomass, hydro, landfill gas, geothermal, wind, solar, and photovoltaic) to the costs associated with purchases from LG&E Energy Marketing. Refer to Section 5.2.1.1 of this report.

Big Rivers should include a thorough analysis of purchase power options that considers non-utility generation being developed in Kentucky and Indiana in its next IRP filing.

Big Rivers has, and continues to analyze the purchase of non-utility generation. Refer to Sections 5.1.3.1 regarding new cogeneration at an industrial location within the Big Rivers control area.

Integration and Plan Optimization

Big Rivers should update the Commission on the status of the 62-MW distributed generation project on a quarterly basis, and provide copies of the update to the parties in the case. Such updates should begin one month from the issuance of this report, and continue until the project is operational or until Big Rivers has decided upon an alternative solution.

Big Rivers submitted the appropriate contracts to the KPSC for approval prior to the first status update requirement. As a result, and since no changes were made to the contract, additional status reports were not necessary. Section 5.1.3.1 of this report provides the current status of the cogeneration project.

Conclusions

The following conclusions were made based on the analysis completed during the course of the IRP study:

1. Load growth Big Rivers' service area is expected to be stable, yet low, with energy requirements increasing at an average rate of 0.7% per year and peak demand increasing at an average rate of 1.0% per year. Growth rates in rural system energy and peak demand requirements (total system less special industrial contract customers) are projected to be 2.4% and 2.3%, respectively, over the next fifteen years.
2. Big Rivers' demand requirements were reduced by 50 MW in June 2001 when the cogeneration capacity came on-line at Willamette Industries, since purchased by Weyerhauser Company.
3. Big Rivers' capacity is expected to exceed base case and high case peak demand through 2017; therefore, no additional capacity is needed to meet customer demand for electricity for the next fifteen years.

4. Big Rivers is well positioned to acquire non-utility generated power from Weyerhauser Company, which operates a cogeneration plant in Big Rivers' service area.

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 2001 Load Forecast, presented as Appendix A, and the 2002 Demand-Side Management Study, presented as Appendix B.

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 December 2, 2002, in accordance with 807 KAR 5:058 § 2(d).

1.4. Issues Raised in the Staff Report on Big River's 1999 IRP

In its report titled *Staff Report on the Integrated Resource Plan Report of Big Rivers Electric Corporation, Case No. 99-429, April 2001*, the KPSC staff made recommendations in four areas with respect to Big Rivers 1999 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' 1999 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 1999-2001. 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' 1999 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 1999-2001. 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' 2001 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 following two years; therefore, the load forecast did not include any impacts associated with customer choice or any other deregulation issues. 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.

In development of the 2001 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 were assumed to be insignificant at the time the 2001 load forecast was developed, and projections included in the forecast do not include any environmental impacts. Big Rivers will continue to monitor environmental issues that potentially impact the demand for electricity.

Big Rivers estimates its cost of NOx compliance to approximate the benefit it received from a sale-leaseback transaction it consummated April 18, 2000. The sale-leaseback generated an up-front cash benefit of $64.0 million, which Big Rivers applied to its 5.75% RUS debt, resulting in an annual interest savings of $3.7 million. Big Rivers plans to use this benefit, which is currently serving to reduce its member wholesale rates approximately 3.4%, for its NOx compliance cost. The NOx compliance effective date is May 31, 2004.

1.4.2. Demand-Side Planning Issues

1.4.2.1. In its next IRP filing due in November 2002, Big Rivers should discuss its progress in implementing Net Metering tariffs that are beneficial to both itself and its members.

Big Rivers is addressing the possible implementation of net metering by evaluating work currently being performed by LG&E. Refer to Section 5.7.4.

1.4.2.2. Big Rivers should meet with the DOE and the AG well in advance of the next IRP filing to establish a constructive dialogue relative to DSM and other concerns raised by the parties. In addition, Big Rivers should discuss the results of this dialogue and how it has incorporated the parties' concerns into the 2002 IRP analysis.

In April 2002, representatives of Big Rivers met with the Kentucky Division of Energy (DOE), to discuss DOE input regarding Big Rivers' 2002 IRP. Big

Rivers was informed at the meeting that the DOE had raised all of their concerns regarding the 1999 IRP filing that they concluded needed to be addressed in the 2002 IRP. The DOE representative concurred that a DSM study should be included in the 2002 IRP. Big Rivers indicated at the April 2002 meeting their intention of completing a new demand-side management study prior to filing the 2002 IRP.

A representative of the AG's office reviewed and provided constructive comments on the draft 2002 IRP.

1.4.2.3. Big Rivers should provide a more extensive discussion of potential improvements to and more efficient utilization of its transmission system in its next IRP filing.

In the 2002 IRP, Big Rivers has provided a more extensive discussion of potential improvements to and more efficient utilization of its transmission system. Refer to Section 5.4.2 of this report.

1.4.2.4. In its next IRP filing, Big Rivers should report on efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and other initiatives of the type advocated by DOE and the AG.

Since the 1999 IRP was completed, Big Rivers has initiated local integrated resource planning efforts with respect to cogeneration and consideration of distributed generation facilities. Refer to Sections 5.1.3.1 and 5.7.5 of this report.

1.4.2.5. Big Rivers should perform a new DSM study prior to its next IRP filing and consider expanding its load management programs to include residential and small commercial customers, with a particular emphasis on air conditioning cycling programs.

Big Rivers completed a new DSM study in November 2002. The study, included as Appendix B in this IRP report, expands significantly beyond the analysis completed in the 1995 DSM study. The study included a comprehensive economic screening process and considered, among a number of other options, load management programs for residential and small commercial customers. Results from the study were used to prepare a three-year action plan regarding energy efficiency measures, which is summarized in Table 5.9 on page 26.

1.4.3. Supply-Side Resource Issues

1.4.3.1. Big Rivers should explore the renewable resource options of hydropower and biomass as suggested by the AG, and report the results in its next IRP filing.

Big Rivers has addressed renewable resource options in its evaluation of supply-side resources. Specifically, Big Rivers has compared the costs associated with alternative renewable resources (biomass, hydro, landfill gas, geothermal, wind, solar, and photovoltaic) to the costs associated with purchases from LG&E Energy Marketing. Refer to Section 5.2.1.1 of this report.

1.4.3.2. Big Rivers should include a thorough analysis of purchase power options that considers non-utility generation being developed in Kentucky and Indiana in its next IRP filing.

Big Rivers has, and continues to analyze the purchase of non-utility generation. Refer to Sections 5.1.3.1 regarding new cogeneration at an industrial location within the Big Rivers control area.

1.4.4. Integration and Plan Optimization

1.4.4.1. Big Rivers should update the Commission on the status of the 62-MW distributed generation project on a quarterly basis, and provide copies of the update to the parties in the case. Such updates should begin one month from the issuance of this report, and continue until the project is operational or until Big Rivers has decided upon an alternative solution.

Big Rivers submitted the appropriate contracts to the KPSC for approval prior to the first status update requirement. As a result, and since no changes were made to the contract, additional status reports were not necessary. Section 5.1.3.1 of this report provides the current status of the cogeneration project.

2. Filing Schedule

During 2001, Big Rivers requested and was granted approval from the KPSC to move its next IRP filing date to November 2002. Big Rivers plans to provide copies of the 2002 IRP to those parties intervening in the 1999 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 2002 Integrated Resource Plan was prepared for Big Rivers Electric Corporation ("Big Rivers") by GDS Associates, Inc. ("GDS"). The study was completed in November 2002, approved by Big Rivers' Board of Directors in November, and filed with the KPSC on or before November 30, 2002. A number of people from Big Rivers, Meade County Rural Electric Cooperative Corporation, Kenergy Corp., Jackson Purchase Energy Corporation, and GDS

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

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
Mark Hite		Finance
David Spainhoward		Regulatory Affairs
Burns Mercer, President	Meade County Rural Electric Cooperative Corporation	Review
Kelly Nuckols, President	Jackson Purchase Energy Corporation	Review
Dean Stanley, President	Kenergy Corp.	Review
Jack Madden	GDS Associates, Inc.	Power Supply and Resource Planning
Brian Smith		
Dick Spellman		Demand Side Planning
Amber Roberts		
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		
Mark Hite		
David Spainhoward		
John Hutts	GDS Associates, Inc.	770-425-8100
Jack Madden		
Dick Spellman		
Brian Smith		

5. Plan Summary

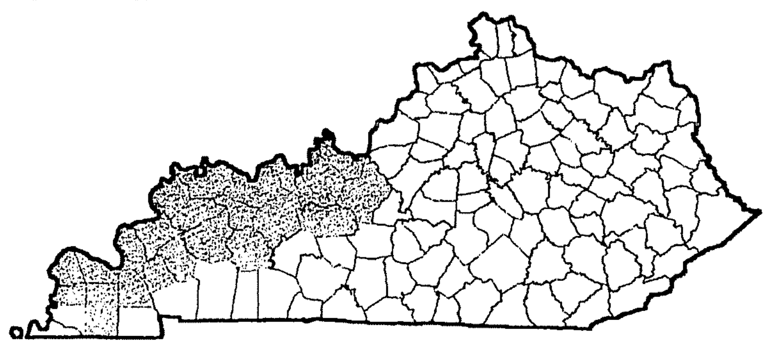
5.1. Utility Description, Current Facilities, and Plan Results

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 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. 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 400 feet above sea level. The climate in the area is humid, temperate and continental.

Big Rivers' annual peak demand for 2000, 655 MW, occurred on August 17, 2000, at hour ending 5 p.m. The winter peak, 615 MW, occurred on December 19, 2000, at hour ending 7 p.m. Figures 5.2 and 5.3 on the following page present the annual load characteristics for year 2000. Load data for 2000 provides for a more normal load shape than year 2001 as data for 2001 reflect a significant reduction in load due to approximately 50 MW of cogeneration that came on-line at an industrial location in mid 2001.

Figure 5.2
Annual Load Shape - 2000

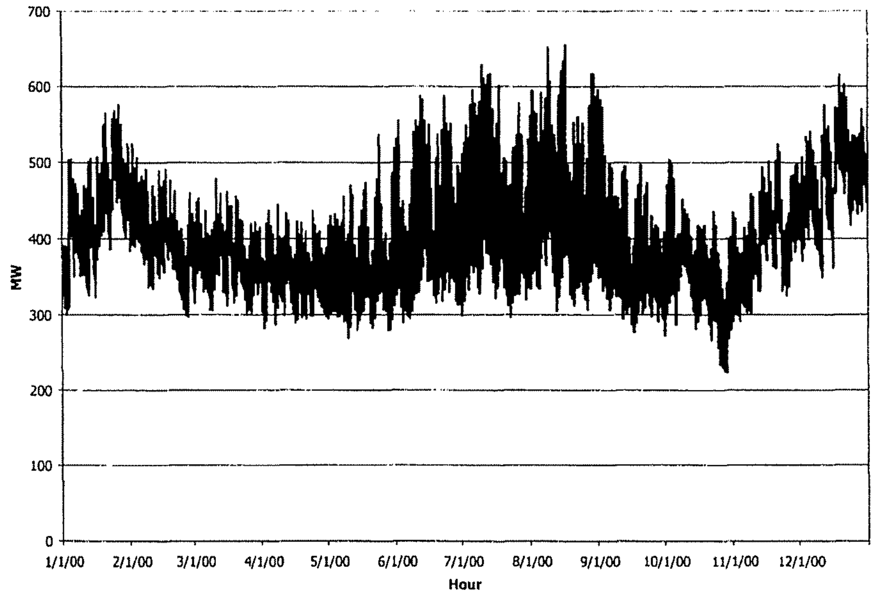
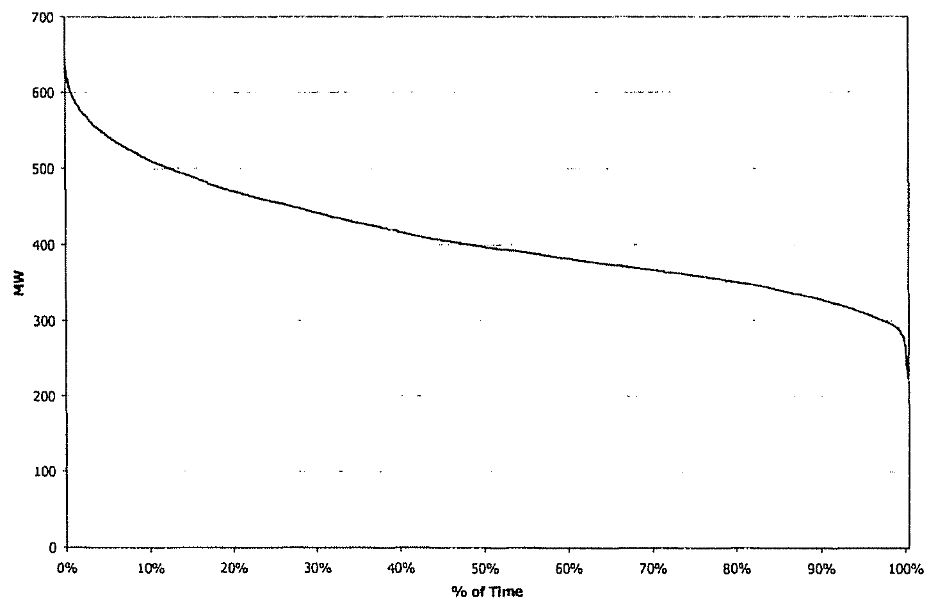


Figure 5.3
Annual Load Duration Curve - 2000



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 and four of LG&E's 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.

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 2017 through the SEPA and LEM contracts. In year 2010, the high range forecast approaches total capacity; however, the increase in the LEM contract beginning in 2011 keeps Big Rivers in a surplus mode throughout year 2017. 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

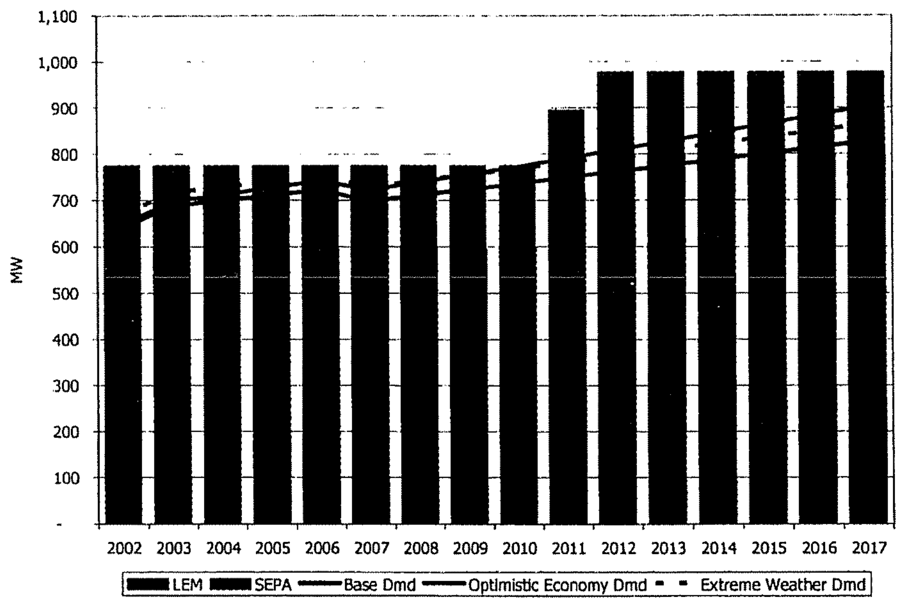
Year	System Peak Demand (MW)[2]	Total Energy Requirements for Generation Service (MWh)[3]	LEM Contract Maximum Capacity (MW)	LEM Contract Maximum Energy (MWh)	SEPA Contract Maximum Capacity (MW)	SEPA Contract Maximum Energy (MWh)	Total Capacity (MW)	Capacity Surplus (MW)
2002	641	3,298,001	597	5,327,285	178	267,000	775	134
2003	688	3,625,665	597	5,327,285	178	267,000	775	87
2004	699	3,676,821	597	5,327,285	178	267,000	775	76
2005	711	3,734,545	597	5,327,285	178	267,000	775	64
2006	722	3,783,971	597	5,327,285	178	267,000	775	53
2007	698	3,537,386	597	5,327,285	178	267,000	775	77
2008	711	3,596,195	597	5,327,285	178	267,000	775	64
2009	723	3,650,147	597	5,327,285	178	267,000	775	52
2010	735	3,705,392	597	5,327,285	178	267,000	775	40
2011	749	3,766,818	717	6,321,741	178	267,000	895	146
2012	761	3,823,153	800	7,008,000	178	267,000	978	217
2013	774	3,880,729	800	7,008,000	178	267,000	978	204
2014	788	3,943,476	800	7,008,000	178	267,000	978	190
2015	801	4,002,583	800	7,008,000	178	267,000	978	177
2016	814	4,061,689	800	7,008,000	178	267,000	978	164
2017	827	4,120,796	800	7,008,000	178	267,000	978	151

Figure 5.4 on page 10 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 2003 through 2017 period under (1) Base Case, (2) Optimistic Economy, and (3) Extreme Weather forecasts. Big Rivers' purchases from SEPA and LEM are firm contracts, and the LEM contract includes liquidated damages for non-delivery

[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 1.39 percent.

(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, recently purchased by Weyerhauser Company, and a customer of Kenergy Corp. Due to operating restraints, Weyerhauser 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 Weyerhauser, 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 will be evaluating the feasibility of making a capital investment at the Weyerhauser facility that will enable excess steam to be recycled and used for generation of up to an additional 20-30 MW of capacity.

Electricity generated at the Weyerhauser site is renewable energy, as the plant is fueled by waste by-products and gases. Big Rivers has initiated discussions with Weyerhauser and is currently evaluating a potential purchase (1 MW per hour) of this source of renewable resource power for its customers. Outside of any potential arrangements made with Weyerhauser, 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
1999-2002 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			0	
2001			0	
2002 ytd			0	

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

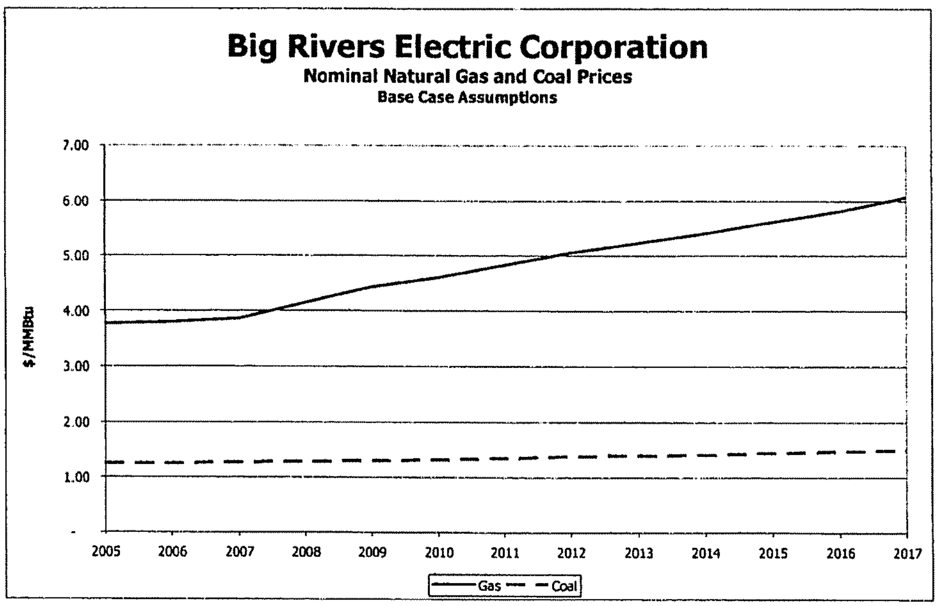
An Excel spreadsheet model was developed to compare costs of alternative power sources to costs associated with Big Rivers' contract with LEM. The model quantifies fixed and variable costs of power supply resources. Fixed costs include interest, depreciation, and fixed O&M expenses. Variable costs include 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 (5.68%). 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") 2002 Annual Energy Outlook for all resource options except hydroelectric power, which were obtained from the U.S. Department of Energy. 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 2008. For years 2003 through 2007, NYMEX Henry Hub gas futures prices published on June 3, 2002 were used. A 2008 value was calculated to smooth the transition between the 2007 futures price and the 2009 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

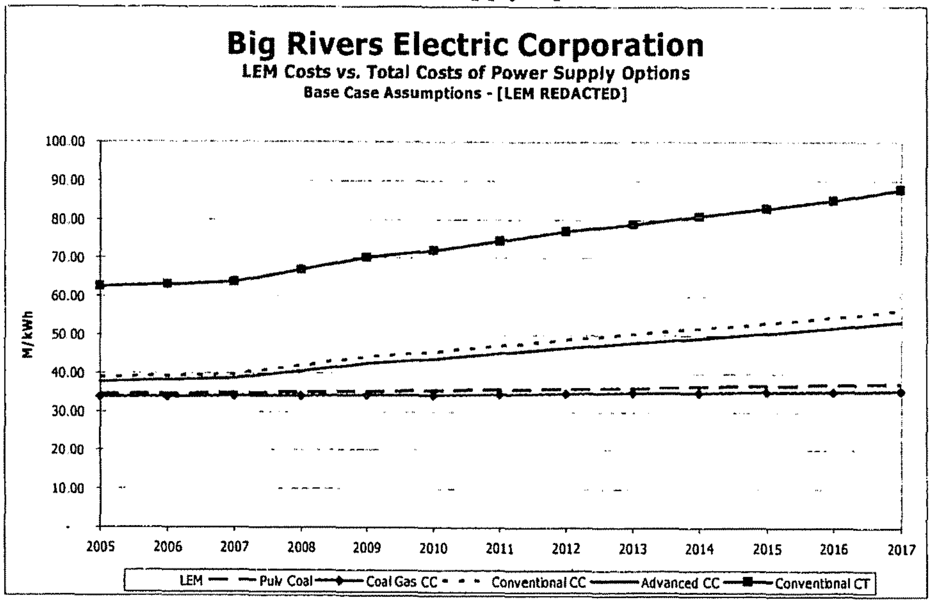


Figure 5.6b
LEM Costs vs. Total Costs of Power Supply Options

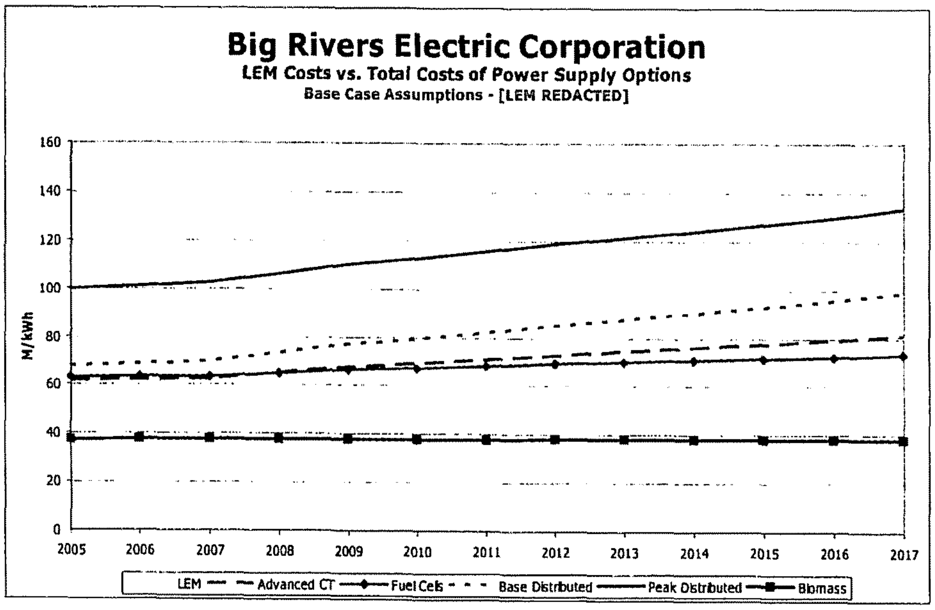
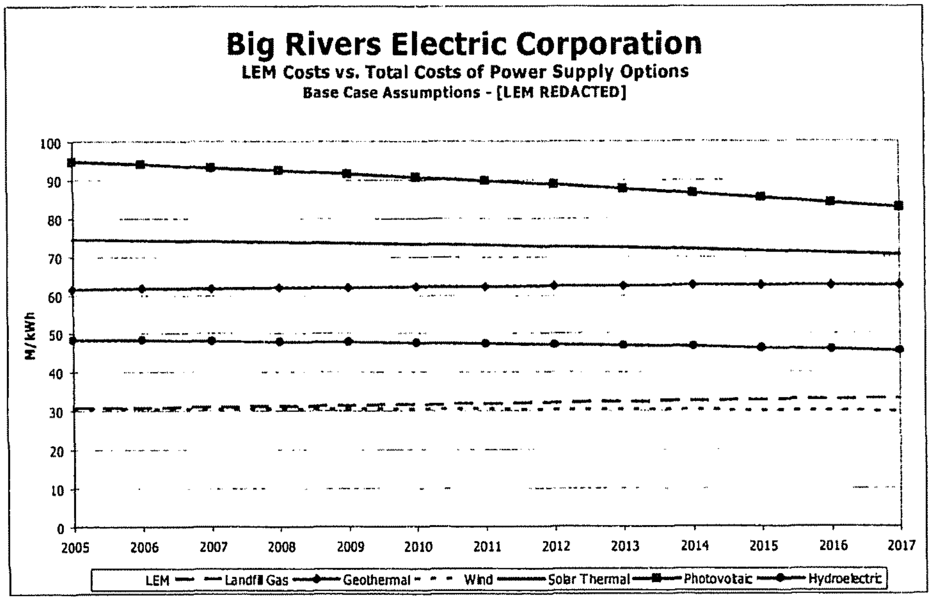


Figure 5.6c
LEM Costs vs. Total Costs of Power Supply Options



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 $/kW	Regional Multiplier	Adjusted Capital Cost	Constr. Period	Serv. Life
Pulverized Coal	1,119.00	1.004	1,123.48	4	30
Coal Gasification CC	1,338.00	1.004	1,343.35	4	30
Conventional CC	456.00	1.004	457.82	3	30
Advanced CC	590.00	1.004	592.36	3	30
Conventional CT	339.00	1.004	340.36	2	30
Advanced CT	474.00	1.004	475.90	2	30
Fuel Cess	2,091.00	1.004	2,099.36	3	30
Base Distributed	623.00	1.004	625.49	3	30
Peak Distributed	559.00	1.004	561.24	2	30
Biomass	1,725.00	1.004	1,731.90	4	30
Landfill Gas	1,429.00	1.004	1,434.72	3	30
Geothermal	1,746.00	1.004	1,752.98	4	30
Wind	982.00	1.004	985.93	3	30
Solar Thermal	2,539.00	1.004	2,549.16	3	30
Photovoltaic	3,831.00	1.004	3,846.32	2	30
Hydroelectric	1,700.00	1.000	1,700.00	2	30

Technology	Primary Fuel	Variable O&M mill/kWh	Fixed O&M $/kW	Capacity Factor	Heat Rate
Pulverized Coal	Coal	3.38	23.41	90.00%	9.386
Coal Gasification CC	Coal	0.80	32.67	90.00%	7.869
Conventional CC	Gas	0.52	15.61	80.00%	7.618
Advanced CC	Gas	0.52	14.46	80.00%	6.870
Conventional CT	Gas	0.10	6.45	25.00%	11.380
Advanced CT	Gas	0.10	9.16	25.00%	9.020
Fuel Cess	Gas	2.08	14.98	70.00%	5.744
Base Distributed	Gas	15.11	4.02	90.00%	10.991
Peak Distributed	Gas	23.10	12.56	25.00%	10.620
Biomass	None	2.90	44.95	80.00%	N/A
Landfill Gas	None	0.01	96.31	98.00%	N/A
Geothermal	None		70.07	50.00%	N/A
Wind	None		25.54	50.00%	N/A
Solar Thermal	None		47.87	50.00%	N/A
Photovoltaic	None		9.85	50.00%	N/A
Hydroelectric	None		6.67	50.00%	N/A

5.3. Load Forecast Summary

Big Rivers' 2001 Load Forecast was completed in July 2001 and updated the most recent forecast that was completed in July 1999. The forecast contains projections of energy and demand requirements for the 2001-2015 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 2001 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 0.7% and 1.0%, respectively, from 2000 through 2015[4]. Growth in energy sales is projected to be similar to the 1990-2000 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 2.4% and 2.3%, respectively, over the same period.

The primary influence on growth in system requirements over the forecast period will continue to be growth in residential sales, which is primarily a function of growth in number of customers. In addition, one industrial customer has reduced

[4] Based on weather normalized values for 2000 and 2015.

load by 50 MW as a result of its cogeneration facilities. The forecast is summarized below in Tables 5.4 and 5.5.

Table 5.4
Load Forecast Summary

		Total System		Rural System	
Year	Consumers	Energy Requirements (MWH)	Peak Demand (NCP)	Energy Requirements (MWH)	Peak Demand (NCP)
1990	81,047	2,321,109	484,826	na	na
1995	89,393	2,855,739	569,093	1,640,333	387,914
2000	100,270	3,596,398	655,000	1,971,031	453,010
2005	110,063	3,434,545	666,502	2,262,330	509,763
2010	119,943	3,705,392	725,328	2,524,053	568,590
2015	130,161	4,002,583	790,117	2,811,405	633,378

Table 5.5
Load Forecast – Average Annual Growth Rates

Description	2000-2005	2000-2015
Total Native System Energy Requirements	-0.9%	0.7%
Total Native System Peak Demand (NCP)	-0.3%	1.0%
Rural System Energy Requirements	2.8%	2.4%
Rural System Peak Demand (NCP)	2.4%	2.3%
Residential Energy Sales	2.9%	2.5%
Residential Consumers	1.9%	1.8%
Small Commercial Energy Sales	2.5%	2.3%
Small Commercial Energy Consumers	1.5%	1.4%
Large Commercial Energy Sales	-5.9%	-1.9%
Large Commercial Consumers	-2.8%	-0.4%
Irrigation Sales	0.0%	0.0%
Public Street Lighting Sales	2.5%	2.3%

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 0.6% per year from 2000-2015.

- Employment will increase at an average rate of 1.0% per year from 2000-2015.
- Real personal income will increase at an average rate of 2.0% per year from 2000-2015.
- Real retail sales will increase at an average rate of 1.3% per year from 2000-2015.
- Inflation, as measured by the Personal Consumption Expenditure Index, will increase at an average compound rate of 2.9%.
- 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 1981 to 2000 for Evansville and 1984-2000 for Paducah.
- 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 within the next two years; 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 1999 through 2001. In the 1999 load forecast, peak demand was projected on an annual basis only rather than by season; therefore, values from the 1999 forecast represent the summer, which under normal peaking weather conditions was expected to be the peak season. In 2001, the forecasting process was changed to project long-term peak demand on a summer/winter basis.

Table 5.6
Actual vs. Forecasted Peak Demand

		Summer Peak (MW)			
Year	Actual	1999 Forecast	2001 Forecast	1999 % Error	2001 % Error
1999	664	683		2.9%	
2000	655	717		9.5%	
2001	596	735	649	23.3%	8.9%

		Winter Peak (MW)			
Year	Actual	1999 Forecast	2001 Forecast	1999 % Error	2001 % Error
1999	576	n/a		n/a	
2000	576	n/a		n/a	
2001	598	n/a	622	n/a	4.0%

Cogeneration at Willamette Industries reduced Big Rivers' peak demand requirements by 50 MW beginning in June 2001; therefore, actual peak demand for the summer of 2001 was significantly less than the summer peak of 2000. The 1999 forecast did not reflect the reduction in load due to the cogeneration at Willamette. In addition, the projections in the 1999 load forecast are higher than actual amounts in years 1999-2001 because the 1999 forecast included projected growth in the industrial class that did not materialize. Projected load growth in the 2001 load forecast, 1.0% per year, is lower than that developed in the 1999 forecast, 2.1% per year, and begins in year 2001 at 86 MW lower than the 1999 forecast.

A comparison of actual and forecasted energy sales is presented below in Table 5.7. Amounts are presented on an annual basis for years 1999 through 2001.

Table 5.7
Actual vs. Forecasted Energy Sales

Annual Energy Sales (GWH)

Year	Actual	1999 Forecast	2001 Forecast	1999 % Error	2001 % Error
1999	3,531	3,686		4.4%	
2000	3,596	3,913		8.8%	
2001	3,335	4,008	3,499	20.2%	4.9%

Cogeneration at Willamette Industries reduced Big Rivers' annual energy requirements by approximately 438 GWH beginning in June 2001; therefore, actual energy requirements in 2001 reflect that reduction in sales. The primary reason that the projections in the 1999 load forecast are higher than actual amounts in years 1999-2001 is that the 1999 forecast included projected growth in the industrial class that did not materialize. The 2001 forecast is high in part due to the fact that actual sales reflect milder than normal winter weather conditions. Projected energy requirements growth in the 2001 load forecast, 0.7% per year, is lower than that developed in the 1999 forecast, 2.0% per year, and begins in year 2001 at 509 GWH lower than the 1999 forecast.

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. 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 is currently evaluating the feasibility of installing distributed generation in lieu of making capital additions to its transmission facilities. The evaluation is being performed in anticipation that at some point in the future, additional investment will be required for Big Rivers to maintain 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 made for years 1999-2002, 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 2002 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 November 2002, the results of which are presented in the 2002 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 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.

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 have assisted dozens of commercial and industrial customers correct low power factor, resulting in significant savings those customers each year. Few customers experience low power factor, which results in higher electricity costs. The cooperatives provide engineering assistance and will work with a customer's electric contractor.

5.7.1.7. Power Quality Assessment

Customers who experience equipment damage or productivity losses as a result of power quality problems should call their 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 assist commercial and industrial customers to correctly identified power quality problems.

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 log on 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 may soon make 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 Programs

5.7.2.1. Kenergy

Kenergy offers educational and informative brochures, magazine articles, and television and radio commercials relating to energy efficiency topics. Ground source heat pump is the central HVAC technology promoted. 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 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 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). JPEC also provides a link to the electronic copy of the Energy Savers pamphlet. 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 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 is not currently conducting any load management programs.

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 Energy Efficiency Initiatives Offered By Big Rivers Electric Corporation And Its Distribution Cooperative Members

Type of Energy Efficiency Initiative	Kenergy	MCRECC	JPEC
Energy Efficiency Informational Brochures	"Geothermal Heating and Cooling - The Answer to Comfortable and Affordable Living" "Kenergy" Pamphlet with programs and offerings	"Geothermal Heating and Cooling Systems"	"Keep An Eye On That Thermostat" "Energy Savers - Tips on Saving Energy & Money at Home"
Heat Pump Programs – Rebates	None	None	None
Special Financing for Energy Efficient Equipment	5% financing on GSHP for 5 years	None	None
Load Management Program	Performs heat loss/gain for HVAC contractors. One per	None	None

Type of Energy Efficiency Initiative	Kenergy	MCRECC	JPEC
	week.		
Energy Efficiency Information on Cooperative's website	"Geothermal Heat Pump Systems" "US Dept of Energy's Energy-Saving Tips for Consumers" "US Dept of Energy Home Energy Audit" "Commercial Building Energy Checklist"	None	Link to: Home Energy Saver (LBL)
Energy Audits	On as needed basis. Perform 10-20 per year.	On as needed basis. Perform 10 per year.	On as needed basis. Perform 10 per year.
Newspaper Advertisements	"Geothermal Heating & Cooling" February - November 2001 "Unearth Great Savings"(geothermal heating and cooling) January-July 2002 "Frustrated with the cost of heating & cooling?" (geothermal heating and cooling) January-July 2002	Safety and office hour information.	None
Magazine Advertisements	Kentucky Living - Business Edition "Are you heating and cooling your business effectively? Geothermal - Using Earth's Natural Energy" August 2000 Commercial & Industrial News "Top 10 Energy Recommendations for 2000" Second Quarter 2001 Commercial & Industrial News "Energy Shorts" Commercial & Industrial News "Superior Power Quality" Second Quarter 2002 Focus "5% financing available on geothermal systems"	Kentucky Living - "Top 10 (easy) Ways to save on heating bills" February 2002 Kentucky Living - "Did You Know?" March 2002 Kentucky Living - "Cool Summer Savings Tips" July 2002	Plugged In - "A Great Energy Saving Idea" September 2001

Type of Energy Efficiency Initiative	Kenergy	MCRECC	JPEC
	February 2001		
Radio Advertisements	Aired on WMJL, WHRZ, WBKR and WSON on a rotating basis throughout 2001 -Geothermal Efficiency -Prevent the Great Escape - Insulate -Geothermal Heating and Cooling -All-Seasons Comfort and Energy Efficiency	"Making Your Home Comfortable" "Drippy Faucets" "Beat the heat...and save" Aired on station KAEC for Winter 2001"Make the Most of It"	None
TV Advertisements	broadcast on WTVW-Fox 7 "Geothermal Heating and Cooling Efficiency" (January - July 2002)	None	None
Other		Report: "Energy Saving Construction Techniques"	

5.7.3. Demand-Side Action Plan

The results of the economic screening of the energy efficiency and load management options indicate that a few energy efficiency measures are cost effective before the inclusion of administrative, marketing, evaluation and incentive costs. When these additional costs are included in the cost effectiveness analyses, few individual measures or programs pass the Total Resource Cost Test; nonetheless, Big Rivers has reviewed a considerable range of technical reports and market research analyses to prepare this report, 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 given that barriers to energy efficiency remain, Big Rivers has developed a 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	Big Rivers and its member cooperatives plan to conduct a consumer attitude survey in 2003 to assess the current penetration of energy efficient products and practices in the residential sector. This baseline information is needed in order to determine where high market penetration already exists, and to determine where significant market barriers to energy efficiency remain.	Lack of market baseline information	$50,000
2	Big Rivers proposes to work with its three member distribution cooperatives to enhance the energy efficiency information provided on its web site and the web sites of its member cooperatives. The enhanced information shall include links to pertinent state, regional and national energy efficiency web sites, including the US EPA ENERGY STAR® programs, the US DOE, the State of Kentucky Department of Energy, and other sites providing financing alternatives for energy efficiency measures.	Lack of information on energy efficiency technologies and building practices by members	$5,000
3	Kenergy currently offers web based software that consumers can use to identify energy saving opportunities in their homes and businesses. Big Rivers will examine the feasibility of offering similar products on the other member cooperative web sites.	Lack of information on costs and benefits of energy efficiency measures	$2,500
4	Big Rivers will develop a brochure for members who are considering building a new home to explain energy efficient equipment and building practices that should be considered during the construction process. This brochure will follow the guidelines of the US EPA's ENERGY STAR Homes Program. Big Rivers will also examine the feasibility of offering the ENERGY STAR Homes program to its three member distribution cooperatives.	Lack of information and lack of awareness of the ENERGY STAR programs	$10,000
5	Big Rivers will examine the feasibility of sponsoring the US EPA "Change a Light" Initiative, and timing the introduction of this program with the major advertising for this national initiative planned for 2003 by the US EPA. Big Rivers will seek co-funding for this research from Federal and State government sources.	Lack of information and lack of awareness	$5,000

Action	Description	Market Barrier Addressed	Proposed Annual Budget
6	For the industrial sector, Big Rivers will examine the feasibility of seeking funding from the US EPA to promote demonstration projects for new, energy efficient technologies in the industrial sector. Big Rivers will work closely with other States that are participating in this national EPA effort to help make industrial organizations in the Big Rivers service area more energy efficient. Big Rivers will seek co-funding for this research from Federal and State government sources as well as private businesses.		$20,000
7	Big Rivers will collect information on resources and programs available to low-income members to assist them with purchasing and installing energy efficiency measures. Big Rivers will develop recommendations for its three member cooperatives on additional web site links that could be added to the cooperative web sites to help members find these resources for low-income households.		$5,000
8	Big Rivers will study the possibility of working with its members, builders (for new installations), and HVAC installers (for replacements) to present the following: Install add-on heat pumps with gas furnaces for auxiliary heat. This would increase the efficiency of Big Rivers by increasing the load factor and help the member cooperative by increasing MWh sales and load factor. The customer could receive the benefit of an up front rebate for the installation as well as a lower rate for their power consumption.		Under Consider-ation, No budget assigned
	TOTAL ANNUAL BUDGET		$97,500

5.7.4. Net Metering

During the development of this IRP, Big Rivers reviewed all existing Net Metering Tariffs approved by the KPSC. These approved tariffs are available on the KPSC website. Big Rivers' has closely examined the pilot net metering project underway by Louisville Gas and Electric. Big Rivers is following the progress and results of the program, and at its conclusion will review the findings and recommendations to be provided by LG&E in the final report to the KPSC. After the final report is available, Big Rivers will also review any Commission order that directs LG&E either to implement a full-scale net metering program or forego such a program. At that time Big Rivers' staff will present recommendations to the Big Rivers Board of Directors on how to proceed with net metering tariffs.

5.7.5. Local Integrated Resource Planning

With respect to local integrated resource planning, Big Rivers has taken positive steps since the 1999 IRP as evidenced by the 85 MW cogeneration unit brought on-line in 2001 by an industrial customer. Big Rivers is currently in the preliminary stages of determining the feasibility of making a capital investment at this site, which would potentially provide for the generation of an additional 20-30 MW.

Big Rivers is evaluating the purchase of renewable resource power from neighboring utilities. Big Rivers management met with representatives from Wabash Valley Power Association and from East Kentucky Power Cooperative to discuss the potential purchase of renewable resource power from these utilities. Big Rivers is evaluating the purchase of block power for customers expressing a desire for renewable resource power.

In addition to cogeneration, Big Rivers is currently evaluating distributed generation options as a complement to traditional transmission planning. While no economic analysis has been competed to date, Big Rivers staff have recently met with local distributed generation representatives to begin the evaluation process. The evaluation will focus on determining the feasibility of using distributed generation in remote areas in conjunction with existing transmission facilities.

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 1999 IRP

Big Rivers' 1999 IRP identified a capacity deficiency in 2009. The plan at that time recommended combustion turbines and peaking power purchases to meet the deficiency. Big Rivers' purchases from SEPA and LEM are expected to adequately serve the revised load and energy forecast during the 2003 through 2017 period.

The second change since completion of the 1999 IRP is that Willamette Industries (now Weyerhauser Company) brought on-line during 2001 an 85 MW cogeneration unit, which has been operating at 50 MW. This reduced Big Rivers' annual load and energy requirements by 50 MW and approximately 438,000 MWh. As a result, the current load forecast is considerably lower than the forecast filed with the 1999 IRP. The plant is a bio-mass unit fueled by burning waste by-products and gases. The reduced demand obligation resulted in an overall capacity surplus for Big Rivers that extends beyond 2017.

Kentucky Public Service Commission

Staff Report On the

2002 Integrated Resource Plan Report

of Big Rivers Electric Corporation

Case No. 2002-00428

March 2004

SECTION 1

INTRODUCTION

Administrative Regulation 807 KAR 5:058, promulgated in 1990 by the Kentucky Public Service Commission, ("Commission") established an integrated resource planning ("IRP") process that provides for regular review by the Commission Staff of the long-range resource plans of the six major electric utilities under its jurisdiction. The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.

On November 27, 2002, Big Rivers Electric Corporation ("Big Rivers") filed its 2002 IRP with the Commission. The IRP report submitted by Big Rivers was prepared by GDS Associates, Inc. and it included Big Rivers' plans for meeting the electricity requirements of the customers of its member cooperatives for the 2002-2017 period.

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. It provides all of the power requirements of Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County Rural Electric Cooperative Corporation, with the exception of 2 aluminum smelters served by Kenergy. The 3 distribution cooperatives, which provide service in 22 counties located in western Kentucky, primarily serve residential customers, which account for roughly 90 percent of the total 103,000 customers they served in 2002.

Since 1998, Big Rivers has not operated the generating units it owns. Big Rivers leases those units to a non-regulated subsidiary of LG&E Energy Corp. and purchases a portion of the capacity and energy of its units through an arrangement with another subsidiary of LG&E Energy Corp., LG&E Energy Marketing, Inc. "(LEM"). Under this arrangement, Big Rivers no longer provides wholesale power for Kenergy's retail sales to the aluminum smelters, Alcan and Century Aluminum; however, it continues to provide transmission service for the smelters. In addition to purchasing from LEM, Big Rivers also purchases power from the Southeastern Power Administration ("SEPA").

The purpose of this report is to review and evaluate the IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered in future IRP filings. The Staff recognizes that resource planning is a dynamic ongoing process. Thus, this review is designed to offer suggestions and recommendations to Big Rivers on how to improve its resource plan in the future. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and

- The selected plan represents the least-cost, least risk plan for the ultimate customers served by Big Rivers and its member cooperatives.

The report also includes an incremental component, noting any significant changes from Big Rivers' most recent IRP filed in 1999.

Based on forecasted average annual growth rates of 1.0% for peak demand and 0.7% for energy, Big Rivers projects that it will require no additional supply resources over the 2002-2017 forecast period. This reflects a capacity surplus throughout the planning period based on Big Rivers' power purchase arrangements with LEM and SEPA. This ongoing capacity surplus is due in part to the addition of 50 megawatts ("MW") of cogeneration capacity by one of its industrial customers in June 2001.

The remainder of this report is organized as follows:

- Section 2, Load Forecasting, reviews Big Rivers' projected load growth and load forecasting methodology.

- Section 3, Demand-Side Management, summarizes Big Rivers' evaluation of demand side management ("DSM") opportunities.

- Section 4, Supply-Side Resource Assessment, focuses on Big Rivers' evaluation of supply resources options to meet future load requirements.

- Section 5, Integration and Plan Optimization, discusses Big Rivers' overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

SECTION 2

LOAD FORECASTING

Introduction

This section summarizes the methodology and results of Big Rivers' load forecast, describes changes that have occurred since its last IRP and discusses the reasonableness of its current approach. The load forecast was prepared in 2001 to comply with the Rural Utilities Service's ("RUS") requirement that Big Rivers prepare forecasts on a biennial basis. The forecast was developed by Big Rivers and GDS Associates, Inc. Big Rivers, which is headquartered in Henderson, Kentucky, provides wholesale power to three member distribution cooperatives: Kenergy Corporation, Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation who provide retail electric service to consumers in 22 western Kentucky counties. Approximately 90% of the cooperatives' customers are residential; however, because of Big Rivers' large industrial load, residential customers account for only 40% of Big Rivers' energy sales.

Methodology

The purpose of both its long term and short term load forecasts is to provide Big Rivers with reliable load projections, which are essential components of its resource, transmission and financial planning functions. Developing reliable load forecasts is one of the first steps Big Rivers must take in order to continue to provide adequate and reliable service at the lowest reasonable cost.

It is accepted that energy sales track economic activity generally. However, national economic conditions do not always reflect economic conditions at the local level. Therefore, Big Rivers' load forecasts were developed based on a "bottoms-up" approach. The essence of this type of approach is the realization that the customer classes within and between the member cooperatives and the 22 counties in which they operate are not all the same and that local economic conditions are important factors in forecasting energy consumption. County level economic and demographic data were collected for each of the 22 counties in which Big Rivers' member cooperatives provide service. Since the cooperatives serve only portions of some counties, the number of residential households and the number of residential customers located within each county were used to develop county weighting factors, which then represented each cooperative's market share of each county served.

Energy sales projections were developed at the customer class level for each cooperative and aggregated to provide system projections. The cooperatives' customer classes include Residential, Small Commercial, Large Commercial, and Public, Street, and Highway Lighting classes. Big Rivers also has several large direct serve industrial customers. Projections of peak demand were developed for the rural system, total native system, and total native system plus direct serve customers. Historical data used by Big Rivers covers 1981 – 2000. The forecast period covers the years 2001 – 2015.

The data necessary to develop each of the forecast scenarios comes from a variety of sources. Historical system data including the number of customers, energy sales revenue by customer class, system energy requirements, power costs and peak demand were obtained from RUS Form 7 databases. Bureau of Labor Statistics databases provided historical price and personal consumption information. Woods & Poole Economics, Inc. provided historical and forecasted economic and demographic data including personal income, retail sales, sector earnings levels, population, households and employment. Additional historical and forecasted economic and demographic data were obtained from the University of Louisville and NPA Data Services, Inc. Historical and forecasted natural gas prices came from the Gas Research Institute and the Energy Information Administration. The National Oceanic and Atmospheric Administration provided historical monthly heating and cooling degree days and temperature extremes data for both the Evansville, Indiana and the Paducah, Kentucky areas.

Short Term Forecast

Big Rivers' short-term forecast contains monthly projections of energy sales and demand for the years 2001 – 2005. Sales projections include projections by customer class, rural system sales, rural system Non-Coincident Peak ("NCP") demand, total system sales, and total system NCP demand.

Big Rivers' load forecast was developed using standard forecasting methods including econometric models, exponential smoothing, historical trends and informed judgement. The number of consumers and energy sales were projected at the customer class level and aggregated for the total system forecast. Econometric models were used to project energy sales for the residential and small commercial customer classes for each of the three member cooperatives. The energy models quantify relationships between monthly energy consumption, per capita income, electricity prices, retail sales, and heating and cooling degree days. The consumer models quantify relationships between consumer growth, employment, and population. Energy sales and the number of customers for all other classes were developed using trend models.

Large commercial sales were developed individually for each consumer by the member cooperatives' management based on historical trends and information provided by individual consumers. Public street lighting projections were based on historical trends. Rural system energy sales were computed as total system sales minus sales to direct serve customers, all of which are large commercial / industrial sales customers. The forecast of rural system NCP demand is the sum of the individual member cooperative's projections of rural system coincident demand, which were based on econometric models. Projections of non-rural peak demand (direct serve customers) were made by individual member cooperative staff based upon historical trends and customer supplied information. Total system energy requirements were forecast using an average line loss factor applied to projected total system energy sales.

Long Term Forecast

Big Rivers' long-term forecast methodology is very similar to that used to make its short-term projections. Econometric models were developed to forecast total system coincident peak demand by the member cooperatives on a summer (May-October) and winter (November-April) seasonal basis. Econometric models were used to make projections of energy sales for the residential class, as well as commercial energy sales and rural system coincident peak demand. Large commercial demand and energy projections were developed using information provided by Big Rivers' member cooperatives regarding local industrial operations. Energy sales for all other classifications were developed using linear trends. Finally, projections of direct serve peak demand were developed by member cooperatives and based on informed judgement. Total system NCP projections are the sum of individual rural system NCP and direct serve NCP projections.

At the time Big Rivers' load forecast was being prepared, the Kentucky General Assembly had not enacted any legislation to deregulate Kentucky's electric industry. Therefore, Big Rivers' forecasts do not include any explicit effects associated with electric industry restructuring.

Results

Big Rivers' short-term (2001-2005) forecast results indicate that total native system energy requirements will decline by an annual average rate of 0.9%. Total native Coincident Peak ("CP") will also decline by an annual average rate of 0.3%. However, rural system energy requirements are projected to grow at an annual average rate of 2.8% and rural system NCP demand is projected to grow at an annual average rate of 2.4%. The primary drivers behind the declines are the projected decrease in large commercial energy sales and consumers. This is primarily the result of the loss of load due to the installation cogeneration facilities by the large commercial / industrial customer class. This customer class represents just over 46% of Big Rivers' total system energy sales. One industrial customer has already reduced its load by 50 MW as a result of installing cogeneration facilities. Residential and small commercial energy sales are projected to grow at an annual average rate of 2.9% and 2.5%, respectively.

For Big Rivers' long term forecast, the total native system energy requirements and CP demand for generation service are projected to grow at average compound rates of 0.7% and 1.0%, respectively, for the period 2001-2015. The residential class accounts for about 90% of all customer accounts. Long-term residential sales are projected to increase at an average annual rate of 2.5%. The small commercial and industrial class is relatively small and accounted for about 15% of total system energy sales in 2000. The long-term forecast for energy sales for the small commercial and industrial class is projected to increase at an average annual rate of 2.3%. Total rural system energy requirements and rural system NCP demand are projected to grow at average rates of 2.4% and 2.3%, respectively, for the forecast period. Rural system energy and peak demand requirements are total native system requirements less those associated with direct-serve customers. The primary influence on growth in system requirements continues to be growth in residential sales, which is primarily a function in growth in the number of customers.

Table 6.3 of Big Rivers' Load Forecast study provides a comparison of its 1999 and 2001 load forecasts. There is a significant difference between the two projections. For the 2001 forecast, both total native energy requirements and CP demand are smaller than that projected in 1999. The 1999 forecast projected total native energy requirements of 5,253,381 megawatt hours ("MWh") and a CP of 984 MW by 2015. In contrast, the 2001 forecast projected a total native energy requirement of 4,002,583 MWh and a CP of 790 MW. The differences are due to the short-term loss of large commercial customer load and to realized population growth being smaller than the 1999 projections. In the 2001 forecast, total native energy requirements (MWh) were projected to decline through 2002 and then begin to recover. Energy requirements are not forecast to surpass the 2000 level of 3,596,398 MWh until 2009.

Uncertainty Analysis

An uncertainty analysis was performed to examine the impact of varying conditions upon Big Rivers' rural load growth. A base case forecast was developed using the expected economic outlook and normal weather conditions. Then, four additional forecast scenarios were developed: base case economic conditions with mild weather, base case economics with extreme weather, optimistic economic conditions with normal weather, and pessimistic economic conditions with normal weather. For the weather variations, only the residential class and the small commercial and industrial class were deemed to be weather sensitive. Thus, as to be expected, the weather variations produced relatively small variations in total system energy requirements. The extreme and mild weather scenarios accelerated or moderated the long-term annual average growth rate by only 0.1%. Changes in economic conditions had a much larger effect on the long-term forecasts. Changes in economic activity affect the number of customers (growth), as well as levels of commercial activity, which directly impacts the overall demand for electricity. The optimistic economic scenario increased total system energy requirements average annual growth rate from 0.7% to 1.2%. The pessimistic economic scenario decreased the average annual growth rate to 0.2%.

Discussion of Reasonableness

In its April 2001 Staff report on Big Rivers' 1999 IRP, Staff made the following recommendations for Big Rivers' consideration in preparing its next IRP filing:

- Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Big Rivers' 1999 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.
- Provide a comparison of the annual forecast of energy sales with actual results for the period following the 1999 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.

- 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.
- 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 nitrogen oxide ("Nox") reductions imposed on sources in the Eastern United States.

Staff is generally satisfied that Big Rivers has addressed its recommendations. We do note, however, that Big Rivers did not attempt to incorporate into either its forecasts or its uncertainty analysis any environmental cost impacts associated with Nox reductions. Big Rivers stated that, at the time its load forecast was developed, it assumed the impacts of new environmental regulations on power costs and retail rates to be insignificant. Therefore, the projections contained in its forecast do not include any environmental impacts.

In its response to the first recommendation, Big Rivers indicated that it had made a change to project long-term peak demand on a summer / winter basis, rather than continue to project it only on an annual basis. It also indicated that, other than the load reduction experienced due to the addition of the Willamette / Weyerhaeuser cogeneration facility, the primary reason for actual demands not reaching forecasted demands was that projected growth in the industrial class did not materialize. The same explanation also applied to why actual energy sales did not reach the levels that were forecast as part of Big Rivers' 1999 IRP.

Recommendations

Given the manner in which Big Rivers responded to the Staff's recommendations contained in its report on Big Rivers' 1999 IRP and the changes reported by Big Rivers, and discussed in the previous paragraph, Staff concludes that all that is necessary is to repeat its previous recommendations. Therefore, we recommend that Big Rivers should include consideration of the following items in preparing its next IRP filing:

- 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.

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

- 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.

- 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.

SECTION 3

DEMAND SIDE MANAGEMENT

Introduction

This section summarizes the issues presented in Big Rivers' DSM plan included in its 2002 IRP. Big Rivers stated that its plan is designed to help its members save energy and money, to provide up-to-date information to members about energy efficiency options, and to take advantage of the environmental and other benefits of energy efficiency programs so that consumers can make informed decisions.[1]

Response to Staff's Report on the 1999 IRP

In its IRP, Big Rivers addresses issues raised by the Staff and intervenors in its previous IRP case.[2] In that case, Staff recommended that Big Rivers report on its efforts to evaluate Local Integrated Resource Planning ("LIRP"), co-generation and distributed generation, and other initiatives of the type advocated by the Kentucky Department of Energy ("KDOE") and the Office of the Attorney General ("AG"). Big Rivers states that it has taken positive steps toward LIRP planning with the 85 MW cogeneration unit brought on line in 2001 by an industrial customer. Big Rivers also reports that it is in the preliminary stages of determining the feasibility of making a capital investment at this site, which would potentially provide for an additional 20-30 MW of generation.

Another DSM issue addressed in the previous IRP is net metering. Big Rivers reviewed all existing net metering tariffs on file with the Commission, in particular the 36-month pilot programs of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU").[3] Big Rivers stated that it plans to present its recommendation on net metering programs to its Board of Directors after LG&E's and KU's pilot programs are completed and the Commission issues a final ruling thereon.

Big Rivers also addressed Staff's recommendation to establish a constructive dialogue between KDOE and the AG in developing its DSM proposal for this IRP. Big Rivers reports that its representatives met with KDOE in April 2002 to discuss KDOE input. Big Rivers states that a representative of the AG's office reviewed and provided

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[1] Integrated Resource Plan, Appendix B, page 99.

[2] Case No. 1999-00429, the Filing by Big Rivers Electric Corporation of Its 1999 Integrated Resource Plan, Order dated April 12, 2001.

[3] Case Nos. 2001-00303 and 2001-00304 The Tariff Filing of Louisville Gas and Electric Company and Kentucky Utilities Company to Add Pilot Net Metering Electric Service, Order dated March 14, 2002.

constructive comments on the draft 2002 IRP. Big Rivers also completed a new DSM study in November 2002, as recommended in the previous case. Big Rivers states that the study expands significantly beyond the analysis of the 1995 DSM study. The results of the 2002 DSM study were used to prepare a three-year action plan regarding energy efficiency measures.

In addition to responding to these issues from Staff's report on its 1999 IRP, Big Rivers' IRP indicated that it was evaluating a possible purchase of renewable resource power ("Green Power") from two neighboring utilities, East Kentucky Power Cooperative and Wabash Valley Power Association. In a data response, Big Rivers also indicated that it was developing an incentive program for homes and business that need high efficiency heating systems. Such a program, according to the data response, would be designed to increase the efficiency of Big Rivers by increasing its system load factor.

Screen Process and Results

The DSM study was performed for Big Rivers by GDS Associates using a list of potential demand-side resource options developed from GDS's own library, as well as options identified by other state and federal agencies, research organizations and Big Rivers' previous IRPs. GDS developed the following seven task areas as part of its process to assess the DSM options:

Task 1: Preview draft work plan for DSM and the proposed methodology
Task 2: Select benefit/cost model
Task 3: Collect Input Data on a Broad Range of DSM Option
Task 4: Develop general assumptions
Task 5: Input data into the model for preliminary economic screening
Task 6: Run the screening model for individual DSM options
Task 7: Prepare report with action plan

GDS reviewed 25 residential DSM options and 45 commercial DSM options, employing the Total Resource Cost Test ("TRC") to screen the economic feasibility of each of the options. Application of the TRC results in 13 residential and 12 commercial programs that have a benefit to cost ratio greater than one. The residential measures involved mainly lighting programs, nine involving combinations of wattage and usage hours for compact fluorescent lights. The commercial measures contained programs for more efficient lighting and machinery.

Comments of the Attorney General

The AG provided several comments on Big Rivers' DSM efforts. His comments were generally favorable, although he disagrees with Big Rivers' plan to review the results of the LG&E and KU net metering programs before proceeding with its own program. The AG encourages Big Rivers to move forward with a net metering program rather than wait until the LG&E and KU pilot programs are complete. The AG cited LG&E's and KU's not informing customers about their net metering programs as the reason why few customers are likely to participate. The AG expects current benefits for Big Rivers' distribution cooperatives if they participate in net metering. He suggested a pilot program with a limit on the number of participants in order to minimize possible liability for Big Rivers until it becomes comfortable with net metering. The AG believes a net metering program would encourage the development of small-scale renewable energy projects and provide good will and publicity for Big Rivers at little cost.

In its reply comments, Big Rivers responded to comments on its plans for net metering by stating that it continues to believe that it is more prudent to wait until LG&E and KU complete their pilot net metering programs before proceeding with its own program. Big Rivers argues that its approach is driven by lack of demand in its service areas and the possible detrimental impacts of net metering. Examples of such impacts are the safety issues associated with allowing a meter to spin backwards and the costs to insure the safety of an electric system that utilizes net metering.

Comments of the Kentucky Division of Energy

KDOE also commented on Big Rivers' plan to postpone a net metering program until LG&E's and KU's pilot programs are complete. KDOE shares the AG's concern that the absence of publicity by LG&E/KU will hold down the number of participants in their programs. Big Rivers' response to KDOE and the AG's position on net metering programs were addressed in the preceding section.

KDOE commented extensively on Big Rivers' DSM study performed by GDS. KDOE expressed disappointment in its limited input into the development of the DSM study, which in its view, resulted in duplicate programs being included therein. KDOE also disagreed with the use of zero as the cost for avoided capacity, since, it argues, any excess capacity could be sold in the wholesale market for a profit. KDOE believes that the use of a value greater than zero could have a significant effect on Big Rivers' and GDS's quantitative analysis of DSM options. KDOE reiterated that it was not recommending that Big Rivers implement DSM programs for the sole purpose of becoming an energy marketer or freeing up capacity to sell power in wholesale markets. It emphasized that any energy sales would only be a side effect of the DSM programs.

In its reply comments, Big Rivers addressed the extent to which it had included KDOE in its IRP and DSM planning. Big Rivers stated that it had visited KDOE and that its consultant, GDS Associates, contacted KDOE approximately twelve times to obtain information for the DSM analysis. It states that it will continue to attempt to include KDOE in its DSM planning. Big Rivers states that it continues to believe that zero is the appropriate value for the avoided cost of capacity in analyzing DSM measures. It argues that its current power contracts do not include discrete demand costs, therefore, it would not realize a decrease in demand costs with a decrease in MWh purchased. The reduced purchases would, however, decrease the cost of purchased power, which was already factored into the DSM analysis. Big Rivers agrees with KDOE that it should not implement DSM programs for the sole purpose of energy marketing.

KDOE also discussed its criticism of Big Rivers' previous IRP, criticism which concerned the fact that the DSM plan placed little or no emphasis on new buildings and manufacturing processes. KDOE believes this criticism is still valid in light of the programs examined in the GDS study. Big Rivers responded that energy efficient new homes, new commercial building design and combined heat and power were programs it did not analyze. Big Rivers also argued that programs such as the Energy Star new home program would not be cost effective given its own cost structure. Big Rivers concluded that other programs not specifically addressed in the DSM study would be non-beneficial due to the low cost of wholesale power under Big Rivers' power purchase agreement with LG&E Energy Marketing.

Discussion of Reasonableness

Staff is generally encouraged with Big Rivers' progress in the area of DSM. However, Staff does not believe it is reasonable for Big Rivers to delay implementing a net metering pilot program until LG&E and KU complete their pilot programs. Big Rivers indicated in its response to a data request that it was conducting a study which included net metering, which would be filed with the Commission in the fall of 2003. Big Rivers has not yet filed such a study.

Some of KDOE's comments on Big Rivers's DSM plan focus on similar themes – i.e, the plan's concentration on individual technologies rather than a broader view of areas such as new housing construction and improved manufacturing processes. While it does not necessarily believe that Big Rivers, or any utility, can have a significant impact on the housing industry, Staff does believe that Big Rivers' future IRPs should evaluate DSM programs that provide increased efficiency for all customers, not just residential and commercial customers. Therefore, Staff believes that Big Rivers should include an evaluation of programs related to improved manufacturing processes in its next IRP. Staff looks forward to seeing an expansion of the type and variety of potential DSM programs evaluated in Big Rivers' future IRPs.

Big Rivers argues that its market sales are typically short-term and do not provide any certainty that it will make similar sales in the future. Big Rivers questions the viability of any DSM measure that depends on the wholesale price of electricity. KDOE and Big Rivers are in agreement that Big Rivers should not implement a DSM program for the sole purpose of energy marketing. Staff agrees with Big Rivers' position that the IRP process, as defined by 807 KAR 5:058, focuses on meeting future demand within Big Rivers' service area, as opposed to the expansive view offered by KDOE, which includes wholesale sales off-system.

Given the results of Big Rivers' demand and energy forecast and considering its wholesale supply arrangements, Staff concludes that Big Rivers' use of zero as the cost of avoided capacity is reasonable. While Staff does not disagree with KDOE that using a value greater than zero could have an effect on Big Rivers' and GDS's analysis of DSM options, it does not agree with KDOE that Big Rivers must use a value greater than zero, given that it forecasts no capacity needs over its entire planning horizon.

Recommendations

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.

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.

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.

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.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

Introduction

This section summarizes and reviews Big Rivers' evaluation of supply-side resource options. Because it no longer operates its generating units, many of the IRP filing requirements are no longer applicable to Big Rivers and are not discussed herein.

Existing Power Supply

Big Rivers' current power supply consists largely of contracts to purchase power from LEM and SEPA. Table 1 shows Big Rivers' load forecast through 2017 and the maximum capacity and energy available under these contracts. Big Rivers' purchase contracts with LEM and SEPA are for firm power. Table 1 shows that Big Rivers projects that it will have surplus capacity through 2017. The LEM contract, which accounts for most of Big Rivers' power supply, includes liquidated damages for non-delivery; therefore, unlike utilities that operate generating facilities, Big Rivers is not required to maintain a reserve margin. Big Rivers also has access to the wholesale power markets to buy and sell power as needed subject to market availability.

Table 1: Load Forecast, Capacity, Peak Demand, and Energy Requirements

Year	System Peak Demand (MW)[1]	Total Energy Requirements for Generation Service (MWh)[2]	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)
2002	641	3,298,001	597	5,327,285	178	267,000	775	134
2003	688	3,625,665	597	5,327,285	178	267,000	775	87
2004	699	3,676,821	597	5,327,285	178	267,000	775	76
2005	711	3,734,545	597	5,327,285	178	267,000	775	64
2006	722	3,783,971	597	5,327,285	178	267,000	775	53
2007	698	3,537,386	597	5,327,285	178	267,000	775	77
2008	711	3,596,195	597	5,327,285	178	267,000	775	64
2009	723	3,650,147	597	5,327,285	178	267,000	775	52
2010	735	3,705,392	597	5,327,285	178	267,000	775	40
2011	749	3,766,818	717	6,321,741	178	267,000	895	146
2012	761	3,823,153	800	7,008,000	178	267,000	978	217
2013	774	3,880,729	800	7,008,000	178	267,000	978	204
2014	788	3,943,476	800	7,008,000	178	267,000	978	190
2015	801	4,002,583	800	7,008,000	178	267,000	978	177
2016	814	4,061,689	800	7,008,000	178	267,000	978	164
2017	827	4,120,796	800	7,008,000	178	267,000	978	151

1 System peak demand represents the sum of rural system coincident peak demand plus all non-rural demand, net of smelters, plus transmission losses.

2 Total energy requirements include transmission losses of 1.39 percent.

Weyerhaeuser, a customer of Kenergy Corporation, recently purchased the paper processing facilities formerly operated by Willamette Industries. In 2001, Willamette installed 85 MW of cogeneration facilities, which has reduced Big Rivers' demand and energy requirement obligation. Big Rivers indicated it would be evaluating the feasibility of making a capital investment at the Weyerhaeuser facility to allow excess steam to be recycled and used to generate up to an additional 20 to 30 MW of capacity. It also indicated that it expected to complete its cost estimate and feasibility study of such an investment in October of 2003. Big Rivers has yet to make a filing with the Commission regarding its study. Staff recommends 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.

Supply-Side Evaluation

Big Rivers analyzed the costs of the alternative sources shown in Table 2 and compared them to the costs associated with its LEM contract. The analysis quantifies the 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. Tables 2a and 2b below show the key inputs used in Big Rivers' supply-side screening model.

Table 2: Supply-Side Sources Evaluated

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

Table 2a: Key Inputs in Supply-Side Screening Model

Technology	Capital Cost $/kW	Regional Multiplier	Adjusted Capital Cost	Constr. Period	Serv. Life
Pulverized Coal	1,119.00	1.004	1,123.48	4	30
Coal Gasification CC	1,338.00	1.004	1,343.35	4	30
Conventional CC	456.00	1.004	457.82	3	30
Advanced CC	590.00	1.004	592.36	3	30
Conventional CT	339.00	1.004	340.36	2	30
Advanced CT	474.00	1.004	475.90	2	30
Fuel Cess	2,091.00	1.004	2,099.36	3	30
Base Distributed	623.00	1.004	625.49	3	30
Peak Distributed	559.00	1.004	561.24	2	30
Biomass	1,725.00	1.004	1,731.90	4	30
Landfill Gas	1,429.00	1.004	1,434.72	3	30
Geothermal	1,746.00	1.004	1,752.98	4	30
Wind	982.00	1.004	985.93	3	30
Solar Thermal	2,539.00	1.004	2,549.16	3	30
Photovoltaic	3,831.00	1.004	3,846.32	2	30
Hydroelectric	1,700.00	1.000	1,700.00	2	30

Table 2b: Key Inputs in Supply-Side Screening Model

Technology	Primary Fuel	Variable O&M mill/kWh	Fixed O&M $/kW	Capacity Factor	Heat Rate
Pulverized Coal	Coal	3.38	23.41	90.00%	9.386
Coal Gasification CC	Coal	0.80	32.67	90.00%	7.869
Conventional CC	Gas	0.52	15.61	80.00%	7.618
Advanced CC	Gas	0.52	14.46	80.00%	6.870
Conventional CT	Gas	0.10	6.45	25.00%	11.380
Advanced CT	Gas	0.10	9.16	25.00%	9.020
Fuel Cess	Gas	2.08	14.98	70.00%	5.744
Base Distributed	Gas	15.11	4.02	90.00%	10.991
Peak Distributed	Gas	23.10	12.56	25.00%	10.620
Biomass	None	2.90	44.95	80.00%	N/A
Landfill Gas	None	0.01	96.31	98.00%	N/A
Geothermal	None		70.07	50.00%	N/A
Wind	None		25.54	50.00%	N/A
Solar Thermal	None		47.87	50.00%	N/A
Photovoltaic	None		9.85	50.00%	N/A
Hydroelectric	None		6.67	50.00%	N/A

Big Rivers points out that some of these alternatives will not be available to it due to geographical or other constraints. However, the comparison shows that the cost of alternatives will be more expensive than its LEM contract's costs. Figures 1 through 3 below show the total costs of the various power supply options Big Rivers compared.

Figure 1

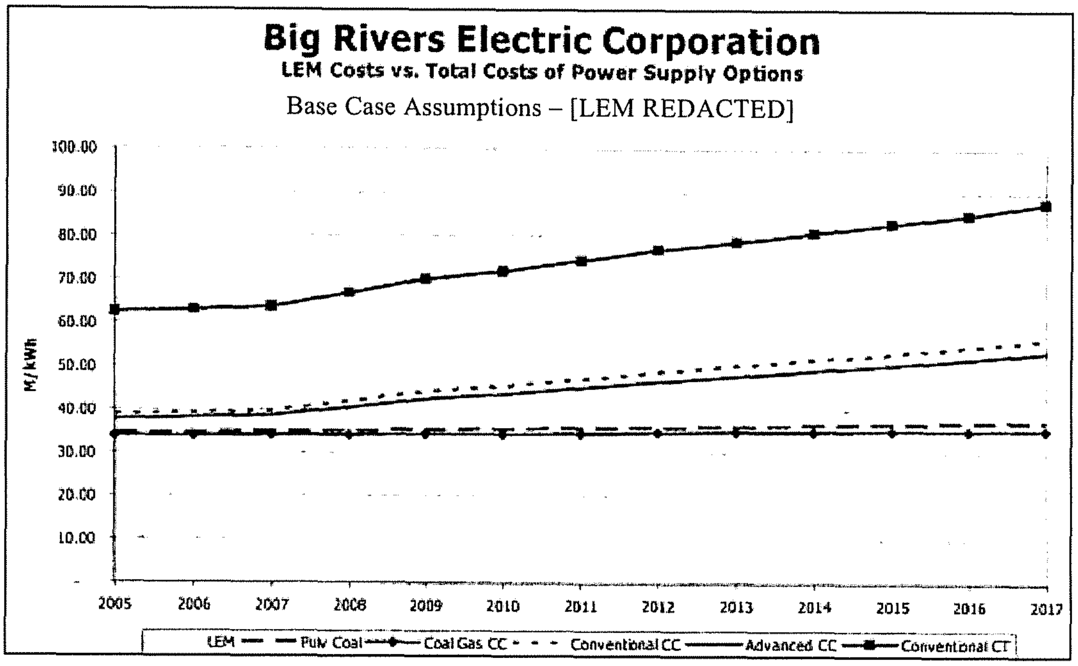


Figure 2

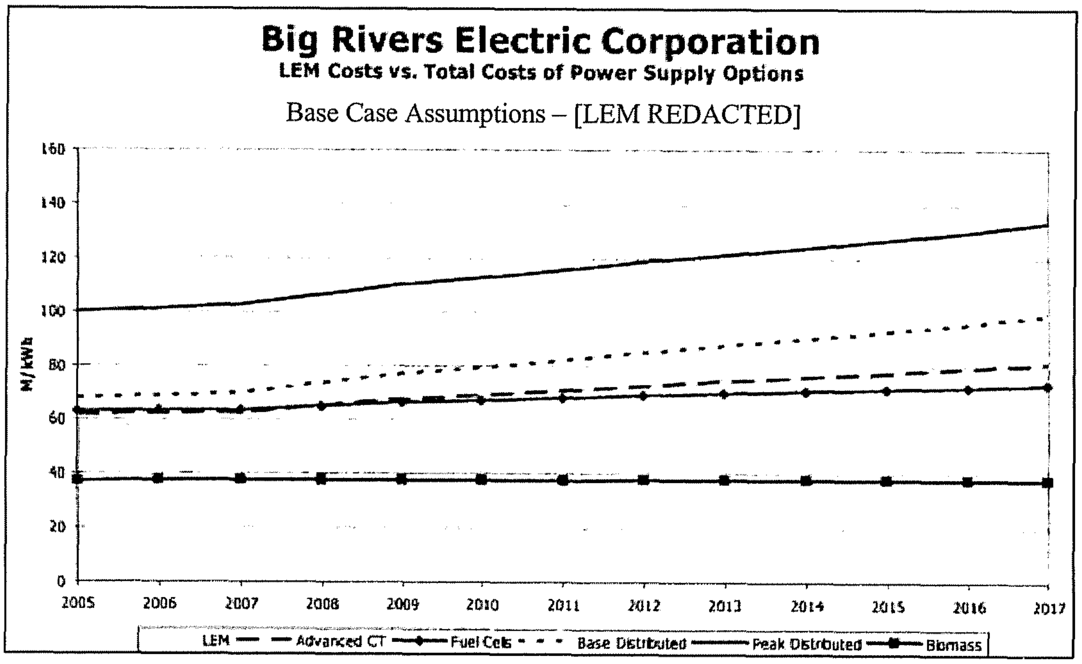
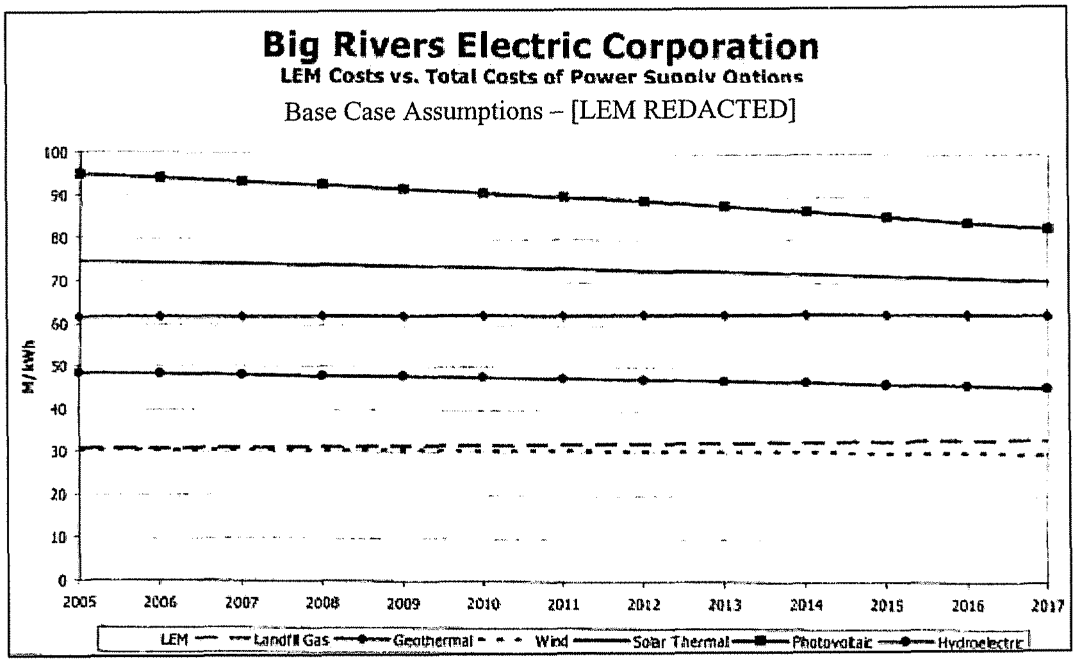


Figure 3



Discussion of Reasonableness

Based on the results of its load forecast, Big Rivers does not project a need to add generation during the 15-year forecast period. Its analysis of supply-side options shows the existing LEM contract to be the lowest cost supply-side resource available to it over the foreseeable future. Given the results, Staff believes it is reasonable that Big Rivers has no plans to add additional resources over the forecast period, other than its investigation of a possible investment at the Weyerhaeuser facility that could generate an additional 20-30 MW.

Recommendations

Commission Staff agrees with Big Rivers regarding the lack of need for additional supply-side resources during the forecast period. However, the 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.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is the integration of supply-side and demand-side options to arrive at the optimal integrated resource plan. This section will discuss integration issues and how they were addressed by Big Rivers.

Integration Issues

Due to it having need for no additional generating capacity over its fifteen-year planning horizon, Big Rivers' integration process is much less extensive than what is typical. Big Rivers completed a DSM study in late 2002, the results of which were included in its IRP. The study identified new programs for inclusion in Big Rivers' three-year action plan that are educational in nature and designed to help consumers conserve energy. Due to the educational nature of the programs, no energy and peak demand savings estimates were developed for the IRP.

Big Rivers' analysis of supply-side resources included coal-fired generation, gas-fired generation, distributed generation, fuel cells, and renewable energy. Coal-fired generation, landfill gas, and wind-powered options had the lowest "all-in" costs, but none of these options were less costly than Big Rivers' existing power supplies. While it forecasts no new capacity needs over its planning horizon, Big Rivers is evaluating the purchase of blocks of renewable power for customers with an interest in purchasing renewable power.

Big Rivers is also analyzing distributed generation as a complement to traditional transmission planning. Its analysis focuses on the feasibility of using distributed generation in remote areas instead of making capital additions to transmission facilities. This evaluation is in anticipation that, at some future point, Big Rivers will be required to make additional investment in facilities in order to maintain its existing standards of reliability.

Discussion of Reasonableness

The Staff's report on Big Rivers' 1999 IRP included two recommendations related to integration and optimization. They were as follows:

- Big Rivers should update the Commission on the status of its 62-MW distributed generation project on a quarterly basis, and provide copies of that update to the parties in this case. Such updates should begin one month from the issuance of this report, and continue until the project is operational or until Big Rivers has decided upon an alternative solution.

- Big Rivers should discuss, in significant detail in its next IRP filing, its efforts relative to the 1999 IRP's recommendations to continue evaluation of the combined commercial/industrial load management plan; to encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide greater flexibility in power supply operations; to maintain an ongoing dialogue with other power suppliers regarding low cost energy and capacity sources; and to monitor the progress of state and federal legislation to determine its potential impacts upon the Big Rivers system.

Big Rivers finalized work related to the distributed generation project (Willamette, now Weyerhaeuser) in "mid 2001" and made the required filings with the Commission. Throughout its IRP, Big Rivers discussed a number of issues related to the second recommendation included in the Staff's report on its 1999 IRP. Hence, Staff is satisfied that Big Rivers has adequately responded to those previous recommendations.

Recommendations

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.

With that in mind, Staff will merely reiterate the recommendations contained in Sections 3 and 4 of this report regarding demand-side and supply-side issues that are applicable to Big Rivers. Of course, if circumstances should change and Big Rivers have a need for new capacity, its next IRP will need to evaluate and integrate demand-side and supply-side alternatives into a more traditional optimal resource plan.

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EAST KENTUCKY POWER COOPERATIVE

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Integrated Resource Plan

Case No. 2006-~~00017~~ 00471

REDACTED

October 21, 2006

A Touchstone Energy Cooperative

5. PLAN SUMMARY

5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative located in Winchester, Kentucky. It serves 16 member distribution cooperatives who serve approximately 495,000 retail customers. Member distribution cooperatives currently served by EKPC are listed below:

Big Sandy RECC	Jackson Energy Cooperative
Blue Grass Energy Coop. Corp.	Licking Valley RECC
Clark Energy Cooperative, Inc.	Nolin RECC
Cumberland Valley Electric	Owen Electric Cooperative, Inc.
Farmers RECC	Salt River Electric Cooperative
Fleming-Mason Energy Cooperative, Inc.	Shelby Energy Cooperative, Inc.
Grayson RECC	South Kentucky RECC
Inter-County Energy Coop. Corp.	Taylor County RECC

In April of 2008, Warren RECC will become a member of EKPC.

EKPC owns and operates three coal fired generating stations – Dale Station (196 MW), Cooper Station (341 MW), and Spurlock Station (1,118 MW). EKPC's newest coal fired unit is the E.A. Gilbert Unit at Spurlock Station (268 MW) that began commercial operation on March 1, 2005. EKPC has three 150 MW gas fired combustion turbines (450 MW - winter rating) and four 98 MW gas fired combustion turbines (392 MW – winter rating) at Smith Station. EKPC also purchases 170 MW of hydropower from the Southeastern Power Administration (SEPA) on a long-term basis. In addition, EKPC owns and operates 12 MW of landfill gas generating plant capacity resulting in a total of 2,679 MW of capacity (winter rating).

EKPC has one purchase contract (other than the purchase from SEPA) in its portfolio that extends through 2006. New capacity additions were selected through an RFP process that began in April 2004 to meet EKPC's capacity needs through 2010.

EKPC owns and operates a 2,759-circuit mile network of high voltage transmission lines consisting of 69 kV, 138 kV, 161 kV, and 345 kV lines, and all the related substations. EKPC was a member of the East Central Area Reliability Council ("ECAR") until late 2005. ECAR and three other regional reliability councils were replaced by a larger regional reliability council made up primarily of members of the Midwest ISO and PJM. EKPC evaluated its options for selecting a new reliability council and decided to join the Southeastern Electric Reliability Council ("SERC"). EKPC maintains 59 normally closed free-flowing interconnections with its neighboring utilities.

In 2005, EKPC's peak load was 2,477 MW and energy requirements for sales to its members were 12,528 GWh.

EKPC submitted its 2003 IRP (PSC Case No. 2003-00051) to the Commission on April 21, 2003. The report submitted by EKPC provided its plan to meet the power requirements of its 16 member distribution cooperatives over the period from 2003 to 2017. On September 14, 2004, EKPC received the Commission Staff's Report on the 2003 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. The purpose of the report was to review and evaluate EKPC's 2003 IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing and offer suggestions and recommendations to be considered in subsequent filings.

The EKPC IRP Team, which consists of various personnel within the organization, used the PSC Staff Report as a starting point in their analysis for the next IRP. The PSC Staff Report recommendations along with the basic requirements of the Commission's regulations become the foundation leading to this Integrated Resource Plan ("IRP").

EKPC states that the objective of the power supply plan is to minimize the cost to serve its Member Systems.

The following summary of recommendations from the PSC Staff Report on EKPC's 2003 IRP was used as guidance in the development of EKPC's 2006 IRP. EKPC's response follows each recommendation.

Load Forecasting:

1. Provide a complete description of each model, component and variable for each model including the class models, regional economic model, peak models and the high / low variation in peak demand.

   Please see the 2006 Load Forecast Report, Section 8.0 and Appendix B, Section 1 and Section 3.

2. Provide a complete description of how the economic and demographic data is constructed for the six economic regions, including how the data is manipulated so as to be useful for forecasting individual member system class usage.

   Please see the 2006 Load Forecast Report, Section 2.0 and Section 4.0 and Appendix B, Section 1.

3. Provide a complete description of the assumptions made to produce the high and low case variations in the seasonal peak demand forecasts.

   Please see the 2006 Load Forecast Report, Section 8 and Appendix B, Section 2 – Data CD.

Demand Side Management:

1. Discuss the results of any dialogue East Kentucky has with the AG, KDOE, or other parties related to DSM issues prior to filing the IRP and explain how the parties' concerns are incorporated in the IRP.

   In late 2005, representatives of EKPC met with the Office of the Attorney General and had telephone discussions with the Kentucky Department of Energy Policy, Division of Renewable Energy and Energy Efficiency regarding EKPC's proposed Direct Load Control ("DLC") DSM program.

   Currently, EKPC participates in an energy efficiency working group consisting of utilities, the Attorney General, the Sierra Club, and the Division of Renewable Energy and Energy Efficiency.

2. Report on efforts to evaluate and support local integrated resource planning, cogeneration and distributed generation, and other initiatives of the type advocated by KDOE.

   EKPC has a cogeneration tariff that is evaluated and typically updated every five years. EKPC has a 3,200 kW distributed generating unit in Clinton County. EKPC has landfill generating units in Boone, KY, Lily, KY, and in Greenup County, Hardin County, and Pendleton County. In 2005, EKPC assisted its member systems in developing a net-metering tariff. And, EKPC has conducted numerous transmission open houses that allow for public input.

   Section 8 of this report describes both supply-side and demand-side power supply analysis. Several demand-side programs have shown strong benefit/cost ratios, in particular, direct load control of water heaters and air-conditioners. EKPC and two of its member systems are currently engaged in the aforementioned DLC demonstration project. The objective of this project is to better understand how

DLC can be an explicit part of EKPC's power supply. DLC is not shown as an explicit part of the resource plan but that could change as the demonstration project provides more insights.

The remaining DLC programs in Section 8 that have relatively high benefit/cost ratios will be discussed and further evaluated with EKPC member systems. EKPC is utilizing DSM options in its power supply.

3. Explicitly discuss how it has factored environmental cost considerations into its DSM evaluation, or at minimum, provide an explanation for why it has not or cannot do so.

   EKPC explicitly includes environmental externalities in its analysis. See Section 8.(5)(c) of this IRP.

Supply-Side Resource Assessment:

1. East Kentucky should include an analysis in its next IRP on what planning reserve margin is optimal. In addition to regional capacity or reserve margins, this analysis should be based upon probabilistic criteria such as Loss of Load Expectation or Probability, the size of its largest generating unit, forced outage rates, import capability, ECAR operating reserve requirements, etc. In the alternative, if East Kentucky believes that these criteria are inappropriate, it should explain why.

   A reserve margin study is discussed in Section 8.(5)(d).

2. East Kentucky's next IRP, scheduled to be filed in the spring of 2006, should reflect its plans for serving its growing system demand, including the addition of WRECC.

WRECC is an explicit part of EKPC's planning resource process. WRECC is addressed in Section 8.(2)(c) of the IRP.

3. In its next IRP, East Kentucky should provide more discussion about the supply alternatives it selects to analyze. This discussion should identify all criteria, assumptions, etc. relied upon in making these selections and explain the basis for the criteria, assumptions, etc.

   Section 8.(2)(c) discusses supply-side alternatives.

4. East Kentucky should consider using methods, such as described above, or other methods, to levelize or otherwise mitigate the effects that very "lumpy" investments have in studies of this type.

   Section 8.(5)(a) discusses annualized fixed costs.

5. East Kentucky should carefully evaluate the potential of the Gilbert Unit to burn a mix of wood waste and coal. It should also consider carbon dioxide emissions, or the absence thereof, when evaluating hydro generation options.

   EKPC is currently evaluating the economics and technical feasibility of using wood waste at the Gilbert Unit. Please see Section 8.(5)(f) for a discussion of carbon dioxide emissions.

5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan.

Load Forecast

EKPC's load forecast methodology includes regional economic modeling that incorporates historical data on population, income, employment levels and wages. This data is collected county by county from the U. S. Bureau of Labor Statistics ("BLS") and the U.S. Bureau of Economic Analysis ("BEA").

EKPC uses Metrix products for forecasting hourly load, annual energy, and seasonal peaks. MetrixND uses monthly weather and calendar data inputs to produce seasonal peaks and energy. MetrixLT uses historical hourly load data and daily weather and calendar data to calibrate to the forecasted seasonal peak demands and energy.

Key forecast assumptions used in developing the EKPC and member system load forecasts are:

1. EKPC's member systems will add approximately 260,000 residential customers by 2026. This represents an increase of 2.3 percent per year. This includes Warren RECC beginning April 2008.

2. EKPC uses an economic model to help develop its load forecast. The model uses data for 89 Kentucky counties in seven geographic regions. The economy of these counties will experience modest growth over the next 20 years. The average unemployment rate will remain relatively flat at 6.8 percent during the 2006 to 2026 timeframe. Total employment levels will rise by 330,000 jobs. Manufacturing employment will decrease to from 272,000 jobs in 2004 to 210,000 jobs in 2020. Regional population will grow from 3.5 million people in 2006 to 4.0 million people in 2026, an average growth of 0.7 percent per year.

3. From 2006 through 2026, approximately 70 percent of all new households will have electric heat. Eighty-five percent of all new households will have electric water heating. Nearly all new homes will have electric air-conditioning, either central or room.

4. Over the forecast period, naturally occurring appliance efficiency improvements will decrease retail sales by nearly 1,500,000 MWh. Appliances particularly affected are refrigerators, freezers, and air conditioners.

5. Residential customer growth and local area economic activity will be the major determinants of small commercial growth.

6. Forecasted load growth is based on the assumption of normal weather, as defined by the National Oceanic and Atmospheric Administration, occurring over the next 20 years. Seven different stations are used depending on geographic location of the member system.

Demand-Side Management

Over the past 25 years, East Kentucky Power Cooperative, Inc. (EKPC) member systems have offered various demand-side management ("DSM") marketing programs to the retail consumer. These programs have been developed to meet the needs of the end consumer and to delay the need for additional generating capacity. In order to satisfy these needs, a diverse menu of marketing programs has been developed and deployed.

This IRP evaluates the benefits and costs of existing DSM marketing programs and screens new marketing programs to be implemented in partnership with member systems. EKPC utilizes DSMANAGER, a computer program created by the Electric Power Research Institute ("EPRI"), in order to evaluate the relative benefits of these programs.

New DSM/marketing programs are reviewed and discussed in Section 7. EKPC and Member Systems will continue to work together to implement these programs as they fit their organizational goals.

Supply Side Resources

EKPC's existing capacity consists of base load coal fired units and peaking units (SEPA hydro and combustion turbines).

EKPC utilizes several computer models in the Resource Planning Process. EKPC uses EPRI's Technical Assessment Guide – Supply Side Technologies Software ("TAG-

Supply") for use in detailed cost information as well as estimates based on current projects. The RTSim model is used for detailed production costing and emission estimating studies. This program simulates system operation on an hourly chronological basis.

RTSim's Resource Optimizer was used to produce EKPC's optimal expansion plan. The optimizer evaluated a variety of resource options, startup dates, and market and load conditions to produce the lowest cost plans. Supply side capacity alternatives considered in this study included:

- Combustion Turbines (Peaking)
- Combustion Turbines with Steam Injection Option
- Fluidized Bed Boiler Units (Base Load)
- Long Term Purchases to be evaluated in RFP's as needed

In general, the construction cost for peaking units is the least, with intermediate capacity and base load capacity costing progressively more. The reverse is true, however, for variable costs, with base load capacity having the lowest variable production costs.

5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts.

EKPC's most recent load forecast (*EKPC 2006 Load Forecast Report, August 2006*) projects that total energy requirements are expected to increase by 3.0 percent per year over the 2006 through 2026 period. Net winter peak demand will increase by approximately 2,400 MW, and net summer peak demand will increase by approximately 1,700 MW. Annual load factor projections are remaining steady at approximately 53 percent. Below and in Table 5.(3) are summaries of projected energy and peak growth rates.

Energy and Peak Growth Rates			
	2006-2011	2006-2016	2006-2026
Total Energy Requirements	5.6%	3.9%	3.0%
Residential Sales	4.7%	3.5%	2.9%
Total Commercial and Industrial Sales (Excluding Gallatin Steel)	8.2%	5.2%	3.6%
Firm Winter Peak Demand	6.3%	4.2%	3.2%
Firm Summer Peak Demand	5.8%	3.9%	3.0%

Table 5.(3)

Season	Net Winter Peak Demand (MW)	Year	Net Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
2005 - 06	2,477	2006	2,151	2006	12,556,759	58%
2006 - 07	2,773	2007	2,213	2007	12,956,841	53%
2007 - 08	2,848	2008	2,643	2008	14,793,556	59%
2008 - 09	3,346	2009	2,721	2009	15,716,559	54%
2009 - 10	3,439	2010	2,791	2010	16,133,913	53%
2010 - 11	3,520	2011	2,852	2011	16,499,166	54%
2011 - 12	3,595	2012	2,907	2012	16,879,983	54%
2012 - 13	3,694	2013	2,978	2013	17,261,436	53%
2013 - 14	3,775	2014	3,036	2014	17,621,408	53%
2014 - 15	3,856	2015	3,096	2015	17,981,314	53%
2015- 16	3,931	2016	3,153	2016	18,370,418	53%
2016 - 17	4,031	2017	3,225	2017	18,744,186	53%
2017 - 18	4,118	2018	3,290	2018	19,129,686	53%
2018 - 19	4,209	2019	3,359	2019	19,539,698	53%
2019 - 20	4,299	2020	3,423	2020	19,977,370	53%
2020 - 21	4,408	2021	3,505	2021	20,408,388	53%
2021 - 22	4,503	2022	3,577	2022	20,837,354	53%
2022 - 23	4,597	2023	3,648	2023	21,258,006	53%
2023 - 24	4,678	2024	3,709	2024	21,683,180	53%
2024 - 25	4,781	2025	3,788	2025	22,086,886	53%
2025 - 26	4,869	2026	3,853	2026	22,475,651	53%

Key economic and demographic assumptions underlying these forecasts are:

1. moderate growth in population;

2. steady growth in regional income;
3. an increase in per capital income in the region from $29,000 in 2006 to $32,500 in constant dollars by 2026; and
4. moderate growth in employment.

5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

Planned Resource Acquisitions

EKPC's resource planning process evaluates the economics of available options to meet the needs of our Member Systems at the lowest practical cost. Utilizing a reserve margin of 12%, the plan resulting from the IRP is shown below in Table 5.(4)-1 and is detailed in Section 8. Table 5.(4)-1 lists annual peak demand figures and compares resulting capacity requirements with existing and committed resources. The Table shows that EKPC will need to provide over 2,100 MW of additional resources to serve projected loads by 2020.

Table 5.(4)-2 shows the expected capacity additions based on the 2006 IRP. EKPC's IRP has identified the need for 900 MW of additional baseload capacity and 200 MW of peaking capacity from 2013 through 2020.

Improvement in Operational Efficiency of Existing Facilities

EKPC recognizes that maintenance management for existing units is vital to keeping facilities efficient. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units. This plan is discussed in Section 8 of the IRP.

Table 5.(4)-1

EKPC Projected Capacity Needs

(MW)

Year	Projected Peaks		12% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2006	2,673	2,151	321	258	2,994	2,409	2,752	2,543	242	-134
2007	2,773	2,213	333	266	3,105	2,479	2,719	2,505	386	-26
2008	2,848	2,643	342	317	3,190	2,960	2,721	2,505	469	455
2009	3,346	2,721	401	327	3,747	3,048	2,693	2,477	1,054	571
2010	3,439	2,791	413	335	3,851	3,126	2,683	2,467	1,168	659
2011	3,520	2,852	422	342	3,942	3,194	2,683	2,467	1,259	727
2012	3,595	2,907	431	349	4,027	3,256	2,683	2,467	1,344	789
2013	3,694	2,978	443	357	4,137	3,335	2,683	2,467	1,454	868
2014	3,775	3,036	453	364	4,228	3,400	2,683	2,467	1,545	933
2015	3,856	3,096	463	372	4,318	3,467	2,683	2,467	1,635	1,000
2016	3,931	3,153	472	378	4,403	3,531	2,683	2,467	1,720	1,064
2017	4,031	3,225	484	387	4,515	3,612	2,683	2,467	1,832	1,145
2018	4,118	3,290	494	395	4,612	3,685	2,683	2,467	1,929	1,218
2019	4,209	3,359	505	403	4,714	3,762	2,683	2,467	2,031	1,295
2020	4,299	3,423	516	411	4,814	3,834	2,683	2,467	2,131	1,367

Demand-Side Management

The plan described in Table 5.(4)-2 includes the evaluation of new DSM programs. EKPC evaluated 93 DSM measures for the 2006 IRP. Thirty-four measures passed the Qualitative Screen and were passed on to Quantitative Evaluation. After combining several programs, twenty-seven programs were prepared for Quantitative Evaluation. Detailed analyses of these programs are discussed in Sections 7 and 8 of the IRP.

Table 5.(4)-2
EKPC Projected Major Capacity Additions
(MW)

Year	Baseload Capacity	Peaking/Intermediate Capacity	Cumulative Capacity Additions
2006			
2007			
2008			
2009	278 (Spurlock 4)	485 (Smith CTs 8-12)	763
2010	278 (Smith 1)		1,041
2011			
2012			
2013	300*		1,341
2014			
2015	300*		1,641
2016		100*	1,741
2017		100*	1,841
2018			
2019	300*		2,141
2020			

*Rounded. Exact MWs are modeled in Section 8.

Non-Utility Sources of Generation

The plan described in Table 5.(4)-2 does not include non-utility generation.

EKPC is working very diligently to seek power supply options other than construction its own generation. This includes discussions with other utilities and non-utilities. The discussions have covered partnerships, joint ventures, and long-term power purchase contracts. This work is ongoing.

New Power Plants

As shown in Table 5.(4)-2, Spurlock 4, 278 MW of capacity, is already under construction. In an Order dated August 29, 2006 in Case No. 2005-00053, the Commission granted a Certificate of Convenience and Necessity ("CPCN") to EKPC to construct the 278 MW Smith circulating fluidized bed coal-fired unit ("Smith CFB") and five 90 MW combustion turbines ("Smith CTs 8-12") in Clark County.

The plan calls for 300 MW of base load capacity to be added in 2013, 2015, and 2019. Additionally, the plan calls for 100 MW of intermediate/peaking capacity in 2016 and 100 MW in 2017.

Transmission Improvements

EKPC regularly identifies transmission projects and upgrades that are required for maintaining the capability of its transmission system in order to meet the demands of its Member Systems. Transmission projects are discussed in Section 8 of this IRP.

Bulk Power Purchases and Sales

EKPC has a purchase power agreement with Duke Energy to purchase the output of the Greenup hydro project for approximately 40 MW of capacity that expires at the end of 2006. Negotiations are underway to possibly extend this agreement through 2010.

Interconnections with other Utilities

EKPC and Big Rivers Electric Corporation (BREC) intend to establish a free-flowing interconnection at the D.B. Wilson Power Plant in 2008. EKPC is constructing more than 90 miles of 161 kV transmission line from its Barren County Substation through the Bowling Green area to connect the Warren Rural Electric Cooperative (WRECC) to the EKPC system.

To provide system support and reliability, EKPC is also adding four free-flowing interconnections to utilities with existing transmission facilities in the area.

5.(5) Steps to be taken during the next three (3) years to implement the plan.

Spurlock 4, with 278 MW of baseload capacity, is expected to be online in 2009. Smith CTs 8-12 are expected to be online by 2009 and the 278 MW Smith 1 CFB generating unit in 2010. EKPC anticipates that a Request for Proposals ("RFP") for additional baseload capacity will be issued in the first quarter of 2007.

Demand-Side Management

The DSM alternatives are complex endeavors. DSM programs that may be implemented will require a rigorous program design effort. A demonstration or pilot program may precede complete implementation to test the validity of the program concept.

5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

EKPC's 2006 load forecast methodology uses historic relationships between electric consumption and key determinants of that consumption, e.g. population, income, employment levels, and wages.

The load forecast assumes that these relationships will continue into the future. EKPC updates its load forecast annually in order to test whether these relationships continue to hold.

The implementation of DSM programs may exceed the target peak reduction that is incorporated in this IRP due to variations in the peak reduction per customer and customer participation.

While the power supply plan identifies the need for baseload and peaking resources, it has not yet addressed the uncertainties of carbon dioxide regulation, significant increases in transmission expenses, partnerships, and generation construction cost uncertainty. These points are either still evolving or will be addressed via the RFP.

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Σ of 1's = 24.63%

Table 9. Retail Electricity Sales Statistics, 2006

Item	Full Service Providers					Other Providers		Total
	Investor-Owned	Public	Federal	Cooperative	Facility	Energy	Delivery	
Kentucky								
Number of Entities	4	31	1	24	1	NA	NA	61
Number of Retail Customers	1,203,388	209,195	22	782,522	2	NA	NA	2,195,129
Retail Sales (thousand megawatthours)	40,758	7,055	14,675	26,128	127	NA	NA	88,743
Percentage of Retail Sales	45.93	7.95 1	16.54 1	29.44	0.14 1	NA	NA	100.00
Revenue from Retail Sales (million dollars)	2,288	433	530	1,561	4	NA	NA	4,817
Percentage of Revenue	47.50	9.00	11.00	32.41	0.09	NA	NA	100.00
Average Retail Price (cents/kWh)	5.61	6.14	3.61	5.98	3.40	NA	NA	5.43

Table 9 Notes: Data are shown for All Sectors. Full Service Providers sell bundled electricity services (e.g., both energy and delivery) to end users. Full Service Providers may purchase electricity from others (such as independent Power Producers or other full service providers) prior to delivery. Other Providers sell either the energy or the delivery services, but not both. Sales volumes and customer counts shown for Other Providers refer to delivered electricity, which is a joint activity of both energy and delivery providers; for clarity, they are reported only in the Energy column in this table. The revenue shown under Other Providers represents the revenue realized from the sale of the energy and the delivery services distinctly. "Public" entities include municipalities, State power agencies, and municipal marketing authorities. "Federal" entities are either owned or financed by the Federal Government. "Cooperatives" are electric utilities legally established to be owned by and operated for the benefit of those using its services. The cooperative will generate, transmit and/or distribute supplies of electric energy to a specified area not being serviced by another utility. "Facility" sales represent direct electricity transactions from independent generators to end use consumers.

Table 10. Supply and Disposition of Electricity, 1990, 1995, and 2001 Through 2006
(Million Kilowatthours)

Category	1990	1995	2001	2002	2003	2004	2005	2006
Kentucky								
Supply								
Generation								
Electric Utilities	73,807	86,162	83,678	80,162	80,697	82,921	85,680	86,816
Independent Power Producers	-	-	11,448	11,369	10,566	11,097	11,622	11,449
Electric Power Sector Generation Subtotal	**73,807**	**86,162**	**95,126**	**91,530**	**91,263**	**94,018**	**97,302**	**98,266**
Combined Heat and Power, Commercial	-	-	98	-	-	-	-	-
Combined Heat and Power, Industrial	-	4	194	576	456	512	521	526
Industrial and Commercial Generation Subtotal	**-**	**4**	**291**	**576**	**456**	**512**	**521**	**526**
Total Net Generation	**73,807**	**86,166**	**95,418**	**92,107**	**91,719**	**94,530**	**97,822**	**98,792**
Total Supply	**73,807**	**86,166**	**95,418**	**92,107**	**91,719**	**94,530**	**97,822**	**98,792**
Disposition								
Retail Sales								
Full Service Providers	61,097	74,548	79,975	87,267	85,176	86,521	89,218	88,616
Facility Direct Retail Sales	-	-	-	-	44	-	133	127
Total Electric Industry Retail Sales	**61,097**	**74,548**	**79,975**	**87,267**	**85,220**	**86,521**	**89,351**	**88,743**
Direct Use	**-**	**3**	**182**	**186**	**188**	**188**	**389**	**400**
Total International Exports	**-**	**-**	**-**	**-**	**-**	**-**	*****	**-**
Estimated Losses	**4,581**	**5,659**	**4,286**	**6,459**	**5,690**	**6,765**	**6,687**	**6,515**
Total Disposition	**65,678**	**80,211**	**84,444**	**93,912**	**91,098**	**93,475**	**96,428**	**95,659**
Net Interstate Trade	**8,130**	**5,955**	**10,974**	**-1,805**	**621**	**1,055**	**1,394**	**3,133**
Net Trade Index (ratio)	**1.12**	**1.07**	**1.13**	**0.98**	**1.01**	**1.01**	**1.01**	**1.03**

R = Revised.
NA = Not applicable; NM = Not meaningful.
W = Withheld to avoid disclosure of individual company data.
- = Data not available.
* = Value is less than half of the smallest unit of measure (e.g., for values with no decimals, the smallest unit is 1 and values under 0.5 are shown as *.)
Totals may not equal sum of components because of independent rounding.
Table 10 Notes: Estimated Losses are reported at the utility level, and then allocated to States based on the utility's retail sales by State. Reported losses may include electricity unaccounted for by the utility. Net Interstate Trade represents the difference between the amount of electricity produced in the State and consumed in the State. Positive values indicate a State that is a net interstate exporter of electricity; negative values indicate a State that is a net interstate importer of electricity. The Net Trade Index represents a State's electricity self-sufficiency. Values greater than 1 indicate that, on an annual net basis, the State supplied electricity consumed outside the State; values less than 1 indicate that, on an annual net basis, the State consumed electricity produced outside the State.
General Notes: Table 4 "Other Renewables" includes wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. The "Other" category includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies. However, Table 5 "Other Renewables" includes only biogenic municipal solid waste, in addition to wood, black liquor, other wood waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. In Table 5 "Other" includes Non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuels and miscellaneous technologies. In Table 7, "Other Renewables" emissions include biogenic municipal solid waste, and other renewable waste.
Direct use is commercial or industrial use of electricity that (1) is self-generated (2) is produced by either the same entity that consumes the power or an affiliate, and (3) is used in direct support of a service or industrial process located within the same facility or group of facilities that houses the generating equipment. Direct use is exclusive of station use.

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278.020 Certificate of convenience and necessity required for construction provision of utility service or of utility -- Exceptions -- Approval required for acquisition or transfer of ownership -- Public hearing on proposed transmission line -- Severability of provisions.

(1) No person, partnership, public or private corporation, or combination thereof shall commence providing utility service to or for the public or begin the construction of any plant, equipment, property, or facility for furnishing to the public any of the services enumerated in KRS 278.010, except retail electric suppliers for service connections to electric-consuming facilities located within its certified territory and ordinary extensions of existing systems in the usual course of business, until that person has obtained from the Public Service Commission a certificate that public convenience and necessity require the service or construction. Upon the filing of an application for a certificate, and after any public hearing which the commission may in its discretion conduct for all interested parties, the commission may issue or refuse to issue the certificate, or issue it in part and refuse it in part, except that the commission shall not refuse or modify an application submitted under KRS 278.023 without consent by the parties to the agreement. The commission, when considering an application for a certificate to construct a base load electric generating facility, may consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities serving the Commonwealth. The commission, when considering an application for a certificate to construct an electric transmission line, may consider the interstate benefits expected to be achieved by the proposed construction or modification of electric transmission facilities in the Commonwealth. Unless exercised within one (1) year from the grant thereof, exclusive of any delay due to the order of any court or failure to obtain any necessary grant or consent, the authority conferred by the issuance of the certificate of convenience and necessity shall be void, but the beginning of any new construction or facility in good faith within the time prescribed by the commission and the prosecution thereof with reasonable diligence shall constitute an exercise of authority under the certificate.

(2) For the purposes of this section, construction of any electric transmission line of one hundred thirty-eight (138) kilovolts or more and of more than five thousand two hundred eighty (5,280) feet in length shall not be considered an ordinary extension of an existing system in the usual course of business and shall require a certificate of public convenience and necessity. However, ordinary extensions of existing systems in the usual course of business not requiring such a certificate shall include:

(a) The replacement or upgrading of any existing electric transmission line; or

(b) The relocation of any existing electric transmission line to accommodate construction or expansion of a roadway or other transportation infrastructure; or

(c) An electric transmission line that is constructed solely to serve a single customer and that will pass over no property other than that owned by the customer to be served.

(3) No utility shall exercise any right or privilege under any franchise or permit, after the exercise of that right or privilege has been voluntarily suspended or discontinued for more than one (1) year, without first obtaining from the commission, in the manner provided in subsection (1) of this section, a certificate of convenience and necessity authorizing the exercise of that right or privilege.

(4) No utility shall apply for or obtain any franchise, license, or permit from any city or other governmental agency until it has obtained from the commission, in the manner provided in subsection (1) of this section, a certificate of convenience and necessity showing that there is a demand and need for the service sought to be rendered.

(5) No person shall acquire or transfer ownership of, or control, or the right to control, any utility under the jurisdiction of the commission by sale of assets, transfer of stock, or otherwise, or abandon the same, without prior approval by the commission. The commission shall grant its approval if the person acquiring the utility has the financial, technical, and managerial abilities to provide reasonable service.

(6) No individual, group, syndicate, general or limited partnership, association, corporation, joint stock company, trust, or other entity (an "acquirer"), whether or not organized under the laws of this state, shall acquire control, either directly or indirectly, of any utility furnishing utility service in this state, without having first obtained the approval of the commission. Any acquisition of control without prior authorization shall be void and of no effect. As used in this subsection, the term "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a utility, whether through the ownership of voting securities, by effecting a change in the composition of the board of directors, by contract or otherwise. Control shall be presumed to exist if any individual or entity, directly or indirectly, owns ten percent (10%) or more of the voting securities of the utility. This presumption may be rebutted by a showing that ownership does not in fact confer control. Application for any approval or authorization shall be made to the commission in writing, verified by oath or affirmation, and be in a form and contain the information as the commission requires. The commission shall approve any proposed acquisition when it finds that the same is to be made in accordance with law, for a proper purpose and is consistent with the public interest. The commission may make investigation and hold hearings in the matter as it deems necessary, and thereafter may grant any application under this subsection in whole or in part and with modification and upon terms and conditions as it deems necessary or appropriate. The commission shall grant, modify, refuse, or prescribe appropriate terms and conditions with respect to every such application within sixty (60) days after the filing of the application therefor, unless it is necessary, for good cause shown, to continue the application for up to sixty (60) additional days. The order continuing the application shall state fully the facts that make continuance necessary. In the absence of that action within that period of time, any proposed acquisition shall be deemed to be approved.

(7) Subsection (6) of this section shall not apply to any acquisition of control of any:

(a) Utility which derives a greater percentage of its gross revenue from business in another jurisdiction than from business in this state if the commission determines that the other jurisdiction has statutes or rules which are applicable and are being applied and which afford protection to ratepayers in this state substantially equal to that afforded such ratepayers by subsection (6) of this section;

(b) Utility by an acquirer who directly, or indirectly through one (1) or more intermediaries, controls, or is controlled by, or is under common control with, the utility, including any entity created at the direction of such utility for purposes of corporate reorganization; or

(c) Utility pursuant to the terms of any indebtedness of the utility, provided the issuance of indebtedness was approved by the commission.

(8) In a proceeding on an application filed pursuant to this section, any interested person, including a person over whose property the proposed transmission line will cross, may request intervention, and the commission shall, if requested, conduct a public hearing in the county in which the transmission line is proposed to be constructed, or, if the transmission line is proposed to be constructed in more than one county, in one of those counties. The commission shall issue its decision no later than ninety (90) days after the application is filed, unless the commission extends this period, for good cause, to one hundred twenty (120) days. The commission may utilize the provisions of KRS 278.255(3) if, in the exercise of its discretion, it deems it necessary to hire a competent, qualified and independent firm to assist it in reaching its decision. The issuance by the commission of a certificate that public convenience and necessity require the construction of an electric transmission line shall be deemed to be a determination by the commission that, as of the date of issuance, the construction of the line is a prudent investment.

(9) If any provision of this section or the application thereof to any person or circumstance is held invalid, the invalidity shall not affect other provisions or applications of this section which can be given effect without the invalid provision or application, and to that end the provisions are declared to be severable.

Effective: July 12, 2006

History: Amended 2006 Ky. Acts ch. 137, sec. 1, effective July 12, 2006. -- Amended 2004 Ky. Acts ch. 75, sec. 1, effective July 13, 2004. -- Amended 2001 Ky. Acts ch. 35, sec. 1, effective June 21, 2001. -- Amended 1998 Ky. Acts ch. 388, sec. 1, effective July 15, 1998. -- Amended 1994 Ky. Acts ch. 144, sec. 1, effective July 15, 1994. – Amended 1992 Ky. Acts ch. 102, sec. 2, effective July 14, 1992. -- Amended 1988 Ky. Acts ch. 12, sec. 3, effective July 15, 1988; ch. 22, sec. 5, effective July 15, 1988; ch. 335, sec. 1, effective July 15, 1988. -- Amended 1986 Ky. Acts ch. 368, sec. 1, effective July 15, 1986. -- Amended 1982 Ky. Acts ch. 82, sec. 5, effective July 15, 1982; ch. 130, sec. 1, effective July 15, 1982. -- Amended 1978 Ky. Acts ch. 379, sec. 6, effective April 1, 1979. -- Amended 1974 Ky. Acts ch. 388, sec. 3. -- Amended 1972 Ky. Acts ch. 83, sec. 5. -- Recodified 1942 Ky. Acts ch. 208, sec. 1, effective October 1, 1942, from Ky. Stat. sec. 3952-25.

FN 94

PSC allows East Kentucky Power to increase electric generating capacity

Last Modified: 5/11/2007

May 2007

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Most planned plants still needed despite loss of prospective major customer

Contact: Andrew Melnykovych 502-564-3940

FRANKFORT, Ky. (May 11, 2007) – The Kentucky Public Service Commission (PSC) is allowing the East Kentucky Power Cooperative (EKPC) to proceed with construction of most of the electric generating facilities the company says are needed to meet rising demand.

In an order issued today, the PSC said the new power plants will be needed despite the fact that the 30,000-customer Warren Rural Electric Cooperative Corp. (RECC) rescinded its contract to purchase its power from EKPC. The decision by Warren RECC triggered a review by the PSC of seven plants it had earlier authorized EKPC to construct.

EKPC will be allowed to complete construction of a coal-burning 278-megawatt plant near Maysville in Mason County and to build a similar generating facility near Trapp in Clark County. The PSC also allowed EKPC to build two of the five 90-megawatt gas-fired turbine generators planned at its Clark County plant. EKPC voluntarily dropped plans for the other three.

In allowing EKPC to continue expanding its generating capacity, the PSC said it was balancing the cost of constructing the plants and possibly creating excess capacity against the costs of canceling or delaying projects already underway and the potential costs to EKPC and its customers should the utility have to purchase power from outside suppliers.

"The circumstances in which EKPC found itself presented the commission with some difficult choices," PSC Chairman Mark David Goss said. "But it appears that a potential excess of generating capacity holds fewer risks for EKPC and its customers than a possible deficit."

In its review, the PSC examined the need for each facility individually.

The first of the facilities to receive a PSC certificate, in September 2005, was the 278-megawatt Spurlock 4 plant in Mason County. Scheduled for completion in April 2009, it was intended to help meet the additional electric demand created when Warren RECC joined the EKPC system in April 2008.

Construction on Spurlock 4 began in June 2006 and EKPC had spent more than $210 million on the plant by November 2006. Warren RECC cancelled its contract with EKPC in December 2006, opting instead to remain in the Tennessee Valley Authority (TVA) system.

In today's order, the PSC said that the power from Spurlock 4 will be needed in order to meet growing demand from the other 16 distribution cooperatives that both own and purchase power from EKPC.

The PSC granted a certificate for the 278-megawatt coal-burning plant in Clark County in November 2006. Known as Smith 1, the plant was designed to serve additional customers throughout EKPC's service territory.

To date, EKPC has invested nearly $50 million in Smith 1. Construction is scheduled to begin later this year, with completion in June 2011, nearly a year later than originally scheduled. That delay reduces the likelihood that EKPC will find itself with excess generating capacity, the PSC said in today's order. Ordering a further delay to Smith 1 would cost EKPC both in contract penalties and in the likely escalation of the cost of the plant, the PSC said.

"In the long run, EKPC's ratepayers and the public interest at large will be best served by allowing EKPC to complete construction" of Smith 1, the PSC said in the order. But EKPC also should make plans for selling excess power if the need arises, the commission added.

Unlike the coal-burning plants, which are used to meet steady demand for power, EKPC's gas turbine generators are used mostly to supply electricity during short periods of peak demand. After Warren RECC decided to remain with TVA, EKPC voluntarily decided to build only two of the five units that the PSC had authorized in November 2006. Citing reasons similar to those in the decision regarding Smith 1, the PSC said the remaining two gas turbine units may proceed. EKPC said it would not reapply for the others until 2011 at the earliest.

Today's order and other documents in the case are available on the PSC Web site. The case number is 2006-00564.

The PSC is an independent agency attached for administrative purposes to the Department of Public Protection in the Environmental and Public Protection Cabinet. It regulates more than 1,500 gas, water, sewer, electric and telecommunication utilities operating in the commonwealth of Kentucky and has approximately 110 employees.

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