TW

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

Ronald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
William R. Dexter
Allen W. Holbrook
R. Michael Sullivan
Bryan R. Reynolds
Tyson A. Kamuf
Mark W. Starnes
C. Ellsworth Mountjoy
Susan Montalvo-Gesser

August 30, 2007

RECEIVED
AUG 31 2007
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: In the matter of: The Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 kV Transmission Line in Ohio County, Kentucky, Case No. 2007-00177

Dear Ms. O'Donnell:

Enclosed on behalf of Big Rivers Electric Corporation are an original and ten copies of the testimony of Chris Bradley. I certify that a copy of the testimony has been served on the attached service list.

Sincerely,

TAK

Tyson Kamuf

TAK/ej
Enclosures

cc: Michael H. Core
David Spainhoward
David Crockett
John Talbert
Chris Bradley
Bill Blackburn
Mark A. Bailey
Service List

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

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

SERVICE LIST
PSC CASE NO. 2007-00177

David Brown, Esq.
STITES & HARBISON
1800 Providian Center
400 West Market Street
Louisville, Kentucky 40202

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202 .

COUNSEL FOR ALCAN ALUMINUM AND CENTURY ALUMINUM

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
The Application of Big Rivers Electric Corporation	)	Case No. 2007-00177
for a Certificate of Public Convenience and	)	
Necessity to Construct a 161 kV Transmission Line	)	
in Ohio County, Kentucky	)	

TESTIMONY OF CHRIS BRADLEY
ON BEHALF OF
BIG RIVERS ELECTRIC CORPORATION

August 31, 2007

TESTIMONY OF CHRIS BRADLEY

Q1. Please state your name, occupation, and business address.

Response: My name is Chris Bradley. My current position is System Planning & Reliability Compliance Supervisor for Big Rivers Electric Corporation. My business address is 201 Third Street, Henderson, Kentucky 42419. I have been an employee of Big Rivers since May of 1989 and in my current position since 2006.

Q2. Please describe your educational background and experience in the electric utility industry.

Response: I received a Bachelor of Science Degree in Electrical Engineering from the University of Evansville in 1989 and a Master of Science Degree in Engineering Management from the University of Evansville in 1992. I am a licensed Professional Engineer in the State of Kentucky and a Member of the Institute of Electronic and Electrical Engineers.

I have 18 years of electric utility experience at Big Rivers primarily in the area of transmission planning. In my current position as System Planning & Reliability Compliance Supervisor, I am responsible for operational planning and support, transmission system planning, and ensuring compliance with NERC reliability standards.

Q3. In your position at Big Rivers, were you responsible for producing the Bulk Transmission System Assessment that is attached as Appendix A to Big Rivers' application in this matter?

Response: Yes.

Q4. Explain briefly what the Bulk Transmission System Assessment shows?

Response: The purpose of the Bulk Transmission System Assessment was to prepare a complete analysis of the Big Rivers bulk transmission system with and without the loss of the load of two aluminum smelters under a variety of system conditions. The two aluminum smelters have loads that total approximately 850 MW. If Big Rivers regains operation of its generating stations from E.On U.S., LLC and its affiliates, it is critical, for reasons explained by others, that Big Rivers be able to export the excess generation resulting from the loss of the smelter load. The Bulk Transmission System Assessment establishes that the proposed 13 mile transmission line for which Big Rivers is seeking a certificate of public convenience and necessity in this case is necessary to reliably export all excess generation in the event of the loss of both aluminum smelters.

Q5. Why was the Bulk Transmission System Assessment based primarily on 2015 summer peak study results?

Response: Under the proposed contacts, the aluminum smelters cannot terminate their contracts prior to 2011. Therefore, selecting a study year beyond 2011 was deemed appropriate. However, longer-term models introduce greater uncertainties in the load forecast, the system topology, and the generation dispatch. The 2015 summer peak model provides a reasonable forward-looking view of the transmission system without many of the uncertainties associated with longer-term models. The additional studies completed with off-peak load levels and heavy north to south power transfers across the Big Rivers system encompass a realistic yet wide-range of system conditions.

Q6. Does the fact that the Bulk Transmission System Assessment is based on 2015 summer peak study results affect the validity or reliability of the study results?

Response: No. The Bulk Transmission System Assessment included power flow simulations of anticipated summer peak and off-peak conditions. The wide-range of load levels encompassed by these simulations ensured a valid and complete assessment of the proposed project.

Q7. Has Big Rivers conducted any other studies evaluating the proposed transmission line?

Response: Yes. The proposed construction or a variation of the proposed construction (*i.e.*, a direct Wilson to Paradise 161 kV interconnection) has been evaluated with various study models over the past 12 years. The Bulk Transmission System Assessment itself documented sensitivity studies performed with off peak load levels. In addition, north to south power transfers across the Big Rivers system were modeled and included in that study.

A 1995 Big Rivers-Kentucky Utilities Joint Interconnection Study that documented the need for the subsequently constructed Wilson to Green River 161 kV interconnection included an evaluation of a Wilson to Paradise 161 kV circuit. While not selected as the preferred option at that time, the circuit was found to be a responsive and beneficial interconnection. That study was completed with 1997 and 2005 summer peak models. A copy of that study is attached hereto as Exhibit 1.

A 2003 Thoroughbred Energy Campus Interconnection Study, which was filed with the Public Service Commission as Exhibit 3 to the application of Big Rivers in *In* *the Matter of: Application of Big Rivers Electric Corporation for Approval of Electrical Interconnection Service to Thoroughbred Generating Company, LLC*, PSC Case No. 2005-00300, also identified a Wilson to Paradise 161 kV interconnection as a necessary system improvement to allow for the connection and operation of Thoroughbred Generating Company's proposed generating unit on the Big Rivers system. A 2005 summer peak model and a 2002 light load model were used for that evaluation. A copy of the Thoroughbred Energy Campus Interconnection Study (without Appendices) is attached hereto as Exhibit 2.

Q8. Does this conclude your testimony?

Response: Yes.

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Chris Bradley

Chris Bradley

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

Subscribed and sworn to before me by Chris Bradley on this the 29th day of August, 2007.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires: 1-12-09

BIG RIVERS ELECTRIC CORPORATION-KENTUCKY UTILITIES JOINT INTERCONNECTION STUDY

An interconnection study has been undertaken by Big Rivers Electric Corporation (Big Rivers) and Kentucky Utilities Company (KU) to determine the need for, and costs and benefits of, a second interconnection between the companies. The Big Rivers' transmission system allows only a limited flow of power from and/or through Big Rivers. This limitation is evident during times of large power flows from utilities north of Big Rivers to utilities south of Big Rivers. These limitations restrict the ability of Big Rivers to transfer power to other utilities, and cause overloads and voltage problems during contingencies. In addition, KU's Western Division transmission system will eventually require additional facilities to alleviate voltage problems during contingencies. The transmission limitations of the Big Rivers' system are documented in the attached report entitled "1995 Summer Assessment of Transmission System Performance," dated May 1995, produced by ECAR, as well as in the report entitled "1995 MAIN Transmission Assessment Study," dated May 1995, produced by MAIN. Big Rivers' transmission system limitations are also illustrated by the actual events of July 22, 1993. These events are discussed in the attached ECAR report entitled "Assessment of System Conditions in ECAR on July 22, 1993."

I. Big Rivers' Transmission System Requirements

The study of Big Rivers' transmission system has been completed. This study initially focused on the transmission limitations outlined in the ECAR and MAIN reports, and on Big Rivers' goal to export 450 MW (or handle flow-through power) to other utilities during normal peak load conditions and 300 MW during peak load conditions with any single contingency. After the study was completed, Big Rivers then identified the need to determine system improvements necessary to increase the desired 450 MW export/transfer capability during normal conditions to 650 MW. It was found that the system improvements required to reach the 450 MW export/transfer level would also allow a 650 MW export/transfer level.

The ECAR 1995 Summer Assessment report describes the details of a loadflow analysis and makes the following findings: (1) while exporting power, Big Rivers can expect overloads on many of its 161 kV lines during normal and contingency conditions. When these overloads occur, Big Rivers first redispatches its units in an attempt to solve the problem. If this is unsuccessful, Big Rivers then opens either the Wilson-Coleman or Wilson-Reid 345 kV line, depending on the overloads. If the problem still exists, Big Rivers will ask neighboring utilities to redispatch their units to relieve Big Rivers' overloaded lines. Finally, if all other steps are unsuccessful, Big Rivers will curtail its exports and reduce generating station output to relieve its overloads. (2) Big Rivers severely restricts Southern Indiana Gas and Electric's (SIGE) ability to export power. All exports from SIGE to its neighboring utilities are limited to 10-20 MW by an overload of SIGE's Culley-Newtonville 138 kV line during an outage of the AB Brown (SIGE) - Henderson County (Big Rivers) 138 kV line. (3) The Hopkins County (Big Rivers) - Barkley (TVA) 161 kV circuit is identified as a key outaged facility which would result in an overload of the Newtonville (SIGE) - Cloverport (LGE) 138 kV line that would limit transfers from the Kentucky/Southern Ohio area of ECAR to the Indiana, Northern Ohio/Pennsylvania, and Southeastern areas of ECAR. Additionally, several Big Rivers' transmission facilities are identified as limiting facilities for transfers from the Kentucky/Southern Ohio area to these other ECAR areas. Also, the MAIN report listed above identifies several Big Rivers' transmission facilities as the limiting facilities for transfers from ECAR to MAIN, from ECAR to TVA, and from TVA to MAIN. The July 22, 1993 assessment report describes a series of events during which Big Rivers was required to first curtail all off-system power sales and finally open all its interconnections to the north. As part of this assessment, ECAR developed a power flow database representing the actual July 22, 1993 system conditions. Power flow studies run with the base case show that if Big Rivers did not open its northern interconnections, several facilities would have been overloaded. The Reid-Hopkins County-Barkley 161 kV circuit may have been overloaded at or near 150% of its rating; the Coleman-National Aluminum 161 kV circuit may have been loaded at 100%; and the New Hardinsburg-Paradise 161 kV interconnection (Big Rivers/TVA) may have been overloaded at 113% of its rating.

The study of the Big Rivers transmission system began with an analysis of the 1997 Summer peak-load loadflow case which showed, at the 450 MW export/transfer level, several lines would be overloaded under normal conditions and additional overloaded lines would occur during contingencies. Big Rivers' export (or transfer) was then reduced in subsequent loadflow studies until the flow on each overloaded line was below that line's rating. The export value at which a line would no longer be overloaded was then identified as Big Rivers' limitation on its export/transfer capability imposed by that line. These limits for the 1997 Summer loadflow case are listed in Table 1.

Table 1
1997 Summer Limits on Big Rivers' Export Capability

ITEM	TOTAL TRANSFER	LIMITING FACILITY	RATING (MVA)	OUTAGED FACILITY
1	25 MW	Newtonville (SIGE)-Cloverport (LGE) 138 kV	143	Coleman-National Aluminum 161 kV
2	30 MW	Reid-Daviess County 161 kV	265	Coleman-Wilson 345 kV
3	170 MW	Coleman-Newtonville (HE) 161 kV	250	Coleman-National Aluminum 161 kV
4	180 MW	Coleman-National Aluminum 161 kV	265	Coleman-Newtonville (HE) 161 kV
5	200 MW	National Aluminum-Skillman 161 kV	265	Coleman-Newtonville (HE) 161 kV
6	210 MW	Newtonville (SIGE) 161-138 kV	185	Coleman-National Aluminum 161 kV
7	305 MW	Reid-Hopkins County 161 kV	265	Coleman-Wilson 345 kV
8	310 MW	Hopkins County-Barkley (TVA) 161 kV	265	Coleman-Wilson 345 kV
9	365 MW	Newtonville (SIGE)-Cloverport (LGE) 138 kV	143	None
10	375 MW	Newtonville (SIGE) 161-138 kV	150	None
11	415 MW	Skillman-N. Hardinsburg 161 kV	265	Coleman-Newtonville (HE) 161 kV
12	420 MW	Coleman-National Aluminum 161 kV	265	None
13	450 MW	National Aluminum-Skillman 161 kV	265	None

Table 1 shows that Big Rivers' export/transfer capability would be restricted to a level below 450 MW during normal conditions in the projected 1997 Summer period due to potential overloads on three lines and one transformer (Items 9,10,12 and 13). Table 1 also shows that Big Rivers' export/transfer capability would be restricted to a level below 300 MW in the projected 1997 Summer period during any one of three contingencies (Items 1-6).

Loadflow studies show that the construction of a second 161 kV line between Coleman and New Hardinsburg, approximately 23 miles, would eliminate the export/transfer limitations imposed due to the Coleman-National Aluminum 161 kV line outage by providing a parallel path for that line outage. This new line would also eliminate the limitations imposed both during normal conditions and during the Coleman-Newtonville 161 kV contingency outage by providing a parallel path for the overloaded facilities.

However, loadflow studies show that the construction of a second Coleman-New Hardinsburg 161 kV line would not improve Big Rivers' export/transfer capability during the Coleman-Wilson 345 kV contingency outage, since the power flows on the transmission outlets from the Reid generating station would not be significantly changed. The Wilson Plant presently has two 345 kV transmission outlets to the Coleman and Reid generating stations (see Attachment 1). Therefore, during the Coleman-Wilson 345 kV contingency outage, all power generated at the Wilson Plant must flow to Reid on the Wilson-Reid 345 kV line. This power, along with the power generated at the Reid generating station, must then be transmitted on the transmission system from the Reid 161 kV bus over four 161 kV outlets. In order to increase the export/transfer capability during the Coleman-Wilson 345 kV outage to 300 MW, the Reid-Daviess County 161 kV line (22 miles) would need to be upgraded to a higher capacity (see Table 1).

In summary, Big Rivers could increase its export/transfer capability to 650 MW during normal conditions and to 300 MW during any single contingency by constructing 23 miles of new 161 kV line and upgrading 22 miles of existing 161 kV line. Loadflow studies indicate a less-costly option of constructing 15 miles of 161 kV line from Wilson to TVA's Paradise Plant would also be adequate to increase the export/transfer capability as above. This new construction would provide parallel outlet facilities between Wilson and TVA and between Wilson and New Hardinsburg. With this line constructed using bundled 795 kcm ACSR conductor, no overloaded lines were identified at the 650 MW export/transfer level during normal conditions or at the 300 MW export/transfer level during any single-contingency condition.

Since KU's Green River Plant is approximately eight miles from the Wilson Plant, while TVA's Paradise Plant is 15 miles from the Wilson Plant, the impact of a 161 kV line between Big Rivers' Wilson Plant and KU's Green River Plant was also investigated to determine if this line could be a less costly solution than the line to TVA's Paradise Plant. A 1997 Summer loadflow analysis identified no overloaded lines on either Big Rivers' or SIGE's transmission systems at the 650 MW export/transfer level during normal conditions or at the 300 MW export/transfer level during contingency conditions with the Wilson-Green River 161 kV line. Also, loadflow studies show that a Wilson-Green River 161 kV line would provide Big Rivers with transmission system benefits equal to those benefits which would be provided by a Wilson-Paradise 161 kV line. Therefore, Big Rivers has also identified the Wilson-Green River 161 kV line as a possible solution to its transmission system limitations, assuming that any KU transmission problems or overloads which may result could be economically alleviated.

II. KU Transmission System Requirements

An evaluation of the transmission system construction requirements necessary to prevent low voltages and overloaded lines in KU's Western Division through the first 15 years of the planning period has been conducted. The only problems identified within this period in KU's Western Division were overloads of sections of the Green River-Indian Hill and Indian Hill-Ohio County 69 kV lines during an outage of the Green River-Ohio County 138 kV line, with the Indian Hill-Pyramid Mine section of the Indian Hill-Ohio County 69 kV line being the first section to overload, which would occur in 1995 Summer. Two alternatives have been identified to eliminate the overloads of these 69 kV lines during the Green River-Ohio County 138 kV contingency outage. One alternative would be to reconductor the 69 kV lines (17.3 miles) with 556 kcm ACSR conductor. A second alternative would be to convert the Green River-Matanzas 69 kV line to 138 kV and construct 7.9 miles of 138 kV line from Matanzas to Ohio County using 556 kcm ACSR conductor. The Green River-Matanzas line is already constructed for 138 kV operation (presently operating at 69 kV); therefore, the cost of converting this line would be minimal. Previous analysis has shown the conversion to 138 kV and construction of the additional 138 kV line to be the preferred alternative.

Therefore, the only construction necessary in the area prior to 2011 would be conversion of the Green River-Matanzas 69 kV line to 138 kV and construction of 7.9 miles of 138 kV line from Matanzas to Ohio County in 1997 using 556 kcm ACSR conductor.

Although this construction is the only construction identified, KU does anticipate the need for additional voltage support in its Western Division at some point beyond 2011. At that time, KU would need to construct either a 161 kV line from its Green River to Big Rivers' Wilson Plant, a 161 kV line from Green River to TVA's Paradise Plant, or a 345 kV line from Green River to OMU's Smith Plant. The Green River-Wilson 161 kV line would be the most economic means of providing this support.

III. KU-Big Rivers Interconnection Options

The results of Big Rivers' export/transfer capability evaluation and KU's evaluation of its transmission system requirements show that an interconnection between Big Rivers' Wilson Plant and KU's Green River Plant would improve Big Rivers' export/transfer capability to the desired level, but would not aid in the elimination of the transmission system problems for KU prior to 2011. However, KU would gain other benefits from this interconnection, and would satisfy transmission system requirements which are currently projected beyond 2011. Although little or no load growth is forecasted for KU's Western Division area at present through the study period, a relatively small increase in KU's Western Division load would accelerate the need for additional transmission support in this area. Establishing this interconnection would ensure sufficient voltage support for KU's

Western Division transmission system east of Livingston County in the case of any large load additions or a return to a normal load growth forecast in the area consistent with the load growth expected in KU's other divisions. Additionally, sufficient support would be provided by this interconnection so that generating units at Green River could be off-line for maintenance or other periods, including peak-load periods. Without the interconnection, KU's Western Division voltages could be marginal during the critical contingencies without at least one unit on-line at the Green River Power Plant. Also, without completing this interconnection with Big Rivers, if a large load was added in the area or the forecasted load growth returned to a normal level in this area within the next few years, KU would need to construct the 161 kV line from Green River to Wilson. Finally, the interconnected capacity between Big Rivers and KU would increase from 224 MVA Summer and Winter to approximately 742 MVA Summer and 782 MVA Winter, providing the opportunity for larger transactions between the two companies. As stated in Section II, KU's analysis shows that conversion of the Green River-Matanzas 69 kV line to 138 kV and construction of a 138 kV line from Matanzas to Ohio County is necessary to prevent overloads of sections of the Green River-Indian Hill and Indian Hill-Ohio County 69 kV lines. Since Big Rivers' analysis includes a 161 kV line to TVA's Paradise Plant, a second interconnection between Green River and the New Hardinsburg-Paradise (TVA) line was discussed as a possible alternative to KU's 138 kV line construction. Therefore, the two companies agreed to evaluate the following two interconnection options in this area:

i) a 161 kV line from the Wilson Plant to the Green River Plant

ii) a 161 kV line from the Wilson Plant to the Green River Plant and a 161 kV line from Green River to Big Rivers' New Hardinsburg-Paradise (TVA) 161 kV line

i. Wilson-Green River 161 kV Interconnection

A loadflow analysis has been conducted for the 1997 Summer peak-load period with a 161 kV line from Wilson Plant to Green River Plant to determine the conductor requirements for this interconnection. With 1590 kcm ACSR conductor, the power flow during a Big Rivers' export/transfer of 650 MW was found to be 364 MVA, which is marginally close to the 1590 kcm ACSR conductor's normal rating of 382 MVA. With bundled 556 kcm ACSR conductor, the power flow would be 377 MVA under similar conditions, whereas the normal conductor rating for bundled 556 kcm ACSR is 422 MVA. With bundled 795 kcm ACSR conductor, the flow would also be 377 MVA, whereas its normal conductor rating is 530 MVA. Therefore, although any of these conductors would be adequate for the flows listed, bundled 795 kcm ACSR conductor was modeled in this loadflow analysis. This conductor provides a comfortable margin between the maximum power flow and its normal rating in 1997 Summer. A contingency loadflow analysis of the 1997 Summer peak-load period was then conducted with a Big Rivers' total export/transfer of 300 MW. Table 2 lists the overloaded lines identified on KU's transmission system with the interconnection modeled.

Table 2
1997 Summer Overloads on KU's System with Wilson-Green River 161 kV

TOTAL TRANSFER	LIMITING FACILITY	MVA FLOW	EMERGENCY RATING	OUTAGED FACILITY
300 MW	GR River 161-138 Xfmr #2	128	115	GR River 161-138 Xfmr #1
300 MW	GR River 161-138 Xfmr #1	126	115	GR River 161-138 Xfmr #2
300 MW	Ohio Co. 138-69 kV Xfmr	60	58	Ohio Co-Shrewsbury-Bonnieville 138

Two construction projects were identified to eliminate the overloads of the Green River 161-138 kV transformers. One alternative would be to replace both transformers with 150 MVA transformers. The other alternative would be to install a third 100 MVA transformer. The purchase and installation of two 150 MVA transformers would require a larger expenditure than the purchase and installation of the single 100 MVA transformer. Therefore, the installation of a third 161-138 kV, 100 MVA transformer at Green River would be the least-cost alternative of the above alternatives. The overload of the Ohio County 138-69 kV transformer during the Ohio County-Shrewsbury-Bonnieville 138 kV line outage could be eliminated by replacing the Ohio County transformer with a larger unit.

However, both companies concluded that neither of the above alternatives was least-cost nor necessary. A mutually agreeable operating procedure could be used as an alternative to adding the third Green River 161-138 kV transformer and replacing the Ohio County 138-69 kV, 50 MVA transformer. Since either of the Green River 161-138 kV transformers would overload during an outage of the other transformer, KU identified opening the remaining 161-138 kV transformer as a means to eliminate the overload problem. This operating procedure would not cause any other problems within either KU's or Big Rivers' systems. Additionally, opening both Green River 161-138 kV transformers was tested as a means to eliminate the overload of the Ohio County 138-69 kV, 50 MVA transformer. This operating procedure was found to eliminate both overloads without causing problems within KU's system, and Big Rivers could still export 300 MW with this operating procedure in effect without overloads. Therefore, both companies agreed that these operating procedures could be used when necessary as an alternative to transmission system upgrades.

A contingency analysis through the planning period using a combination of operating procedures and an upgraded interconnection found no overloaded lines within KU's system. Hence, the following is the construction required for this interconnection option:

Construct eight miles of 161 kV line from the Wilson Plant to the Green River Plant using bundled 795 kcm ACSR conductor. Provide a 161 kV bus at Green River on which to terminate: 1) the interconnection, 2) the two existing 161 kV lines, and 3) the two existing 161-138 kV transformers.

With Big Rivers' export/transfer level at 650 MW and the above construction modeled, no overloads were identified within either Big Rivers' or KU's system during normal conditions through the study period. With Big Rivers' export/transfer at 300 MW, no overloads were identified through the study period during any single contingency.

The Wilson-Green River 161 kV line and associated construction would provide a significant reduction in transmission system losses for Big Rivers. In fact, as Big Rivers' export level increases, its transmission system losses decrease significantly. Conversely, although KU would receive some loss-reduction benefit for Big Rivers' export levels below 200 MW, as this export level increases, KU's transmission system losses increase. Table 3 lists the change in system losses for Big Rivers and KU when the interconnection is modeled in 1997 Summer for various exports from Big Rivers to TVA.

Table 3
Big Rivers-KU Interconnection Study Loss Evaluation
1997 Summer Comparison of KU losses with Wilson-Green River 161 kV
versus without for various Big Rivers export levels to TVA

Big Rivers Incremental Export to TVA	Change in MW Losses W/Interconnection KU	Big Rivers
100 MW	(1.0) MW	(5.7) MW
300 MW	1.2 MW	(9.8) MW
400 MW	2.6 MW	(12.6) MW
500 MW	4.1 MW	(15.2) MW
600 MW	5.3 MW	(17.5) MW

ii. Wilson to Green River 161 kV and Green
River to New Hardinsburg-Paradise (TVA) 161 kV

A loadflow analysis was previously conducted for the 1997 and 2003 Summer peak-load periods with a 161 kV line from Wilson Plant to Green River Plant and a 161 kV line from Green River Plant to a point on Big Rivers' New Hardinsburg-Paradise (TVA) 161 kV line. This analysis found that the additional interconnection requires building an additional 9.6 miles of 161 kV line but:

- does not eliminate any construction required when only the Wilson-Green River 161 kV line is constructed.
- is slightly more restrictive on Big Rivers' export/transfer capability.
- has basically no additional impact on transmission system losses for either company.

For these reasons, the single interconnection from Wilson Plant to Green River Plant is the preferred option. An economic analysis and a discussion of the benefits of this interconnection option follow.

IV. Cost-Benefit Analysis of the Wilson-Green River 161 kV Interconnection

A comparison of the total construction costs if each company were to pursue its independent construction plans (Sections I & II) as opposed to joint construction of the Wilson-Green River 161 kV interconnection (Section III) was made and a summary of the benefits follow.

i. Cost of Big Rivers' and KU's Independent Construction Plans

Big Rivers' independent construction requirements, along with the 1995 cost, inflated cost, and present value in 1995 dollars of each project are shown in Table 4. KU's independent construction requirements in its Western Division within the planning period are not listed, since the required construction is unaffected by the interconnection (see Section II). However, since KU does anticipate the need for additional transmission system support in the future, this cost analysis assumes that the Wilson-Green River 161 kV line would be completed in 2011, and KU would be responsible for construction of the line. This cost analysis also assumes that Big Rivers would agree to install a terminal at the Wilson substation in 2011 for the termination of the Wilson-Green River 161 kV line. This assumption is based on benefits Big Rivers would receive from the interconnection. These benefits include an increase contractual tie capacity with KU, an increased transfer capability, and reduced losses.

Table 4
Big Rivers' and KU's Independent Construction Requirements and Associated Costs

Year	Description	1995 Cost	Inflated Cost	Present Value
Big Rivers				
1996	Construct 15 miles of 161 kV line from the Wilson Plant to* TVA's Paradise Plant using bundled 795 kcm ACSR conductor.	$2,700,000	$2,810,700	$2,666,153
	Add facilities at Wilson to provide a 161 kV line exit.*	500,000	520,500	493,732
2011	Add facilities at Wilson to provide a 161 kV line exit.**	500,000	951,003	236,178
	Add 161 kV metering at Wilson.**	44,000	83,688	20,785
	Big Rivers' Totals	$3,744,000	$4,365,891	$3,416,848
Kentucky Utilities				
2011	Provide facilities at the Green River Plant for a 161 kV *** line exit, including breaker protection for the existing 161 kV lines and transformers.	$1,222,059	$2,119,033	$ 549,313
	Construct eight miles of 161 kV line from Green River to**** Big Rivers' Wilson Plant using bundled 795 kcm ACSR conductor.	$1,440,000	$2,496,940	$ 687,363
	Kentucky Utilities' Totals	$2,662,059	$4,615,973	$1,236,676
	Combined Totals	**$6,406,059**	**$8,981,864**	**$4,653,524**

*Costs inflated at 4.1% per year, discounted at 8.00% per year to 1995 dollars with a levelized fixed charge rate of 9.1%.
**Costs inflated at 4.1% per year, discounted at 8.00% per year to 1995 dollars with a levelized fixed charge rate of 9.94%.
***Costs inflated at 3.5% per year, discounted at 8.91% per year to 1995 dollars with a levelized fixed charge rate of 12.73%.
****Cost inflated at 3.5% per year, discounted at 8.91% per year to 1995 dollars with a levelized fixed charge rate of 13.31%.

ii. Cost of Big Rivers-KU Joint Construction Plan

The costs incurred by each company should the Wilson-Green River interconnection option be completed in 1996 are shown in Table 5. Table 5 assumes Big Rivers would construct terminal facilities at its Wilson Plant and construct eight miles of 161 kV line to KU's Green River Plant. KU would construct the remaining facilities.

Table 5
Big Rivers-KU Joint Construction Requirements and Associated Costs

Year	Description	1995 Cost	Inflated Cost	Present Value
Big Rivers*				
1996	Add facilities at the Wilson Plant to provide 161 kV line exit.	$ 500,000	$ 520,500	$ 493,732
	Construct eight miles of 161 kV line from the Wilson Plant to the Green River Plant using bundled 795 kcm ACSR conductor.	1,440,000	1,499,040	1,421,948
	Big Rivers' Totals	$ 1,940,000	$ 2,019,540	$1,915,680
Kentucky Utilities**				
1996	Provide facilities at the Green River Plant for a 161 kV line exit, including breaker protection for the existing 161 kV lines and transformers and metering for the new line.	$ 1,266,059	$ 1,310,371	$1,396,053
	Kentucky Utilities' Totals	$ 1,266,059	$ 1,310,371	$1,396,053
	Combined Totals	**$ 3,206,059**	**$ 3,329,911**	**$ 3,311,733**

*Costs inflated at 4.1% per year, discounted at 8.00% per year to 1995 dollars with a levelized fixed charge rate of 9.1%.
**Costs inflated at 3.5% per year, discounted at 8.91% per year to 1995 dollars with a levelized fixed charge rate of 11.57%.

iii. Benefits of Wilson-Green River 161 kV Interconnection

Establishing the Wilson-Green River 161 kV interconnection in 1996 provides the following five primary benefits to Big Rivers and KU:

- Big Rivers' export/transfer capability would increase to 650 MW during normal conditions and to 300 MW during any single contingency.
- Total system peak-load losses for Big Rivers are estimated to decrease when the interconnection is energized based upon loadflow results, thereby providing a savings to Big Rivers.
- The interconnected capacity between the two companies would increase from 224 MVA Summer and Winter to approximately 742 MVA Summer and 782 MVA

Winter, providing the opportunity for larger power transactions between the two companies.

- KU would eliminate the need for additional transmission system support in its Western Division area.
- Big Rivers' ability to safely and reliably operate its transmission system while experiencing parallel flows is significantly enhanced. This is evidenced by power flow studies performed with the July 22, 1993 base case. These studies showed that a Wilson to Green River interconnection would have allowed Big Rivers to operate its transmission system with all interconnection in service during the July 22, 1993 events. The heaviest loaded Big Rivers facility would have been the Reid-Hopkins County-Barkley 161 kV circuit at 96% (compared to 150% loaded without the interconnection addition).

iv. Proposed Construction Cost-Sharing Plan

Table 6 summarizes the present value of the costs of each company and in total from Tables 4 and 5.

Table 6
Cost Summary of Joint and Independent construction Plans (PV-1995$)

	Big Rivers	**KU**	**Total**
Joint Project	$1,915,680	$1,396,053	$3,311,733
Independent Project	3,416,848	1,236,676	4,653,524
Joint Minus Independent	($1,501,168)	$ 159,377	($1,341,791)

Table 6 shows that the joint construction plan would provide Big Rivers a present value savings of $1.5 million compared with the expenditures required for its independent construction plan, and the joint construction plan would result in a present value increase for KU of about $160,000. Additionally, Table 6 shows that the joint plan would save over $1.3 million (1995 PV) versus the independent construction plans of the two companies. Because Big Rivers saves $1.5 million while KU's cost increases by $160,000 for the interconnection, Big Rivers has agreed to pay the cost for installation of the breaker at Green River for the 161 kV line to Wilson to more equitably share the savings of the joint construction plan. This cost is estimated to be $377,000 (1995$), which would have a 1995 present value for KU of $429,436 and $336,469 for Big Rivers. Therefore, the present values of the costs for each company and in total become as listed in Table 7.

Table 7
Cost Summary of Joint & Independent Construction Plans Including Big Rivers Absorbing Breaker Cost (PV-1995$))

	Big Rivers	KU	Total
Joint Project	$2,252,149	$ 966,617	$3,218,766
Independent Project	3,416,848	1,236,676	4,653,524
Joint Minus Independent	($1,164,699)	($ 270,059)	($1,434,758)

Table 7 indicates that because Big Rivers bears the cost of the breaker at Green River, the total present value savings of the joint construction plan versus the independent construction plan increases from $1.34 million to $1.40 million due to the different discount rates and fixed charge rates of the two companies.

In addition to the sharing of construction costs, both companies have agreed that, because KU's transmission system losses could potentially increase while Big Rivers' transmission system losses would decrease with the interconnection, KU should be reimbursed for the additional losses.

Loadflow analysis shows that, other than for transactions to SIGE, KU's incremental losses are basically independent of the company with which Big Rivers is transacting. The method used to determine this is the following: loadflow cases simulating Big Rivers incremental (above sales to Henderson Municipal) exports from 100-600 MW in 100 MW increments to all interconnected utilities were run with and without the interconnection. Because the results were similar for all companies other than SIGE, KU's incremental loss values were averaged to obtain KU's incremental losses for a "generic" Big Rivers' export scenario. These average values were then plotted and a linear regression was performed on these points. The linear regression provided a means to calculate KU's incremental system losses for any Big Rivers' export level to any company or combination of companies, excluding any transaction to SIGE or KU. Hence, using this regression, Big Rivers and KU agreed that generation for losses should be scheduled from Big Rivers to KU at Big Rivers' net export levels of 250 MW and above as listed in Table 8.

Table 8
Big Rivers to KU Scheduled Generation Reimbursement for Losses

Big Rivers' Net Export Level (MW)	Big Rivers to KU Schedule (MW)
250-349	1
350-449	2
450-499	3
500-599	4
600+	5

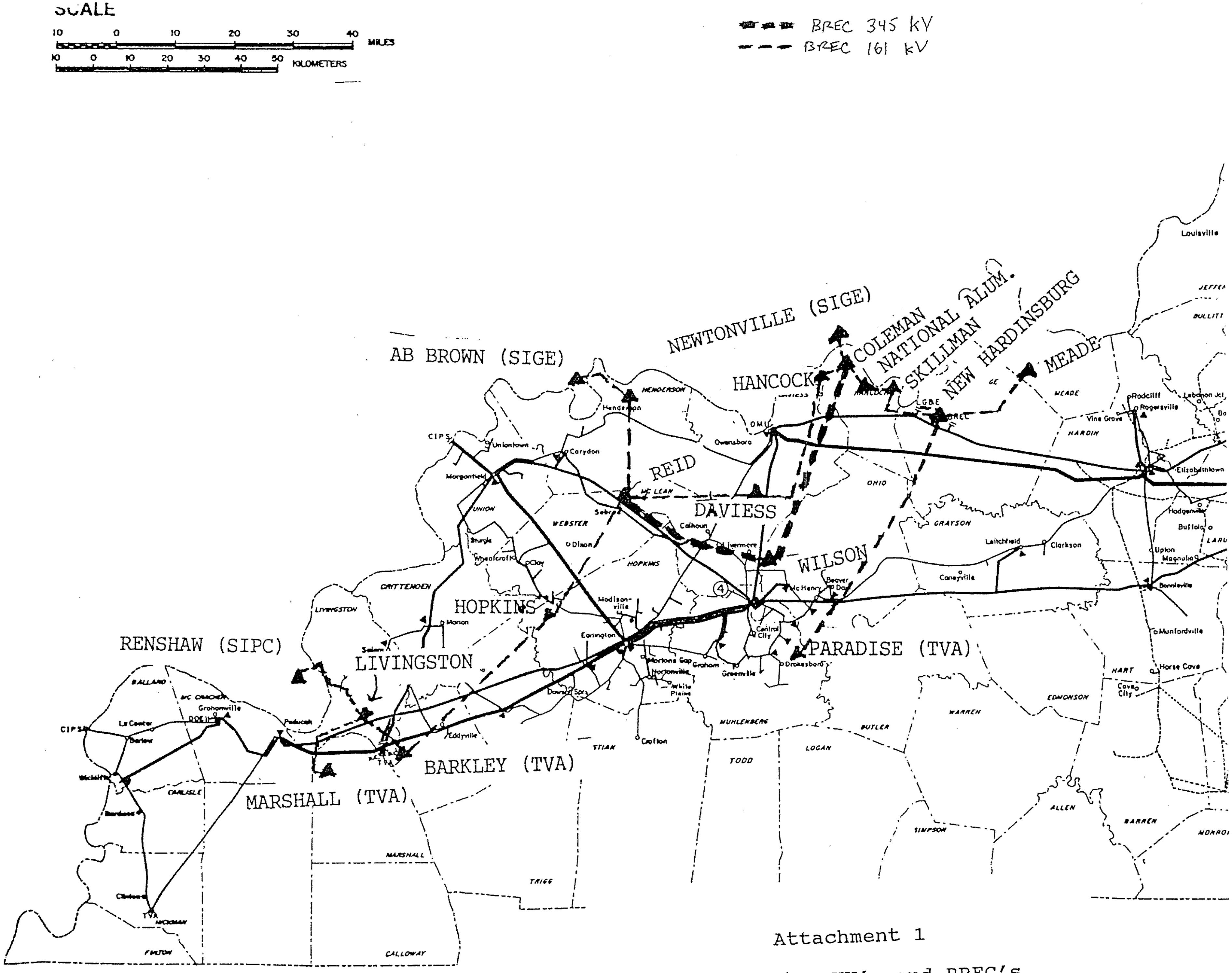
As for transactions to SIGE, KU's transmission system losses would not increase for exports from Big Rivers to SIGE which are within the capability of the Big Rivers-SIGE interconnections.

This analysis of loss reimbursement will be conducted in the future at the request of either company.

The methodology and principles of the cost-sharing plan outlined above have been agreed to by both companies. However, the cost which Big Rivers will bear for the breaker at Green River will be the lesser of the actual cost or 110% of the estimated cost of $377,000 (1995 dollars).

V. Conclusion

The results of this analysis show that the Wilson-Green River 161 kV line adequately eliminates Big Rivers' transmission limitations while increasing its export/transfer capability to the desired level, and is the least expensive option in total. Furthermore, this option provides the smallest expenditure for Big Rivers of any of its alternatives, even though Big Rivers has agreed to assume the cost of the breaker at Green River for the Wilson-Green River 161 kV line. KU's cost of construction is balanced against the additional voltage support which the interconnection would provide, thereby eliminating the risk of alternative construction cost due to a return to normal load growth or the addition of large customers in the eastern portion of KU's Western Division. Therefore, both Big Rivers and KU recommend that all construction requirements to facilitate the interconnection at Green River Plant be completed as soon as feasible.



Attachment 1

Map showing KU's and BREC's transmission system in Western KY

THOROUGHBRED

ENERGY

CAMPUS

INTERCONNECTION STUDY

REPORT

Prepared for

Big Rivers Electric Corp.

Participating Utilities:

LG&E Energy
Owensboro Municipal Utilities
Tennessee Valley Authority

Prepared by:

CAI Commonwealth Associates, Inc.

Exhibit 2

THOROUGHBRED ENERGY CAMPUS

INTERCONNECTION STUDY

REPORT

Prepared for

Big Rivers Electric Corp.

Participating Utilities:

LG&E Energy
Owensboro Municipal Utilities
Tennessee Valley Authority

Prepared by
R.D. Cook, P.E.
T.L. Orloff

At the offices of
Commonwealth Associates, Inc.
P.O. Box 1124
Jackson, Michigan 49204-1124
February 26, 2003

Approved for submittal:

David A. Shafer, P.E.
Manager, Electrical Systems

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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

2-750 MW Plants – Cases 241, 251, and 261

- 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

1-750 MW Plant – Cases 171, 181, and 191

- 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

2-750 MW Plants - Cases 271, 281, and 291

- 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.