Blue Grass Energy Cooperative Corporation

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March 30, 2005

Beth O'Donnell Executive Director
Kentucky Public Service Commission
P O Box 615
Frankfort Kentucky 40602

Dear Ms. O'Donnell,

We are filing an original and 10 copies of the information as requested by the Kentucky Public Service Commission in administrative case no. 2005-00090. This information concerns an assessment of Kentucky Electric Generation, Transmission and Distribution needs.

If you have any questions, please contact me at (859) 885-2114. As always, your continued assistance and cooperation is appreciated.

Sincerely,

J. Donald Smothers
Vice President, Financial Services

1. Provide a summary description of your utility's resource planning process.

Distribution resource planning is handled with a construction work plan (CWP) that is done every 2 to 4 years. The CWP deals with new construction, line conversions, pole replacements, sectionalizing and other appropriate distribution resources. The CWP is used to determine the appropriate amount of resources that are needed to complete the proposed work. A copy of Blue Grass Energy's latest CWP was filed with the PSC as part of case no. 2004-000251. Demand-side management is reviewed as conditions warrant as part of Blue Grass Energy's on-going distribution operations. Blue Grass Energy does not have any active demand-side management programs implemented at this time. Generation and transmission is handled by East Kentucky Power Cooperative with whom we have an all power requirements contract.

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

Blue Grass Energy aggressively seeks new cost effective technologies for improving reliability, efficiency and safety. Some of the technologies that have been implemented in the past or are in the implementation process include SCADA, Outage Management, Computerized Mapping systems and PORCHE an Integrated Voice Response system.

Each service truck is equipped with a laptop computer for access to customer information and navigation. The truck computers have the ability to do customer inquiry and staking technicians can stake new construction in the field.

Technologies that improve customer service are also researched. BGE is in the process of deploying an Automated Meter Reading System. BGE uses the internet for customers to make bill payments online and request membership applications and other services. BGE customers can also access information and pay bills through our automated telephone customer link using a touch tone telephone.

To improve security and safety an access control system was installed in early 2004. This system monitors and limits access in the warehouse, computer room and operations center. Safety training has been computerized; an internet based training system where employees can get required annual safety training was recently implemented.

Presently BGE is researching mobile computer communications through the cellular phone system using Blackberry technology and AirCard technology. These communication systems will allow real-time access to email for work orders and service orders.

5. Provide actual and weather-normalized annual coincident peak demands for calendar years 2000 through 2004 disaggregated into:

Actual annual coincident peak demand (KW)

	Peak Demand	Firm	Non-firm
2004	283,233.59	280,421.59	2,812.00
2003	284,249.28	277,006.28	4,243.00
2002	241,058.39	236,970.39	4,088.00
2001	250,465.44	247,154.44	3,311.00
2000	247,450.11	244,064.11	3,386.00

Weather-normalized annual coincident peak demands (MW)

2004	271.7
2003	272.3
2002	253.4
2001	270.2
2000	277.5

Off-system Demand:

Not Applicable

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

Blue Grass Energy does not currently have an active DSM program although we have a consultant studying potential opportunities in DSM. Blue Grass Energy has some member services programs which are designed to improve load factor and conserve energy. These programs are passive in nature.

a. Annual DSM budget

None

b. Demand and energy impacts

None

c. Termination dates of the programs.

Not Applicable.

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

Blue Grass Energy's definition of distribution would be any voltage up to and including 25 KV phase to phase. Transmission is any voltage above 25 KV phase to phase.

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

Blue Grass Energy is not interconnected at transmission voltage with any utility. East Kentucky Power delivers all our requirements at distribution voltages.

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

Not Applicable

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

Not Applicable

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

Not Applicable

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

Not Applicable

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

Not Applicable

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

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

Not Applicable

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

Not Applicable

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

Not Applicable

26. Provide the yearly System Average Interruption Duration Index ("SADI") and the System Average Interruption Frequency Index ("SAIFI"), excluding major outages, by feeder for each distribution substation on your system for the last 5 years.

    The SAIDI and SAIFI indices by district are included in the following reports back to 2002. We have incomplete data for the period before 2002 due to the consolidation of the original Blue Grass Energy and Harrison RECC at the beginning of 2002. The indices are calculated by district. We currently do not have the data to calculate the indices by feeder for each distribution substation. We are currently implementing a new mapping program that will interface with an outage program that should allow us to track this data by feeder in the future.

Outage Report w/o Major Storms

01/01/2002 Thru 12/31/2002

District	InterruptionCause	MembersAffected	Member Hours	Outage Time (HRS)	# of Outages
Nicholasville					
	District Totals	10308	17751	735.8	478
	SAIFI 0.6414 CAIDI 103.3254 SAIDI 66.2692				
Madison					
	District Totals	8430	13864	712.5	417
	SAIFI 0.8702 CAIDI 98.6734 SAIDI 85.8694				
Foxcreek					
	District Totals	10223	17034	1011.4	511
	SAIFI 0.8664 CAIDI 99.9744 SAIDI 86.6134				
Harrison					
	District Totals	20703	36533	1631.9	732
	SAIFI 1.4352 CAIDI 105.8769 SAIDI 151.9563				
Grand Total		49664	85181.7	4091.6	2138
	SAIFI 1.0538 CAIDI 102.9096 SAIDI 108.4426				

Outage Report w/o Major Storms

01/01/2003 Thru 12/31/2003

District	InterruptionCause	MembersAffected	Member Hours	Outage Time (HRS)	# of Outages
Nicholasville					
	District Totals	17549	9312	549.2	407
	SAIFI 1.0919 CAIDI 31.8385 SAIDI 34.7644				
Madison					
	District Totals	8806	11076	582.3	399
	SAIFI 0.9091 CAIDI 75.4645 SAIDI 68.6012				
Foxcreek					
	District Totals	20544	39775	1558.4	539
	SAIFI 1.7410 CAIDI 116.1660 SAIDI 202.2470				
Harrison					
	District Totals	17500	28773	1266.7	736
	SAIFI 1.2132 CAIDI 98.6495 SAIDI 119.6788				
Grand Total		64399	88935.9	3956.6	2081
	SAIFI 1.3664 CAIDI 82.8608 SAIDI 113.2220				

Outage Report w/o Major Storms

01/01/2004 Thru 12/31/2004

District	InterruptionCause	MembersAffected	Member Hours	Outage Time (HRS)	# of Outages
Nicholasville					
	District Totals	24688	23396	757.9	508
	SAIFI 1.5361 CAIDI 56.8594 SAIDI 87.3410				
Madison					
	District Totals	21681	26088	630.3	391
	SAIFI 2.2382 CAIDI 72.1967 SAIDI 161.5874				
Foxcreek					
	District Totals	21601	38109	1288.1	638
	SAIFI 1.8306 CAIDI 105.8540 SAIDI 193.7756				
Harrison					
	District Totals	26597	63782	1482.1	769
	SAIFI 1.8438 CAIDI 143.8863 SAIDI 265.2994				
Grand Total		94567	151375.6	4158.3	2306
	SAIFI 2.0065 CAIDI 96.0434 SAIDI 192.7125				

27. Provide the yearly SAIDI and SAIFI, including major outages, by feeder for each distribution substation on your system for the last 5 years. Explain how you define major outages.

The SAIDI and SAIFI indices by district are included in the following reports back to 2002. We have incomplete data for the period before 2002 due to the consolidation of the original Blue Grass Energy and Harrison RECC at the beginning of 2002. The indices are calculated by district. We currently do not have the data to calculate the indices by feeder for each distribution substation. We are currently implementing a new mapping program that will interface with an outage program that should allow us to track this data by feeder in the future. Major outages would be defined as outages where 10% of the customers in the affected district are out for at least 24 hours.

Outage Report

01/01/2002 Thru 12/31/2002

District	InterruptionCause	MembersAffected	Member Hours	Outage Time (HRS)	# of Outages
Nicholasville					
	District Totals	12329	22122	748.3	482
	SAIFI 0.7671 CAIDI 107.6575 SAIDI 82.5852				
Madison					
	District Totals	8585	14085	719.1	421
	SAIFI 0.8862 CAIDI 98.4372 SAIDI 87.2389				
Foxcreek					
	District Totals	12352	22037	1074.0	522
	SAIFI 1.0468 CAIDI 107.0449 SAIDI 112.0525				
Harrison					
	District Totals	20742	36853	1645.3	736
	SAIFI 1.4379 CAIDI 106.6048 SAIDI 153.2892				
Grand Total		54008	95096.8	4186.8	2161
	SAIFI 1.1459 CAIDI 105.6474 SAIDI 121.0653				

Outage Report

01/01/2003 Thru 12/31/2003

District	InterruptionCause	MembersAffected	Member Hours	Outage Time (HRS)	# of Outages
Nicholasville					
	District Totals	22610	104542	653.3	415
	SAIFI 1.4068 CAIDI 277.4215 SAIDI 390.2750				
Madison					
	District Totals	8807	11077	583.3	400
	SAIFI 0.9092 CAIDI 75.4628 SAIDI 68.6075				
Foxcreek					
	District Totals	37324	305830	1796.1	554
	SAIFI 3.1631 CAIDI 491.6351 SAIDI 1555.0667				
Harrison					
	District Totals	42855	517129	1540.7	760
	SAIFI 2.9709 CAIDI 724.0169 SAIDI 2150.9703				
Grand Total		111596	938577.2	4573.4	2129
	SAIFI 2.3678 CAIDI 504.6295 SAIDI 1194.8787				

Outage Report

01/01/2004 Thru 12/31/2004

District	InterruptionCause	MembersAffected	Member Hours	Outage Time (HRS)	# of Outages
Nicholasville					
	District Totals	24694	23482	833.0	510
	SAIFI 1.5365 CAIDI 57.0541 SAIDI 87.6615				
Madison					
	District Totals	21732	26201	635.6	394
	SAIFI 2.2434 CAIDI 72.3391 SAIDI 162.2870				
Foxcreek					
	District Totals	23794	72094	1576.7	652
	SAIFI 2.0164 CAIDI 181.7962 SAIDI 366.5812				
Harrison					
	District Totals	29826	145026	2127.0	794
	SAIFI 2.0677 CAIDI 291.7448 SAIDI 603.2292				
Grand Total		100046	266803.5	5172.3	2350
	SAIFI 2.1228 CAIDI 160.0085 SAIDI 339.6607				

28. What is an acceptable value for SAIDI and SAIFI? Explain how it was derived.

Acceptable SAIDI and SAIFI indices will vary greatly depending on the characteristics of the area served.

29. Provide the yearly Customer Average Interruption Duration Index ("CAIDI") and the Customer Average Interruption Frequency Index ("CAIFI"), including and excluding major outages, on your system for the last five years. What is an acceptable value for CAIDI and CAIFI? Explain how it was derived.

The CAIDI indices are included in the reports that are in the responses to questions 26 and 27. We have incomplete data for the period before 2002 due to the consolidation of the original Blue Grass Energy and Harrison RECC at the beginning of 2002. We do not have the data to calculate the CAIFI indices. We are currently implementing a new mapping program that will interface with an outage program that should allow us to track this data in the future.

Acceptable CAIDI and CAIFI indices will vary greatly depending on the characteristics of the area served.

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

Cause	Frequency
Ice Storm	2
Thunderstorm	5
Transmission	1

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

Blue Grass Energy's distribution reliability improvement program is a combination of our CWP which was discussed in response no. 1 and the right-of-way and vegetation management programs and the distribution inspection programs that are discussed in the response no. 32

a. How does your utility measure reliability?

SAIFI, SAIDI, and CAIDI indices are tracked by month for each one of Blue Grass Energy's four districts. Also, interruption causes are tracked as a part of our program and used in the formulation of the CWP

b. How is the program monitored?

Blue Grass Energy management receives a copy of all the reports. Also, a report is given to our board of directors at the monthly board meetings.

c. What are the results of the system?

The results of our system are contained in the report in responses no. 26, 27 and 29.

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

The Construction work plan is currently approved by our board of directors, Rural Utilities Service and reviewed by the Public Service Commission. The right-of-way and vegetation management programs are approved annually by our board of directors. The proposed improvements are implemented by a combination of cooperative employees and contractor crews.

32. Provide a summary description of your utility's:

a. Right of Way management program.

Blue Grass Energy's Right-of-Way maintenance program consist of trimming, cutting, and bush hogging 5800 miles of line in our service area on a five-year cycle by contract labor. The contractor is to attempt to provide thirty (30) feet on all V or three phase lines and twenty (20) feet of cleared right-of-way on all single phase lines depending upon permission obtained, including side trim and overhang on all lines. All lines are cleared from ground to sky, dead and dangerous trees removed and all yard trees laterally trimmed where feasible. Each of the Blue Grass Energy's district offices has one contract right-of-way crew assigned to them for hot spot work to clear-up blinking lines and danger trees, not on the present year cycle.

Provide the budget for the last 5 years:

2004	$2,132,667
2003	$2,485,147
2002	$1,727,046
2001	$1,284,470
2000	$1,213,765

b. Vegetation management program.

The following year after the right-of-way has been cleared on these designated lines, the contractor will then follow-up on the circuits and apply herbicides. The application of herbicides are scheduled during the summer months of May - September as weather permits.

The vegetation management program budget is included as part of the right of way budget in 32a.

c. Transmission and distribution inspection program.

Blue Grass Energy has one person who does a sound and visual check of our poles and a two man Underground inspection crew that visually inspect every aspect of our under ground distribution system. This is done on a rotating basis among each district. Any danger poles or dangerous conditions are immediately reported and repaired as soon as possible. Pole and URD equipment flagged for change out are sent to the appropriate line superintendent for replacement or repair.

Provide the budget for the last 5 years.

2004	$172,924
2003	$130,478
2002	$ 83,540
2001	$ 83,797
2000	$ 67,783

33. Explain the criteria your utility uses to determine if pole or conductor replacement is necessary.

Poles are inspected by doing a visual inspection and sounding using a hammer. Any poles that have visual damage are repaired or replaced depending on the amount and type of damage. Poles that have a hollow sound are marked for replacement.

Conductors (and associated poles and hardware as required) will be considered for replacement if any of the following conditions exist:

a. More than 3 outages or 10 outage hours per year excluding major storms and power supplier for two out of the past three years.

b. Conductors with an average of greater than one splice per phase per span in one mile increments.

c. Ordinary replacement of old deteriorated conductor on a systematic basis.

Historical distribution facilities replacement costs are contained on the following reports beginning with 2002. We have incomplete data for the period before 2002 due to the consolidation of the original Blue Grass Energy and Harrison RECC at the beginning of 2002. Future costs of distribution facilities replacement are contained in the Construction Work Plan that was filed as part of PSC case no. 2004-000251. Future costs beyond the construction work plan period are contained in the 20 year financial forecast. This forecast reflects total plant additions to 2013 which includes future replacement cost and new construction.

WORK PLAN NUMBERS
300 AND 600
1/02-2/05

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02
	SCH 680	SCH 681	SCH 682	SCH 683	SCH 684	SCH 685	SCH 686	SCH 687	SCH 688	SCH 689
							TA-2 LOAN	TA-2 LOAN		
305										
307										
308					25,134.13					245,605.12
327										
328										
3292										
330										
333										
339										
345										
347										
351										
374										
3863										
3872										
600	74,489.38	110,935.44	59,875.11	94,530.36	66,639.04	83,702.85	84,542.62	71,109.08	122,977.64	67,533.30
	74,489.38	110,935.44	59,875.11	94,530.36	91,773.17	83,702.85	84,542.62	71,109.08	122,977.64	313,138.42

WORK PLAN NUMBERS
300 AND 600
1/02-2/05

	Nov-02	Dec-02	Jan-03	Feb	Mar-03	Apr-03	May-03	Jun-03	Jul-03	AUG-03
	SCH 690	SCH 691	SCH 692	SCH 693	SCH 694	SCH 695	SCH 696	SCH 697	SCH 698	SCH 699
305										
307										
308										
327										
328										
3292										
330										
333										
339										
345										
347										
351										
374										
3863										
3872										
600	56,369.83	35,446.37	77,584.33	31,082.91	46,529.52	129,624.92	51,310.13	33,197.79	99,396.61	82,992.45
	56,369.83	35,446.37	77,584.33	31,082.91	46,529.52	129,624.92	51,310.13	33,197.79	99,396.61	82,992.45

WORK PLAN NUMBERS
300 AND 600
1/02-2/05

	SEP-03	OCT-03	NOV-03	DEC-03	JAN-04	FEB-04	MAR-04	APR-04	MAY-04	JUNE-04
	SCH 700	SCH 701	SCH 702	SCH 703	SCH 013104	SCH 204	SCH 304	SCH 404	SCH 504	SCH 604
305					59,586.90					
307		234,712.45								
308										
327										
328										
3292				120,827.12						
330					142,017.66					
333					67,161.81					
339		99,608.18								
345										
347										
351					181,924.17		90,357.81			
374					233,901.93					
3863					181,862.39					
3872										
600	109,529.67	138,255.07	54,240.36	47,706.35	75,310.82	111,329.33	94,444.54	60,645.05	236,720.51	65,398.71
	109,529.67	472,575.70	54,240.36	168,533.47	941,765.68	111,329.33	184,802.35	60,645.05	236,720.51	65,398.71

WORK PLAN NUMBERS
300 AND 600
1/02-2/05

	JULY-04	AUG-04	SEP-04	OCT-04	NOV-04	DEC-04	Jan-05	Feb-05		
	SCH 704	SCH 804	SCH 904	SCH 1004	SCH 1104	SCH 1204	SCH 0105	SCH 0205		
305										$59,586.90
307										$234,712.45
308										$270,739.25
327					206,169.71					$206,169.71
328					19,862.36					$19,862.36
3292			67,091.90							$187,919.02
330										$142,017.66
333										$67,161.81
339										$99,608.18
345				302,146.88						$302,146.88
347			203,898.56							$203,898.56
351						171,195.67				$443,477.65
374					155,564.83	157,247.68				$546,714.44
3863										$181,862.39
3872			177,894.74							$177,894.74
600	137,750.75	113,220.39	105,629.11	39,199.94	60,515.56	94,598.14	50,565.51	46,740.26		$3,121,669.75
	137,750.75	113,220.39	554,514.31	341,346.82	442,112.46	423,041.49	50,565.51	46740.26		$6,265,441.75

FINANCIAL FORECAST RUS FORM 325G - DETERMINATION OF PLANT INVESTMENT & LOAN REQUIREMENTS

	PREVIOUS YEARS					FUTURE YEARS							
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
1. PLANT SUMMARY													
a. TOTAL UTILITY PLANT (FIRST OF YEAR)	112,671,643	121,246,246	128,182,695	135,033,326	144,156,234	156,144,613	168,112,645	180,033,967	190,407,179	201,060,837	212,003,355	223,243,398	234,789,893
b. PLUS: GROSS ADDITIONS AND REPLACEMENTS	11,045,961	8,399,116	8,275,478	10,590,500	13,500,000	13,525,000	13,525,000	12,025,000	12,355,000	12,694,900	13,044,997	13,405,597	13,777,015
c. LESS: CONTRIBUTION IN AID OF CONSTRUCTION	0	0	0	0	0	0	0	0	0	0	0	0	0
d. LESS: RETIREMENTS	2,471,358	1,462,667	1,424,847	1,467,592	1,511,620	1,556,969	1,603,678	1,651,788	1,701,342	1,752,382	1,804,954	1,859,102	1,914,875
e. TOTAL UTILITY PLANT (END OF YEAR)	121,246,246	128,182,695	135,033,326	144,156,234	156,144,613	168,112,645	180,033,967	190,407,179	201,060,837	212,003,355	223,243,398	234,789,893	246,652,032
2. PLANT ADDITIONS & REPLACEMENTS													
Type / Priority													
a. Distribution Y	10,046,851	7,137,681	7,383,028	9,000,000	12,500,000	12,500,000	12,500,000	11,000,000	11,330,000	11,669,900	12,019,997	12,380,597	12,752,015
b. Subtransmission Y	0	0	0	0	0	0	0		0	0	0	0	0
c. Bulk Transmission N	0	0	0	0	0	0	0	0	0	0	0	0	0
d. Generation N	0	0	0	0	0	0	0	0	0	0	0	0	0
e. Hdq - Warehouse Y	341,117	115,241	54,112	0	0	0	0	0	0	0	0	0	0
f. Hdq - Office N	0	0	0	0	0	0	0	0	0	0	0	0	0
g. General Plant N	657,993	1,146,194	838,338	1,590,500	1,000,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000
h. Acquisitions N	0	0	0	0	0	0	0	0	0	0	0	0	0
i. Other N	0	0	0	0	0	0	0	0	0	0	0	0	0
j. Other N	0	0	0	0	0	0	0	0	0	0	0	0	0
k. Other N	0	0	0	0	0	0	0	0	0	0	0	0	0
l. Less Contributions-in-Aid of Construction	0	0	0	0	0	0	0	0	0	0	0	0	0
NET PLANT ADDITIONS	11,045,961	8,399,116	8,275,478	10,590,500	13,500,000	13,525,000	13,525,000	12,025,000	12,355,000	12,694,900	13,044,997	13,405,597	13,777,015
3. PRIORITY FINANCING REQUIREMENTS													
SUBTOTAL PRIORITY PLANT ADDITIONS	10,387,968	7,252,922	7,437,140	9,000,000	12,500,000	12,500,000	12,500,000	11,000,000	11,330,000	11,669,900	12,019,997	12,380,597	12,752,015
REIMBURSEMENT OF GENERAL FUNDS				0	4,228,000	0	0	0	0	0	0	0	0
EXISTING PRIORITY LOAN FUNDS													
(1) PRIOR RUS LOAN FUNDS APPLIED				0	0	0	0	0	0	0	0	0	0
(2) PRIOR SUPL. LOAN FUNDS APPLIED				0	0	0	0	0	0	0	0	0	0
(3) PRIOR GUARANTEED FUNDS APPLIED				2,888,000	0	0	0	0	0	0	0	0	0
GENERAL FUNDS INVESTED													
(1) GEN. FUNDS PLANT INVEST.				6,112,000	0	0	500,000	0	330,000	669,900	19,997	380,597	752,015
(2) GEN. FUNDS AVAILABLE TO MEET GOAL				5,070,982	12,075,155	15,745,559	18,825,935	22,948,291	26,925,932	31,098,259	36,506,116	41,763,755	46,804,230
(3) BORROW NEW LOAN FUNDS IN ANY YEAR?				N	Y	Y	Y	Y	Y	Y	Y	Y	Y
NEW PRIORITY FINANCING REQUIRED				0	16,728,000	12,500,000	12,000,000	11,000,000	11,000,000	11,000,000	12,000,000	12,000,000	12,000,000
(1) RUS PORTION Percentage				100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Amount				0	16,728,000	12,500,000	12,000,000	11,000,000	11,000,000	11,000,000	12,000,000	12,000,000	12,000,000
(2) SUPPL. PORTION Percentage				0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Amount				0	0	0	0	0	0	0	0	0	0
(3) GUARANTEED PORTIO Percentage				0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Amount				0	0	0	0	0	0	0	0	0	0
4. NON-PRIORITY FINANCING REQUIRED													
SUBTOTAL NON-PRIORITY PLANT ADDITIONS	657,993	1,146,194	838,338	1,590,500	1,000,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000
REIMBURSEMENT OF GENERAL FUNDS				0	0	0	0	0	0	0	0	0	0
EXISTING NON-PRIORITY LOAN FUNDS													
(1) PRIOR SUPL. LOAN FUNDS APPLIED				0	0	0	0	0	0	0	0	0	0
(2) PRIOR GUARANTEED FUNDS APPLIED				0	0	0	0	0	0	0	0	0	0
GENERAL FUNDS INVESTED				1,590,500	1,000,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000	1,025,000
NEW NON-PRIORITY FINANCING REQUIRED				0	0	0	0	0	0	0	0	0	0
(1) SUPPL. PORTION				0	0	0	0	0	0	0	0	0	0
(2) GUARANTEED PORTION				0	0	0	0	0	0	0	0	0	0
5. PLANT INVESTMENT SUMMARY													
a. TOTAL GENERAL FUNDS REQUIRED				7,702,500	1,000,000	1,025,000	1,525,000	1,025,000	1,355,000	1,694,900	1,044,997	1,405,597	1,777,015
b. TOTAL RUS LOAN FUNDS REQUIRED				0	16,728,000	12,500,000	12,000,000	11,000,000	11,000,000	11,000,000	12,000,000	12,000,000	12,000,000
c. TOTAL GUARANTEED FUNDS REQUIRED				2,888,000	0	0	0	0	0	0	0	0	0
d. TOTAL OTHER FUNDS REQUIRED				0	0	0	0	0	0	0	0	0	0
e. TOTAL FUNDING REQUIRED				10,590,500	17,728,000	13,525,000	13,525,000	12,025,000	12,355,000	12,694,900	13,044,997	13,405,597	13,777,015