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March 30, 2005

RECEIVED
MAR 31 2005
PUBLIC SERVICE COMMISSION

Via Federal Express

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

Re: **BIG RIVERS ELECTRIC CORPORATION**
PSC Administrative Case No. 2005-00090

Dear Ms. O'Donnell:

Enclosed are an original and ten copies of the response of Big Rivers Electric Corporation to the data requests propounded to it in the March 10, 2005, order of the Public Service Commission in the above-styled matter. I certify that a copy of this filing has been served this day on the persons shown on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller
Tyson Kamuf
Counsel for Big Rivers Electric Corporation

JMM/ej
Enclosures

cc: Michael H. Core
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION
OF KENTUCKY

In the Matter of:

AN ASSESSMENT OF	**)**	
KENTUCKY'S ELECTRIC	**)**	**ADMINISTRATIVE**
GENERATION, TRANSMISSION	**)**	**CASE NO. 2005-00090**
AND DISTRIBUTION NEEDS	**)**	

1 2005
SERVICE
MISSION

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE INFORMATION REQUESTS CONTAINED IN THE PUBLIC SERVICE COMMISSION'S ORDER OF MARCH 10, 2005

March 31, 2005

Item 1) Provide a summary description of your utility's resource planning process. This should include a discussion of generation, transmission, demand-side, and distribution resource planning.

Response) Big Rivers is a Kentucky Public Service Commission ("Commission") jurisdictional utility that files an integrated resource plan with the Commission triennially in accordance with the Commission's integrated resource plan regulation, 807 K.A.R. 5:058. Big Rivers' latest integrated resource plan, covering the period through 2017, is on file with the Commission in P.S.C. Case No. 2002-00428. This integrated resource planning process is integral to Big Rivers' overall resource planning process.

Big Rivers regular resource planning process is affected by its unique resource structure. In 1998, Big Rivers entered into a series of transactions with subsidiaries or affiliates of LG&E Energy, LLC. One of those transactions was a lease of Big Rivers' generating assets to Western Kentucky Energy Corp. for a period of approximately 25 years. Another of those transactions establish arrangements under which Big Rivers purchases most of the power required for its needs. Big Rivers also receives power under a contract with the Southeastern Power Administration, pursuant to certain entitlement rights of its member distribution cooperatives.

Big Rivers' regular resource planning process starts with assisting its three member cooperatives in determining their overall power requirements and combining those requirements to arrive at Big Rivers' annual load forecast for the next 15 years.

Big Rivers screens various Demand Side Management (DSM) measures through the appropriate cost/benefit analyses to determine acceptable DSM measures to initiate. Big Rivers also works with its Members' industrial customers who wish to add generation facilities of their own which reduces demand on Big Rivers' supply requirements.

Big Rivers then determines the amount of supply resources required for each year. Those requirements are compared with the resources available under existing, firm power supply contracts to assure sufficient power is available to meet Big Rivers' obligations to its Members.

Big Rivers' transmission-related resource planning is reflected in three-year construction work plans, and long-term (15-year) plans. Transmission planning is a process of making decisions regarding the investments required to reliably meet the power needs of the customers served. Justifications used in any such decisions are based on technical and economic evaluations of options that may be implemented to meet these needs.

Big Rivers follows two RUS recommended criteria for analyzing the adequacy of its transmission system. The first criterion defines single contingency outages to be used in all system planning studies. This criterion serves as the basis for planning and justifying system improvements. The second criterion outlines double contingency outages that can be analyzed to determine the extent of problems encountered on the system under extreme outage or emergency situations. In most double contingency cases, system improvements would not be considered justifiable. However, the type and severity of the system problems encountered is useful information in planning those system improvements that are justifiable. In addition, Big Rivers also analyzes and plans its transmission system to comply with NERC Planning Standards.

System studies are typically run for summer and winter peak conditions. Extreme conditions (peak load forecast with extreme weather) studies are also performed, and may be used to evaluate construction alternatives. The load levels used are consistent with the latest available corporate load forecast (power requirements) for the desired study year. Input from each distribution cooperative is sought when distributing the load forecast to the individual delivery points.

The power flow model interchange, as received from ECAR, is typically based on firm contract sales and purchases. However, firm transmission reservations that are confirmed on the Big Rivers' Open Access Same-Time Information System (OASIS) may also be modeled as part of Big Rivers' scheduled interchange. The model is not adjusted to account for any external transactions not originally included in the ECAR models. Single contingency outages of each line of Big Rivers' system (excluding radial lines) are studies. Single contingencies which yield unacceptable system results are identified. Alternate systems switching arrangements or changes in transformer tap settings are evaluated as the first solution option. If operational changes will not correct the problem, system improvement alternatives are then defined, modeled, and studied to determine their merits in correcting the system problem. Alternatives considered include the modification or expansion of existing facilities as well as new construction. The system improvements that prove to be successful solutions for the system problem are then evaluated based on economics, reliability, practicality, and possible system benefits on a near-term and long-term basis.

Costs and revenues associated with the load, power supply, transmission, and DSM measures are then incorporated into the analysis to arrive at the least cost plan for Big Rivers in the planning horizon.

Witness) C. William Blackburn
Travis Housley, P.E.
David Crockett, P.E.

Item 2) Are new technologies for improving reliability, efficiency and safety investigated and considered for implementation in your power generation, transmission and distribution system?

a) If yes, discuss the new technologies that were considered in the last 5 years and indicate which, if any, were implemented.

b) If no, explain in detail why new technologies are not considered.

Response) **Power Generation** - No. Big Rivers' generating plants are operated by another entity and Big Rivers does not have control over new technologies investigated or considered for power generation.

Transmission - Yes. Over the past two years or so, Big Rivers and its three member distribution cooperatives have jointly been involved with the purchase of geo-spatial information system (GIS) software and the development of system databases and data retrieval options. The utilization of this technology is intended to promote efficiencies through quick access of system data and other records by both field and office personnel and to promote safety for field personnel involved in maintenance and operations activities through precise geo-spatial locators.

Big Rivers is currently involved in the replacement of its analog microwave equipment with a digital microwave system scheduled for completion later in year 2005, which will enhance data exchange between Big Rivers and its Members and enhance Big Rivers' operational capabilities.

Distribution - No. Big Rivers' three member distribution cooperatives own and operate their own distribution systems.

Witness) C. William Blackburn
Travis Housley, P.E.
David G. Crockett, P.E.

Item 3) Is your utility researching any renewable fuels for generating electricity?

a) If so, what fuels are being researched?

b) What obstacles need to be overcome to implement the new fuels?

Response) No. As noted in Big Rivers' response to Data Request 1, Big Rivers has leased its generating units to Western Kentucky Energy Corp., which makes all fuel purchasing decisions for those units, and Big Rivers purchases its principal power requirements under contracts with LG&E Energy Marketing, and the Southeastern Power Administration. Big Rivers has cooperated with a paper mill to facilitate its generation of power from biomass, and is investigating sources from which it can purchase small amounts of "Green Power". Big Rivers' Power Supply is furnished through power purchase contracts and Big Rivers does not have control over fuel selection.

Witness) C. William Blackburn

Item 4) Provide actual and weather-normalized annual native load energy sales for calendar years 2000 through 2004. Provide actual annual off-system energy sales for this same period disaggregated into full requirements sales, firm capacity sales, and non-firm or economy energy sales. Off-system sales should be further disaggregated to show separately those sales in which your utility acts as a reseller, or transporter, in a power transaction between two or more other parties.

Response) Table #4 shows the annual native and off-system sales for 2000 through 2004 and the further breakdowns as applicable to Big Rivers. Big Rivers supplies power to be used for back-up of the Willamette cogeneration facility. However, this back-up power is received by Big Rivers through a separate back-up power supply agreement and is not included in Table #4.

Please note that "TOTAL NATIVE LOAD & OFF-SYSTEM ENERGY SALES" category in Table #4 represents energy associated with Big Rivers' power supply only. The category "LOAD NOT SERVED BY BIG RIVERS" represents additional energy that is on the Big Rivers' transmission system. The "Control Area" load is composed of energy provided by others to Kenergy Corp. for resale to the aluminum smelters as well as part of the load for the City of Henderson and Big Rivers acts as the "transporter" for control area load. In addition, Big Rivers acts as transporter for energy, generated from Big Rivers as well as HMP&L Station Two units, sold off-system by LG&E Energy Marketing. Big Rivers does not track megawatt hours for these transports.

Witness) C. William Blackburn
Travis Housley, P.E.
David Crockett, P.E.

Table #4

BIG RIVERS ELECTRIC CORPORATION

	TOTAL NATIVE LOAD & OFF-SYSTEM ENERGY SALES (MWh)					LOAD NOT SERVED BY BIG RIVERS	
	Native Load		Off-System				
	Total Energy		Off-System Energy			Control Area Load	Wheeling
Year	Actual	Weather Normalized	Firm	Non-Firm	Reseller		
2000	3,540,662	3,544,203	651,217	471,422	-	6,336,368	35,738
2001	3,334,698	3,366,798	782,230	196,219	-	7,002,269	26,907
2002	3,156,645	3,184,021	818,343	178,973	-	7,187,740	59,478
2003	3,087,530	3,011,717	529,612	965,803	31,430	7,324,866	127,809
2004	3,158,698	3,091,785	959,696	873,770	35,191	7,349,341	91,096

Note 1: Big Rivers off-system sales are market blocks of power. Therefore, the off-system sales cannot be weather normalized.

Item 5) Provide actual and weather-normalized annual coincident peak demands for calendar years 2000 through 2004 disaggregated into (a) native load demand, firm and non-firm; and (b) off-system demand, firm and non-firm.

Response) Table #5 shows the actual and weather normalized native load demand and the off-system annual coincident demand for 2000 through 2004. Big Rivers sells its surplus power into the market and therefore the off-system sales cannot be weather normalized. Please see second paragraph of the response to Item #4 for additional explanation.

Witness) C. William Blackburn
Travis Housley, P.E.
David Crockett, P.E.

TABLE #5

BIG RIVERS ELECTRIC CORPORATION

TOTAL NATIVE LOAD & OFF-SYSTEM COINCIDENT PEAK DEMANDS (MW)					Load Not Served By Big Rivers	
	Native Load		Off-System Sales			
	All Firm					
	Peak Demand		Off-System Demand		Control Area Load	Off System Firm(OPC)
Year	Actual	Weather Normalized	Firm	Non-Firm		
2000	645	661	50	0	717	103
2001	598	575	35	0	799	57
2002	603	610	91	0	816	-----
2003	585	523	105	60	893	-----
2004	604	602	90	73	871	-----

Note: Big Rivers off-system sales are market blocks of power. Therefore, the off-system sales cannot be weather normalized.

Item 6) Provide a summary of monthly power purchases for calendar years 2000 through 2004 disaggregated into firm capacity purchases required to serve native load, economy energy purchases, and purchases in which your utility acts as a reseller, or transporter, in a power transaction between two or more other parties. Include the average cost per megawatt-hour for each purchase category.

Response) Table #6 header "Annual Power Purchases by Big Rivers" shows energy purchases, both firm and economy, which were recorded by Big Rivers' Power Supply Department for 2000 through 2004. Table #6 header "Load Not Served By Big Rivers" also shows additional energy purchased for the control area by others and it shows the quantity of power wheeled for 2001 through 2004.

Witness) C. William Blackburn
Travis Housley, P.E.
David Crockett, P.E.

TABLE #6

BIG RIVERS ELECTRIC CORPORATION

	Annual Power Purchases by Big Rivers						Load Not Served By Big Rivers	
	Native Load Firm Capacity		Economy Energy		Resell Energy			
Year	MWh	Average $/MWh	MWh	Average $/MWh	MWh	Average $/MWh	Control Area Load MWh	Wheeling MWh
Jan-00	325,602	$19.18	31,042	$17.69	-	$0.00	1,040	3,718
Feb-00	282,421	$19.11	29,721	$15.00	-	$0.00	720	1,242
Mar-00	280,644	$19.15	45,277	$15.55	-	$0.00	720	5,794
Apr-00	257,304	$19.22	68,758	$17.05	-	$0.00	720	190
May-00	275,820	$19.25	69,241	$19.25	-	$0.00	1,040	7,380
Jun-00	306,549	$19.46	37,371	$16.67	-	$0.00	2,640	4,573
Jul-00	335,281	$19.43	40,416	$16.74	-	$0.00	2,640	3,953
Aug-00	342,741	$19.34	38,259	$13.66	-	$0.00	2,640	3,852
Sep-00	280,776	$19.09	45,791	$16.46	-	$0.00	2,080	3,682
Oct-00	265,165	$19.09	80,112	$18.55	-	$0.00	2,000	582
Nov-00	287,417	$19.08	76,797	$16.60	-	$0.00	1,040	287
Dec-00	357,781	$19.05	45,691	$14.37	-	$0.00	1,040	485
Jan-01	317,520	$19.08	19,974	$18.73	-	$0.00	55,473	3,410
Feb-01	263,461	$19.10	17,864	$18.25	-	$0.00	59,184	1,396
Mar-01	279,274	$19.10	16,652	$18.43	-	$0.00	53,448	187
Apr-01	244,873	$19.60	14,995	$18.70	-	$0.00	51,998	2,110
May-01	254,537	$19.56	21,332	$18.79	-	$0.00	44,592	6,084
Jun-01	257,906	$19.54	26,753	$18.52	-	$0.00	48,325	228
Jul-01	284,955	$19.46	23,742	$18.30	-	$0.00	45,267	3,744
Aug-01	291,742	$19.40	21,412	$18.67	-	$0.00	47,512	5,294
Sep-01	233,704	$19.29	19,860	$18.79	-	$0.00	53,675	2,211
Oct-01	221,669	$19.33	15,668	$13.28	-	$0.00	46,683	1,297
Nov-01	214,439	$19.16	17,085	$19.44	-	$0.00	46,181	1,174

TABLE #6

BIG RIVERS ELECTRIC CORPORATION

Year	Annual Power Purchases by Big Rivers: Native Load Firm Capacity MWh	Native Load Firm Capacity Average $/MWh	Economy Energy MWh	Economy Energy Average $/MWh	Resell Energy MWh	Resell Energy Average $/MWh	Load Not Served By Big Rivers: Control Area Load MWh	Wheeling MWh
Dec-01	248,259	$19.17	23,434	$12.32	-	$0.00	60,048	171
Jan-02	286,477	$19.29	34,612	$15.62	-	$0.00	45,791	1,762
Feb-02	252,369	$19.30	-	$18.83	-	$0.00	37,741	-
Mar-02	265,170	$19.30	3,226	$19.47	-	$0.00	38,381	1,548
Apr-02	230,982	$19.81	935	$19.65	-	$0.00	59,175	4,570
May-02	238,002	$19.77	5,483	$18.61	-	$0.00	65,682	150
Jun-02	287,165	$19.65	9,672	$18.60	-	$0.00	63,799	-
Jul-02	327,044	$19.57	8,439	$18.77	-	$0.00	61,584	22,286
Aug-02	312,927	$19.55	6,672	$18.69	-	$0.00	59,546	20,958
Sep-02	265,167	$19.43	4,437	$19.13	-	$0.00	46,139	3,154
Oct-02	234,150	$19.49	10,148	$19.01	-	$0.00	87,468	800
Nov-02	172,485	$19.41	15,839	$19.12	-	$0.00	93,872	4,220
Dec-02	284,708	$19.33	37,038	$18.53	-	$0.00	63,125	794
Jan-03	311,451	$19.62	119,124	$19.45	1,940	$37.91	73,905	6,385
Feb-03	270,205	$19.61	120,918	$19.21	170	$30.04	72,237	4,400
Mar-03	244,209	$19.43	165,346	$19.58	1,701	$34.58	28,580	41,308
Apr-03	221,207	$19.42	157,508	$19.33	1,079	$47.32	23,719	3,998
May-03	219,859	$19.42	128,532	$18.97	274	$20.57	50,409	1,810
Jun-03	240,536	$19.80	109,226	$18.61	991	$21.39	64,190	5,651
Jul-03	297,623	$19.64	101,729	$18.99	891	$40.06	37,584	31,376
Aug-03	301,425	$19.77	114,220	$19.10	2,151	$30.90	61,619	19,775
Sep-03	241,407	$19.41	100,511	$18.83	5,146	$28.34	36,267	2,655
Oct-03	225,385	$19.58	127,054	$18.98	1,024	$31.58	17,365	3,251

TABLE #6

BIG RIVERS ELECTRIC CORPORATION

	Annual Power Purchases by Big Rivers						Load Not Served By Big Rivers	
	Native Load Firm Capacity		Economy Energy		Resell Energy			
Year	MWh	Average $/MWh	MWh	Average $/MWh	MWh	Average $/MWh	Control Area Load MWh	Wheeling MWh
Nov-03	233,748	$19.58	124,618	$19.29	1,712	$38.24	37,807	6,433
Dec-03	280,476	$19.59	116,728	$20.70	14,351	$35.31	49,993	2,290
Jan-04	301,481	$20.28	136,767	$20.91	14,205	$41.87	45,978	7,421
Feb-04	269,384	$20.13	140,923	$19.36	30	$34.50	40,869	16,193
Mar-04	244,507	$19.83	178,696	$19.73	4,605	$36.68	21,194	2,790
Apr-04	221,929	$19.88	181,090	$19.36	44	$30.11	23,545	32,735
May-04	256,744	$20.11	168,531	$19.27	185	$22.59	30,149	5,983
Jun-04	272,105	$19.89	125,446	$19.18	0	$0.00	20,319	4,700
Jul-04	292,529	$20.11	132,086	$20.26	6,480	$45.94	30,428	6,700
Aug-04	278,782	$20.21	145,039	$19.05	0	$0.00	32,687	6,700
Sep-04	256,251	$19.95	142,164	$19.29	1,200	$32.50	35,086	2,400
Oct-04	228,447	$19.70	183,385	$19.49	1,600	$43.50	11,490	2,100
Nov-04	237,388	$19.73	182,272	$19.42	42	$34.00	20,746	1,520
Dec-04	299,151	$19.73	132,367	$20.89	6,800	$41.14	16,694	1,960

Item 7) Provide the most current base case and high case demand and energy forecasts for the period 2005 through 2025, if available. If the current forecast does not extend to 2025, provide forecast data for the longest forecast period available. The information should be disaggregated into (a) native load, firm and non-firm demand; and (b) off-system load, both firm and non-firm demand.

Response) Table #7 tabulates the forecasted base case and high case demand and energy in the associated demand breakdowns as requested. Big Rivers does not have any native load non-firm demand.

Please note that this table represents power that was scheduled through Big Rivers' Power Supply and does not represent the activity of others in the Big Rivers' control area. Big Rivers does not have the data to supply information regarding the remaining power that flows through the control area.

Witness) C. William Blackburn

TABLE #7

BIG RIVERS ELECTRIC CORPORATION

TOTAL NATIVE LOAD & OFF-SYSTEM LOADS
BASE & HIGH CASE FORECASTS

	Native Load*				Off-System Sales**			
	Base Case		High Case		Base Case		High Case	
					FIRM	NON-FIRM	FIRM	NON-FIRM
Year	Demand (MW)	Energy (MWh)	Demand (MW)	Energy (MWh)	Demand (MW)	Demand (MW)	Demand (MW)	Demand (MW)
2005	634	3,215,084	650	3,341,928	80	60	80	60
2006	644	3,262,191	661	3,390,360	85	30	85	30
2007	656	3,316,135	673	3,445,723	50	0	50	0
2008	667	3,365,334	685	3,496,298	50	0	50	0
2009	679	3,419,567	697	3,551,958	50	0	50	0
2010	690	3,470,083	712	3,618,623	50	0	50	0
2011	703	3,528,118	728	3,694,277	50	0	50	0
2012	715	3,581,000	743	3,765,510	50	0	50	0
2013	728	3,639,371	760	3,843,171	50	0	50	0
2014	740	3,694,234	776	3,918,180	50	0	50	0
2015	754	3,756,811	794	4,001,923	50	0	50	0
2016	766	3,814,448	811	4,081,575	50	0	50	0
2017	780	3,877,847	829	4,168,085	50	0	50	0

End of current forecast

*Big Rivers does not have any non-firm native load.

Item 8) Provide the target reserve margin currently used for planning purposes, stated as a percentage of demand, and a summary of your utility's most recent reserve margin study. If this target reserve margin has changed since 2002, provide the prior target reserve margin and explain the reasons for the change. If the target reserve margin is expected to be reevaluated in the next 3 years, explain the reasons for the reevaluation.

Response) When Big Rivers operated its own generation, a generation planning reserve margin was calculated using output data from statistical calculations for loss of load probabilities and loss of generation expectations for various states of the generators.

Big Rivers is now a unique utility in Kentucky because it leases all of its generation capacity and purchases most of its power requirements as liquidated damages firm (LD firm) power. Reserve margins are calculated from historical generator operating characteristics and various states of generator outages. Big Rivers' native load is now supplied with LD firm power from LG&E Energy Marketing and firm power from the Southeastern Power Administration. Because of this, Big Rivers has no formal planning reserve margin.

Witness) C. William Blackburn

Item 9) For the period 2005 through 2025, provide projected reserve margins stated in megawatts ("MW") and as a percentage of demand. Identify projected deficits and current plans for addressing these deficits.

Response) Please see response to Item #7 relative to reserve margins. Big Rivers has no projected deficits in its projected planning horizon through 2017.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE INFORMATION REQUESTS CONTAINED IN THE PUBLIC SERVICE COMMISSION'S ORDER OF MARCH 10, 2005
ADMINISTRATIVE CASE NO. 2005-00090
March 21, 2005

Item 10) Provide the following information for every generation station operated in Kentucky.

a) Name
b) Location (including county).
c) Number of units.
d) Date in service for each unit.
e) Type of fuel for each unit.
f) Net rating (MW) for each unit.
g) Emission control equipment in service (list by type).
h) Date emission control equipment in service.

Response) Big Rivers Electric Corporation entered into various agreements with Western Kentucky Energy Corp. ("WKE") and with WKE Station Two Inc., ("WKE Station Two") which require the two companies to operate and maintain Big Rivers' generating stations and Henderson Municipal Power and Light's Station Two generating stations respectively. The requested information is attached as page 2 of 2. Big Rivers is forwarding a copy of this response to Western Kentucky Energy Corp. and WKE Station Two Inc., Attention: Mr. Robert Toerne, Contract Manager, Western Kentucky Energy Corp., P.O. Box 1518, Henderson, KY 42419-1518.

Witness) David Spainhoward

Big Rivers Electric Corp Generation Station Summary

Name	Location	Units	Capacity net MW	Commercial Date	Design Coal	Emission controls	Date in-service
Reid	near Sebree, Webster Co.	one	65	Jan-66	Hi Sulfur Bituminous	precipitators	(original equip.)
						NG/coal co-firing system *	2004
Coleman	near Hawesville, Hancock Co.	one	150	Nov-69	Hi Sulfur Bituminous	precipitators	(original equip.)
		two	150	Sep-70		Lo-NOx burners	1993
		three	155	Jan-72		over-fire air systems	2004
						FGD system	(under constr.)
HMP&L Station Two	near Sebree, Henderson Co.	one	153	Jun-73	Hi Sulfur Bituminous	precipitators	(original equip.)
		two	159	Apr-74		Lo-NOx burners	1994
						SCR's **	2004
						FGD system	1995
Reid	near Sebree, Webster Co.	CT ***	65	Mar-76	fuel oil	NG fuel conversion *	2004
Green	near Sebree, Webster Co.	one	231	Dec-79	Hi Sulfur Bituminous	precipitators	(original equip.)
		two	223	Jan-81		Lo-NOx burners	(original equip.)
						coal re-burn systems	2004
						FGD system	(original equip.)
Wilson	near Centertown, Ohio Co.	one	420	Nov-86	Hi Sulfur Bituminous	precipitators	(original equip.)
						Lo-NOx burners	(original equip.)
						SCR's **	2004
						FGD system	(original equip.)

* "NG" = natural gas
** "SCR" = Selective Catalytic Reduction
*** "CT" = combustion turbine

Item 11) Provide a summary of any planned base load or peaking capacity additions to meet native load requirements in the years 2005 through 2025. Include capacity additions by the utility, and those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.

Response) Currently, Big Rivers has no plans to add base load or peaking capacity in the years 2005 through 2017 of its planning horizon.

Witness) C. William Blackburn

Item 12) What is the estimated capital cost per KW and energy cost per kWh for new generation by technology?

Response) Since Big Rivers has no immediate plans to add generation capacity, it has not investigated these capital costs.

Witness) C. William Blackburn

Item 13) If current plans for addressing projected capacity deficits include the addition of gas-fired generation, describe the extent to which fluctuations in natural gas prices have been incorporated into these plans. Explain how fluctuations in natural gas prices may have altered the results of previous plans.

Response) Big Rivers presently has no plans for adding gas-fired generation.

Witness) C. William Blackburn

Item 14) Provide a summary of any permanent reductions in utilization of generation capacity due to Clean Air Act compliance from 2000 through 2004. Identify and describe any forecasted reductions during the 2005 through 2025 period.

Response) Big Rivers Electric Corporation entered into various agreements with Western Kentucky Energy Corp. ("WKE") and with WKE Station Two, Inc., ("WKE Station Two") which require the two companies to operate and maintain Big Rivers' generating stations and Henderson Municipal Power and Light's Station Two generating stations respectively. The requested information cannot be provided by Big Rivers without written approval from WKE and WKE Station Two. Big Rivers is forwarding a copy of this response to Western Kentucky Energy Corp. and WKE Station Two Inc., Attention: Mr. Robert Toerne, Contract Manager, Western Kentucky Energy Corp., P.O. Box 1518, Henderson, KY 42419-1518.

Witness) David Spainhoward

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE INFORMATION REQUESTS CONTAINED IN THE PUBLIC SERVICE COMMISSION'S ORDER OF MARCH 10, 2005
ADMINISTRATIVE CASE NO. 2005-00090
March 31, 2005

Item 15) Provide a summary of all forced outages and generating capacity retirements occurring during the years 2000 through 2004.

Response) Big Rivers Electric Corporation entered into various agreements with Western Kentucky Energy Corp., ("WKE") and with WKE Station Two Inc., ("WKE Station Two") which require the two companies to operate and maintain Big Rivers' generating stations and Henderson Municipal Power and Light's Station Two generating stations respectively. The requested information regarding forced outages cannot be provided by Big Rivers without written approval from WKE and WKE Station Two. Big Rivers is forwarding a copy of this response to Western Kentucky Energy Corp. and WKE Station Two Inc., Attention: Mr. Robert Toerne, Contract Manager, Western Kentucky Energy Corp., P.O. Box 1518, Henderson, KY 42419-1518. There was no generating capacity retired during 2000 through 2004.

Witness) David Spainhoward

Item 16) Provide a summary of the utility's plans for the retirement of existing generating capacity during the 2005 through 2025 period.

Response) Big Rivers Electric Corporation entered into various agreements with Western Kentucky Energy Corp., ("WKE") and with WKE Station Two Inc., ("WKE Station Two") which require the two companies to operate and maintain Big Rivers' generating stations and Henderson Municipal Power and Light's Station Two generating stations respectively. Big Rivers is forwarding a copy of this response to Western Kentucky Energy Corp. and WKE Station Two Inc., Attention: Mr. Rob Toerne, Contract Manager, Western Kentucky Energy Corp., P.O. Box 1518, Henderson, KY 42419-1518. There are no retirements of generating capacity planned for the period 2005 through 2025.

Witness) David Spainhoward

Item 17) Provide a summary description of your utility's existing demand-side management ("DSM") programs, which includes:

a) Annual DSM budget,

b) Demand and energy impacts.

c) The currently scheduled termination dates for the programs.

Response) Big Rivers Electric Corporation provides financial participation and technical support to the distribution cooperatives for the following programs. Currently not all distribution cooperatives are offering these programs:

1. Add-on heat pump incentive of $90 per ton installed capacity for the replacement of an air conditioning system with a heat pump when the primary heating system is fossil fuel. The heat pump must be a 12 SEER or higher.

2. All Electric Touchstone Energy Home incentive ranges between $265 per ton if heating and cooling with an air-source heat pump and $225 per ton for ground source heat pump based on heat loss / heat gain analysis. The incentive payment requires the new home be located within 1,200 feet of a natural gas distribution line and be constructed to energy efficient specifications.

3. Electric water heater incentive, currently at $300 per installation requires the member replace an existing fossil fuel water heater with an electric water heater.

The 2005 budget for the above listed incentives is $136,950; 2006 - $174,250; 2007 and following years $255,500.

Demand and energy impacts: The add-on heat pump will add no cooling season demand or energy consumption and will likely result in a modest reduction since the new HVAC equipment will be more efficient. Additional demand and energy use will replace the fossil fuel consumption during moderate heating load. The estimated demand increase per unit for heating season operating periods is 1.06 kW and additional kWh use for the heating season is 2,484 kWh per home.

The Touchstone Energy Home will add no HVAC cooling season demand and may result in a net reduction in the cooling season demand and energy consumption since the construction requirements and HVAC equipment will likely be more efficient than the alternatives. An additional average water heating demand of 1.16 kW and an average of 2.01 kW demand for HVAC will result for a total of 3.17 kW per home. An estimated additional annual kWh use of 8,482 per home will replace natural gas consumption per home.

The electric water heater will add an additional average 1.16 kW demand and approximately 4,224 kWh directly replacing fossil fuel per unit.
There is currently no scheduled termination date for any of the end-use initiatives listed in this answer

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 residential, commercial and industrial services through Jackson Purchase Energy Corporation, Kenergy, and Meade County RECC:

Energy Efficiency and Safety Workshops. Jackson Purchase Energy Corporation, Meade County RECC and Kenergy provide educational workshops for commercial and institutional member employees and school students on energy saving devices and techniques and safety. The training takes place at the member's facilities.

Energy-Use Assessment. This assessment or energy audit assists members in improving energy efficiency by using the utility's expertise in energy delivery and use combined with a customer's knowledge to identify opportunities to lower energy costs and improve efficiency.

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

Customer Billing Review. Customer service staff from Kenergy, Meade County RECC and Jackson Purchase Energy Corporation will visit a customer's facility to explain and answer questions about billing documents and rate structures.

Commercial Lighting Evaluation. Cooperative staff evaluate the necessary facility and security lighting to provide productive and safe light levels. Meade County RECC, Jackson Purchase Energy Corporation and Kenergy can also provide leased lighting options.

Power Factor Correction Assistance. Jackson Purchase Energy Corporation, Meade County RECC and Kenergy have assisted dozens of commercial and industrial customers to correct low power factor, thus saving those customers hundreds of thousands of dollars per year. A relative minority of customers experience low power factor, but when it does occur, this can be very costly. The cooperatives provide engineering assistance and will work with a customer's electric contractor.

Power Quality Assessment. Members who experience equipment damage or productivity losses as a result of power quality problems can contact their cooperative commercial and industrial service representative. Cooperative staff assists to identify the source of the problem whether it is inside the facility, on the power system or a result of a neighboring customer and help fix the problem.

Energy Use Summary. Meade County RECC, Kenergy and Jackson Purchase Energy Corporation 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. Online bill display is also available to residential, commercial and industrial members.

Customized Billing Services. Recent changes in bill printing make available to cooperative members the ability to receive multiple bills in the same mailing.

Residential energy auditing. At the cooperatives request, Big Rivers' staff provide telephone and onsite residential energy audits and Energy Star rating for new construction.

Weyerhaeuser Generation. Big Rivers has worked with Weyerhaeuser (formerly Willamette) to allow them to construct a generator at their paper plant and use bio-mass and waste steam to generate part of their electrical needs. This has reduced Big Rivers' demand by 50 MW. There are no plans to eliminate this arrangement. However, backup power to provide power when the generator is off or has reduced output is handled through a backup agreement with Reliant Energy. This agreement currently runs through March of 2011.

Distribution Cooperative Communication Initiatives

Kenergy offers educational and informative brochures, magazine articles, and television and radio commercials relating to energy efficiency topics. The 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.

Jackson Purchase Energy Corporation 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"; a USDOE publication that compiles ideas and measures that will help reduce energy usage and save money for members. Magazine articles are also posted on the cooperative's web site with ideas on how to save energy (for example, by providing shade trees around a home to reduce peak air-conditioning loads). The Jackson Purchase Energy Corporation website also provides a link to the electronic copy of the Energy Savers pamphlet.

Meade County RECC provides energy efficiency informational brochures on geothermal heating and cooling systems, and 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 (i.e. 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.

Witness) C. William Blackburn
Russell L. Pogue

Item 18) Provide your utility's definition of "transmission" and "distribution".

Response) Big Rivers defines "transmission" as all line and station facilities from its interconnection points with neighboring utility systems and interconnections with generation facilities within its control area to the high voltage connection point at the distribution delivery stations and direct-serviced industrial customer stations of its three member cooperatives. Big Rivers defines "distribution" as all line and station facilities from the transmission interconnect point at the member cooperative distribution stations and direct-served industrial customer stations to the connection point of the retail customer facilities. The Big Rivers transmission system consists of facilities operated at 345 kV, 161 kV, and 138 kV in its bulk delivery system and facilities operated at 69 kV in its sub-transmission delivery system, which is in conformity to ANSI Table 14-1. Big Rivers considers all facilities operated at voltages below 69 kV as distribution facilities. Big Rivers owns no distribution facilities.

Witness) Travis D. Housley, P.E.
David Crockett, P.E.

BIG RIVERS ELECTRIC CORPORATION
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March 31, 2005

Item 19) Identify all utilities with which your utility is interconnected and the transmission capacity at all points of interconnection.

Response) The listing of utilities with whom Big Rivers has interconnections and the individual summer and winter capacity ratings for those interconnections are included in the attached Table #19.

Witness) Travis D. Housley, P.E.
David G. Crockett

Company	Location	Summer MVA Rating[1]	Winter MVA Rating[1]
HMP&L	Reid EHV-Sub 4	254	254
	Reid/Hend. Co.-Sub 4	254	254
	Geneva/Weav-Sub 4 69 kV	40	40
	Reid-Sub 7 69 kV	63	63
	Henderson Co.-Sub 3 69 kV	63	63
	Zion Tap-Sub 6 69 kV	63	63
	HMP&L Total	737	737
Hoosier	Coleman-Newtonville	265	335
LG&E[2]	New Hardinsburg Transformer	224	224
	Wilson-Green River	530	558
	Centertown 69 kV Back-up[3]	---	---
	LG&E Total	754	782
Vectren	Henderson Co.-AB Brown	224 (transformer)	224
SIPC	Livingston Co.-Renshaw	223	223
	Morganfield - Gallatin 69 kV	36	42
	Southern Illinois Power Cooperative Total	259	265
TVA	Livingston Co.-Barkley	223	223
	Hopkins Co.-Barkley	265	335
	Lyon Co.-Barkley 69 kV	35	40
	Livingston Co.-Marshall	223	223
	McCracken Co.-Marshall	265	335
	McCracken Co.-L Tap(Shawnee)	335	335
	New Hardinsburg-Paradise	265	335
	TVA Total	1611	1826

[1] Maximum rating.
[2] A single transformer interconnects Big Rivers with LG&E at New Hardinsburg. Two LG&E lines terminate at New Hardinsburg. The transformer rating is considered the total contract path at this location.
[3] The rating of this normally open back-up circuit is based on excess LG&E system capacity and is determined at the time of use.

Item 20) Provide the peak hourly MW transfers into and out of each interconnection for each month of the last 5 years. Provide the date and time of each peak.

Response) The peak hourly MW transfer into and out of each of Big Rivers' interconnections by month for years 2000 through 2004 are included in the attached tables identified as Table 20.

Witness) Travis D. Housley, P.E.
David G. Crockett

Table 20

2000	Barkley/Hopkins		Shawnee		Marshall/Livingston		Marshall/ Bryan Rd.		SIPC/Galatin		SIPC/Livingston		Wilson/Green River	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	0	199 @ 1500 1/30	157 @ 0600 1/28	0	27 @ 0800 1/28	72 @ 0100 1/15	45 @ 1200 1/12	98 @ 0200 1/28	4 @0300 1/2	24 @ 1500 1/29	134 @ 1400 1/22	34 @ 1800 1/12	0	437 @ 2400 1/31
February	0	188 @ 1500 2/4	151 @ 0900 2/6	0	22 @ 0800 2/17	61 @ 0400 2/5	18 @ 1200 2/26	88 @ 0600 2/6	4 @ 1500 2/17	29 @ 0200 2/11	133 @ 0100 2/6	3 @ 0800 2/18	0	415 @ 1000 2/1
March	0	205 @ 1200 3/25	91 @ 0400 3/17	16 @ 0700 3/27	0	120 @ 1500 3/23	60 @ 0700 3/27	45 @ 0100 3/13	4 @ 0100 3/1	28 @ 2000 3/10	141 @ 1400 3/8	7 @ 0700 3/15	0	368 @ 1200 3/8
April	39 @ 0900 4/12	167 @ 0900 4/1	104 @ 0700 4/5	42 @ 1200 4/28	0	120 @ 1500 4/16	82 @ 1200 4/28	50 @ 0600 4/5	6 @ 0100 4/26	26 @ 1100 4/3	119 @ 0900 4/1	3 @ 1300 4/18	0	368 @ 0800 4/28
May	20 @ 1600 5/9	246 @ 1300 5/23	261 @ 0900 5/13	0	30 @ 1900 5/8	137 @ 1500 5/25	0	210 @ 0800 5/13	18 @ 1600 5/9	26 @ 1300 5/23	228 @ 1500 5/13	0	0	425 @ 1000 5/23
June	0	186@1900 6/8	259@1400 6/2	0	28@0100 6/1	49@2000 6/8	0	174@1400 6/2	6@1300 6/11	24@1500 6/8	166@1700 6/16	0	0	392@1500 6/25
July	5@0400 7/13	215@1400 7/8	216@1400 7/20	0	11@1800 7/11	55@0700 7/20	62@1000 7/15	143@1500 7/20	2@0200 7/26	28@1400 7/8	140@0800 7/19	0	0	420@1700 7/8
August	0	203@1700 8/5	174@1200 8/6	0	32@1000 8/28	65@1200 8/4	1@2000 8/30	0	6@1200 8/29	28@1700 8/12	121@1100 8/5	0	0	431@1600 8/8
September	0	210@1800 9/22	128@1400 9/4	19@0300 9/30	1@0900 9/22	74@1400 9/28	52@0400 9/30	66@0800 9/6	0	34@1500 9/11	138@1600 9/20	0	0	463@1700 9/21
October	0	219@1500 10/9	145@1600 10/5	25@0300 10/1	0	99@1700 10/11	56@0700 10/1	78@1400 10/5	10@2400 10/15	32@0900 10/9	128@1500 10/5	0	0	390@1500 10/5
November	0	231@1400 11/19	138@2300 11/30	0	11@1200 11/25	107@1500 11/25	69@2100 11/20	91@0100 11/30	16@1400 11/25	24@1300 11/3	161@0600 11/30	0	0	337@1000 11/17
December	13@0600 12/23	176@1100 12/1	161@0500 12/30	0	30@1900 12/21	63@0500 12/9	0	105@2300 12/31	26@2400 12/28	18@2100 12/12	157@0100 12/1	18@2000 12/17	0	351@2300 12/6

Table 20

2000	KU/Hardinsburg		Hoosier		Vectren		LGEE/Cloverport		Paradise		Barkley/Livingston		Barkley/Lyon	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	37 @ 1300 1/30	158 @1800 1/18	195 @ 2200 1/30	119 @ 1800 1/18	150 @ 2100 1/3	4 @ 1700 1/9	103 @ 1200 1/27	0	149 @ 1800 1/18	196 @ 1500 1/30	60 @ 0800 1/11	103 @ 0200 1/28	10 @ 1900 1/18	9 @ 1600 1/30
February	52 @ 0100 2/6	66 @ 1800 2/3	199 @ 1400 2/3	14 @ 0600 2/14	190 @ 1200 2/29	28 @ 0200 2/11	102 @ 0700 2/6	0	62 @ 1900 2/14	194 @0100 2/1	45 @ 0800 2/14	80 @ 1300 2/1	11 @ 1900 2/4	8 @ 1200 2/1
March	99 @ 1500 3/30	96 @ 0800 3/3	254 @ 1500 3/23	0	174 @ 1200 3/8	22 @ 0100 3/28	121 @ 1700 3/30	0	86 @ 0800 3/3	185 @ 1700 3/27	63 @ 1100 3/20	63 @ 1100 3/20	10 @ 1900 3/11	0
April	114 @ 0300 4/23	94 @ 0900 4/12	181@ 0200 4/15	27 @ 0600 4/28	140 @ 0700 4/27	74 @ 1100 4/22	94 @ 1800 4/5	22 @ 0800 4/12	247 @ 0900 4/12	188 @ 1600 4/3	100 @ 1100 4/7	27 @ 0600 4/21	8 @ 0700 4/5	0
May	99 @ 1300 5/23	104 @ 1300 5/5	198 @ 1600 5/20	107 @ 1100 5/9	134 @ 1500 5/11	62 @ 0400 5/22	119 @ 1400 5/25	2 @ 2200 5/5	137 @ 2100 5/5	236 @ 1700 5/18	47@ 2200 5/1	107 @ 1500 5/18	11 @ 1800 5/31	0
June	90 @ 1300 6/4	72 @ 0800 6/10	177 @ 0900 6/22	30 @ 0300 6/20	134 @ 1600 6/21	66 @ 0300 6/30	122 @ 1100 6/3	0	57@0200 6/8	245@100 6/3	0	109@1300 6/2	12@1600 6/10	5@0900 6/14
July	92@0900 7/14	51@0700 7/5	215@2100 7/15	12@0700 7/31	194@1900 7/15	24@0600 7/2	122@0900 7/14	0	63@0200 7/3	243@1000 7/12	2@2000 7/8	80@0200 7/12	7@0400 7/13	8@1500 7/8
August	89@1400 8/27	47@0700 8/1	201@1100 8/17	0	154@1600 8/8	104@1000 8/28	117@1400 8/27	0	25 @0400 8/1	214@1200 8/25	42@1600 8/30	57@0600 8/25	7@1600 8/1	8@1100 8/18
September	71@1700 9/22	71@0600 9/19	201@1800 9/23	25@0800 9/1	206@1900 9/11	28@0500 9/26	106@0900 9/21	0	68@0300 9/26	214@1600 9/22	73@1600 9/12	71@1300 9/22	6@1500 9/1	11@1000 9/22
October	98@1400 10/14	55@0600 10/27	206@1600 10/14	10@0200 10/1	208@1100 10/16	20@0300 10/1	130@1300 10/31	0	27@0100 10/16	0	40@2000 10/18	64@0400 10/10	6@1900 10/25	12@1300 10/9
November	124@2100 11/13	96@0600 11/6	308@1800 11/29	4@0600 11/6	226@1800 11/29	0	125@2200 11/30	0	47@0600 11/6	232@1100 11/13	30@2200 11/15	115@2400 11/1	11@0700 11/21	7@1000 11/1
December	85@1100 12/1	87@2000 12/23	304@2100 12/31	0	232@0900 12/12	0	131@1100 12/1	0	96@1700 12/27	224@1100 12/1	45@2200 12/18	107@2400 12/31	14@1800 12/19	0

Table 20

2001	Barkley/Hopkins		Shawnee		Marshall/Livingston		Marshall/Bryan Rd.		SIPC/Galatin		SIPC/Livingston		Wilson-Green River	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	10 @0400 1/1	204 @2000 1/10	172 @0600 1/3	0	13 @0500 1/3	31 @1200 1/2	0	112 @1700 1/26	20 @0400 1/1	24 @1500 1/11	171 @1100 1/17	0	0	444 @1300 1/31
February	0	177 @1300 2/1	127 @0600 2/6	0	30 @1900 2/15	73 @0200 2/3	0	76 @0400 2/5	6 @0600 2/27	32 @1400 2/21	116 @0600 2/6	0	0	0412 @0600 2/3
March	0	165 @16003/29	117 @0600 3/1	0	6 @0800 3/1	109 @1700 3/14	29 @0200 3/4	59 @0600 3/1	4 @0600 3/1	26 @1900 3/3	119 @1300 3/20	0	0	367 @0900 3/4
April	39 @1000 4/18	202 @1700 4/28	96 @1800 4/9	0	17 @0900 4/28	97 @1700 4/28	24 @0400 4/8	42 @0900 4/28	8 @1000 4/18	28 @1600 4/28	91 @1500 4/28	27 @1000 4/17	0	314 @1700 4/28
May	0	208 @1300 5/8	176 @1300 5/10	0	50 @2000 5/15	75 @1500 5/8	0	122 @1300 5/10	4 @1100 5/1	34 @1000 5/21	139 @1500 5/20	0	37 @1200 5/1	333 @1500 5/29
June	3/ @1700 6/13	188 @1400 6/4	214 @1100 6/21	0	50 @1700 6/13	78 @1400 6/16	19 @1400 6/11	148 @2100 6/21	14 @1700 6/13	26 @1800 6/16	155 @1500 6/4	0	0	438 @1000 6/6
July	41 @1600 7/24	168 @1400 7/6	185 @1600 7/18	0	70 @1600 7/23	48 @0800 7/12	0	114 @1700 7/12	8 @1200 7/23	26 @1300 7/7	112 @0500 7/19	72 @1700 7/23	0	389 @1200 7/7
August	169 @1400 8/29	145 @1000 8/21	199 @1400 8/25	0	97 @1600 8/7	45 @1100 8/17	0	112 @1200 8/26	24 @2400 8/29	24 @1300 8/21	124 @0600 8/29	28 @1700 8/6	0	372 @1100 8/22
September	52 @1400 9/7	90 @1100 9/13	165 @1400 9/6	0	40 @1800 9/4	56 @2300 9/14	0	102 @1500 9/21	20 @1500 9/7	12 @2000 9/4	129 @1500 9/24	0	0	313 @1700 9/22
October	85 @0500 10/29	162 @1700 10/23	121 @0700 10/28	0	14 @2300 10/13	89 @1600 10/29	9 @0300 10/21	78 @0700 10/28	24 @1200 10/28	17 @1300 10/8	204 @0500 10/30	0	19 @1900 10/2	322 @0900 10/8
November	15 @0300 11/23	189 @1700 11/3	117 @0600 11/21	0	21 @0100 11/20	124 @1700 11/3	1 @0900 11/2	78 @0400 11/21	20 @0100 11/20	16 @1900 11/3	188 @0700 11/7	0	0	0345 @1800 11/3
December	18 @1200 12/19	105 @2000 12/23	116 @1600 12/20	13 @1100 12/14	21 @1800 12/19	69 @1000 12/13	56 @1100 12/14	65 @0600 12/20	20 @0300 12/19	14 @2000 12/23	145 @2400 12/18	0	0	357 @0800 12/30

Table 20

2001	KU-Hard.		Hoosier		Vectren		LGEE/Cloverport		Paradise		Barkley/Livingston		Barkley/Lyon	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	10 @110 1/2	240 @2400 1/3	245 @0800 1/21	31 @1500 1/24	210 @ 2100 1/1	0	141 @0800 1/13	0	49 @0600 1/8	208 @0900 1/10	16 @1900 1/30	109 @0600 1/16	13 @1900 1/1	9 @1600 1/11
February	35 @2100 2/11	64 @0500 2/2	205 @1200 2/1	43 @1900 2/12	142 @0900 2/21	32 @1200 2/18	104 @0800 2/11	0	142 @0300 2/9	168 @1200 2/1	81 @1500 2/15	67 @0200 2/6	11 @1900 2/21	8 @1400 2/6
March	17 @2300 3/19	86 @0600 3/2	177 @0300 3/6	7 @1000 3/16	196 @0600 3/10	12 @0800 3/16	79 @1600 3/20	0	143 @1900 3/8	112 @1300 3/20	114 @0900 3/16	66 @1400 3/20	10 @2100 3/4	0
April	117 @2100 4/9	35 @0800 4/18	239 @1700 4/29	42 @0900 4/23	164 @1800 4/3	94 @1100 4/18	103 @1800 4/25	0	74 @0800 4/18	203 @1600 4/9	90 @1500 4/16	69 @0900 4/28	8 @0800 4/1	0
May	100 @2200 5/19	39 @0400 5/7	240 @1700 5/20	59 @1000 5/7	176 @1700 5/20	0	119 @1400 5/17	0	79 @1400 5/3	229 @1400 5/17	52 @1100 5/7	106 @0600 5/17	10 @1800 5/16	0
June	90 @1400 6/4	107 @1200 6/29	238 @1400 6/4	73 v@1600 6/28	146 @2100 6/16	32 @0600 6/19	119 @1400 6/4	0	89 @1800 6/29	265 @1400 6/4	35 @1500 6/16	104 @2100 6/20	11 @1500 6/13	0
July	62 @1700 7/28	105 @0700 7/31	207 @1300 7/7	157 @ 0600 7/24	180 @1700 7/15	36 @0700 7/31	107 1400 7/7	4 @0700 7/31	137 @1600 7/24	1630 @1700 7/28	47 @1900 7/7	59 @0300 7/11	13 @1400 7/8	0
August	50 @1500 8/25	152 @1700 8/7	175 @1800 8/19	170 @1600 8/7	150 @1700 8/18	74 @1600 8/9	89 @1700 8/16	15 @1400 8/7	220 @1700 8/7	120 @2000 8/25	36 @1800 8/18	84 @1000 8/10	120 @1300 8/1	0
September	6 @1300 9/6	97 @1600 9/10	116 @2000 9/30	98 @1500 9/7	68 @1200 9/6	54 @ 0700 9/8	64 @1800 9/13	1 @1700 9/26	133 @1800 9/26	50 @1900 9/13	27 @1700 9/3	67 @1600 9/9	10 @1800 9/4	0
October	40 @2000 10/14	61 @0900 10/1	221 @1000 10/28	52 @1300 10/3	170 @1000 10/28	120 @2000 10/26	91 @1900 10/12	0	57 @2000 10/26	170 @1900 10/12	23 @1100 10/30	108 @0600 10/29	9 @1900 10/16	4 @1900 10/16
November	73 @1400 11/3	100 @0600 11/26	179 @1700 11/3	11 @0600 11/26	189 @1900 11/3	0	99 @1600 11/3	0	107 @0700 11/24	188 @1800 11/3	41 @1800 11/28	125 @2400 11/20	9 @1700 11/28	5 @1200 11/2
December	37 @0800 12/18	119 @1600 12/27	3202 @2300 12/17	53 @1700 12/4	180 @2200 12/17	48 @1/00 12/12	80 @2200 12/17	0	144 @1900 12/2	77 @2200 12/17	46 @1000 12/16	100 @0600 12/20	10 @1800 12/26	0

Table 20

2002	Barkley/Hopkins		Shawnee		Marshall/Livingston		Marshall/Bryan Rd.		SIPC/Galatin		SIPC/Livingston		Wilson/Green River	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	137 @ 2100 1/13	0	111 @ 1700 1/6	19 @ 1700 1/31	32 @ 0200 1/9	61 @ 0500 1/4	61 @ 0500 1/31	64 @ 0500 1/8	16 @ 0400 1/9	21 @1800 1/15	153 @0500 1/8	82 @ 0100 1/1	0	413 @ 0900 1/8
February	1 @ 1800 2/4	138 @ 0300 2/27	107 @ 1800 2/27	18 @ 0300 2/1	33 @ 1100 2/4	52 @1000 2/13	58 @ 0800 2/1	52 @ 1700 2/27	10 @ 0600 2/5	20 @1800 2/25	125 @0300 2/27	15 @ 0800 2/1	0	384 @ 0200 2/27
March	23 @ 1900 3/10	150 @ 0800 3/3	102 @ 0600 3/11	10 @ 0900 3/25	19 @ 2400 3/4	88 @ 2100 3/17	48 @ 0800 3/25	58 @ 0400 3/11	16 @ 2400 3/10	20 @ 0900 3/4	113 @ 1100 3/3	1 @ 1100 3/25	0	411 @ 0900 3/3
April	8 @ 0600 4/30	157 @ 1300 4/21	69 @ 0700 4/30	36 @ 0400 4/9	17 @ 2000 4/18	94 @ 1300 4/21	61 @ 0400 4/9	35 @ 0600 4/30	18 @ 0100 4/15	20 @ 2100 4/7	176 @1600 4/20	13 @0900 4/3	0	399 @ 1900 4/21
May	7 @ 0800 5/22	180 @ 1800 5/6	154 @ 1200 5/28	0	29 @ 1500 5/29	91 @ 1700 5/5	44 @ 1300 5/5	109 @ 0800 5/28	14 @ 0200 5/21	22 @ 1800 5/6	154 @ 1500 5/12	0	0	422 @ 1800 5/6
June	16 @ 1500 6/20	110 @ 2000 6/7	189 @ 1400 6/5	1 @ 0500 6/18	89 @ 1500 6/24	37 @ 0700 6/2	76 @ 1700 6/18	124 @ 1800 6/10	18 @ 1000 6/4	12 @ 1900 6/7	124 @ 0100 6/11	0	0	362 @ 1700 6/2
July	106 @ 1400 7/31	124 @ 0100 7/26	197 @1200 7/29	0	97 @ 1300 7/22	51 @ 0400 7/26	0	129 @ 2300 7/10	30 @ 1300 7/31	10 @ 1600 7/26	146 @ 1000 7/14	2 @ 1600 7/14	0	326 @ 1500 7/26
August	84 @ 1700 8/1	119 @ 1400 8/7	189 @ 1200 8/18	0	110 @ 1700 8/1	35 @ 1400 8/7	0	122 @ 1200 8/18	27 @ 0700 8/14	10 @ 2300 8/4	156 @ 1200 8/18	6 @ 1400 8/1	0	336 @ 2300 8/24
September	74 @ 1900 9/10	149 @ 1800 9/15	156 @ 1300 9/4	0	87 @ 1800 9/10	70 @ 2400 9/30	58 @ 1200 9/19	88 @ 1200 9/4	28 @ 2100 9/10	16 @ 1400 9/15	139 @ 0500 9/11	0	0	380 @ 1800 9/21
October	22 @ 0600 10/29	153 @ 1300 10/9	110 @ 1600 10/2	0	26 @ 0500 10/25	87 @ 1500 10/9	8 @ 0900 10/16	55 @ 1400 10/5	17 @ 0200 10/15	16 @ 1500 10/9	122 @ 1800 10/6	0	0	371 @ 1300 10/1
November	96 @ 0600 11/11	132 @ 1200 11/27	118 @ 0600 11/18	0	22 @ 0500 11/1	61 @ 1000 11/20	16 @ 1900 11/11	72 @ 0600 11/18	26 @ 0300 11/10	22 @ 0800 11/27	153 @ 0600 11/20	2 @ 1900 11/26	75 @ 0300 11/11	332 @ 1300 11/27
December	49 @ 1000 12/9	137 @ 1000 12/27	111 @ 0800 12/8	0	25 @ 1800 12/10	69 @ 0700 12/26	14 @ 1500 12/19	61 @ 0400 12/7	26 @ 0500 12/17	16 @ 2000 12/19	140 @ 2400 12/6	11 @ 1900 12/17	0	366 @ 1800 12/1

Table 20

2002	KU/Hardinsburg		Hoosier		Vectren		LGEE/Cloverport		Paradise		Barkley/Livingston		Barkley/Lyon	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	65 @2100 1/8	82 @0100 1/1	211 @ 1900 1/5	14 @ 1800 1/22	182 @ 1900 1/5	0	139 @2000 1/8	0	97 @ 0300 1/31	143 @ 2400 1/7	61 @ 0800 1/31	109 @ 0400 1/9	10 @ 0900 1/1	0
February	72 @ 0900 2/28	74 @0900 2/19	204 @ 2100 2/28	59 @ 1600 2/8	146 @0300 2/27	14 @1000 2/25	127 @0300 27	0	63 @0100 2/1	225 @ 0300 2/27	54 @ 0800 2/1	90 @ 0300 2/28	10 @ 1900 2/4	4 @ 1500 2/25
March	68 @ 0600 3/3	114 @ 0600 3/7	207 @ 0200 3/27	36 @ 1000 3/7	150 @ 0900 3/4	84 @ 1000 3/25	120 @ 0900 3/3	26 @ 0500 3/20	170 @ 0500 3/20	211 @ 0900 3/3	67 @ 2100 3/17	77 @ 0300 3/1	11 @ 0700 3/11	7 @ 1500 3/8
April	56 @ 1300 4/21	106 @ 2000 4/18	205 @ 2200 4/14	37 @1100 4/22	180 @ 1600 4/30	122 @ 0700 4/3	63 @ 1300 4/21	21 @ 0800 4/3	170 @ 0800 4/3	95 @ 1300 4/21	52 @ 1600 4/1	92 @ 0600 4/30	10 @ 1800 4/18	8 @1400 4/28
May	65 @ 1700 5/16	114 @2000 3/29	243 @ 1300 5/12	51 @ 0700 5/30	204 @1700 5/16	46 @ 0900 5/30	94 @ 1800 5/16	0	94 @ 0400 5/7	135 @ 1700 5/16	46 @ 1800 5/6	88 @ 1500 5/25	9 @ 1300 5/31	9 @ 1700 5/15
June	49 @ 1700 6/30	112 @ 1000 6/24	124 @ 1200 6/2	119 @ 1600 6/24	140 @ 1400 6/4	84 @ 1400 6/19	81 @ 1800 6/2	13 @ 2000 6/22	142 @ 1800 6/22	90 @ 1100 6/29	9 @ 0600 6/2	124 @ 0100 6/11	13 @ 1300 6/4	2 @ 0800 6/8
July	85 @ 1300 7/12	158 @ 1000 7/29	180 @ 1500 7/13	129 @ 0900 7/17	174 @ 1400 7/13	82 @ 2400 7/31	99 @ 1300 7/12	10 @ 1700 7/30	184 @ 1300 7/22	149 @ 1300 7/12	0	126 @ 2100 7/14	12 @ 1600 7/31	5 @ 2400 7/25
August	7 @ 1699 8/6	150 @ 0900 8/1	142 @ 1400 8/14	190 @ 1100 8/14	128 @ 1800 8/26	114 @ 1000 8/13	77 @ 1700 8/7	24 @ 1400 8/2	196 @ 1400 8/1	93 @ 1900 8/6	20 @ 1800 8/30	141 @ 0900 8/14	13 @ 1700 8/1	3 @ 0100 8/4
September	71 @ 1800 9/29	127 @ 1700 9/20	204 @ 1700 9/29	52 @ 0700 9/10	190 @ 1600 9/30	18 @ 0700 9/2	103 @ 1700 9/29	7 @ 1700 9/10	140 @ 1600 9/10	179 @ 1300 9/29	31 @ 1800 9/30	113 @ 2400 9/10	18 @ 1900 9/10	6 @ 1800 9/15
October	0	106 @ 2000 10/3	237 @ 1900 10/26	1 @ 1300 10/4	192 @ 1800 10/29	38 @ 1300 10/5	79 @ 1300 10/9	0	113 @ 0900 10/18	99 @ 1300 10/10	45 @ 2000 10/16	98 @ 0500 10/25	11 @ 0600 10/29	6 @ 0900 10/10
November	33 @ 1800 11/10	105 @ 1200 11/18	284 @ 1300 11/10	40 @ 1700 11/24	206 @ 0800 11/12	48 @ 1600 11/24	71 @ 2100 11/17	0	141 @ 0600 11/11	56 @ 0500 11/18	67 @ 2000 11/25	101 @ 0600 11/20	15 @ 0200 11/10	2 @ 2300 11/3
December	32 @ 2100 12/24	139 @ 1800 12/17	237 @ 0800 12/27	0	208 @ 2200 12/26	0	91 @ 0900 12/28	8 @ 1800 12/17	191 @ 1800 12/17	78 @ 0900 12/27	47 @ 2100 12/19	76 @ 0100 12/2	16 @ 1800 12/10	1 @ 0100 12/5

Table 20

2003	Barkley/Hopkins		Shawnee		Marshall/Livingston		Marshall/Bryan Rd.		SIPC/Galatin		SIPC/Livingston		Wilson/Green River	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	94 @ 2000 1/22	101 @ 2200 1/11	152@0700 1/24	0	71@2000 1/22	49@0800 1/1	82@0600 1/27	55@2400 1/3	30@1700 1/27	6@1100 1/3	157@0500 1/13	0	15@0200 1/10	197@2400 1/17
February	53 @ 1700 2/2	120 @ 0200 2/18	112@1200 2/18	0	35@0700 2/5	58@2200 2/9	17@2100 2/22	63@1200 2/18	22@1700 2/2	12@1300 2/21	146@2300 2/18	32@1600 2/12	2@0700 2/3	297@1200 2/20
March	79 @0700 3/10	147 @1700 3/25	88@0700 3/31	0	86@0700 3/10	64@0500 3/27	30@0800 3/9	53@1800 3/30	26@0900 3/31	18@1700 3/25	154@1700 3/30	20@1000 3/10	0	326@2300 3/6
April	124 @1600 4/22	190 @1700 4/6	100@1900 4/9	0	60@0900 4/8	100@1900 4/19	13@1100 4/19	48@1500 4/9	16@0400 4/2	26@1100 4/6	128@0600 4/2	27@1000 4/8	0	342@1700 4/6
May	99 @2000 5/1	122 @1800 5/15	120@1000 5/30	12@0300 5/8	33@1800 5/1	106@1500 5/16	40@0300 5/8	74@0600 5/30	32@1600 5/7	8@1600 5/15	178@1500 5/16	12@1900 5/1	23@2000 5/1	334@1700 5/15
June	46 @1500 6/26	133 @1600 6/19	155@1600 6/9	0	47@1600 6/25	77@1600 6/5	0	106@2000 6/6	22@1000 6/6	16@1800 6/11	145@2000 6/6	4@1700 6/24	26@0300 6/1	397@1700 6/15
July	50 @1700 7/5	164 @2000 7/11	140 @1700 7/27	0	58@1600 7/1	68@0500 7/3	47@1300 7/9	83@0200 7/27	22@0100 7/7	22@2000 7/11	120@0300 7/12	29@1700 7/3	1@0700 7/6	371@2000 7/11
August	56 @1700 8/27	144 @1600 8/3	187 @1800 8/31	0	65@1700 8/21	66@0100 8/25	3@1700 8/15	109@1800 8/31	26@1800 8/31	24@1800 8/2	162@1000 8/31	25@1600 8/20	0	357@1400 8/6
September	15 @0600 9/1	176 @1700 9/23	176 @1500 9/1	0	2@1800 9/10	93@1700 9/23	12@2100 9/30	108@1500 9/1	24@0100 9/1	24@1200 9/26	199@1200 9/19	0	0	416@1700 9/23
October	28 @0600 10/23	148 @2100 10/1	92 @1000 10/4	0	17@1000 10/24	80@1600 10/1	11@0800 10/16	53@1000 10/4	21@0600 10/20	18@2100 10/1	142@1400 10/4	0	0	401@1800 10/8
November	48 @2300 11/2	126 @2200 11/29	103 @0700 11/25	0	27@1800 /1124	67@0600 11/29	52@2100 11/13	61@0300 11/30	24@2300 11/2	0	180@0500 11/30	0	52@2200 11/2	308@0100 11/26
December	29 @0500 12/27	146 @1000 12/10	204 @2300 12/15	0	22@1800 12/8	62@0100 12/16	1@2200 12/18	153@2300 12/15	26@0500 12/27	16@1100 12/10	172@0100 12/16	0	0	381@1100 12/10

Table 20

2003	KU/Hardinsburg		Hoosier		Vectren		LGEE/Cloverport		Paradise		Barkley/Livingston		Barkley/Lyon	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	65@0300 1/7	113@1700 1/27	259@0300 1/18	4@1900 1/28	226@0100 1/18	30@1800 1/29	106@0600 1/7	0	160 @1900 1/28	157 @ 0400 1/7	11 @ 1300 1/2	128 @ 0400 1/13	20 @ 1900 1/22	2 @ 1200 1/11
February	26@2200 2/22	145@1800 2/11	231@0500 2/8	29@1800 2/11	188@2300 2/5	26@1600 2/4	81@0900 2/23	5@0900 2/5	198 @ 1800 2/11	43 @ 1500 2/9	37 @ 1600 2/12	108 @ 1300 2/18	16 @ 07002/5	3 @ 0300 2/27
March	110@2000 3/23	101@0700 3/10	213@2200 3/16	76@0700 3/6	174@1200 3/15	4@1800 3/10	118@2000 3/23	0	181 @0700 3/10	201 @2000 3/23	30 @0800 3/21	142 @1800 3/30	16 @0700 3/10	8 @2300 3/24
April	99@1700 4/5	67@0600 4/14	223@1700 4/6	2@0800 4/17	218@2100 4/11	6@0400 4/19	106@0800 4/6	1@0100 4/28	128 @0600 4/28	153 @1700 4/5	89 @1400 4/14	77 @0500 4/3	13 @1100 4/9	9 @1500 4/6
May	97@1500 5/29	86@0900 5/5	259@1700 5/10	2@0900 5/2	260@1800 5/10	0	85@1300 5/29	8@0500 5/4	145 @2100 5/1	127 @1600 5/15	80 @0200 5/8	73 @0900 5/22	15 @2000 5/1	2 @1600 5/31
June	33@1400 6/15	98@1200 6/26	197@1400 6/15	17@1200 6/25	174@1300 6/12	10@0800 6/18	127@1600 6/5	0	111 @1800 6/30	138 @1200 6/10	37 @2200 6/24	94 @1000 6/6	11 @1600 6/25	0
July	100@1300 7/12	85@1400 7/1	223@1300 7/12	43@2100 7/7	174@1700 7/12	34@2200 7/4	108@2000 7/11	2@1500 7/1	154 @1500 7/1	204 @2000 7/11	86 @1800 7/1	68 @1500 7/8	16 @1700 7/5	3 @2000 7/23
August	38@1400 8/31	135@1400 8/14	152@2400 8/4	95@1400 8/15	138@1400 8/29	28@1300 8/15	85@1300 8/2	13@1500 8/6	144 @1800 8/27	102 @2200 8/10	62 @2100 8/22	114 @1100 8/31	17 @1600 8/27	3 @0100 8/23
September	81@1700 9/18	73@0600 9/10	235@2000 9/5	6@1000 9/26	160@2000 9/16	30@0500 9/30	98@1300 9/18	0	89 @0400 9/11	186 @2200 9/4	35 @1500 9/24	133 @0600 9/4	11 @1300 9/1	7 @1200 9/17
October	71@2000 10/18	81@0600 10/6	163@1500 10/26	41@0800 10/31	136@1000 10/2	32@0300 10/1	83@1200 10/31	1@0200 10/7	88 @0200 10/6	135 @2100 10/1	50 @1600 10/10	108 @0800 10/4	11 @0800 10/27	6 @1100 10/2
November	95@2300 11/28	85@1700 11/13	241@2300 11/28	4@1200 11/4	176@2300 11/29	18@1700 11/4	122@0600 11/29	3@1900 11/3	63 @1000 11/4	211 @2200 11/29	9 @0800 11/19	123 @0500 11/15	13 @2000 11/2	2 @1400 11/11
December	88@1000 12/7	90@0600 12/31	179@1300 12/04	56@1800 12/15	178@2200 12/2	64@2200 12/23	114@2300 12/20	0	72 @0500 12/31	205 @2300 12/20	0	137 @0600 12/8	13 @0500 12/27	1 @1500 12/6

Table 20

2004	Barkley/Hopkins		Shawnee		Marshall/Livingston		Marshall/Bryan Rd.		SIPC/Galatin		SIPC/Livingston		Wilson/Green River	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	2 @2300 1/26	138 @1600 1/5	124 @0700 1/7	0	43 @0800 1/23	66 @1400 1/18	4 @2400 1/29	67 @0600 1/8	0	23 @2100 1/5	157 @0500 1/11	35 @0800 1/30	0	389 @0200 1/23
February	21 @0800 2/16	152 @0500 2/8	122 @2000 2/26	18 @1400 2/17	59 @1600 2/25	69 @2400 2/4	52 @1800 2/16	69 @0500 2/23	14 @1200 2/14	24 @0100 2/2	151 @2400 2/29	8 @0900 2/3	0	356 @2400 2/21
March	118 @1100 3/12	71 @1600 3/3	165 @1500 3/29	0	70 @1900 3/8	78 @1500 3/4	0	141 @0500 3/29	32 @1800 3/9	16 @2200 3/5	171 @1500 3/28	0	53 @1100 3/12	335 @1700 3/21
April	89 @1100 4/1	16 @1600 4/9	95 @1800 4/13	24 @2400 4/22	22 @2000 4/12	66 @1400 4/7	56 @2100 4/20	67 @0300 4/2	28 @1100 4/1	22 @1700 4/9	146 @0400 4/2	0	0	375 @1600 4/9
May	74 @1400 5/21	147 @2200 5/16	130 @1300 5/23	0	38 @2100 5/12	87 @2200 5/16	0	67 @1200 5/28	30 @1200 5/24	28 @1600 5/5	160 @1800 5/15	0	0	405 @1700 5/5
June	70 @1300 6/17	134 @2300 6/1	175 @1200 6/12	0	63 @1700 6/8	66 @2200 6/12	0	106 @1200 6/12	32 @1300 6/17	12 @2300 6/10	147 @1300 6/2	0	0	417 @1600 6/27
July	67 @1700 7/20	121 @2300 7/31	182 @1800 7/9	0	53 @1600 7/13	61 @0400 7/14	78 @0900 7/2	104 @1800 7/9	22 @1700 7/6	12 @2400 7/13	146 @0100 7/31	0	0	352 @2100 7/3
August	113 @1600 8/27	104 @2300 8/17	336 @1000 8/28	0	71 @1700 8/10	82 @1400 8/29	0	262 @1000 8/28	30 @1600 8/23	10 @2200 8/1	184 @0900 8/28	0	37 @2200 8/26	393 @2100 8/16
September	83 @1300 9/13	93 @2300 917	187 @1500 9/6	0	51 @1300 9/13	103 @0200 9/22	0	117 @1000 9/7	30 @1100 9/29	16 @2100 9/25	150 @0100 9/25	0	0	360 @1800 9/26
October	35 @0100 10/1	143 @1100 10/9	105 @1200 10/2	0	22 @0200 10/19	83 @1300 10/26	14 @0900 10/13	102 @1200 10/29	27 @0100 10/1	18 @1800 10/22	149 @1200 10/26	25 @0800 10/19	0	380 @1100 10/9
November	80 @0600 11/16	94 @2300 11/30	120 @1000 11/25	0	27 @1700 11/12	60 @2300 11/16	2 @2000 11/30	76 @0800 11/26	30 @1600 11/12	14 @2100 11/30	151 @0200 11/10	0	0	375 @1500 11/29
December	50 @1700 12/14	140 @2200 12/9	142 @0700 12/20	0	42 @1700 12/13	62 @0400 12/17	16 @2200 12/22	80 @0200 12/20	22 @1700 12/14	22 @1800 12/10	138 @1600 12/31	17 @1800 12/22	0	399 @2300 12/26

Table 20

2004														
	KU/Hardinsburg		Hoosier		Vectren		LGEE/Cloverport		Paradise		Barkley/Livingston		Barkley/Lyon	
Month	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)	In (mw)	Out (mw)
January	40 @0100 1/29	168 @1000 1/29	166 @0100 1/25	60 @1300 1/26	188 @0100 1/7	20 @0800 1/16	99 @0600 1/11	7 @1000 1/28	193 @0900 1/26	130 @0600 1/11	56 @2200 1/29	88 @0600 1/8	14 @0700 1/23	1 @1000 1/12
February	4 @0400 2/8	151 @0700 2/2	174 @0200 2/12	82 @1800 2/5	158 @1200 2/14	2 @1800 2/3	81 @0500 2/9	24 @1800 2/21	170 @0700 2/2	113 @0400 2/13	57 @0700 2/3	86 @0600 2/19	12 @0700 2/2	5 @0800 2/16
March	33 @1700 3/13	140 @0500 3/19	194 @0300 3/24	73 @0800 3/18	168 @1400 3/13	102 @1000 3/5	69 @1100 3/2	27 @1200 3/30	223 @0900 3/12	50 @1600 3/3	40 @2100 3/3	142 @0600 3/10	15 @1100 3/12	3/ #2200 3/26
April	45 @2300 4/28	164 @1000 4/5	240 @1500 4/24	61 @0800 4/1	120 @1600 4/9	68 @0900 4/27	78 @1800 4/29	22 @1100 4/6	177 @1100 4/1	96 @1500 4/24	31 @1800 4/17	113 @0500 4/2	15 @1900 4/1	11 @0500 4/23
May	88 @2300 5/17	117 @1300 5/13	232 @1700 5/31	54 @1300 5/13	142 @2100 5/30	94 @1300 5/13	75 @2400 5/21	7 @1300 5/13	167 @1300 5/13	200 @2300 5/17	20 @1300 5/3	116 @150 5/24	16 @1200 5/20	12 @0100 5/6
June	86 @1600 6/4	168 @1300 6/9	263 @1400 6/2	75 @1500 6/15	164 @1600 6/4	38 @1100 6/18	88 @2200 6/1	16 @1600 6/9	155 @1300 6/9	133 @2100 6/1	5 @2000 6/13	119 @1500 6/9	17 @1400 6/15	5 @2100 6/1
July	25 @2400 7/10	116 @1900 7/1	214 @2400 7/20	69 @1500 7/2	182 @1400 7/5	0	111 @2100 7/24	4 @1300 7/16	147 @0600 7/16	158 @1600 7/13	21 @1900 7/14	97 @2400 7/25	16 @1700 7/20	3 @2400 7/11
August	77 @2300 8/26	101 @0800 8/16	226 @2300 8/26	38 @1100 8/3	152 @2300 8/31	16 @2400 8/9	101 @1600 8/8	0	149 @1600 8/23	155 @1800 8/6	17 @1900 8/17	118 @2400 8/10	20 @1600 8/23	8 @0100 8/19
September	58 @1800 9/17	106 @0700 9/21	179 @1300 9/17	85 @1100 9/21	140 @1800 9/17	42 @1200 9/13	93 @1900 9/17	0	163 @1600 9/13	116 @1900 9/17	12 @1600 9/4	125 @1600 9/16	14 @1600 9/3	2 @2100 9/25
October	89 @1100 9/17	73 @1600 10/17	216 @1700 10/29	8 @0800 10/10	124 @1700 10/29	48 @0800 10/12	97 @1600 10/27	0	55 @0400 10/1	158 @1500 10/27	43 @2200 10/18	88 @0200 10/30	12 @0800 10/3	7 @1200 10/3
November	49 @2200 11/11	120 @0600 11/17	221 @2300 11/1	38 @0500 11/22	154 @0500 11/27	22 @0200 11/13	83 @2300 11/16	0	124 @1700 11/30	92 @2300 11/1	26 @200011/30	115 @2400 11/14	17 @1700 11/4	0
December	4 @1200 12/23	153 @1700 12/4	225 @1000 12/23	25 @0500 12/7	172 @2300 12/14	2 @0600 12/9	102 @0800 12/27	0	132 @2300 12/26	22 @1700 12/14	62 @1800 12/22	98 @0200 12/20	10 @1700 12/14	4 @0900 12/10

Item 21) Identify any areas on your utility's system where capacity constraints, bottlenecks, or other transmission problems have been experienced from January 1, 2003 until the present date. Identify all incidents of transmission problems by date and hour, with a brief narrative description of the nature of the problem. Provide the MW transfers for each of your utility's interconnection for these times.

Response) The Big Rivers system facilities which experienced transmission loading or congestion problems either due to actual flows or potential flows resulting from a contingency (loss of another facility) during 2003 and 2004 are identified in attached Table #21. The specific incidents involving these system facilities are detailed in successive narrative summaries included with the table. The Big Rivers interconnection flows are also provided for each incident during 2003 and 2004. In each case, the NERC transmission loading relief (TLR) procedures were utilized to relieve the congestion problem.

Big Rivers' ability to export and/or import energy has from time to time been limited by TLRs from constraints on other utility systems.

Witness) Travis D. Housley, P.E.
C. William Blackburn
David G. Crockett, P.E.

BIG RIVERS ELECTRIC CORPORATION
LISTING OF TRANSMISSION FACILITIES EXPERIENCING CONGESTION (2003 – 2004)

FACILITY (OWNER)	NERC ID NUMBER
A.B. BROWN (VECT) – HENDERSON CO. (BREC) 138 kV LINE	2077
HARDINSBURG 161 – 138 kV TRANSFORMER (BREC)	2194
COLEMAN (BREC) – NEWTONVILLE (VECT/HEC) 161 kV LINE	2026
RENSHAW (SIPC) – LIVINGSTON CO. (BREC) 161 kV LINE	3163
HOPKINS CO. (BREC) – BARKLEY (TVA) 161 kV LINE	2102
COLEMAN – NATIONAL ALUMINUM 161 kV LINE (BREC)	2100
HARDINSBURG (BREC) – PARADISE (TVA) 161 kV LINE	2423
HARDINSBURG (BREC) – HARDINSBURG (LGEE) 138 kV LINE	2871

Table 21
Attachment (1) page 1

BIG RIVERS ELECTRIC CORPORATION
INCIDENTS OF TRANSMISSION CONGESTION (2003 – 2004)

Year: 2003

1. On March 22, TLR called for Hardinsburg 161-138 kV transformer due primarily to north to south regional flows. Export 75-100 MW.

2. On March 23, same circumstances as March 22. Export 75-100MW.

3. On March 24, same circumstances as March 22. Export 75-100 MW.

4. On April 6, TLR called for A.B. Brown – Henderson Co. 138 kV tie and operating with Hardinsburg – Paradise 161 kV tie open due to north to south flows. TVA Paradise units 1 and 2 were off line.

5. On April 9 –10, TLR called for A.B. Brown – Henderson Co. 138 kV tie due primarily to four system units off line (HMPL #1 & #2, Coleman #2 & Reid #1). Import 200 – 275 MW

6. On April 11, same circumstances as April 9-10. Import 150 – 200 MW.

7. On May 10, TLR called for A.B. Brown – Henderson Co. 138 kV tie due primarily to three system units off line (HMPL #1 & #2, and Green #1). Import 250 – 700 MW.

8. On July 12, TLR call for Hardinsburg 161 – 138 kV transformer due primarily to north to south regional flows. Import 25 – 75 MW.

9. On September 3, TLR called for Coleman -- National Aluminum 161 kV line for contingency loss of Wilson – Green River 161 kV tie due primarily to west to east regional flows. Export 125 – 300 MW.

10. On September 4, TLR called for Hardinsburg – Paradise 161 kV tie due primarily to to north to south regional flows. Export 50 – 150 MW.

11. On September 13, TLR called for Coleman – National Aluminum 161 kV line for contingency loss of Wilson – Green River 161 kV tie due primarily to west to east regional flows. Export 150 – 200 MW.

12. On September 14, same circumstances as September 13. Export 200 – 250 MW.

13. On September 18, TLRs called for Hardinsburg 161 – 138 kV transformer and Coleman – National Aluminum 161 kV line for contingency loss of Wilson – Green River 161 kV tie due primarily to north to south regional flows. Export 150 – 300 MW.

14. On September 19, TLR called on Renshaw – Livingston Co. 161 kV tie due primarily to north to south regional flows. Export 150 – 300 MW.

Table 21
Attachment (2) page 1

15. On September 22, TLR called on Coleman – National Aluminum 161 kV line due to the outage of Wilson – Green River 161 kV tie line due primarily to west to east regional flows. Export 150 -- 200 MW.

16. On September 23, TLRs called for Coleman – National Aluminum 161 kV line and Hopkins Co. – Barkley 161 kV tie for contingency loss of Wilson – Green River 161 kV tie due primarily to north to south regional flows. Export 200 – 300 MW.

17. On November 29, TLR called for Hardinsburg 161 – 138 kV transformer due to reduced generation at Coleman station and Wilson unit off line. Import 100 – 200 MW.

18. On December 6, TLR called for Hardinsburg 161 – 138 kV transformer due to reduced generation on all three Coleman units. TVA Paradise unit was off line as well. Export 150 – 250 MW.

19. On December 7, same circumstances as December 6. Export 0 – 100 MW.

<u>Year: 2004</u>

1. On January 28, TLR called for Hardinsburg 161 – 138 kV transformer due primarily to west to east regional flows. Export 125 –225 MW.

2. On May 16, TLR called for A.B. Brown – Henderson Co. 138 kV tie for contingency loss of Culley – Grandview 138 kV line in Vectren (SIGECO) system due primarily to north to south regional flows. Export 50 – 125 MW.

3. On May 17, TLR called for Hardinsburg 161 – 138 kV transformer for contingency loss of Coleman – National Aluminum 161 kV line. TVA Paradise lost two generating units.

4. On May 18, same circumstances as May 17.

5. On May 28, TLR called for A.B. Brown – Henderson Co. 138 kV tie due primarily to system generating units off line (Coleman #1 & Wilson #1). Import 300 – 400 MW.

6. On June 2, TLRs called for Coleman – Newtonville 161 kV tie and A.B. Brown – Henderson Co. 138 kV tie due primarily to system generating units off line (Coleman #1, Reid #1, & Wilson #1). Import 350 – 400 MW

7. On December 28, TLR called for A.B. Brown – Henderson Co. 138 kV tie for contingency loss of Culley – Grandview 138 kV line on Vectren (SIGECO) system due primarily to north to south and west to east regional flows.

Table 21
Attachment (2) page 2

2003

Date	KU-Hard.		Hoosier		Vectren		LGEE-Clov.		Paradise		Bark/Liv Co		Bark/Lyon		Bark/Hop Co		Shawnee		Marsh/Liv Co		Marsh/Bryan		SIPC-Galatin		SIPC-Liv Co		Wilson-GR	
	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out
3/22/2003	100		157		158		109			186		67	2			130	64			51		33		16	104			311
3/23/2003	110		162		132		118			201		61	2			136	64			46		30		16	109			309
3/24/2003	108		142		128		106			179		27		6		136	33			62	9			16	102			310
4/6/2003	28		223		204		77		0	0		39		9		190	72			58		21		26	110			342
4/10/2003	66		209		204		102			136	63		9			90	89			58		41		12	26			268
4/11/2003	37		182		184		86		57		88		6			74	44			62		2		16		7		267
5/10/2003	27		259		260		44		68		61		9			54	93			40		36	0	0	0	0		241
7/12/2003	100		223		174		104			172		49	6			135	135			39		72		18	107			346
9/3/2003		71	118		106		41			43		52	6			99	121			40		70		4	126			405
9/4/2003	45		235		154		93			226		104	7			123	139			51		94	12		173			377
9/13/2003		19	179		126		69			109		86	5			153	150			73		95		10	176			393
9/14/2003	16		183		144		74			144		73	2			154	138			72		85		12	172			399
9/18/2003	81		173		134		98			186		36		8		161	88			62		29		18	127			385
9/19/2003	65		167		96		87			174		98		5		132	95			83		52	10		199			368
9/22/2003		48	118		122		57			95		57		5		119	83			61		43		12	120			368
9/23/2003	20		150		144		70			110	18			3		176	54			93		9		22	112			416
11/29/2003	95		231		144		122			209		77	3			124	97			67		46		4	170			172
12/6/2003	72		105		120		110			201		103	5			134	116			45		67		8	158			302
12/7/2003	88		129		146		113			186		104	5			93	117			36		68	8		165			269

2004

Date	KU-Hard.		Hoosier		Vectren		LGEE-Clov.		Paradise		Bark/Liv Co		Bark/Lyon		Bark/Hop Co		Shawnee		Marsh/Liv Co		Marsh/Bryan		SIPC-Galatin		SIPC-Liv Co		Wilson-GR	
	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out	In	Out
1/28/2004		172		38	44			7	183		27		13		23		85		28			29	6		16			293
5/16/2004	32		209		130		49			89		41	3			147	93			87		50		14	140			354
5/17/2004	88		185		116		94			200		105	10			84	109			39		63	16		152			279
5/18/2004	66		184		92		85			140		98	8			71	96			45		61	16		156			259
5/28/2004	64		218		140		71			100		90		4		135	103			23		55		14	134			121
6/2/2004	54		263		160		81			81		86		4		125	164			54		95	12		149			341
6/2/2004	29		252		160		67			55		83		1		78	150			31		84	8		149			152
12/28/2004		46	141		140		90			107		67	6			110	112			23		56		8	121			374

Item 22) Provide details of any planned transmission capacity additions for the 2005 through 2025 period. If the transmission capacity additions are for existing or expected constraints, bottlenecks, or other transmission problems, identify the problem the addition is intended to address.

Response) Big Rivers' planned transmission capacity additions for 2005 through 2025 are included in the attached Table #22. The projects identified in this table were generally taken from Big Rivers Transmission System Long Range Plan (1995-2015) with some refinements from updates performed during the development of three-year Construction Work Plans dated 1997 - 1999, 2000 - 2002, and 2003 - 2005. The transmission planning horizon is defined by and concurrent with the load forecast horizon. Big Rivers is currently using the load forecast derived in its Long Term Load Forecast, 2003 - 2017. Therefore, transmission projects have not been identified beyond year 2015. Big Rivers is currently working on a Construction Work Plan, 2006 - 2008 and will soon begin development of a Transmission System Long Range Plan (2006 - 2021) using the load forecast from a new Long Term Load Forecast covering the same time span.

Witness) Travis D.Housley, P.E.
David G. Crockett, P.E.

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2025

Project Description	Notes
Year: 2005	
Madisonville 69 kV Line	Member Substation tap line and metering
Meade County Substation 161 kV Line	Support for radial fed Substation
Meade County 161 kV Line Terminal	Support for radial fed Substation
Possum Trot 69 kV Tap/Metering	Member Substation tap line and metering
Cumberland Resources 69 kV Line	Member Substation tap line and metering
Year: 2006	
McCracken Co. – Olivet Church 69 kV Line (4 miles)	Up-grading infrastructure to meet system load growth
Falls of Rough – McDaniels 69 kV line (5 miles)	Up-grading infrastructure to meet system load growth
LGEE (KU) 345 kV line Interconnection	Increase off-system import/export capability
McCracken Co. 69 kV line Terminal	Up-grading infrastructure to meet system load growth
Year: 2007	
Hardinsburg 161 kV Substation Modification	Increase Substation operational flexibility
Hardinsburg Transformer Upgrades (100 MVA)	Up-grading infrastructure to meet system load growth
Re-conductor Reid – Niagara to 336 MCM (6 miles)	Up-grading infrastructure to meet system load growth
Re-conductor Corydon – Geneva to 336 MCM (6 miles)	Up-grading infrastructure to meet system load growth
Re-Sag Hardinsburg – Fordsville Tie (1 mile)	Additional line capacity for load growth
Re-Sag Livingston Co. - Smithland (5.3 miles)	Additional line capacity for load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2025

Project Description	Notes
Year: 2008	
East Owensboro Substation (50 MVA)	New Substation to meet system load growth
East Owensboro 69 kV and 161 kV Lines (5 miles)	Transmission lines to connect new Substation
Re-conductor Henderson Co. – Zion tap (1.6 miles)	Up-grading infrastructure to meet system load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2009	
Re-conductor Meade Co. – Garrett (8.5 miles)	Up-grading infrastructure to meet system load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2010	
Hancock Co. Transformer Upgrades (100 MVA)	Up-grading infrastructure to meet system load growth
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2011	
Corydon 161/69 kV Substation (50 MVA)	New Substation to meet system load growth
HMP&L #4 161 kV Line Terminal	Transmission Line to connect new Substation
Corydon-HMP&L #4 161 kV Line (9 miles)	Transmission Line to connect new Substation
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering

BIG RIVERS ELECTRIC TRANSMISSION ADDITIONS, 2005 – 2025

Project Description	Notes
Year: 2012	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2013	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Year: 2014	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering
Years: 2015-2025 (each year)	
Co-op Substation 69 kV Line (2 miles)	Member Substation tap line and metering

Item 23) Is your utility researching or considering methods of increasing transmission capacity of existing transmission routes? If yes, discuss those methods.

Response) Yes. As indicated in the response to Item 1, Big Rivers considers transmission capacity increases as a routine part of its transmission planning process. Big Rivers has implemented project efforts specifically targeting capacity increases of existing transmission facilities including a 69 kV line reconductor effort in the 1970's, 161 kV structure height increases and wavetrap terminal equipment replacements in the 1980's, and 69 kV structure height increases and wire re-sags in the 1990's. Big Rivers continues to consider such in seeking the most cost effective solution to transmission problems identified through its power flow studies. The transmission construction plans included as part of the response to Item 22 includes reconductor and re-sag projects in year 2007 and reconductor projects in years 2008 and 2009.

Witness) Travis Housley, P.E.
David Crockett, P.E.

Item 24) Provide copies of reports prepared by your utility or for your utility that analyze the capabilities of the transmission system to meet present and future needs for import and export of capacity.

Response) Big Rivers addressed the current year (2005) transmission system capabilities in terms of the renewal of existing annual firm point-to-point reservations for LG&E Energy Marketing (LEM) and Big Rivers Power Supply. The results are summarized in the attached memo from Chris Bradley dated January 6, 2005. Big Rivers addressed future import and export capabilities through power flow studies to evaluate alternative system improvements and potential interconnections needed to provide 450 MW of additional transmission service requested by Big Rivers Power Supply. These results are summarized in a second attached memo entitled "Alternatives to Increase Capability: 12/17/04 Summary of Studies". Big Rivers also addressed the interconnection requirements on its transmission system for the proposed Peabody Thoroughbred power plant. The results of this study are summarized in a third document entitled "Thoroughbred Energy Campus Interconnection Study" dated February 26, 2003.

Witness) Travis Housley, P.E.
David Crockett, P.E.

Memo

To: David Crockett

From: Chris Bradley

CC:

Date: 1/6/05

Re: **Available Transfer Capability Values for the Year 2005**

In order to respond to yearly and monthly transmission requests received from Big Rivers and LEM, the available transfer capability (ATC) values for the year 2005 have been calculated. The ATC values were first calculated with the most restrictive period (summer peak). Since the excess control area generation is not sufficient to fully utilize the requested transmission, the ATC was also calculated using an off-peak model. The power flow cases were taken from the 2004 ECAR/MMWG series.

Since the majority of the yearly transmission requests involve the Big Rivers to TVA path, only ATC values for that export paths are presented.

CASE	PATH	STUDY RESULTS	MODEL TRANSFER	TOTAL ATC (LESS TRM)
2005 Summer	BREC-TVA	287 MW	144 MW	387 MW
2005 Off-Peak (summer ratings and 60% rural loads)	BREC-TVA	352 MW	244 MW	552 MW

Big Rivers Power Supply has requested 102 MW of renewal transmission and an additional 25 MW of monthly firm transmission (12 months) to TVA. LEM has requested 360 MW of renewal transmission (BREC to TVA) plus an additional 63 MW of monthly firm transmission (12 months) to TVA.

The requested transmission exceeds the summer peak ATC. However, the summer peak ATC required over-generating to reach the ATC limit was reached. With the reduced loads, summer ratings, and maximum generation levels, the ATC is sufficient to grant all of the requested transmission.

Based on these ATC calculations results and historical loading, Big Rivers can grant the requested renewals but not all of the monthly transmission requests. However, the monthly requests can be granted for the non-summer months (January, February, March, April, October, November, and December).

In addition to the ATC studies, the CBM to be applied in 2005 was also reviewed. No changes were found to be necessary.

Big Rivers
Electric Corporation

Memorandum

Alternatives to Increase Export Capability
12/17/04 Summary of Studies

Big Rivers Power Supply requested 450 MW of additional transmission for the year 2006. The primary need for the additional ATC is to ensure that excess generation that may be available due to the loss of one or both aluminum smelters can be exported off-system. Two improvement options have been studied. The first option includes a new 345 kV switching station east of Owensboro. This station will interconnect the existing Wilson to Coleman 345 kV circuit to the existing Smith (OMU) to Hardin County (KU) 345 kV circuit. The second alternative includes a new 161 kV Wilson to Aberdeen (EKPC) circuit.

Both options were studied with traditional power flow studies with maximum generation output and single contingency conditions (i.e. can all excess power be exported with the option under study?). In addition, ATC studies based on linear extrapolation were completed. In these studies, a 40 MW test transfer is simulated. Transfer factors calculated with the 40 MW test level are used to find the transfer level at which a facility limit is reached. These studies look beyond generation limitations. Therefore, results may be inaccurate beyond the export levels for which actual generation is available.

The study results of both options are described below:

345 kV Owensboro Substation: As described above, this option includes a new 345 kV switching station east of Owensboro. The new station will interconnect the existing Wilson to Coleman 345 kV circuit to the existing Smith (OMU) to Hardin County (KU) 345 kV circuit. No additional transmission construction is expected for Big Rivers. However, improvements that may be required by LG&E are unknown at this time. A MISO interconnection study and transmission deliverability study would be required to determine the MISO facility requirements.

Peak Load Results: ATC studies showed a total export capability of 569 MW (well above the 155 MW net export level supported by the available generation). Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

Off-Peak Load Results: ATC studies showed a total export capability of 734 MW (well above the available generation). This compares to an ATC of 624 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

No Century Results: ATC studies showed a total export capability of 900 MW to 1000 MW (well above the 625 MW net export supported by the available generation). This compares to an ATC of 300 MW to 550 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

No Smelters Results: ATC studies showed a total export capability of 924 MW (less than the 960 MW net export supported by the available generation). Traditional power flows studies showed no overloads with an export level of approximately 900 MW, but did show overloads with full generation dispatch.

Overall: Due to the study method limitations, the ATC values vary greatly with the generation dispatch and other assumptions. However, both the "no Century" and "no smelters" studies resulted in an ATC of approximately 900 MW. Traditional power flow studies showed that all excess generation could be exported with peak loads, off-peak loads, and with Century Aluminum at 0 MW (approximately 620 MW net export). The excess generation available with both smelters at 0 MW (approximately 960 MW) cannot be exported with this option. If the already sold 460 MW is subtracted from a 900 MW export capability, the resulting ATC is 440 MW. This would allow most or all of the requested ATC to be accepted.

161 kV Wilson to Aberdeen (EKPC) Circuit: As described above, this option includes the construction a new 161 kV Wilson to Aberdeen (EKPC) circuit approximately 25 miles in length. An alternative to this construction includes a much shorter 161 kV (13 miles?) from Aberdeen to a tap point on the existing New Hardinsburg to Paradise 161 kV circuit. The alternative construction provides no increase in the ability to export power. The alternative construction also increases the flow on the New Hardinsburg transformer (see attachment). The focus of this ATC analysis is the 25 mile Wilson to Aberdeen circuit.

Peak Load Results: ATC studies showed a total export capability of 655 MW (well above the available generation). Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

Off-Peak Load Results: ATC studies showed a total export capability of 827 MW (well above the available generation). This compares to an ATC of 624 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage.

No Century Results: ATC studies showed a total export capability of 670 MW to 900 MW (above the 625 MW net export supported by the available generation). This compares to an ATC of 300 MW to 550 MW with no system improvements. Traditional power flows studies showed no overloads with a maximum generation dispatch and each single contingency outage. However, during an outage of the Wilson to Green River circuit, the Coleman to Newtonville loading was approximately 100%. This indicates that the maximum export capability is approximately 625 MW.

No Smelters Results: ATC studies showed a total export capability of 730 MW (less than the 960 MW net export supported by the available generation). Traditional power flows studies showed overloads with an export level of approximately 900 MW. The export level was not reduced to find the actual transfer limit. However, it seems reasonable to assume an export level similar to the "no Century" studies would be found.

Overall: Due to the study method limitations, the ATC values vary greatly with the generation dispatch and other assumptions. However, the increase in ATC (above that with no system improvements) appears to be 200 MW to 350 MW (200 MW seems to be a safe assumption for ATC increase resulting from this improvement). Traditional power flow studies showed that all excess generation could be exported with peak loads, off-peak loads, and with Century Aluminum at 0 MW (approximately 620 MW net export). The excess generation available with both smelters at 0 MW (approximately 960 MW) cannot be exported with this option.

Summary

Either option will allow all excess generation to be exported off-system with both smelters in operation during peak or off-peak loads.

Either option will allow all excess generation to be exported off-system with Century Aluminum at 0 MW during peak conditions.

With both Century and Alcan at 0 MW, neither option will allow all excess generation to be exported.

Even though some ATC results were higher with the Wilson to Aberdeen option, the traditional power flow studies show the 345 kV option to be a more robust system improvement for Big Rivers.

At this time, LG&E/MISO concerns with the 345 kV option are unknown. The impact the option may have on the MISO and the resulting MISO ATC is also unknown.

Since the EKPC option results in significant power flow to the Warren load, the MISO impact may be less with this option. However, this may or may not result in the ability to sink additional power in the MISO system. As stated before, the Wilson to Aberdeen circuit is much longer than the Aberdeen to New Hardinsburg/Paradise tap option. As a result, the ATC increase (required to accept the TSR) may be the primary justification for the extra circuit miles if the project is presented to the PSC.

Based on both the "no Century" and "no smelter" study results, it appears that the 450 MW request could be accepted contingent upon construction of the 345 kV station. With the Wilson to Aberdeen interconnection, approximately 200 MW could be accepted. However, the deliverability of this power into MISO or TVA is unknown at this time.

Memo

To: David Crockett

From: Chris Bradley

CC:

Date: 1/6/05

Re: **Available Transfer Capability Values for the Year 2005**

In order to respond to yearly and monthly transmission requests received from Big Rivers and LEM, the available transfer capability (ATC) values for the year 2005 have been calculated. The ATC values were first calculated with the most restrictive period (summer peak). Since the excess control area generation is not sufficient to fully utilize the requested transmission, the ATC was also calculated using an off-peak model. The power flow cases were taken from the 2004 ECAR/MMWG series.

Since the majority of the yearly transmission requests involve the Big Rivers to TVA path, only ATC values for that export paths are presented.

CASE	PATH	STUDY RESULTS	MODEL TRANSFER	TOTAL ATC (LESS TRM)
2005 Summer	BREC-TVA	287 MW	144 MW	387 MW
2005 Off-Peak (summer ratings and 60% rural loads)	BREC-TVA	352 MW	244 MW	552 MW

Big Rivers Power Supply has requested 102 MW of renewal transmission and an additional 25 MW of monthly firm transmission (12 months) to TVA. LEM has requested 360 MW of renewal transmission (BREC to TVA) plus an additional 63 MW of monthly firm transmission (12 months) to TVA.

The requested transmission exceeds the summer peak ATC. However, the summer peak ATC required over-generating to reach the ATC limit was reached. With the reduced loads, summer ratings, and maximum generation levels, the ATC is sufficient to grant all of the requested transmission.

Based on these ATC calculations results and historical loading, Big Rivers can grant the requested renewals but not all of the monthly transmission requests. However, the monthly requests can be granted for the non-summer months (January, February, March, April, October, November, and December).

In addition to the ATC studies, the CBM to be applied in 2005 was also reviewed. No changes were found to be necessary.

THOROUGHBRED ENERGY CAMPUS

INTERCONNECTION STUDY

REPORT

Prepared for

Big Rivers Electric Corp.

Participating Utilities:

LG&E Energy
Owensboro Municipal Utilities
Tennessee Valley Authority

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INTRODUCTION

Peabody Energy has requested that they be allowed to interconnect the Thoroughbred Energy Campus, a planned 1,500-megawatt mine mouth, coal-fueled electric generating station in Muhlenberg County, Kentucky. One of the two proposed 750 MW generators is to be interconnected to the Big Rivers Electric Corporation (BREC) 345 kV Wilson Substation and the second 750 MW generator is to be connected to the Tennessee Valley Authority (TVA) 500 kV Paradise Substation. Since this project jointly impacts BREC, LG&E Energy (LGEE), Owensboro Municipal Utilities (OMU) and TVA, Commonwealth Associates, Inc. (CAI) was contracted by BREC to perform a joint Transmission Interconnection Study combining the interest of all the parties.

The preliminary studies investigated three interconnection concepts, as shown in the one-line drawing B4. Each concept included either one 750 MW generator connected to the 345 kV Wilson Substation or two 750 MW generators connected separately to the 345 kV Wilson Substation and to the 500 kV Paradise Substation.

EXECUTIVE SUMMARY

Power Flow Results

The base case power flow model was developed by modifying the 2005 Summer reference power flow model provided by the North American Electric Reliability Council (NERC), with facility and dispatch changes provided by the participating utilities, to represent conditions expected to be in place on the bulk power transmission system for the summer of 2005. The base case was analyzed under contingent conditions for a variety of base case and study case models to identify transmission facilities that are expected to become overloaded due to the introduction of the new generating station.

A preliminary analysis of these three interconnection options included power flow and short circuit studies. The results of these preliminary studies were jointly reviewed by CAI, Peabody Energy, and the participating utilities, and case 271 (Interconnection Option III) was selected as the preferred interconnection plan. A summary of the preliminary power flow results is shown in Appendix A, Exhibits A21 through A30. Results of the short circuit studies are summarized in Appendix A, Exhibits A2 and A3. Case 271 interconnects both Thoroughbred generators separately, as indicated above, utilizes an existing 345 kV branch circuit between Wilson and Coleman to be looped into Elmer Smith Station (OMU) and also includes a new 161 kV branch circuit between Wilson and Paradise. These new connections are identified in Exhibit B4 by the bold and dashed lines. This case will be referred to as the preferred interconnection plan for all further studies. While the preferred interconnection plan could initially be slightly more expensive than the other alternatives, Peabody Energy desires the most robust and cost effective interconnection.

The interconnection of the second generator connected to the 500 kV Paradise Substation was studied by TVA independently. TVA has forwarded its results to Peabody. Therefore impacts on TVA's system have not been studied in detail.

The new facilities that will be required for interconnecting the Thoroughbred generators in the preferred plan include five transmission lines: one 500 kV line, three 345 kV lines and one 161 kV line, these are shown in Appendix B, drawing B4. In addition, LGEE conducted an independent study (using their in-house model, which includes the underlying 69 kV system) under varying system load levels and determined that an existing 345 kV transmission line between Brown and Pineville should be energized (terminal work at both Brown and Pineville will be required to complete this).

Using the preliminary results of the power flow contingency analysis, the preferred plan was compared to the base case and 17 facilities in the BREC and LGEE systems were identified as being loaded to more than 100 percent of their emergency ratings. After the review of the initial results, ratings were increased on 15 transmission lines and two transformers. There will be costs associated with upgrading the 17 facilities in order to reach these limits. The upgrades may include improving terminal facilities and re-conductoring or re-sagging the transmission lines to eliminate the overloading. These 17 facilities are listed in the table at the end of the executive summary and in Appendix A, Exhibit A11; they are marked with an asterisk. The seven other facilities listed in Exhibit A11 had ratings increased after reviewing the power flow case that modeled the preferred interconnection plan with the MISO IA generators.

Fourteen of the Group 1 facilities (new overloads) shown in Exhibit A1 become overloaded due to either the addition of the MISO generators to the base case or the addition of the MISO generators to the preferred plan. Twelve are facilities in the TVA system, which includes ten transmission lines and two transformers. The other two facilities were one transformer in the Southern Indiana Gas and Electric (SIGE) system and one 161 kV transmission line in the Entergy Electric System (EES). Of these 14 facilities, the overloading on one TVA 500 kV line and one EES 161 kV line was eliminated when the MISO generators were added to the preferred interconnection plan. Overloaded facilities in the TVA system were not studied in greater detail since TVA conducted an independent study and has forwarded their results to Peabody Energy.

Area losses in the bulk power transmission system increased due to the addition of the new generators at the Thoroughbred Energy Campus. The increase in area losses for the preliminary studies when compared to the base case are shown in Exhibit A31. The area losses were reviewed by the participating utilities and were considered to be low; as a result the system losses should be evaluated using the more detailed 69 kV models that each utility has for its own system. The issue of system losses, and compensation for such, is usually addressed when the IPP makes a transmission service request with a particular utility.

Short Circuit Results

A short circuit study was conducted by constructing a short circuit model representing the preferred interconnection plan and including additional data associated with short circuit studies. The short circuit model was prepared by combining data provided by the participating utilities into one common short circuit model. The reference model used to develop the base case short circuit model was the 2005 Summer - 2000 Series, NERC/MMWG Base Case Library. The same facility and dispatch changes used in the 2005 Summer base case power flow model were used in the base case short circuit model.

The short circuit study was performed by simulating faults on transmission facilities in the vicinity of the proposed new generator interconnection and determining the resulting fault current levels. The short circuits applied to this model include both three phase and single line to ground faults. A summary identifying the significant impacts of the fault current levels is shown in the chart in Exhibit A2.

The results of these preliminary short circuit studies were reviewed by the participating utilities and it was determined that at least six breakers in the LGEE system are inadequate for the short circuit requirements; five 138 kV breakers and at least one 69 kV breaker. Since the power flow model does not adequately model the underlying 69 kV system, additional studies will be completed as part of a facilities study.

Light Load Power Flow Results

All further studies focused on the preferred interconnection plan. A light load study was conducted to determine what affect the Thoroughbred project would have under light load conditions. The reference case for the light load model was the 2002 Light Load model provided by NERC. The same facility changes used for the 2005 Summer base case model were used in the light load model but the dispatch of generators in the BREC system was slightly different. Under a light load condition the utilization of the transmission system is different than with a summer peak condition. The light load study model was constructed by modeling the same facilities necessary for interconnecting the Thoroughbred generators in the preferred plan.

A power flow contingency analysis was performed and a comparison between the light load base case and the preferred interconnection plan showed no impacts due to overloaded facilities. There was, however, some concern that available transfer capability (ATC) may be constrained during periods of light load.

MISO Power Flow Results

The Midwest Independent System Operator (MISO) became involved in the project during April 2002 and identified 15 Independent Power Producers (IPP) that have signed Interconnection Agreements (IA) in the MISO generator interconnection request queue. The MISO recommended that these projects, located in MISO's Region 11, as well as AEP projects, be included in the studies for the Thoroughbred project. Without the inclusion of these projects the MISO was concerned that stability and short circuit reliability impacts on the AEP or MISO transmission systems would not be adequately addressed. MISO provided the data used for modeling the generators. The drawing in Appendix B, Exhibit B1 shows the probable location of the MISO generators. Exhibit B2 identifies the north and south group of generators modeled. The chart in Exhibit A9 lists the generators included in the MISO power flow models.

The 2005 Summer base case and preferred interconnection plan power flow models were modified to incorporate the 15 IPPs identified by the MISO. In addition, one IPP located in AEP's control area was also included. The AEP generator went into service in June 2002 and was not represented in the previous power flow studies.

Exhibit A1 compares four study models to the base case. The facilities shown in the bolded boxes identify facilities that become overloaded for each study case. The facilities shown in Group 1 are new overloads; the facilities shown in the box labeled A1 are new overloads due to the addition of the MISO generators to the base case. The facilities shown in the box labeled A1 & B1 are overloaded in both the MISO base case and the preferred interconnection plan with no MISO generators, and the five facilities shown in the box labeled B1 are new overloads due to the preferred interconnection plan with no MISO generators. The facilities contained in the box labeled C1 are new overloads due to the addition of just the south group of MISO generators to the preferred interconnection plan and the facilities in the box labeled D1 are due to the preferred interconnection plan, including the MISO generators. Two of the overloaded facilities shown in the box labeled C1 and the three overloaded facilities shown in the box labeled D1 on Exhibit A1 had ratings changed based on limits due to ground clearances and/or terminal limits. Exhibit A11 lists these facilities. They are shown without an asterisk, and also shown in the table at the end of the executive summary. All of the new impacts identified for BREC and LGEE were resolved through rating changes on the impacted facilities.

These MISO power flow studies identified four new Group 1 facilities due to the addition of the MISO generators to the base case and seven new Group 1 facilities due to addition of the MISO generators to the preferred interconnection plan, although five of these overloads were eliminated through facility upgrades. The addition of the MISO generators to the preferred plan eliminated overloading on two facilities; one 500 kV line and one 161 kV line.

Transient Stability Results

Transient stability is a study conducted to investigate the dynamic response of generators due to a fault or some other type of system disturbance near a generator. CAI identified the critical clearing time required for the protection system to clear the disturbance from the system. Faults that are not cleared from the transmission system before the critical clearing time will cause the generator to become unstable and eventually tripped off line. The charts in Exhibits A4 through A6 show the critical clearing times for several facilities near the Thoroughbred generators.

The figures shown in Exhibit A16 show stable responses for several generators due to a 345 kV fault at Wilson, which was cleared before reaching the critical clearing time. Exhibit A17 shows a stable response at the critical clearing time of 8 cycles and an unstable response with 9 cycle clearing, for the same 345 kV fault at Wilson.

Transient stability of a transmission system is studied by simulating faults, including switching operations caused by the protection systems of varying durations on branch circuits near a generator and observing specific generator parameters to determine when instability will occur. Faults are normally cleared from the transmission system by the operation of protective equipment such as relays and breakers.

The reference model used to develop the base case transient stability model was the 2003 Summer - 2001 Series, NERC/MMWG Base Case Library. The same facility and dispatch changes used in the 2005 Summer base case power flow model were used in the transient stability base case model. Transient stability models are constructed using generator dynamics parameters. The data used for modeling these components is shown in Exhibits A12 through A15. The generator dynamics data is used together with the power flow program to arrive at a solution. Three transient stability models were constructed; a base case, a base case with the MISO generators, and the preferred interconnection plan with the MISO generators. The transient stability summary results are shown in Appendix D, Exhibits A4 through A6. The results for the preferred interconnection plan with the MISO generators are shown in Exhibit A4. Exhibits A5 and A6 are the results for base case with the MISO generators and the base case, respectively. These exhibits list the critical clearing times for all of the cases run. Only those facilities in close proximity to the Thoroughbred generators were studied. No instabilities were identified for primary clearing.

The participating utilities have reviewed the protection schemes for their transmission systems and have determined that the protection systems will operate to clear the faults before reaching the critical clearing time. This will prevent the generator from going into instability. Faults that are not cleared before this time will cause the generator to be tripped off line. Clearing a fault before reaching the critical clearing time can be accomplished by fast acting relays and breaker combinations.

Summary

The power flow analysis for the preferred interconnection of the Thoroughbred generators, including the MISO IA generators, will require six new transmission lines, upgrades or replacements on 22 transmission lines and two transformers in the BREC and LGEE systems. In addition there are 12 overloaded facilities in the TVA system, one overload in the SIGE system, and one overload in the EES system. (These facilities are included for informational purposes only. Any upgrades ultimately required will result from a study prepared by TVA, MISO, or others.) One of the new 345 kV transmission lines was identified by LGEE after making its own independent study with the preliminary preferred interconnection plan under varying system load levels. The short circuit analysis identified six breakers that are inadequate for the fault current duty; five 138 kV breakers and one 69 kV breakers. Additional 69 kV breaker replacements could be identified during the facilities study process. The transient stability analysis identifies the critical clearing times required to avoid generator instability in close proximity to the Thoroughbred Energy Campus. The fault clearing times were reviewed by the participating utilities and no instabilities were noted.

New Facilities

Location	**Distance**
Thoroughbred to Paradise Substation (TVA) 500 kV	8 miles
Thoroughbred to Wilson Substation (BREC) 345 kV	10 miles
Wilson (BREC) to Smith (OMU) 345 kV	9 added miles
Coleman (BREC) to Smith (OMU) 345 kV	9 added miles
Wilson (BREC) to Paradise (TVA) 161 kV	15 miles
Brown to Pineville (LGEE) 345 kV	Terminal Facilities

Overloaded Facilities

Branch Circuit	Old Rating		New Rating	
	Normal	Emergency	Normal	Emergency
Big Rivers Electric Corporation				
*Wilson to Coleman 345 kV	598	598	956	956
LG&E Energy				
*Baker Lane to Brown N 138 kV	205	216	224	277
*Earlington N to River Queen Tap 161 kV	184	184	209	257
*Eastview to Stephensburg 69 kV	42	42	56	68
*Elizabethtown to Tharp 69 kV	72	79	90	111
*Green River Steel 138-69 kV Transformer	93	102	93	107
*Green River Steel to OMU 69 kV	72	86	146	181
*Green River to Ohio County 138 kV ckt 1	143	158	179	220
*Green River to Ohio County 138 kV ckt 2	143	158	179	220
*Green River to River Queen Tap 69 kV	55	55	89	110
*Leitchfield 138-69 kV Transformer	72	79	93	107
*Leitchfield to Shrewsbury 138 kV	82	82	179	220
*Newtonville to Cloverport 138 kV	143	143	162	199
*Ohio County to Shrewsbury 138 kV	165	165	179	220
*Smith to Hardin County 345 kV	275	308	1195	1315
*Adams to Tyrone 138 kV	97	97	179	220
Arnold to Delvinta 161 kV	113	113	167	201
Artemus to Farley 161 kV	142	142	209	257
Artemus to Pineville 161 kV	129	129	176	201
Delvinta to West Irvine Tap 161 kV	142	142	176	201
Ghent to Owen County Tap 138 kV	227	227	227	280
Green River Steel to Smith 138 kV	241	241	287	287
Lake Reba Tap to West Irvine Tap 161 kV	165	165	167	223
East Kentucky Power Cooperative				
*Stephensburg to Upton Junction 69 kV	19	19	45	54

Breakers Inadequate for Short Circuit Requirements

Substation	Base kV	Quantity
LG&E Energy		
Green River Substation	69 kV	1
Green River Substation	138 kV	1
Green River Steel Substation	138 kV	4

* Facilities with an asterisk were revised after the preliminary power flow studies
Facilities without an asterisk were revised after the MISO power flow studies
Overloaded facilities requiring upgrades in TVA, SIGE, and EES systems are not shown in this table

ASSUMPTIONS AND CRITERIA

Power Flow Models

The following planning criterion is used to evaluate the power system:

- Normal System Conditions (NS)
  - Loading on transmission lines and transformers should be less than 100 percent of their normal ratings
  - Bus voltages should be no less than 95 percent or greater than 105 percent of nominal

- Single Contingency Conditions
  - Loading on transmission lines and transformers should be less than 100 percent of their emergency ratings
  - Bus voltages should be no less than 90 percent or greater than 105 percent of nominal

Single contingency conditions are defined as the outage of any single transmission facility. The contingencies used to study the system include outages of all of the bulk power transmission lines and transformers (100 kV and above) in a wide neighborhood around the new generation site. This study included 376 single-contingencies that are depicted in the one-line of contingencies, Appendix B, Drawing B5. Two of the single-contingency outages involve multiple elements of three winding transformers located at Montgomery and Hopkinsville Stations in TVA. The 11 multiple contingencies include the simultaneous outage of a generating unit and a transmission facility. A complete list of the contingencies can be found in Appendix A, Exhibit A7. The monitored facilities include the contingent facilities plus all facilities within a four-bus ring around the contingency set.

Short Circuit Models

The criteria used in evaluating short circuit studies is that for a bolted fault (i.e., zero fault impedance), currents seen by the breakers must be less than the breaker rating. The simulated short circuit could be either a three phase or a single line to ground fault.

Transient Stability Models

Criteria used in determining the transient stability of a transmission system demand that the generator not lose synchronism with the electrical system during a transmission line or transformer fault condition which causes the circuit element to be taken off line in order to clear the fault. Transient stability of a transmission system is studied by simulating a fault of varying duration near a generator bus and observing particular generator parameters to determine the time at which instability will occur. In these studies the disturbance simulated was a three phase to ground fault. The time before which a disturbance must be cleared is referred to as the critical clearing time. Faults are normally cleared from the transmission system by the operation of protective equipment such as relays and breakers.

The participating utilities have reviewed the protection schemes for their transmission systems and have determined that their systems can operate to clear the fault before reaching the critical clearing time. This will prevent the generator from unstable operation and tripping off line.

STUDY METHODOLOGY

The power flow study was conducted using CAI's TRANSMISSION 2000® Power Flow (PFLOW) program and its associated Contingency Processor (CP). CP is an automated tool that controls the power flow contingency calculation and summarizes the results. Summary reports for each case are contained in the detailed power flow results found in Volumes I, II, and III, as provided to each of the participating utilities. These include the following reports:

- Overload Summary Report – all overloaded facilities and the number of times overloaded
- Normal System Overload Summary Report
- Undervoltage Summary Report
- Overvoltage Summary Report
- Contingency Summary Report – each contingency and all overloads it causes
- Contingency List
- Various other summary reports

Detailed reports of the results from the most recent studies involving Interconnection Option III, the preferred interconnection plan, are contained in Volume I, Appendices E through J. Preliminary base case studies and studies involving Interconnection I are contained in Volume II, Appendices E through M. Preliminary results from studies involving Interconnections IIA and III are contained in Volume III, Appendices N through Y.

In addition to the summary reports, CAI also prepared a comparison analysis of impacted facilities. Exhibit A1 shows comparisons between the base case, the preferred interconnection plan without MISO, and three study cases:

- Case C271s05 is the preferred interconnection plan, which includes facility rating changes and includes no MISO or AEP IA generators
- Case BS05sMF is the MISO base case with all MISO and AEP IA generators
- Case C271s05MS is the preferred interconnection plan including only the south group of MISO generators, see drawing B2
- Case C271s05MF is the preferred interconnection plan with all MISO and AEP IA generators

The comparisons against the base case were conducted for the above series of cases, and included the base case with the MISO generators and the preferred interconnection plan with and without the MISO generators. The two corresponding study models, representing the loss of a generator in the LGEE system were not modeled for these MISO power flow studies because facilities that were overloaded in these corresponding study cases were the same facilities that were overloaded in the preferred interconnection plan when compared to the base case.

To provide an efficient means for evaluating comparable cases, overloaded facilities are grouped in these exhibits in order of worst overloads at the top of Group 1, to less significant overloads at the bottom of Group 2. These groups are described as follows:

Group 1 - *New Overloads (new generation caused an overload)*

Group 1 facilities are those that are overloaded in one or more of the study cases but were not overloaded in the base case. The overloads on these facilities are attributed to the additions made in the study cases (i.e., one or two 750 MW generators at the Thoroughbred Energy Campus). We will look closely at these overloaded facilities (i.e., further study) to determine causes and mitigation in Phase 2 of this study.

Group 2 - *Pre-existing with increased overloading caused by the new generation*

Group 2 facilities are those that are overloaded in the base case and the study cases but showed an increased overloading in the study cases. Depending upon the magnitude of the change and the number of contingencies that cause these facilities to overload, these facilities may or may not require mitigation.

Preliminary Power Flow Study

The reference case used to develop the base case model was the 2000 Series, NERC/MMWG Base Case Library - 2005 Summer. The base case model (BC05s01) incorporates the dispatch and facility changes submitted by the participating parties, shown in Appendix C, Exhibits C1 through C14. The impedance of the various new transmission lines used to interconnect the Thoroughbred generators were calculated based on data from EPRI's "Transmission Line Reference Book 345 kV and Above" (Red Book), dated 1975.

Two additional base case models were developed to represent the loss of two different generating units in two different locations in the LGEE system. Base case model BC05s11 represents the loss of Brown N Unit # 3 generator (441 MW), and BC05s21 represents the loss of Green River Unit # 4 generator (104 MW). In this series of base case models, generation is dispatched (bought) equally from three utilities in the north only; American Electric Power (AEP), AMEREN, and CINergy (CIN). Analysis of these study models was only performed for the preliminary cases represented in interconnection options I, IIA, and III. See Appendix B, Exhibit B4.

Listed below are the assumed distances between the Thoroughbred Energy Campus and the interconnection points.

Interconnection Point	Line Length
Wilson Substation (BREC) 345 kV	10 miles
Paradise Substation (TVA) 500 kV	8 miles

In these study cases, the first Thoroughbred Energy Campus generating unit is connected into the 345 kV Wilson Substation (BREC) using a double circuit transmission line. The second generator is connected into the 500 kV Paradise Substation (TVA) using a 500 kV transmission line (a three conductor bundle). Both generators are connected into the bulk power transmission system via generator step-up transformers (GSU).

For these preliminary studies, a set of nine power flow models was created; three base case models and six study case models. The Thoroughbred Energy Campus generators were individually connected into BREC and also into TVA. The cases are titled as follows:

Base Case Models – Without Thoroughbred Energy Campus Generators

- Case BC05s01 – Base Case with facility upgrades - 2005 Summer
- Case BC05s11 – Same as Case BC05s01 with the loss of Brown N Unit # 3 - 441 MW
- Case BC05s21 – Same as Case BC05s01 with the loss of Green River Unit # 4 - 104 MW

Interconnection I – Original Scope

<u>1-750 MW Plant – Cases 101, 111, and 121</u>

- Case 101 – Interconnected at 345 kV to Wilson Substation (BREC)
- Case 111 – Same as Case 101 with the loss of Brown N Unit # 3 - 441 MW
- Case 121 – Same as Case 101 with the loss of Green River Unit # 4 - 104 MW

<u>2-750 MW Plants – Cases 201, 211, and 221</u>

- Case 201 – Same as Case 101 with a second 750 MW generator individually connected at 500 kV to Paradise Substation (TVA)
- Case 211 – Same as Case 201 with the loss of Brown N Unit # 3 - 441 MW
- Case 221 – Same as Case 201 with the loss of Green River Unit # 4 - 104 MW

Based on the results of the above series of cases, 101 and 201, two alternative interconnections of the Thoroughbred Energy Campus were proposed (not in the original scope for this project). See Appendix B, Drawing B4 for Interconnections IIA and III.

- Interconnection IIA interconnects one 750 MW generator into the 161 kV transmission system at three sites: Wilson Substation (BREC), Green River Substation (LGEE), and Paradise Substation (TVA)
- Interconnection III is a variation of Interconnection I. The Thoroughbred Energy Campus generator is connected at 345 kV to Wilson and the existing 345 kV line between Wilson and Coleman is looped into OMU's Elmer Smith Station. A new 161 kV branch circuit is added between Wilson and Paradise

For the 200 series of cases, the second 750 MW generator is always interconnected to the 500 kV Paradise Substation. Twelve preliminary study models were developed and are described below:

Interconnection IIA – Three Interconnections at 161 kV

<u>1-750 MW Plant – Cases 141, 151, and 161</u>

- Case 141 – Modify Case 101 by removing the 345 kV connection between Wilson and the Thoroughbred Energy Campus and connecting the 750 MW generator into the 161 kV transmission system at three sites; Wilson Substation (BREC), Green River Substation (LGEE), and Paradise Substation (TVA)

- Case 151 – Same as Case 141 with the loss of Brown N Unit # 3 - 441 MW
- Case 161 – Same as Case 141 with the loss of Green River Unit # 4 - 104 MW

<u>2-750 MW Plants – Cases 241, 251, and 261</u>

- Case 241 – Modify Case 201 by removing the 345 kV connection between Wilson and the Thoroughbred Energy Campus and connecting the 750 MW generator into the 161 kV transmission system at three sites; Wilson Substation (BREC), Green River Substation (LGEE), and Paradise Substation (TVA)
- Case 251 – Same as Case 241 with the loss of Brown N Unit # 3 - 441 MW
- Case 261 – Same as Case 241 with the loss of Green River Unit # 4 - 104 MW

Interconnection III – Interconnection to Wilson at 345 kV with Three Additional Circuits

<u>1-750 MW Plant – Cases 171, 181, and 191</u>

- Case 171 – Modify Case 101 by looping the existing 345 kV Wilson to Coleman line into Elmer Smith Station (OMU), plus add a new 161 kV branch circuit between Wilson and Paradise
- Case 181 – Same as Case 171 with the loss of Brown N Unit # 3 - 441 MW
- Case 191 – Same as Case 171 with the loss of Green River Unit # 4 - 104 MW

<u>2-750 MW Plants - Cases 271, 281, and 291</u>

- Case 271 – Modify Case 201 by looping the existing 345 kV Wilson to Coleman line into Elmer Smith Station (OMU), plus add a new 161 kV branch circuit between Wilson and Paradise
- Case 281 – Same as Case 271 with the loss of Brown N Unit # 3 - 441 MW
- Case 291 – Same as Case 271 with the loss of Green River Unit # 4 - 104 MW

In each of the 18 preliminary study cases and the two light load models, the new generator output is dispatched (sold) equally to six utilities; three in the north (AEP, AMEREN and CIN), and three in the south (Duke Power [DUK], Southern Company [SOCO] and Florida Power & Light [FPL]).

All of the detailed results from these preliminary power flow study cases can be found in Volumes II and III. Volume II, Appendices E through M, contains the detailed results for the preliminary power flow cases identified in the original scope, Interconnection Option I. Volume III, Appendices N through Y, contains the detailed power flow results for Interconnection Options IIA and III. Volumes II and III have only been supplied to the participating utilities.

The interconnection of the second generator at the 500 kV Paradise Substation was studied by TVA independently and TVA has already forwarded its results to Peabody. Therefore impacts on the TVA system have not been studied in as great detail.

Appendix C in the report contains the details of the modifications for the reference model as provided by the participating utilities, and is contained in Exhibits C1 through C14. The reference model used for the power flow studies was the 2000 Series, NERC/MMWG Base Case Library Model - 2005 Summer.

After these preliminary studies were performed the preferred interconnection option selected for all further studies was case 271. This preferred interconnection plan includes one Thoroughbred generator connected to the 345 kV Wilson Substation and the second to the 500 kV Paradise Substation. It also includes an additional circuit that takes the existing 345 kV Wilson to Coleman line and loops it into the Elmer Smith Station (OMU). It also incorporates a new 161 kV line between Wilson and Paradise Substations (see Appendix B, Drawing B4).

Volume I contains the results of the most recent studies conducted for the Thoroughbred Energy Campus. The power flow results contained in this volume are for the base case with the MISO generators, the preferred interconnection plan with and without the MISO generators and the light load study cases. Volume I has been supplied only to the participating utilities.

Based on the preliminary results of the power flow studies that include the MISO and AEP IA generators, the participating utilities identified rating changes on several facilities located in the BREC and LGEE systems. The ratings were changed based on limits due to ground clearances and/or terminal limits (see Exhibit A11). The changes in the facility ratings were reflected in the case comparison summary charts shown in Exhibit A1, but the detailed power flow results contained in Volumes II and III were not rerun and do not reflect these facility changes as related to the addition of the MISO generators.

Detailed power flow results of the cases that incorporated the MISO IA generators are included in Volume I, Appendices E through J. Volume I has been provided only to the participating utilities.

A normal system and first contingency analysis was performed using CAI's TRANSMISSION 2000® Contingency Processor (CP). The contingency list is generated automatically, but multiple contingencies, provided by the participating utilities, were added manually.

There were a total of 376 contingencies of which 365 are single element contingencies and 11 are multiple element contingencies. The contingency set is listed in Appendix A7 and includes 291 buses. The contingencies (outages) were evaluated for the three base cases and 18 preliminary study cases. Nine of the multiple element outages include both a generator outage and transmission facility outage; these contingencies are not included in the analysis for the models that include a generator outage (i.e., Brown N Unit # 3 or Green River Unit # 4) since these models already include a generator outage.

The monitored region includes 2859 buses and covers 29 utility areas. The Area and Zone report, shown in Appendix A, Exhibit A8, shows the number of contingent and monitored buses included in this study. When the 15 Region 11 MISO and AEP IA generators were included in the power flow model, the monitored region contained 2865 buses.

Area losses in the bulk power transmission system increased due to the addition of the new generators at the Thoroughbred Energy Campus. The increase in area losses for the preliminary studies when compared to the base case are shown in Exhibit A31. The area losses were reviewed by the participating utilities and were considered to be low; as a result, the system losses should be evaluated using the more detailed 69 kV models that each utility has for its own system. The issue of system losses is addressed when the IPP makes a transmission service request with a particular utility. The affected utilities will determine the expected increase in losses and will factor those costs into the transmission service request.

Short Circuit Study

The short circuit study was conducted using the TRANSMISSION 2000® Short Circuit (SC) program. The reference model used for this study was the 2005 Summer - 2000 Series, NERC/MMWG Base Case Library. The short circuit models were prepared using data received from the participating utility companies. Since this study covers several regions, it was necessary to combine the short circuit data into one common model. Each utility provided its own short circuit models for this study. The additional data needed for short circuit studies was incorporated from the power flow model used in the preliminary studies. Since the data came from three different sources it was decided to convert the bus numbers and names to conform to those in the existing power flow model.

Summaries of the short circuit results for these preliminary cases are contained in Appendix A, Exhibit A2 and A3. These charts list all facilities whose fault current levels increased by between 0 and 10 percent, when compared to the base case. The utilities reviewed the results and identified breakers that were insufficient for the fault current levels. One 69 kV breaker and five 138 kV breakers were identified as exceeding their ratings. These breakers will probably need to be upgraded or replaced. In addition, since the power flow model does not adequately represent the underlying 69 kV, additional breakers could require replacement.

Light Load Power Flow Study

A light load study model was conducted to determine what affect the Thoroughbred project would have under light load conditions. The reference model used to develop the base case light load model was the 2001 Series, NERC/MMWG Base Case Library, 2002 Light Load Case, Trial #7. The same facility changes provided by the utilities for the 2005 Summer Base Case model were used to create the light load base case model (case BC02LL). Per instructions from the utilities, the generation dispatch used in this model is slightly different than that used in the 2005 Summer studies.

Since case C271s05 was selected as the preferred interconnection plan, this was the only study case modeled for the light load condition (case C271LL02). The interconnection and generation dispatch for the Thoroughbred Energy Campus for the light load study model is identical to case C271s05. Light load study models corresponding to the loss of a generating unit in the LGEE system were not studied.

A contingency analysis was conducted using CAI's TRANSMISSION 2000® Contingency Processor (CP). The contingencies (outages) involved 359 contingencies, including eight multiple contingencies and 290 buses. Contingencies for the light load models were evaluated for the base case and study case only. The monitored region included 2743 buses, covering 27 utility areas. The Area and Zone report shown in Exhibit A8 lists the number of contingent and monitored buses used in this study for each of the 27 utilities and also shows zone data, which utilities use to define groups of circuits internal to their own system. Detailed power flow results and case comparisons are contained in Volume I, Appendices F and G.

The result of the comparison between the light load base case and the study case showed no impacts due to overloaded facilities. There was, however, some concern that available transfer capability (ATC) may be constrained during periods of light load. Using their in-house power flow model (including their underlying 69 kV system), LGEE conducted its own independent study based on the preliminary preferred interconnection plan. They reported the following findings; "We have conducted a power flow analysis on Case 271 at varying LG&E Energy system load levels and have found that for load levels in the range of 70%-95% of system peak, we expect the maximum allowable generation at Brown to decrease by 50 to 150 MW due to the Thoroughbred generators. The limit is the flow on the Brown Plant to Fawkes 138 kV line due to an outage of the Brown-Alcalde-Pineville 345 kV line. Also, because this flow is dependent on the level of generation at East Kentucky Power Cooperative's (EKPC) JK Smith plant, the magnitude of the impact could be more severe if EKPC buys off-system rather than dispatching these units."

LGEE made a recommendation for correcting this limitation on the Brown plant generation level. "The limitations at Brown due to Thoroughbred can be eliminated by energizing the Brown to Pineville 345 kV line. This line is currently in place, but requires terminal facilities at both Brown and Pineville in order to allow energization. Energization of this line would return the maximum allowable generation at Brown to at least the level we expect if Thoroughbred is not constructed. This would be a requirement if Option III is adopted." This one 345 kV new transmission facility will be required for the preferred interconnection of the Thoroughbred generators.

MISO Power Flow Study

The MISO became involved in the project during April 2002 and identified 15 Independent Power Producers (IPP) that have signed Interconnection Agreements (IA) in their generator interconnection request queue. The MISO recommended that these projects (located in MISO's Region 11), as well as AEP projects, be included in the studies for the Thoroughbred project. Without the inclusion of these projects the MISO was concerned that stability and short circuit reliability impacts on the AEP or MISO transmission systems would not be adequately addressed.

Since study case C271s05 was selected as the preferred interconnection plan, all further power flow studies were modeled with the Thoroughbred Energy Campus connected as shown in Drawing B4, for case C271s05. Case C271s05 represents Interconnection Option III and includes two 750 MW Thoroughbred generators, one connected to 500 kV at the Paradise Substation (TVA), and the other to 345 kV at the Wilson Substation (BREC), with the existing 345 kV circuit between Wilson and Coleman looped into OMU's Elmer Smith Station. This model also includes an additional new 161 kV branch circuit between Wilson and Paradise Substations.

MISO provided the data used in modeling the IA generators. The chart in Exhibit A9 lists the 15 MISO Region 11 and AEP generators used in the MISO power flow models. It also includes information about the generator control area, location, generator bus number, MISO queue number and queue date, high side bus number and base voltage, and the interconnection status. The 15 IPPs identified by the MISO are expected to be on-line and producing power prior to the completion of the Thoroughbred Energy Campus project.

Drawing B1 shows the probable relative location of the 15 MISO generators on the bulk power transmission system. Each generator is identified with a circle and labeled with the generator numbers provided by MISO. Within the circle is the generation dispatch used in these models, including the MISO generators and the interconnection status of the generator.

The two corresponding study models, representing a loss of a generator in the LGEE system, were not modeled for these power flow studies that include the MISO generators because facilities that were overloaded in these corresponding study cases were the same facilities that were overloaded in the preferred interconnection plan when compared to the base case.

The 15 IPPs identified by MISO were incorporated into both the 2005 Summer Base Case model and the preferred interconnection models. One IPP located in AEP's control area was also included. The AEP generator went into service in June 2002, and was not represented in the previous power flow studies. Three study models were created and include the addition of the MISO IA generators. In these power flow models, the generation is dispatched (sold) equally to six utilities; the three utilities in the south were the same ones used in the previous studies, but dispatch to utilities in the north changed to PJM, Consumers Energy (Cons), and Northern Indiana (NI). Generation dispatch to the north was changed because several of the IPP generators are located in the CINergy control area. The dispatch to the north in the preliminary power flow models was to CINergy, AMEREN, and AEP.

These two MISO power flow models, the base case (BS05sMF) and the preferred interconnection plan (case C271s05MF), incorporate the same generation dispatch and facility changes provided by the participating utilities for the 2005 Summer Base Case. The data used for modeling the MISO generators was provided by MISO. The data used for modeling the AEP generator was provided by C. Bradley of BREC. This AEP generator was not included in the MISO model or previously modeled in the study cases. This AEP generator is request number 21 in the AEP generator interconnection request queue.

The MISO generators were connected into the power flow model as shown in thumbnail Drawing B3. The net change in generation dispatch is shown in Exhibit A10 and is also depicted in Drawing B1. Since the generators in closer proximity to the Thoroughbred Energy Campus have more potential to influence the power flow than those in the north group, the 15 MISO generators were lumped into two groups, shown in Drawing B2, identifying the north and south groups of MISO generators. The south group of MISO generators includes 11 generators. The north group includes four MISO generators and the one AEP generator.

The preferred interconnection plan with the MISO generators was constructed by modifying case 271 to include all the MISO generators listed in Exhibit A9. This MISO power flow model was built in three steps; first, all generators were added to the model with their generation level set to zero output. Second, the 11 generators in the MISO south group (case 271s05MS) were placed on-line with the net change in generation dispatch as indicated in the circle in Drawing B1 (it is also listed in the chart in Exhibit A10). In the final step, generators identified in the MISO north group were added in the same manner so that all of the IPP generators with signed interconnection agreements identified by MISO and the AEP generator are in the final MISO power flow model (case 271s05MF). The base case model with the MISO generators was prepared in the same way (case BS05sMF).

A contingency analysis was conducted on these MISO power flow models using CP. The contingency set includes a total of 375 contingencies, with 11 being multiple contingencies and involving 291 buses. The contingencies were evaluated for both the MISO base case (case BS05sMF) and the preferred interconnection plan with all the MISO generators (case C271s05MF). The monitored region contained 2865 buses covering 29 utility areas. The Area and Zone report shown in Exhibit A8 lists the number of contingent and monitored buses for each utility area and also shows zone data, which utilities use to define groups of circuits internal to their own systems.

Preliminary results of the MISO power flow study were presented to the participating utilities and resulted in rating changes on seven additional facilities in the LGEE system. The ratings were changed based on limits due to ground clearances and/or terminal limits shown in Exhibit A11 with no asterisk. The revised ratings reduced the number of new overloads (Group 1 facilities) and the loading on the circuits shown in Exhibit A1 reflects the rating increases. This exhibit identifies all new overloads resulting from the addition of the 15 MISO generators to both the base case (BS05sMF) and the preferred interconnection plan (case C271s05MF). This exhibit compares four study cases, with and without the MISO generators, to the 2005 Summer Base Case.

A comparison of the MISO base case model to the 2005 Summer Base Case identified nine new overloads (Group 1 facilities) and five pre-existing overloads that were made worse (Group 2 facilities). These nine Group 1 facilities are shown in the box labeled A1. The five Group 2 facilities are shown in the box labeled A2.

A comparison of the preferred interconnection plan with no MISO generators to the 2005 Summer Base Case also identified nine new overloads (Group 1 facilities) and five pre-existing overloads that were made worse (Group 2 facilities). Four of the nine Group 1 facilities are already overloaded in the MISO Base Case and are shown in the boxes labeled A1 and B1. The other five Group 1 facilities are new overloads resulting from the preferred interconnection plan with no MISO generators and are in the box labeled B1. Three of the five Group 2 facilities are already overloaded in the MISO Base Case but two new facilities overload due to the preferred interconnection plan with no MISO generators and are shown in the box labeled B2.

A comparison of the preferred interconnection plan with only the south group of MISO generators to the 2005 Summer Base Case identified two new overloads (Group 1 facilities) and no new pre-existing overloads that were made worse (Group 2 facilities). These facilities are shown in the box labeled C1. Two of the four facilities were overloaded before the ratings were changed to reflect maximum ground clearances or improved terminal facilities. The facilities are shown in Exhibit A11. Facilities in Exhibit A1 that have had their ratings changed, after including the MISO generators, are indicated by an asterisk.

A comparison of the preferred interconnection plan with all the MISO generators to the 2005 Summer Base Case, identified 12 new overloads (Group 1 facilities) and six pre-existing overloads that were made worse (Group 2 facilities). Seven of the 12 new overloads and five of the six pre-existing overloads are also identified as being overloaded in the MISO Base Case. The facilities in the box labeled D1 were overloaded, but after the ratings were changed they were no longer overloaded. The five new Group 1 overloaded circuits are shown in the two sections of facilities shown above the box labeled D1 in Exhibit A1. Three Group 1 facilities outlined in grey boxes indicates that loading was reduced due to the addition of the Thoroughbred project to the base case, with the MISO generators and the Group 1 facilities shown with a cross-hatched background indicates reduced loading due to the addition of the MISO generators to the preferred plan.

A light load power flow model representing the preferred interconnection plan with the MISO and AEP IA generators was not studied. It is expected that most, if not all, of the new generators would not be base load units and therefore would not be operating under light load conditions.

Transient Stability Power Flow Study

The transient stability study was conducted using CAI's TRANSMISSION 2000® Transient Stability (TS) program. The reference model used for developing the transient stability power flow model was the 2001 Series, NERC/MMWG Base Case Library, 2003 Summer Case, Trial #9 (PLI). The generation dispatch and facility changes already provided for the 2005 Summer Base Case model were used to develop the transient stability base case model (case TS03s1aT1). Transient stability is a study conducted to investigate the dynamic performance of generators under fault conditions, and to determine the time at which a generator will go into instability due to the disturbance.

Critical clearing time is the time before which a disturbance must be cleared by the protection system in order to maintain stable operation. Faults that are not cleared from the system before this time will cause the generator to become unstable and to be tripped off line. Transient stability of a transmission system is studied by simulating faults of varying durations on transmission facilities located near a generator and observing specific generator parameters to determine when instability will occur. Faults are normally cleared from the transmission system by the operation of protective equipment such as relays and breakers. In these studies the disturbance simulated is a three-phase fault.

Three transient stability models were constructed; a base case, a base case with the MISO generators, and the preferred interconnection plan with the MISO generators. Since generator dynamics data for the MISO generators was not available, sample data was used to represent the power system components, including a model for a classical round rotor synchronous machine, an exciter model, and a governor model. The data used for modeling these components is shown in Exhibits A12 through A15. The generator dynamics data is used along with the power flow model to form a complete dynamics model. The transient stability model also requires each generator to be connected by a generator step-up transformer (GSU). If a generator was already modeled with a GSU the existing data was used. Otherwise impedance values for the GSU were calculated based on the generator maximum active power and maximum reactive power values.

The transient stability base case model was modified to include the 15 MISO generators. This model was built in three steps; all the generators were modeled with zero output, next the south group of MISO generators were placed online with the net change in generation dispatch as indicated in the circle shown in the drawing in Exhibit B1 (also listed in the chart in Exhibit A10), and finally the north group of MISO generators were placed online and dispatched in the same fashion (case TS03s1aMF). This represents the MISO Final Transient Stability model for 2003 Summer. The generation was dispatched to the six utilities as previously indicated for the MISO power flow models, then the MISO base case model was modified to include the facilities needed for the preferred interconnection of both 750 MW Thoroughbred generators as shown in Exhibit B4 (case TS03s1aMFth). The generation from the Thoroughbred units was dispatched (sold) to the same six utilities used in the preliminary power flow studies.

The results of the transient stability study are summarized in the tables shown in Appendix A, Exhibits A4, A5, and A6. The results for the preferred interconnection plan with the MISO generators are shown in Exhibit A4. Exhibits A5 and A6 are the results for the MISO base case model and the base case model, respectively. These exhibits list the critical clearing times for the facilities in close proximity to the Thoroughbred generators. The graphs in Appendix D, Exhibits D11 through D260 show the dynamic response of the generators for a three-phase fault applied to a transmission facility. The graphs show the change in machine angle and speed resulting from the disturbance for the generator near the fault. For each fault studied the graph identifies the critical clearing time at which generators will go into instability.

The participating utilities reviewed the protection schemes in their transmission systems and determined that it will operate within these parameters to prevent the generators from going into an unstable condition. This is accomplished by fast-acting relay and breaker combinations.

Item 25) Provide the following transmission energy data forecast for the years 2005 through 2025.

a) Total energy received from all interconnections and generation sources connected to your transmission system.

b) Total energy delivered to all interconnections on your transmission system.

c) Peak demand for summer and winter seasons on your transmission system.

Response) The attached three tables list Big Rivers' transmission system energy, capacity, and demand responses. As stated in the response to Item 22, Big Rivers load forecast and transmission planning is complete from 2005 through 2017. Therefore, the responses for this Item are generally limited to that future time span.

Witness) Travis D. Housley, P.E.
David G. Crockett, P.E.

Big Rivers Electric Corporation

Item 25a

Transmission System Energy Received (MWh)

	Generation	Interconnections	Total
2005	11,500,000	4,000,000	15,500,000
2006	11,500,000	4,000,000	15,500,000
2007	11,500,000	4,000,000	15,500,000
2008	11,500,000	4,000,000	15,500,000
2009	11,500,000	4,000,000	15,500,000
2010	11,500,000	4,000,000	15,500,000
2011	11,500,000	4,000,000	15,500,000
2012	11,500,000	4,000,000	15,500,000
2013	11,500,000	4,000,000	15,500,000
2014	11,500,000	4,000,000	15,500,000
2015	11,500,000	4,000,000	15,500,000
2016	through 2025 assume same as 2015		

Big Rivers Electric Corporation

Item 25b

Transmission System Energy Delivered at Interconnections (MWH)

	Total
2005	4,200,000
2006	4,175,000
2007	4,150,000
2008	4,125,000
2009	4,100,000
2010	4,075,000
2011	no data available due to change in smelter requirements
2012	
2013	
2014	
2015	
2016	
2017	

Big Rivers Electric Corporation

Item 25c

Transmission System Peak Demand (MW)

	Winter	Summer
2005	1800	1800
2006	1800	1800
2007	1800	1800
2008	1800	1800
2009	1800	1800
2010	1800	1800
2011	1800	1800
2012	1800	1800
2013	1800	1800
2014	1800	1800
2015	1800	1800

2016 through 2025 assume same as 2015.

Item 30) Identify and describe all reportable distribution outages from January 1, 2003 until the present date. Categorize the causes and provide the frequency of occurrence for each cause category.

Response) Big Rivers does not own or operate distribution lines. As such, it has no reportable distribution outages.

Witness) Travis Housley, P.E.

Item 31) Does your utility have a distribution and/or transmission reliability improvement program?

a) How does your utility measure reliability?

b) How is the program monitored?

c) What are the results of the system?

d) How are proposed improvements for reliability approved and implemented?

Response) Yes, Big Rivers Electric Corporation has a transmission reliability improvement program.

a) Big Rivers Electric Corporation owns transmission only, and its three member cooperatives own the distribution systems. Big Rivers provides electric service to its three members' substations by way of its 69 kV sub-transmission system. Since a disturbance on a portion of Big Rivers 69 kV system usually results in the loss of voltage to a distribution substation and the retail customers served from the effected substation(s), Big Rivers uses the SAIDI and CAIDI (distribution reliability measures) to measure the reliability of its 69 kV system. Acceptable levels of SAIDI and CAIDI are established by Big Rivers' board of directors upon recommendation from its member cooperatives.

Two additional measures are used to evaluate the performance of the higher voltage portion of the transmission system. Those measures are: percent of load served, and MWH of sales lost. As with SAIDI and CAIDI, the Big Rivers board of directors sets acceptable levels of these two measures.

b) A monthly outage report is provided to the Big Rivers board of directors and copied to the member cooperatives, and a review of the SAIDI and CAIDI calculations is presented to the Big Rivers board each quarter.

At the end of each year the SAIDI and CAIDI results are also reviewed with an operating committee comprised of operations personnel from each member cooperative. At the meeting each transmission outage of the previous year is discussed noting: causation, duration of outage, and measures taken to prevent a recurrence. The previous year's performance and outage causation is compared to previous years to try to identify possible trends and to identify system improvements that need to be made.

c) The system results are very good. The members' concerns are identified and an objective performance review provides information regarding the area in which system improvements are needed.

d) The improvements identified by Big Rivers' review of the performance measures as well as the member suggestions are included in Big Rivers' capital budget for the following year and submitted to the Big Rivers board of directors. Big Rivers board of directors has never failed to approve a budget item submitted for reliability improvement.

Witness) Travis Housley, P.E.

Item 32) Provide a summary description of your utility's:

a) Right-of-way management program. Provide the budget for the last 5 years.

b) Vegetation management program. Provide the budget for the last 5 years.

c) Transmission and distribution inspection program. Provide the budget for the last 5 years.

Response) See below:

a) Right-of-way management and vegetation management are combined on 32. b).

b) The vegetation control along Big Rivers' transmission line rights-of-ways is performed by contracted crews under the supervision of Big Rivers' personnel. This contract consists of either chemically treating or handcutting as dictated by rights-of-way easements' restrictions and/or vegetation size and location. Physical condition of transmission facilities is also observed and noted in conjunction with this operation. This work is performed on a four year cycle.

Right-Of-Way and Vegetation Management Budget

Year	Budget
2001	$485,000
2002	$485,000
2003	$485,000
2004	$485,000
2005	$455,000

c) <u>Transmission Lines Routine Inspection</u>

1. Two-month aerial inspection is performed on each transmission line, and additional aerial patrols are performed when lines lock out or when there is reason to suspect that lines are in trouble. All radio controlled switches are checked for serviceability and/or adjustments monthly.

2. Every six months, all microwave and river crossing towers are inspected for hardware and guy tightness. Towers with aviation warning lights are re-lamped and other maintenance is performed as required. These functions are performed by contractor personnel. Repairs and emergency re-lamping is prepared by Big Rivers.

3. Transmission ground line pole inspection and treatment consists of excavating 18" from ground line of pole, removing decay, and determining if remaining pole circumference is sufficient for strength requirements of pole. Poles are treated with fungicide and insecticide, then dirt is replaced. All above ground inspection of pole is performed to determine serviceability of pole and/or repairs needed to pole and/or crossarms. All observations are recorded on inspection sheets. Big Rivers' transmissions crews perform all in air maintenance (add pole caps, tighten hardware, and repair woodpecker damage). This work is performed upon completion of ground line inspection. This work is performed at the first 15 years of life on a line, next in 10 years, and every 5 years thereafter.

4.

Transmission Line Inspection Budget

Year	**Budget**
2001	$27,300
2002	$26,300
2003	$27,200
2004	$22,400
2005	$27,600

Witness) Travis Housley, P.E.

Item 33) Explain the criteria your utility uses to determine if pole or conductor replacement is necessary. Provide costs/budgets for transmission and distribution facilities replacement for the years 2000 through 2025.

Response)

33. Part One

Pole and Conductor Replacement Criteria

Wood poles are replaced based on criteria established by RUS. (Bulletin 1730B-121) RUS minimum pole strength is based on NESC requirements.

Conductors would be replaced based on failing to meet minimum tensile strength requirements based upon NESC and RUS guidelines.

33. Part Two

Replacement of Facilities Budget

Year	Poles	Other	Total
2000	$215,460	$748,540	$964,000
2001	$240,000	$961,790	$1,201,790
2002	$450,000	$482,400	$932,400
2003	$403,400	$438,000	$841,400
2004	$379,030	$646,670	$1,025,700
2005	$422,700	$5,078,000	$5,500,700
2006	$435,000	$600,000	$1,035,000
2007	$448,000	$618,000	$1,066,000
2008	$461,000	$636,000	$1,097,000
2009	$475,000	$655,000	$1,130,000
2010	$489,000	$675,000	$1,164,000
2011	$504,000	$695,000	$1,199,000
2012	$519,000	$716,000	$1,235,000
2013	$534,000	$738,000	$1,272,000
2014	$550,000	$760,000	$1,310,000
2015	$567,000	$783,000	$1,350,000
2016	$584,000	$806,000	$1,390,000
2017	$602,000	$830,000	$1,432,000
2018	$620,000	$855,000	$1,475,000
2019	$638,000	$880,000	$1,518,000
2020	$657,000	$907,000	$1,564,000
2021	$677,000	$934,000	$1,611,000
2022	$697,000	$962,000	$1,659,000
2023	$718,000	$991,000	$1,709,000
2024	$740,000	$1,021,000	$1,761,000
2025	$762,000	$1,051,000	$1,813,000

Witness) Travis Housley, P.E.