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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 157

Responding Witness: William Steven Seelye

Q-157. With regard to Mr. Seelye's LG&E direct testimony, page 6, line 18 through page 7, line 2, please explain and provide all workpapers showing the method and basis for the decision to increase residential electric revenue by 4.46%, as well as to increase lighting rates by 4.54%.

A-157. LG&E is proposing to increase the two rate classes with rates of return significantly below the overall rate of return by approximately the same percentage. The workpapers are included in the response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 158

Responding Witness: William Steven Seelye

Q-158. With regards to LG&E Seelye Exhibit 2 which references Seeley Exhibit 27 as the source, please provide specific references to Seelye Exhibit 27 as to how (where) the following Residential amounts are developed or determined:

a. Distribution Customer Rate Base ($179,824,501),
b. Rate Base Adjustment (-$2,922,528),
c. Customer-Related Expenses Excluding Taxes ($52,477,846),
d. Adjusted Income Taxes ($2,317,685),
e. Incremental Income Taxes ($1,102,250),
f. Expense Adjustments (-$2,253,096), and,
g. Other Revenue ($5,554,128).

A-158. a. The Distribution Customer Rate Base amount of $179,824,501 contains an allocation of all rate base costs classified as customer related in Seelye Exhibit 26, the Functional Assignment and Classification section of the Cost of Service Study. The accumulation and subsequent allocation of these costs to each rate class can be found in the Rate Base section of the Cost of Service Study, Seelye Exhibit 27. These costs include the customer related portion of primary and secondary distribution related rate base, the customer related portion of distribution transformer rate base, distribution services, distribution meters, customer accounts rate base, and customer service rate base allocated to the residential class. The customer related portion of primary and secondary distribution rate base and distribution transformer rate base is determined through the application of the zero intercept for overhead conductor, underground conductor, and line transformers.

b. The Rate Base Adjustment of -$2,922,528 can be found in Exhibit 27 in the Cost of Service Summary – Pro-Forma. It includes an adjustment to remove Environmental Cost Recovery Rate Base, to reflect a decrease in depreciation reserve, and to reflect a decrease in the calculated value of cash working capital due to various expense adjustments.

c. The Customer-Related Expenses Excluding Taxes of $52,477,846 includes an allocation of all expenses classified as customer related in Seelye Exhibit

26, the Functional Assignment and Classification section of the Cost of Service Study. The expenses from Seelye Exhibit 26 are accumulated and allocated to each rate class in Seelye Exhibit 27. All categories of expenses are included in the calculation of customer-related expenses, including operation and maintenance (O&M), depreciation, regulatory credits, accretion, property and other taxes, amortization of investment tax credit, and other expenses. The components of expenses allocated to the residential class in each category that make up customer-related expenses include the customer related portion of primary and secondary distribution related O&M, the customer related portion of distribution transformer O&M, distribution service expenses, distribution meter expenses, customer accounts expenses, and customer service expenses.

d. The Adjusted Income Taxes of $2,317,685 are the pro-forma income tax adjustment allocated to the residential class found in Seelye Exhibit 27, allocated to the customer component based on rate base.

e. The Incremental Income Taxes of $1,102,250 are the additional income taxes attributable to the increase in revenue associated with the proposed rate increase for the residential class allocated to the customer component based on rate base.

f. The Expense Adjustment of -$2,253,096 is the residential portion of total expense adjustments in Seelye Exhibit 27 allocated to the customer component based on the relationship of customer related expenses to total expenses.

g. The Other Revenue total of $5,554,128 is an allocation of residential other revenue to the customer component based on the relationship of customer related expenses to total expenses.

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Question No. 159

Responding Witness: William Steven Seelye

Q-159. Please provide LG&E Seelye Exhibit 5 in executable Excel format.

A-159. See response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 160

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-160. Please provide LG&E adjusted test year electric General plant by FERC account and sub-account.

A-160. Please see the table below:

ACCOUNT	DESCRIPTION	TOTAL
139210	TRANSPORTATION EQUIPMENT - CARS AND TRUCKS	$ 9,070,917.65
139220	TRANSPORTATION EQUIPMENT - TRAILERS	557,109.76
139400	TOOLS, SHOP, AND GARAGE EQUIPMENT	3,194,244.23
139500	LABORATORY EQUIPMENT	1,496,151.35
139610	POWER OPERATED EQUIP. - HOURLY RATED	2,285,136.20
139620	POWER OPERATED EQUIPMENT - OTHER	51,067.69
	TOTAL GENERAL PLANT	$ 16,654,626.88

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
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Question No. 161

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-161. Please provide LG&E adjusted test year electric CWIP in the greatest detail available. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-161. See attached. The requested information is being provided on CD.

LGE 107001 Electric CWIP Balance
As of April 30, 2008

Description		Amount
RELOC. DIST. HWY FACILITIES	$	(85,919.16)
Repl MT Tr 1 & Tr 2		36.37
MISC. SUBSTATION PROJECTS		720,369.27
METERS-LGE		(1.47)
MC ASH POND EXPANSION STUDY		772,144.76
DISTRIBUTION LINE TRANSFORMER		5,988,858.16
WHAS CENTERFIELD 69KV		(11,099.76)
MIDDLETOWN CENTERFIELD		5,398.78
MIDDLETOWN TRIMBLE 34		(20,164.56)
CR LANDFILL VERTICAL		354,861.04
TC2 PROJECT		73,145,421.22
CANAL - DEL PARK 69 KV LINE (CIRC 6616) SURVEY FOR RECONDUCTOR		29,738.57
SUBSTATION PROTECTION MODIFICATIONS		506,094.54
BEARGRASS 138KV BKR REPL.		17.95
PC INFRASTRUCTURE		2,736.51
TRANSFORMER REWIND (SMYRNA TR1)		2,712,941.76
TC STATOR LEAK MANAGEMENT SYSTEM		40,206.06
TC MB CONDUCTIVITY MONITORS ACID INSTALL		21,190.64
CR5 LP 1&2 FEEDWATER HEATER REPLACEMENT		469,008.21
CR6 SDRS BOOSTER FAN ROTOR REPLACEMENT		355,224.68
CANE RUN ABATEMENT		147,638.88
CR CT 11 CONTROLS UPGRADE		512,097.56
DEVELOPMENT FOR TRIMBLE COUNTY UNIT # 2		11,812,398.80
LG&E SUBSTATION SPILL PREVENTION		1,224,464.80
OHIO FALLS REDEVELOPMENT		12,461,653.79
RELOCATING PSRT		44,722.06
ITSD FINANCE AND MATERIALS DEVELOPMENT TOOLS		(3,788.99)
FORD - MIDDLETOWN 69KV DC		358,442.98
FUEL SUPPLY MANAGEMENT SYSTEM		648,526.31
BLUE LICK BATTERY REPLACEMENT		0.28
LGE DIST. 34.5KV STORM		667.81
LGE TRANS 34.5KV STORM		667.81
SAFETY TAGGING SYSTEM IT		10,546.13
WESTPORT ROAD (KY-1447) REDLEAF DR. TO HURSTBOURNE PKWY		14,031.64
LYNDON SOUTH BREAKER 6693 REPLACEMENT		0.12
CLAY 69 KV BUS TIE BREAKER REPLACEMENT		32,643.00
BRECKENRIDGE 138-69 KV (BR6) TRANSFORMER REPLACEMENT		143,808.79
BECKWITH TAP CHANGER CONTROLLER FOR STEWART TR 2		220,743.71
KNOB CREEK TR 1-115KB BUSHING REPLACEMENT		40,428.30
TAP CHGR AUXILLARY OIL FILTER SYSTEMS FOR VARIOUS STATIONS		28,722.28
REPLACE STATION BATTERIES & CHARGERS		24,313.47
BREATHERS FOR SUBSTA TRANSFORMER TAP CHGR		10,966.85
AUXILLARY CONTROL SWITCHES FOR GE AM13.8-500 BREAKERS		91,892.51
MC FGD QUENCH DIESEL GENERATOR		188,576.07
TC 480V SWITCHGEAR UPGRADE RP & CH		224,821.00
TC LIMESTONE BALL MILL LUBE OIL SYSTEM UPGRADE		51,044.04
TC CONTROL SYSTEM UPGRADE ENGINEERING SCOPE		3,016,877.28

LGE 107001 Electric CWIP Balance
As of April 30, 2008

Description	Amount
LG&E WORST CIRCUITS CIRCUIT HARDENING	498,466.88
CR RESERVE AUX A TRANSFORMER COOLER REPLACEMENT	2.13
CR5 PRIMARY AIR DUCT ASBESTOS REPLACEMENT	94,801.00
CR6 RADIANT REHEAT PARTIAL REPLACEMENT	287,009.76
CR CONTROL ROOM	567,015.49
CR MISCELLANEOUS PROJECT	241,039.59
CR ASBESTOS ABATEMENT	152,995.07
OXMOOR 6653 RELAY PANEL REPL	0.28
BRECKINRIDGE 6653 RELAY PANEL REPLACE	0.24
REPLACE/INSTALL CROSS ARMS & INSULATORS	253,420.60
6623 RIVER PARK RELO	152,279.17
DAHLIA 6660 &6669 REALY PANELS REPL	78,560.36
ETHEL 6669 RELAY PANEL REPL	52,253.05
HIGHLAND 6660 ELAY PANEL REPL	48,210.21
LGE DIST PF CORRECTION	257,567.35
PADDY'S RUN 3311B BREAKER REPLACE	124,414.84
CAMPGROUND 3801 BKR REPLACE	82,568.61
CONTROL CENTER CONSTRUCTION	3,704,209.55
COMPUTER PURCHASES LGE	8,944.42
MILL CREEK 4531 CCVT REPLACEMENT	0.36
FAIRMOUNT TR2 UPGRADE TO 44.8 MVA	1,669,047.64
BLUEGRASS CAPACITY ADDITION	2,025,272.66
LY:REPLACE 6654 DISC SW	6,113.14
REHL ROAD PUMP STATION	202,463.12
MILL CREEK UNIT 4 INTERMEDIATE SUPERHEATER UPGRADE	1,637,776.66
TC 847 LINE TIE DISCONNECTS	24,650.51
TC FGD UPGRADE	(5,867.72)
CANE RUN NEW LANDFILL	117,580.08
ETHEL 138KV POST INSULATORS	24,960.80
MC1 FGD MULTIFUNCTION CONTROLLER	430,882.82
SHIVELY RTU REPLACEMENT	37,365.79
MILL CREEK UNIT 2 SH OUTLET DMW'S	526,004.49
AGC SETPOINT CONTROL	27,068.58
TRIMBLE COUNTY ASH/GYPSUM PONDS	671,911.73
TC2 AQCS LGE	21,438,225.89
MC 2 FGD MULTIFUNCTION CONTROLLERS	443,022.31
MILL CREEK UNIT 3 SUPERHEATER FINAL PENDANT REPLACEMENT	2,196,346.13
MC ASH SYSTEM OUTSIDE PIPING	199,315.38
MC2 RECYCLE PUMP UPGRADE	156,134.69
MC 3A COAL MILL GEARBOX	260,723.20
MC 4C COAL MILL GEARBOX	219,637.69
MC 2 STATOR LEAK MONITORING SYSTEM	109,533.51
MILL CREEK ASH POND PIPING	184,943.21
MILL CREEK 2A HEATER BASKETS	221,000.60
MC LIMESTONE ENGINEERING STUDY	126,049.47
MILL CREEK 3 COOLING TOWER FILL REPLACEMENT	1,157,161.87
MC COAL BARGE UNLOADER BUCKET	135,799.60

LGE 107001 Electric CWIP Balance

As of April 30, 2008

Description	Amount
MC COAL HANDLING RAILROAD TRACK	137,101 03
NESC COMPLIANCE DAHLIA SUB FENCE	82,115.91
INSTALL WILDLIFE PROTECTION OF CANAL SUBSTATION	78,197.86
PTS FOR CANE RUN PLANT	10,089 75
CANE RUN GEN BREAKERS	125,493.05
DISTRIBUTION OPERATIONS REPORTING - LGE	22,877.18
DISTRIBUTION OPERATIONS SOFTWARE LICENSES	28,563.47
PC INFRASTRUCTURE - LGE	189,922.44
SYNERGEE ELECTRIC RELIABILITY	170,418.25
SURVEY & INSPECTION SYSTEM ENHANCEMENT PROJECT	171,795.21
MOBILE COMPUTING INFRASTRUCTURE	217,563.16
IMPLEMENT GIS REDLINING	105,485.35
LGE DOIT MOB COMP FOR GIS	136,213.01
OMS UPGRADE	109,205.52
BLUE LICK / BULLITT CO. 161KV DOUBLE CIRCUIT	49,803.16
JEFFERSONVILLE (DUKE ENERGY) RTU ADDITION	12,722.55
MOISTURE IN OIL ANALYZER	50,116.58
AWARE BOILER TUBE SOFTWARE	82,973.06
PLANT LAB EQUIPMENT UPGRADES	24,217.70
FAIRMONT CIRCUIT WORK	177,333.72
BLUEGRASS CIRCUIT WORK	671,060.14
LGE ELECTRIC METER PURCHASE & INSTALLS	1,350,109.53
CR6 SLUDGE PROCESSING PLANT UPGRADE	4,111,158.41
CAPITAL SALES TAX ENTRY	(473,132.31)
HANCOCK RTU REPLACEMENT	0.19
TC1 LOWER SLOPE TUBE REPLACEMENT	202,401.01
TC SPCC COMPLIANCE CAPITAL	118,617.45
TC IFD VFD CONTROL MODULE UPGRADE	28,480.99
TC1 EXPANSION JOINT REPLACEMENTS	59,414.10
TC1 SCR BYPASS EROSION CONTROL	192,125.08
TC1 ASH PIT SEAL TROUGH SKIRTING REPL	104,013.71
TC PURCHASE ACID DAY TANK	25,096.63
TC REPLACE G1 COAL CONVEYOR BELT	40,745.37
REVISED TC FUEL PIPE REPLACEMENT	490,905.12
TC MISC PLANT ENGINEERING	159,251.02
INSTALL COAL CONVEYOR BELT B	30,666.20
TC 1B AIR HEATER BASKET REPLACEMENT	623,486.40
CR6 BURNER AIR TIPS AND SOFA REPLACEMENT	549,878.29
CR6 LOWER WATER WALL SLOPE REPLACEMENT	157,666.16
CR6 SDRS MODULE PIPING REPLACEMENT	40,154.55
CR5 SDRS EXPANSION JOINT REPLACEMENT	16,538.17
CR SPCC COMPLIANCE	152,175.89
CR SCREENHOUSE RIVER LEVEL INDICATION	50,427.82
CANE RUN RAIL UPGRADE	83,103.24
CR MISCELLANEOUS PROJECTS	220,679.29
CR ASBESTOS ABATEMENT	94,279.96
OF SPCC RISK MITIGATION	33,863.71

LGE 107001 Electric CWIP Balance

As of April 30, 2008

Description	Amount
PR SPCC COMPLIANCE	4,253.75
PR SUMP PUMP & MOTOR REPLACEMENT	21,248.82
BR CT UNDERGROUND PIPE SPCC (DEV)	14,973.41
CT6 A/B CONVERSION	3,799,248.65
PADDY'S RUN PLC EQUIPMENT REPLACEMENT	0.17
WATERSIDE DISTRIBUTION SUBSTATION	858,319.55
WATERSIDE SITE RELOCATION RECONFIGURE TRANSMISSION LINES	4,153,657.43
MC TURBINE TURNING GEAR DIESEL GENERATOR	448,225.07
EKP CEDAR GROVE 16KV TAP	519.40
MILL CREEK UNIT #1 SOOTBLOWER THERMAL DRAIN PIPING	48,929.91
MC1 BOILER CIRCULATING PUMP INJECTION WATER PIPING	4,040.00
SO3 SORBENT INJECTION	2,116,008.90
CR6 COAL PIPE ISOLATION ORIFICE BOXES	80,727.98
CR5 BLOWDOWN TANK REPLACEMENT	40,280.71
CR5 SUPERHEATER PLATEN AND PENDANT REPLACEMENT	3,547,184.26
WATERSIDE AUXILIARY GENERATOR DIESEL FUEL TANK	15,537.49
MT 138KV COLLINS TERMINATION	20,499.64
MIDDLETOWN - COLLINS 138 KV LINE	990.99
COLLINS 138/69KV 150MVA TRNSFRMR	31,234.59
WORTHINGTON CAPACITOR BANK INSTALLATION	39,398.77
LGE RTU PURCHASE	126,394.08
DIST CAPACITORS LGE	385,285.16
NEW BASE GENERATING UNIT - LGE	6.23
TC CT UNIT COMPRESSOR BLADE REPLACEMENTS	118,017.76
RTU REPL. CANAL & CANE RUN SW. STA.	46,230.96
BARCODE SCANNER REPLACEMENT	27,627.11
CR CIRCULATING WATER PUMP PROXIMITY CONTROL SWITCHES	52,043.84
MERCURY MONITORING	6,868.35
GALT HOUSE PROPERTY PURCHASE	301,648.75
MILL CREEK UNIT #2 COOLING TOWER BLEACH TANK	12,746.92
LGE SONET COMMUNICATION	115,880.68
UPS GRADE LANE	2,135,904.43
UPS/GRADE LANE 12KV CIRCUIT WORK	944,987.43
OSI WORKSTATION MEMORY UPGRADE	2,161.87
CR51 BOILER FEED PUMP MOTOR	178,474.70
MAIS II SERVER	19,094.32
TC CT DISCONNECT SWITCH DRIVE UPGRADE	5,637.05
TRANSMISSION OFFICE BUILDOUT	68,474.20
EMS SOFTWARE UPGRADE IMPLEMENTATION	23,432.49
OVHD HUBBARDS LN TO AMBRIDGE CIR PUBLIC WORKS PROJECTS	459,534.96
MUSEUM PLAZA RELOCATION	(464,985.64)
CR HVAC FOR ANNEX BLDG	141,958.19
MC "B" FLYASH SCREW FEEDER AUGER	11,719.30
MC4 COOLING TOWER FAN VARIABLE FREQUENCY DRIVERS	*66,332.51*
MC2 PRECIPITATOR ROOM AIR CONDITIONER	5,838.00
MC GYPSUM TELESCOPIC CHUTE	14,183.79
MC HYDRAULIC LIFT	15,660.57

LGE 107001 Electric CWIP Balance

As of April 30, 2008

Description	Amount
MC2 SEAL TROUGH REAR WATERWALL TUBING	424,014 17
UPS/SEMINOLE SUBSTATION ADDITION	(17,517 72)
UPS/SEMINOLE 12KV CIRCUIT WORK	38,075 50
MC PORTABLE WELDING MACHINES	10,721 20
MILL CREEK UNIT 1 WATERWALL WELD OVERLAY	545,757 45
MC 4-1 MAIN AUXILLARY HIGH VOLTAGE BUSHING	20,413 14
MC 4D COAL MILL GEARBOX	120,888 48
MC 4B COAL MILL GEARBOX	141,204 45
MC3 STACK LIGHTING	80,619 88
MILL CREEK UNIT 4 COOLING TOWER FAN DRIVE	124,239 41
MC1 AIR HEATER BASKETS	66,138 53
MC4 INSTRUCTURE AIR COMPRESSOR	171,430 28
EASTWOOD SUBSTATION DISTR CIRCUIT WORK	171,898 08
PURCHASE PROPERTY FOR CONESTOGA SUBSTATION	457,302 48
REPLACE GE SFC PROTECTIVE RELAYS	217 08
NEW BECKWITH TAP CHANGER CONTROLLER FOR COLLINS TR 1	1,056 43
MILL CREEK UNIT REHEATER REPLACEMENT	276,991 70
MC UNITS 1,2, AND 4 FGD ENGINEERING ASSESSMENT	3,102 57
LGE STORM	82,351 06
MC2 OXYGEN MONITORING SYSTEM	34,322 02
HUMANA DATA CENTER	435,753 02
MC COAL SCALE CERTIFICATION SLAB	162,654 59
TC CT LUBE OIL VARNISH SYSTEM	18,074 25
MC WAREHOUSE 11 DRIVEWAY	9,517 50
CR PLANT REACTANT SUPPLY CONTROL UPGRADE	92,556 63
CR5 REHEAT SAFETY VALVE UPGRADE	104,806 48
CR B REACTANT SCREEN DECK REPLACEMENT	67,256 15
VIDEO WALL RELOCATION INSTALLATION	4,477 51
CR ASBESTOS ABATEMENT	13,821 70
MC "D" CONVEYOR TUNNEL FAN	14,791 10
MC 1B2 RECYCLE PUMP UPGRADE	55,583 64
MILL CREEK BARGE UNLOADING RUNWAY	80,378 85
TECHNOLOGY ROOM	6,833 77
COGNOS FOR STORMS	23,120 09
JT1128 RECONDUCTOR	345,645 77
MC E1 COAL CRUSHER MOTOR	59,133 86
MC2 UPS BATTERIES	12,413 17
MUD LANE HUMANA DATA CENTER	3,777 58
MC "A" LIMESTONE MILL GEARBOX REPLACEMENT	33,432 66
ADDITIONAL PROPERTY ADJACENT TO MADISON SUBSTATION	10,651 60
TC VEHICLE PURCHASES	63,646 33
MC LIMESTONE MILL SPARE GEARBOX REBUILD	95,030 43
SULFUR CHN ANALYZER REPLACEMENTS	34,342 73
MC UTILITY TRUCKS	42,088 54
DIST CONESTOGA TAP	11,308 69
TRUCK FOR SERVICE SHOP	26,992 29
CR4B HOTWELL PUMP MOTOR REWIND	18,895 54

LGE 107001 Electric CWIP Balance

As of April 30, 2008

Description	Amount
WIND STORM	26,223.17
TC1 CATALYST LAYER PURCHASE & INSTALLATION	140,597.54
MC D1 COAL CONVEYOR BELT	31,576.80
STORM	458,628.91
THUNDERSTORM	372,680.34
SNOW & ICE STORM	73,921.50
WIND STORM	19,636.88
CR5 TURBINE GENERATOR COLLECTOR RING REPLACEMENT	66,164.61
CR5 TURBINE STEAM SEALS AND PACKING REPLACEMENT	181,269.05
CR5 52 BOILER FEED PUMP MOTOR REWIND	73,938.87
ICE STORM	87,146.90
CR5 HIGH VOLTAGE BUSHING REPLACEMENT	241,396.79
TC CAP SALVAGE EQUIP	1,914.97
MC GYPSUM OVERLAND CONVEYOR BELT	26,743.97
MOTOR REPLACE. LGE - CORPORATE	12,408.45
MC 3A COOLING TOWER FAN MOTOR REWIND	10,433.81
BLANKET CABLE FOR JOINT TRENCH	2,333,478.10
CAP, REG, RECLOSERS 340	93,613.57
PURCHASE AND INSTALLATION OF ELECTRIC EQUIPMENT	238,824.77
GAS MAIN EXT. 406 ELEC. DIST WORK	163,124.42
TRANSMISSION LINE RELOCATION	175,146.73
TRANS. LINES NEW FACILITIES	(26,201.78)
LINE PARAMETER UPGRADES	207,070.32
LT8	357,165.45
LT9 TRANSMISSION	1,649,095.20
CAP/REG/RECL 340	513,005.15
NEW BUS COMM OH 330	(657.10)
NEW BUS COMM OH 340	358,317.92
NEW BUS COMM UG 340	5,836,694.07
NEW BUS COMM UG 341	4,930.94
NEW BUS COMM UG 344	221,448.89
NEW BUSINESS GAS SERVICE 341 - ELEC. DIST. RELOC.	2,185.56
NEW BUS INDUS OH 340	(54,580.52)
NEW BUS INDUS UG 341	29,842.42
NEW BUS RES OH 340	310,273.00
NEW BUS RES UG	(95,292.60)
NEW BUS RES UG 341	112,327.32
NEW BUS. RES. 344 UG	34,302.12
NEW BUS SUB OH 340	305,808.25
NEW BUS SUB UG 341	9,698,558.68
NEW ELECTRIC SERVICES	1,318,176.10
NEW EL SERV UG	4,526,157.30
NEW BUS. SERV. 341 UG	101.42
NETWORK VAULTS 343	(1,645.50)
NETWORK VAULTS	1,656,311.63
PUB WORKS RELOC OH 330	150,383.29
PUB WORKS RELOC OH	1,350,943.10

LGE 107001 Electric CWIP Balance
As of April 30, 2008

Description	Amount
PUB WORKS RELOC UG 340	3,347 74
PUBLIC RELOCATIONS U/G	175,414 43
PM INSPECTION 340	14,334.28
PRIORITY MAIN REPL. - TRANS LINE WORK	(4,896.71)
CUST REQ 340	(264,107.62)
CUSTOMER REQUESTS 344	5,074.18
CUSTOMER REQUESTED GAS 406 - ELEC. DIST	3,871 81
REPL DEFECTIVE CABLE 340	2,571,941.65
REPAIR REP. DEFECT. EQUIP. 003065	95,231.21
REP./REPL. DEFECTIVE EQUIP RC319	93,132.07
REP DEF EQ OH 340	4,668,357.94
REP DEF EQ UG 340	2,429,117.52
REPL. DEFECT EQUIP OH 345	1,213,867 09
REP DEF POL'S 320	(549.22)
REP DEF POL'S	0.38
POLE REP/REPL 340	5,236,972.23
REPAIR STREET LIGHTING 332	1,716,437.51
REP DEF ST LIGHTS 340	321,958.33
REPAIR DEFECT. STREET LIGHTING	1,221,000.22
LGE GENERAL RELIABILITY 01015	21,276.22
DIST. 0/H RELIABILITY 340	1,216,982.66
DIST U/G RELIABILITY 340	628,331.69
REP THR PARTY DAM 340	2,649,658.27
REPAIR THIRD PARTY DAMAGES-419	30,193 08
STREET LIGHTING 332	898,670.64
STREET LIGHTS OVERHEAD 333	1,158,561.81
STREET LIGHT UG 332	1,588,642.74
STREET LIGHTING 347	1,185,012.65
STORM 003230	96,634.91
SYS ENH EXIST CUST 340	468,177.41
TROUBLE OVERHEAD 340	4,545,327.02
TROUBLE UNDERGROUND 340	1,813,034.17
TOOLS AND EQ 340	579,064.05
WEATHER 003400	55,829.91
TRANSFORMER 340	329,543.65
TRANSFORMER INSTALL - JOINT TRENCH	288,635.64
Total	**$ 263,290,548.24**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 162

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-162. Please provide LG&E adjusted test year electric depreciation reserve and depreciation expense by FERC account.

A-162. See attached.

ACCOUNT	DESCRIPTION	ACCUMULATED DEPRECIATION	DEPRECIATION EXPENSE
PRODUCTION PLANT			
STEAM PLANT			
131100	STRUCTURES AND IMPROVEMENTS	(206,864,177 88)	
131200	BOILER PLANT EQUIPMENT	(568,807,645 04)	
131400	TURBOGENERATOR UNITS	(123,648,834 87)	
131500	ACCESSORY ELECTRIC EQUIPMENT	(106,787,642 51)	
131600	MISCELLANEOUS POWER PLANT EQUIPMENT	(4,952,239 42)	
131700	ASSET RETIREMENT OBLIGATIONS STEAM PLANT	(2,273,547 35)	
	TOTAL STEAM PRODUCTION PLANT	$ (1,013,334,087.07)	$ 57,742,998.83
HYDRAULIC PLANT			
PROJECT 289			
133100	STRUCTURES AND IMPROVEMENTS	(4,195,027 39)	
133200	RESERVOIRS, DAMS AND WATERWAYS	(610,260 52)	
133300	WATERWHEELS, TURBINES AND GENERATORS	(1,718,794 77)	
133400	ACCESSORY ELECTRIC EQUIPMENT	(935,568 59)	
133500	MISCELLANEOUS POWER PLANT EQUIPMENT	(30,196 45)	
133600	ROADS, RAILROADS AND BRIDGES	(16,543 21)	
	TOTAL HYDRAULIC PLANT-PROJECT 289	(7,506,390.93)	
OTHER THAN PROJECT 289			
133100	STRUCTURES AND IMPROVEMENTS	(36,981 83)	
133500	MISCELLANEOUS POWER PLANT EQUIPMENT	(2,249 88)	
133600	ROADS, RAILROADS AND BRIDGES	(857 19)	
133700	ASSET RETIREMENT OBLIGATIONS HYDRO PLANT	(16,982.96)	
	TOTAL HYDRAULIC PLANT - OTHER THAN PROJECT 289	(57,071.86)	
	TOTAL HYDRAULIC PRODUCTION PLANT	$ (7,563,462.79)	$ 702,678.84
PRODUCTION PLANT			
OTHER PRODUCTION PLANT			
134100	STRUCTURES AND IMPROVEMENTS	(2,583,649 74)	
134200	FUEL HOLDERS, PRODUCERS AND ACCESS	(1,570,130 30)	
134300	PRIME MOVERS	(27,750,758 90)	
134400	GENERATORS	(12,959,559 64)	
134500	ACCESSORY ELECTRIC EQUIPMENT	(3,326,408 69)	
134600	MISC POWER PLANT EQUIPMENT	(872,882 43)	
134700	ASSET RETIRE OBLIGATIONS OTHER PRODUCTION PLANT	(115,962 92)	
	TOTAL OTHER PRODUCTION PLANT	$ (49,179,352.62)	$ 7,423,757.07

ACCOUNT	DESCRIPTION	ACCUMULATED DEPRECIATION	DEPRECIATION EXPENSE
TRANSMISSION PLANT			
PROJECT 289			
135310	STATION EQUIP -NON SYS CONTROL/COMM	(430,495 16)	
135600	OVERHEAD CONDUCTORS AND DEVICES	(15,229 78)	
		-	
	TOTAL TRANSMISSION PLANT-PROJECT 289	(445,724.94)	
OTHER THAN PROJECT 289			
135010	LAND RIGHTS	(1,305,788 82)	
135210	STRUCT & IMPROVE-NON SYS CONT /COMM	(1,878,598 65)	
135310	STATION EQUIP -NON SYS CONTROL/COMM	(75,637,201 37)	
135400	TOWERS AND FIXTURES	(21,086,625 97)	
135500	POLES AND FIXTURES	(14,441,750 77)	
135600	OVERHEAD CONDUCTORS AND DEVICES	(21,214,099 33)	
135700	UNDERGROUND CONDUIT	(495,122 60)	
135800	UNDERGROUND CONDUCTORS & DEVICES	(1,742,437 86)	
135910	ASSET RETIRE OBLIGATIONS TRANS PLANT	(2,908 33)	
	TOTAL TRANSMISSION PLANT - OTHER THAN PROJECT 289	(137,804,533.70)	
		-	
	TOTAL TRANSMISSION PLANT	$ (138,250,258.64)	$ 6,076,139.05
DISTRIBUTION PLANT			
136100	STRUCTURES AND IMPROVEMENTS	(4,779,133 11)	
136200	STATION EQUIPMENT	(47,816,486 68)	
136400	POLES, TOWERS AND FIXTURES	(66,050,244 47)	
136500	OVERHEAD CONDUCTORS AND DEVICES	(88,296,089 87)	
136600	UNDERGROUND CONDUIT	(23,750,428 58)	
136700	UNDERGROUND CONDUCTORS & DEVICES	(43,101,015 82)	
136810	LINE TRANSFORMERS	(50,464,654 87)	
136820	LINE TRANSFORMER INSTALLATIONS	(3,968,445 14)	
136910	UNDERGROUND SERVICES	(1,578,497 51)	
136920	OVERHEAD SERVICES	(16,268,906 24)	
137010	METERS	(12,468,356 80)	
137020	METER INSTALLATIONS	(3,820,526 48)	
137310	OVERHEAD STREET LIGHTING	(16,447,235 10)	
137320	UNDERGROUND STREET LIGHTING	(17,561,130 04)	
137340	STREET LIGHTING TRANSFORMERS	(89,350 62)	
137400	ASSET RETIRE OBLIGATIONS DIST PLANT	(12,489 46)	
	TOTAL DISTRIBUTION PLANT	$ (396,472,990.79)	$ 25,756,405.32

ACCOUNT	DESCRIPTION	ACCUMULATED DEPRECIATION	DEPRECIATION EXPENSE
GENERAL PLANT			
139210	TRANSPORTATION EQUIPMENT - CARS AND TRUCKS	(8,987,533.13)	
139220	TRANSPORTATION EQUIPMENT - TRAILERS	(199,257.14)	
139400	TOOLS, SHOP, AND GARAGE EQUIPMENT	(1,075,630.52)	
139500	LABORATORY EQUIPMENT	(854,003.83)	
139610	POWER OPERATED EQUIP. - HOURLY RATED	(2,261,153.76)	
139620	POWER OPERATED EQUIPMENT - OTHER	(22,818.95)	
	TOTAL GENERAL PLANT	$ (13,400,397.33)	$ 161,879.78
	GRAND TOTAL	$ (1,618,200,549.24)	$ 97,863,858.89

NOTE 1: EXPENSE IS NOT TRACKED SEPARATELY BY PLANT ACCOUNT

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 163

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-163. Please provide all LG&E calculated, known, or estimated electric uncollectible expense by customer class.

A-163. This information is not available. The Company does not maintain uncollectible expense by customer class.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 164

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-164. Please provide LG&E electric customer deposits by class as of 4/30/2008.

A-164. See response to Question No. 167. The following information represents the total customer deposits, electric and gas. The Company does not maintain electric and gas customer deposits separately.

Account Type	Deposit Amount
Residential	$ 12,889,889.37
Small Commercial	4,528,581.73
Large Commercial	2,030,463.00
Public Authority	1,156.00
Industrial	622,529.57
Total Deposits	$ 20,072,619.67

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 165

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-165. Please provide LG&E electric interest on customer deposits by class.

A-165. See response to Question No. 167. The following information represents the total customer interest on deposits, electric and gas. The Company does not maintain electric and gas customer deposits separately.

Account Type	Interest Amount
Residential	$ 601,743.64
Small Commercial	163,564.81
Large Commercial	65,184.69
Public Authority	9.83
Industrial	20,379.39
Total Deposits	$ 850,882.36

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 166

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-166. Please provide actual and estimated LG&E electric meter reads by class during the test year.

A-166. The following information represents the total actual and estimated meter reads for both electric and gas. The Company does not maintain meter reads by class separately.

Actual Meter Reads	8,450,676
Estimated Meter Reads	400,365

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 167

Responding Witness: William Steven Seelye

Q-167. Please explain how and where customer deposits and/or interest on customer deposits is reflected in the LG&E electric class cost of service study.

A-167. Consistent with the Commission's Order in Case No. 98-474 (KU) and Case No. 98-426 (LG&E) interest expenses on deposits are not included as a component of revenue requirement and customer deposits are not deducted from rate base or capitalization. Consequently, neither customer deposits nor interest on customer deposits are considered in the class cost of service study.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 168

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-168. Please provide the following by month for the period January 2003 through July 2008 by rate schedule for LG&E electric:

a. customers billed, and,
b. billed KWH (as applicable).

Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-168. a. and b. See attached.

Louisville Gas and Electric Company
Case No. 2008-00252
Customers Billed by Rate Schedule
For the period January 2003 through July 2008

Customers	Jul-2008	Jun-2008	May-2008	Apr-2008	Mar-2008	Feb-2008	Jan-2008	Dec-2007	Nov-2007
Residential Service RS	355,291	355,828	354,401	353,463	354,271	352,676	352,973	352,637	352,884
Total General Service GS	40,976	40,784	40,885	40,756	40,812	40,727	40,735	41,476	41,353
Large Commercial LC	2,818	2,777	2,802	2,763	2,778	2,781	2,766	2,709	2,777
L:arge Commercial Time of Day LC-TOD	65	66	66	66	66	65	66	64	66
Large Commercial Special Contracts	1	1	1	1	1	1	1	1	1
Large Power Industrial Service LP	365	365	368	368	366	364	372	364	369
Large Power Industrial Time of Day LP-TOD	64	63	64	64	64	64	64	64	64
Large Power Industrial Special Contracts	3	3	3	3	3	3	3	3	3
Public Street Lighting PSL	1,625	1,628	1,623	1,660	1,660	1,666	1,654	1,619	1,654
Street Lighting Energy SLE	113	118	117	118	119	119	118	117	119
Outdoor Lighting OL (1)	16,742	16,709	15,734	16,742	16,716	16,722	16,757	15,548	16,601
Traffic Lighting Energy TLE	879	881	877	875	872	893	903	907	908

Louisville Gas and Electric Company
Case No. 2008-00252
Customers Billed by Rate Schedule
For the period January 2003 through July 2008

Customers	Oct-2007	Sep-2007	Aug-2007	Jul-2007	Jun-2007	May-2007	Apr-2007	Mar-2007	Feb-2007
Residential Service RS	352,578	352,926	354,009	353,848	353,401	353,329	352,079	352,294	351,384
Total General Service GS	41,490	41,495	41,463	41,378	41,433	41,234	41,121	41,157	41,042
Large Commercial LC	2,766	2,781	2,786	2,777	2,785	2,775	2,740	2,769	2,737
L:arge Commercial Time of Day LC-TOD	66	67	67	67	67	66	67	66	67
Large Commercial Special Contracts	1	1	1	1	1	1	1	1	1
Large Power Industrial Service LP	371	372	373	374	377	372	372	372	374
Large Power Industrial Time of Day LP-TOD	64	63	64	63	64	65	64	65	65
Large Power Industrial Special Contracts	3	3	2	3	3	3	3	3	3
Public Street Lighting PSL	1,657	1,656	1,660	1,661	1,663	1,665	1,660	1,663	1,665
Street Lighting Energy SLE	121	120	119	117	118	119	120	122	126
Outdoor Lighting OL (1)	16,591	16,626	16,642	16,648	16,677	16,672	16,652	16,664	16,570
Traffic Lighting Energy TLE	910	912	914	910	908	909	910	907	904

Louisville Gas and Electric Company
Case No. 2008-00252
Customers Billed by Rate Schedule
For the period January 2003 through July 2008

Customers	Jan-2007	Dec-2006	Nov-2006	Oct-2006	Sep-2006	Aug-2006	Jul-2006	Jun-2006	May-2006
Residential Service RS	351,023	350,348	350,210	351,200	349,824	351,299	350,857	350,032	350,087
Total General Service GS	41,038	40,798	40,735	40,740	40,602	40,761	40,653	40,647	40,625
Large Commercial LC	2,735	2,655	2,716	2,719	2,730	2,707	2,737	2,742	2,741
L:arge Commercial Time of Day LC-TOD	67	65	65	64	65	64	66	66	61
Large Commercial Special Contracts	1	0	1	1	1	1	1	1	1
Large Power Industrial Service LP	373	376	376	379	376	380	377	380	379
Large Power Industrial Time of Day LP-TOD	65	63	64	65	65	63	66	66	60
Large Power Industrial Special Contracts	3	3	3	3	3	3	3	3	3
Public Street Lighting PSL	1,662	1,660	1,656	1,660	1,660	1,664	1,665	1,666	1,664
Street Lighting Energy SLE	115	119	118	113	119	117	119	117	121
Outdoor Lighting OL (1)	16,546	16,549	16,570	16,602	16,553	16,584	16,640	16,570	16,568
Traffic Lighting Energy TLE	905	903	901	903	903	903	901	897	900

Louisville Gas and Electric Company
Case No. 2008-00252
Customers Billed by Rate Schedule
For the period January 2003 through July 2008

Customers	Apr-2006	Mar-2006	Feb-2006	Jan-2006	Dec-2005	Nov-2005	Oct-2005	Sep-2005	Aug-2005
Residential Service RS	349,142	348,888	348,065	347,902	346,446	347,412	347,098	347,609	347,662
Total General Service GS	40,552	40,595	40,489	40,383	40,326	40,212	40,135	40,382	40,224
Large Commercial LC	2,724	2,751	2,758	2,772	2,749	2,742	2,747	2,723	2,683
L:arge Commercial Time of Day LC-TOD	66	68	65	66	65	67	67	66	66
Large Commercial Special Contracts	1	1	1	1	1	1	1	1	1
Large Power Industrial Service LP	380	384	382	379	376	380	382	381	383
Large Power Industrial Time of Day LP-TOD	68	67	67	62	64	65	65	66	66
Large Power Industrial Special Contracts	3	3	3	3	3	3	3	5	4
Public Street Lighting PSL	1,666	1,662	1,670	1,668	1,668	1,663	1,670	1,669	1,668
Street Lighting Energy SLE	118	121	118	127	109	120	119	118	117
Outdoor Lighting OL (1)	16,568	16,521	16,521	16,446	16,402	16,394	16,447	16,490	16,490
Traffic Lighting Energy TLE	897	894	897	890	881	880	892	889	886

Louisville Gas and Electric Company Case No. 2008-00252 Customers Billed by Rate Schedule For the period January 2003 through July 2008									
Customers	Jul-2005	Jun-2005	May-2005	Apr-2005	Mar-2005	Feb-2005	Jan-2005	Dec-2004	Nov-2004
Residential Service RS	347,118	347,003	346,149	344,441	345,007	344,997	343,024	343,025	343,861
Total General Service GS	40,350	40,093	40,019	39,797	39,923	39,799	39,819	39,847	40,027
Large Commercial LC	2,712	2,709	2,718	2,712	2,734	2,725	2,745	2,728	2,731
L:arge Commercial Time of Day LC-TOD	67	66	65	65	65	65	66	65	65
Large Commercial Special Contracts	1	0	1	1	2	1	1	1	1
Large Power Industrial Service LP	382	379	383	381	384	372	377	365	375
Large Power Industrial Time of Day LP-TOD	66	66	65	64	64	65	63	63	64
Large Power Industrial Special Contracts	3	3	3	4	3	4	4	4	4
Public Street Lighting PSL	1,673	1,674	1,684	1,682	1,674	1,681	1,670	1,684	1,680
Street Lighting Energy SLE	118	118	117	116	119	116	115	119	115
Outdoor Lighting OL (1)	16,514	16,551	16,496	16,466	16,424	16,373	16,268	16,220	16,218
Traffic Lighting Energy TLE	886	884	886	888	892	893	890	886	884

Louisville Gas and Electric Company
Case No. 2008-00252
Customers Billed by Rate Schedule
For the period January 2003 through July 2008

Customers	Oct-2004	Sep-2004	Aug-2004	Jul-2004	Jun-2004	May-2004	Apr-2004	Mar-2004	Feb-2004
Residential Service RS	343,092	343,279	344,468	343,031	343,020	341,820	341,237	340,261	340,529
Total General Service GS	40,400	40,524	40,298	40,381	40,429	40,403	40,356	40,290	40,419
Large Commercial LC	2,735	2,704	2,613	2,578	2,518	2,648	2,673	2,722	2,706
L:arge Commercial Time of Day LC-TOD	66	62	66	64	64	64	60	63	59
Large Commercial Special Contracts	1	1	1	1	1	1	1	1	1
Large Power Industrial Service LP	378	380	385	371	384	386	377	385	388
Large Power Industrial Time of Day LP-TOD	65	66	61	63	61	61	60	63	61
Large Power Industrial Special Contracts	4	5	5	5	5	5	5	5	5
Public Street Lighting PSL	1,681	1,679	1,678	1,677	1,676	1,679	1,678	1,679	1,675
Street Lighting Energy SLE	118	120	119	118	121	120	121	121	121
Outdoor Lighting OL (1)	16,229	16,244	16,237	16,272	16,295	16,318	16,361	16,379	16,327
Traffic Lighting Energy TLE	884	883	882	877	882	885	879	880	881

Louisville Gas and Electric Company Case No. 2008-00252 Customers Billed by Rate Schedule For the period January 2003 through July 2008									
Customers	Jan-2004	Dec-2003	Nov-2003	Oct-2003	Sep-2003	Aug-2003	Jul-2003	Jun-2003	May-2003
Residential Service RS	338,636	340,868	340,203	337,772	338,772	339,079	338,527	338,589	338,146
Total General Service GS	40,377	40,302	40,289	40,331	40,384	40,468	40,490	40,688	40,567
Large Commercial LC	2,672	2,630	2,679	2,662	2,648	2,637	2,640	2,630	2,626
L:arge Commercial Time of Day LC-TOD	57	63	63	64	62	62	62	61	61
Large Commercial Special Contracts	1	1	1	1	1	1	1	1	1
Large Power Industrial Service LP	384	385	393	390	395	395	392	388	397
Large Power Industrial Time of Day LP-TOD	61	64	63	65	64	63	65	62	62
Large Power Industrial Special Contracts	5	5	5	5	5	5	5	5	5
Public Street Lighting PSL	1,682	1,686	1,668	1,668	1,659	1,660	1,655	1,653	1,654
Street Lighting Energy SLE	121	121	120	122	124	123	123	124	124
Outdoor Lighting OL (1)	16,284	16,539	16,303	16,237	16,182	16,177	16,198	16,200	16,234
Traffic Lighting Energy TLE	883	884	880	878	873	871	867	866	864

Louisville Gas and Electric Company Case No. 2008-00252 Customers Billed by Rate Schedule For the period January 2003 through July 2008									
Customers	Apr-2003	Mar-2003	Feb-2003	Jan-2003					
Residential Service RS	336,908	336,665	336,907	334,548					
Total General Service GS	40,653	40,588	40,593	40,506					
Large Commercial LC	2,630	2,682	2,681	2,574					
L:arge Commercial Time of Day LC-TOD	60	60	61	61					
Large Commercial Special Contracts	1	1	1	1					
Large Power Industrial Service LP	394	396	397	397					
Large Power Industrial Time of Day LP-TOD	64	66	64	63					
Large Power Industrial Special Contracts	5	5	5	5					
Public Street Lighting PSL	1,654	1,655	1,652	1,647					
Street Lighting Energy SLE	128	127	125	126					
Outdoor Lighting OL (1)	16,237	16,225	16,267	16,236					
Traffic Lighting Energy TLE	867	864	864	863					

(1) contains residential and commercial customers
who have outdoor lighting service.

Louisville Gas and Electric Company
Case No. 2008-00252
Billed KWH by Rate Schedule
For the period January 2003 through July 2008

KWH	Jul-2008	Jun-2008	May-2008	Apr-2008	Mar-2008	Feb-2008	Jan-2008	Dec-2007	Nov-2007
Residential Service RS	468,635,616	364,031,039	240,130,447	270,158,359	328,868,904	347,779,559	387,270,391	318,973,435	266,773,960
Total General Service GS	145,653,111	128,251,632	103,837,231	106,577,668	113,822,763	117,356,993	124,348,260	110,972,754	107,123,224
Large Commercial LC	223,266,723	206,836,680	171,516,213	174,390,603	178,972,598	179,912,460	194,868,274	178,320,898	176,452,062
L:arge Commercial Time of Day LC-TOD	60,480,896	56,525,787	49,102,530	49,154,930	49,233,685	50,470,076	52,537,044	52,077,184	50,473,948
Large Commercial Special Contracts	22,502,000	20,801,000	15,746,000	14,867,000	16,067,000	16,298,000	17,478,000	15,966,000	14,612,000
Large Power Industrial Service LP	60,298,334	57,444,121	52,465,693	51,662,780	51,776,338	50,636,745	53,312,483	51,549,912	53,492,779
Large Power Industrial Time of Day LP-TOD	197,298,861	206,130,488	186,112,745	190,984,363	196,073,119	175,548,850	205,494,909	187,307,357	191,666,654
Large Power Industrial Special Contracts	12,592,800	12,788,400	10,860,000	11,306,400	12,052,800	16,444,800	17,265,600	17,785,200	17,198,400
Public Street Lighting PSL	3,302,197	3,458,552	3,651,546	3,593,826	4,869,204	4,119,461	5,101,130	5,256,864	4,922,191
Street Lighting Energy SLE	199,953	247,827	247,746	294,256	310,710	318,951	371,887	365,191	345,525
Outdoor Lighting OL (1)	3,853,160	3,940,393	3,801,117	4,405,456	4,948,356	4,864,789	6,181,760	5,613,155	5,485,623
Traffic Lighting Energy TLE	289,666	288,603	279,428	290,611	297,267	306,948	344,389	321,764	306,923

Louisville Gas and Electric Company
Case No. 2008-00252
Billed KWH by Rate Schedule
For the period January 2003 through July 2008

KWH	Oct-2007	Sep-2007	Aug-2007	Jul-2007	Jun-2007	May-2007	Apr-2007	Mar-2007	Feb-2007
Residential Service RS	356,237,245	530,748,105	536,380,632	476,986,362	409,173,882	289,011,979	270,503,866	309,515,507	366,435,112
Total General Service GS	127,997,196	157,875,479	153,573,433	143,662,997	134,834,121	110,978,843	109,355,673	110,844,978	118,995,717
Large Commercial LC	205,281,318	242,882,522	232,624,394	223,189,354	215,481,583	187,482,063	180,970,077	173,914,761	178,896,286
L:arge Commercial Time of Day LC-TOD	55,517,096	68,421,946	61,026,694	61,411,183	59,158,368	52,080,981	50,882,243	51,032,947	49,253,298
Large Commercial Special Contracts	16,597,000	19,026,000	24,352,000	20,656,000	19,091,000	16,856,000	14,313,000	15,024,000	15,490,000
Large Power Industrial Service LP	57,663,482	63,072,897	62,763,221	59,336,154	58,896,970	54,410,945	54,057,199	52,762,707	53,527,435
Large Power Industrial Time of Day LP-TOD	199,297,831	208,696,431	214,953,830	212,386,692	199,876,462	209,110,713	199,081,041	194,915,184	186,597,196
Large Power Industrial Special Contracts	18,178,800	20,532,000	19,812,000	18,416,400	19,210,800	17,503,200	17,181,600	15,942,000	17,713,200
Public Street Lighting PSL	4,690,125	4,110,972	3,816,468	3,485,978	3,282,675	3,598,810	3,846,541	4,421,724	4,409,503
Street Lighting Energy SLE	338,455	299,113	273,901	260,982	258,707	275,919	324,201	313,032	427,625
Outdoor Lighting OL (1)	5,223,091	4,555,172	4,254,633	3,941,697	3,622,671	3,975,356	4,268,381	5,008,141	4,923,464
Traffic Lighting Energy TLE	344,855	287,852	271,827	270,654	296,691	301,867	299,326	323,727	291,393

Louisville Gas and Electric Company
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KWH	Jan-2007	Dec-2006	Nov-2006	Oct-2006	Sep-2006	Aug-2006	Jul-2006	Jun-2006	May-2006
Residential Service RS	347,249,559	316,175,899	265,477,919	262,304,681	402,490,322	517,117,583	463,061,543	350,573,897	250,820,564
Total General Service GS	115,752,560	108,838,380	102,183,105	107,748,386	133,964,466	147,601,754	139,008,995	124,432,211	106,143,404
Large Commercial LC	186,866,881	175,636,190	170,920,117	183,825,499	218,940,544	228,530,308	220,876,716	204,374,372	185,470,722
L:arge Commercial Time of Day LC-TOD	52,004,764	50,406,769	48,167,963	51,726,814	61,398,890	61,056,678	58,076,608	55,772,164	50,075,734
Large Commercial Special Contracts	30,292,000	0	13,889,000	14,568,000	15,833,000	22,890,000	21,790,000	18,210,000	15,309,000
Large Power Industrial Service LP	53,681,124	54,123,344	53,568,038	55,904,141	61,217,880	62,907,621	59,450,932	58,421,183	54,656,804
Large Power Industrial Time of Day LP-TOD	210,141,880	197,971,799	196,374,507	203,160,152	212,291,578	209,111,814	219,852,573	215,933,992	218,212,748
Large Power Industrial Special Contracts	16,819,200	16,848,000	16,089,600	15,020,400	18,063,600	18,690,000	17,631,600	17,562,000	16,736,400
Public Street Lighting PSL	5,186,048	5,303,744	4,922,206	4,702,361	4,118,297	3,822,978	3,343,752	3,289,213	3,603,773
Street Lighting Energy SLE	330,604	387,753	371,240	335,512	297,048	265,216	257,573	252,815	295,447
Outdoor Lighting OL (1)	5,703,832	5,873,394	5,427,522	5,183,603	4,515,260	4,207,774	3,855,316	3,665,566	3,973,680
Traffic Lighting Energy TLE	366,074	333,166	317,343	313,950	322,861	299,395	300,606	328,977	308,174

Louisville Gas and Electric Company Case No. 2008-00252 Billed KWH by Rate Schedule For the period January 2003 through July 2008									
KWH	Apr-2006	Mar-2006	Feb-2006	Jan-2006	Dec-2005	Nov-2005	Oct-2005	Sep-2005	Aug-2005
Residential Service RS	261,505,074	287,037,551	304,616,608	360,229,191	342,939,845	242,563,851	336,828,036	473,869,955	533,127,837
Total General Service GS	101,723,852	102,617,605	104,389,609	114,954,007	112,411,988	97,614,020	119,713,180	141,300,841	146,434,201
Large Commercial LC	171,924,280	168,512,101	168,740,373	190,536,299	187,383,692	173,611,869	200,882,160	228,035,499	226,366,754
L:arge Commercial Time of Day LC-TOD	47,742,932	48,469,102	45,157,187	51,316,542	50,218,598	47,339,521	54,171,247	61,961,729	59,264,110
Large Commercial Special Contracts	13,719,000	14,122,000	13,349,000	14,319,000	14,646,000	13,555,000	14,994,000	18,926,000	22,954,000
Large Power Industrial Service LP	52,701,602	51,931,051	51,876,932	54,175,418	53,311,660	51,718,142	56,767,865	60,782,357	61,166,809
Large Power Industrial Time of Day LP-TOD	205,226,024	197,281,776	197,790,860	215,019,789	191,971,663	200,336,957	204,534,808	227,079,002	222,886,447
Large Power Industrial Special Contracts	17,439,600	15,780,000	16,965,600	18,117,600	17,197,200	16,443,600	14,832,000	30,754,800	19,810,800
Public Street Lighting PSL	3,852,251	4,439,990	4,408,671	5,203,330	5,311,246	4,928,272	4,711,903	4,147,937	3,718,784
Street Lighting Energy SLE	313,109	330,603	352,307	433,342	407,908	365,279	343,821	296,099	262,035
Outdoor Lighting OL (1)	4,282,235	4,761,867	4,874,311	5,674,852	5,752,096	5,322,622	5,119,876	4,491,088	4,142,896
Traffic Lighting Energy TLE	326,425	319,617	351,372	389,432	377,784	377,681	406,770	417,878	399,035

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KWH	Jul-2005	Jun-2005	May-2005	Apr-2005	Mar-2005	Feb-2005	Jan-2005	Dec-2004	Nov-2004
Residential Service RS	499,696,662	355,338,591	240,776,306	247,364,086	284,663,130	303,728,242	354,760,933	294,915,866	235,036,700
Total General Service GS	141,905,237	120,940,752	95,617,636	97,807,488	100,771,989	105,305,191	111,620,329	102,382,271	96,360,825
Large Commercial LC	226,046,224	202,706,711	167,666,567	161,021,778	172,170,852	171,498,691	192,471,512	173,144,801	169,238,354
L:arge Commercial Time of Day LC-TOD	58,064,536	51,986,987	44,285,253	46,198,143	45,368,263	45,969,683	48,394,930	47,198,414	46,836,988
Large Commercial Special Contracts	22,011,000	19,267,000	15,039,000	13,306,000	14,325,000	13,237,000	14,888,000	14,375,000	13,379,000
Large Power Industrial Service LP	60,273,861	58,662,334	50,226,003	52,075,692	54,654,173	50,199,116	53,402,116	51,680,587	54,448,638
Large Power Industrial Time of Day LP-TOD	217,082,581	210,834,233	193,790,396	187,528,493	188,893,671	181,300,853	188,844,258	185,487,620	198,936,093
Large Power Industrial Special Contracts	18,925,200	18,588,000	14,445,600	27,852,000	26,425,200	28,120,800	30,950,400	28,246,800	28,495,200
Public Street Lighting PSL	3,389,355	2,892,273	3,612,497	3,917,674	4,404,665	4,454,706	5,098,425	5,377,877	4,987,169
Street Lighting Energy SLE	231,736	241,944	265,864	298,000	328,622	323,426	374,803	401,944	376,074
Outdoor Lighting OL (1)	3,823,400	3,544,664	4,005,321	4,567,373	4,535,227	4,792,428	5,647,959	5,682,330	5,357,118
Traffic Lighting Energy TLE	435,699	207,052	493,155	609,872	703,870	830,983	1,026,031	989,357	941,653

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KWH	Oct-2004	Sep-2004	Aug-2004	Jul-2004	Jun-2004	May-2004	Apr-2004	Mar-2004	Feb-2004
Residential Service RS	269,725,477	396,907,358	398,497,825	440,586,448	402,808,950	280,945,466	242,056,312	267,836,935	334,091,293
Total General Service GS	106,821,986	128,848,194	124,496,042	132,895,905	131,056,762	105,900,412	93,274,416	103,711,368	109,390,738
Large Commercial LC	186,250,267	210,861,316	204,074,014	212,389,090	208,972,254	179,088,168	169,015,918	168,081,374	175,341,609
L:arge Commercial Time of Day LC-TOD	50,760,214	54,908,593	52,433,152	55,701,484	52,606,735	47,301,058	44,731,303	45,183,440	46,998,277
Large Commercial Special Contracts	13,934,000	17,377,000	20,075,000	20,710,000	19,532,000	17,508,000	13,330,000	13,932,000	13,598,000
Large Power Industrial Service LP	54,908,710	60,257,731	58,783,424	59,277,312	60,237,366	56,888,562	52,093,945	51,157,464	55,289,413
Large Power Industrial Time of Day LP-TOD	188,265,231	187,291,165	175,554,183	177,369,492	178,548,927	183,391,789	164,861,096	160,339,041	170,473,281
Large Power Industrial Special Contracts	28,402,800	49,194,602	49,456,932	49,551,098	49,486,106	45,135,444	41,417,729	43,351,073	45,954,266
Public Street Lighting PSL	4,733,946	4,139,022	3,844,736	3,515,521	3,318,067	3,625,173	3,873,521	4,456,735	4,406,726
Street Lighting Energy SLE	319,942	298,339	259,376	240,945	232,892	28,901	288,683	307,413	323,483
Outdoor Lighting OL (1)	4,996,800	4,385,962	4,030,970	3,710,482	3,499,297	3,818,772	4,102,926	4,940,215	4,645,867
Traffic Lighting Energy TLE	903,976	907,089	893,218	890,761	963,999	658,044	948,546	943,996	952,768

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KWH	Jan-2004	Dec-2003	Nov-2003	Oct-2003	Sep-2003	Aug-2003	Jul-2003	Jun-2003	May-2003
Residential Service RS	347,719,506	304,139,900	233,051,966	243,537,653	417,925,778	439,705,228	446,939,956	283,625,860	251,382,383
Total General Service GS	111,105,129	104,020,649	94,819,603	99,996,105	132,007,923	131,080,766	133,409,243	109,150,221	102,621,402
Large Commercial LC	182,864,607	174,673,544	167,338,682	173,626,420	213,554,923	208,225,350	212,792,076	185,857,773	178,064,267
L:arge Commercial Time of Day LC-TOD	47,138,544	49,839,136	43,121,939	45,726,996	56,044,921	51,802,163	54,710,359	46,201,528	45,839,712
Large Commercial Special Contracts	14,659,000	13,927,000	13,526,000	13,898,000	17,335,000	22,555,000	22,233,000	17,780,000	16,122,000
Large Power Industrial Service LP	50,352,645	53,325,395	54,059,730	55,090,751	60,994,360	60,589,751	60,040,633	55,996,567	54,460,248
Large Power Industrial Time of Day LP-TOD	155,931,201	162,465,912	168,762,997	161,853,384	183,748,428	171,954,404	169,894,688	151,600,198	173,457,110
Large Power Industrial Special Contracts	46,165,466	44,324,849	41,323,687	43,621,716	49,358,180	46,932,999	49,403,943	48,258,487	44,907,540
Public Street Lighting PSL	5,243,582	5,354,099	4,978,658	4,751,374	4,147,296	3,859,763	3,530,446	3,308,158	3,614,087
Street Lighting Energy SLE	388,695	397,730	325,038	286,468	306,265	270,460	260,107	263,588	283,871
Outdoor Lighting OL (1)	5,508,470	5,655,190	5,229,644	5,005,832	4,318,367	4,004,174	3,667,988	3,438,875	3,814,154
Traffic Lighting Energy TLE	1,018,316	1,024,611	939,154	929,338	952,302	902,199	945,475	948,680	952,189

Louisville Gas and Electric Company
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KWH	Apr-2003	Mar-2003	Feb-2003	Jan-2003					
Residential Service RS	229,214,579	284,905,523	333,289,872	341,923,035					
Total General Service GS	94,987,414	103,015,132	110,214,993	110,249,887					
Large Commercial LC	165,395,298	170,125,362	179,953,331	177,665,226					
L:arge Commercial Time of Day LC-TOD	42,471,682	45,975,583	44,317,591	45,907,317					
Large Commercial Special Contracts	14,198,000	14,242,000	13,725,000	15,111,000					
Large Power Industrial Service LP	51,402,795	52,622,821	53,873,692	52,495,901					
Large Power Industrial Time of Day LP-TOD	169,411,476	166,604,716	161,418,604	162,692,899					
Large Power Industrial Special Contracts	42,333,137	42,954,051	46,722,359	49,073,969					
Public Street Lighting PSL	3,860,691	4,444,864	4,395,221	5,219,070					
Street Lighting Energy SLE	325,353	359,710	369,144	421,256					
Outdoor Lighting OL (1)	4,000,450	4,603,913	4,575,011	5,409,416					
Traffic Lighting Energy TLE	950,593	953,033	960,781	1,026,602					

(1) contains residential and commercial customers
who have outdoor lighting service.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 169

Responding Witness: Shannon L. Charnas / William Steven Seelye

Q-169. Please provide the following by month and by billing cycle for the period January 2003 through July 2008 for each LG&E electric rate schedule (separately):

a. customers billed: and.

b. billed KWH.

Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-169. The Company does not retain billing cycle reports. The requested information is not available in a readily reproducible form. The production of this information would require extensive computer programming to compile historical billing cycle data from the Company's customer information system

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General Dated August 27, 2008

Question No. 170

Responding Witness: Valerie L. Scott / Robert M. Conroy / William Steven Seelye

Q-170 With regard to LG&E Purchased Power (Account 555) in Seelye Exhibit 26, page 13, please provide:

a. all workpapers and analyses showing the determination of total demand costs ($10,759,242),

b. all workpapers and analyses showing the determination of total energy costs ($71,042,950).

c. all test year purchased power invoices that include a demand or capacity charge, and,

d. a detailed explanation along with all workpapers and analyses showing the pricing methodology (basis) and amount for sales from LG&E to KU.

Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel)

A-170 a. The total demand and total energy costs provided on page 13 of Seelye Exhibit 26 are incorrect. The total for LG&E Purchased Power – Account 555 was shown correctly at $81,802,192. However, the correct total demand costs should be $17,326,451 and the correct total energy costs should be $64,475,741. See attached. The information is also being provided on CD.

b. The requested information is being provided on CD. See the response to part (a).

c. The requested information is not available in Excel. Due to the volume of data requested, the information is being provided on CD.

d. The pricing methodology for intra-company sales is based upon a shared savings approach. The KU and LG&E generating units are jointly dispatched to serve the combined KU and LG&E customers.

After each utility meets its native load and pre-merger sales, the remaining generation is assigned to the other utility's native load and pre-merger sales.

if lower in cost than its generation. Inter-company sales to serve native load of the receiving utility are made at fuel costs plus one half of the savings realized by the receiving company. Inter-company sales to serve pre-merger sales of the receiving utility are made at fuel costs plus FGD and SCR consumables and environmental allowance cost. The split savings of inter-company sales is one half the difference of the fuel cost of the energy received for native load and the fuel cost or purchase cost displaced as a result of the transfer. This process was established at the time of the LG&E/KU merger to implement the provisions of the Power Supply System Agreement and has been utilized for fuel adjustment clause purposes since May 1998.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Energy	Demand	Total
May-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	124	$ 3,041.67	$ -	$ 3,041.67
May-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	326	33,256.00	-	33,256.00
May-07	AEP	American Electric Power Service Corp.	Monthly Accrual	197	8,608.00		8,608.00
May-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	8	592.00	-	592.00
May-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	40	2,640.00		2,640.00
May-07	CONS	Constellation Energy Comds. Grp. Inc	Monthly Accrual	150	10,600.00		10,600.00
May-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	329	27,369.00		27,369.00
May-07	MLCM	Merrill Lynch Commodities Inc	Monthly Accrual	252	22,146.10		22,146.10
May-07	PROG	Progress Energy Ventures Inc.	Monthly Accrual	75	5,860.00		5,860.00
May-07	SEPA	Southeastern Power Administration	Monthly Accrual	7	401.80		401.80
May-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Apr 07		17.99	-	17.99
May-07	OVEC	Ohio Valley Electric Corporation	True-up Apr 07 Billing	-	(104,152.69)	108,607.60	4,454.91
May-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	60,966	1,278,335.08	1,441,614.12	2,719,949.20
Jun-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	361	34,387.44		34,387.44
Jun-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	672	87,367.56		87,367.56
Jun-07	AECI	Associated Elect Cooperative	Monthly Accrual	463	27,773.73		27,773.73
Jun-07	AEP	American Electric Power Service Corp.	Monthly Accrual	172	10,601.22		10,601.22
Jun-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	98	6,850.15		6,850.15
Jun-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	43	2,365.00		2,365.00
Jun-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	332	21,947.53	-	21,947.53
Jun-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	117	5,580.62	-	5,580.62
Jun-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	175	1,600.00		1,600.00
Jun-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	1,778	136,306.00		136,306.00
Jun-07	IMEA	Illinois Municipal Electric Agency	Monthly Accrual	11	950.62	-	950.62
Jun-07	IMPA	Indiana Municipal Power Agency	Monthly Accrual	11	950.62		950.62
Jun-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	25	1,625.00		1,625.00
Jun-07	SOUT	Southern Company Services, Inc	Monthly Accrual	47	2,629.78	-	2,629.78
Jun-07	SEPA	Southeastern Power Administration	Monthly Accrual	4	229.60		229.60
Jun-07	WSTR	Westar Energy, Inc.	Monthly Accrual	7	434.00		434.00
Jun-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	72,724	1,524,876.83	1,395,125.48	2,920,002.31
Jun-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from May 07	-	2,338.81		2,338.81
Jun-07	OVEC	Ohio Valley Electric Corporation	True-up May 07 Billing	-	4,063.37	(67,038.99)	(62,975.62)
Jul-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	65,785	1,379,379.88	1,441,627.49	2,821,007.37
Jul-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	426	32,095.25		32,095.25
Jul-07	AEP	American Electric Power Service Corp.	Monthly Accrual	331	30,538.71		30,538.71
Jul-07	CONS	Constellation Energy Comds. Grp. Inc	Monthly Accrual	396	40,791.00		40,791.00
Jul-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	437	33,077.45		33,077.45
Jul-07	PROG	Progress Energy Ventures Inc.	Monthly Accrual	154	13,090.00		13,090.00

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Energy	Demand	Total
Jul-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from June 07		14,505.94		14,505.94
Jul-07	OVEC	Ohio Valley Electric Corporation	True-up Jun 07 Billing	-	(619.69)	254,799.19	254,179.50
Aug-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	68,010	1,426,033.68	1,441,627.24	2,867,660.92
Aug-07	MISO	Midwest Independent Transmission System Operator, Inc	Monthly Accrual	5,178	319,918.62		319,918.62
Aug-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	117	12,011.93		12,011.93
Aug-07	AECI	Associated Elect Cooperative	Monthly Accrual	584	53,064.21		53,064.21
Aug-07	AEP	American Electric Power Service Corp	Monthly Accrual	266	33,038.42		33,038.42
Aug-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	20	1,200.00		1,200.00
Aug-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	334	36,017.01		36,017.01
Aug-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	126	7,585.00	-	7,585.00
Aug-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	218	17,474.39	-	17,474.39
Aug-07	KCPL	Kansas City Power & Light	Monthly Accrual	189	17,010.00	-	17,010.00
Aug-07	IMBL	Energy Imbalance	Monthly Accrual	63	3,887.34		3,887.34
Aug-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	174	23,171.00		23,171.00
Aug-07	TEA	The Energy Authority	Monthly Accrual	132	15,180.00		15,180.00
Aug-07	TALT	Transalta Energy Marketing (U.S.) Inc.	Monthly Accrual	137	17,839.75	-	17,839.75
Aug-07	WSTR	Westar Energy, Inc.	Monthly Accrual	474	58,120.02		58,120.02
Aug-07	OVEC	Ohio Valley Electric Corporation	True-up Jul 07 Billing	-	54,723.35	(25,892.64)	28,830.71
Sep-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	66,179	1,387,641.27	1,395,107.83	2,782,749.10
Sep-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	1,967	100,862.02		100,862.02
Sep-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	311	31,044.64		31,044.64
Sep-07	AECI	Associated Elect Cooperative	Monthly Accrual	66	4,261.33	-	4,261.33
Sep-07	AEP	American Electric Power Service Corp.	Monthly Accrual	643	33,548.72		33,548.72
Sep-07	AMEM	Ameren Energy Marketing Company	Monthly Accrual	96	5,088.00		5,088.00
Sep-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	39	2,418.21		2,418.21
Sep-07	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	296	17,625.64		17,625.64
Sep-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	606	46,720.08		46,720.08
Sep-07	IMBL	Energy Imbalance	Monthly Accrual	15	726.73		726.73
Sep-07	PROG	Progress Energy Ventures Inc.	Monthly Accrual	24	1,323.63		1,323.63
Sep-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Aug 07		181.17		181.17
Sep-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Aug 07	-	200.72		200.72
Sep-07	OVEC	Ohio Valley Electric Corporation	True-up Aug 07 Billing	-	54,827.49	100,763.89	155,591.38
Sep-07	OVEC	Ohio Valley Electric Corporation	True-up Jun 07 Billing		(5.31)		(5.31)
Oct-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	60,984	1,278,712.51	1,441,630.38	2,720,342.89
Oct-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	1,889	133,548.63		133,548.63
Oct-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	116	11,629.92	-	11,629.92
Oct-07	PJM	Pjm Interconnection Association	Monthly Accrual	5	431.85	-	431.85
Oct-07	AECI	Associated Elect Cooperative	Monthly Accrual	2	124.00		124.00

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Energy	Demand	Total
Oct-07	AEP	American Electric Power Service Corp.	Monthly Accrual	809	47,755.92		47,755.92
Oct-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	116	7,449.79	-	7,449.79
Oct-07	COBB	Cobb Electric Membership Corporation	Monthly Accrual	540	23,923.00		23,923.00
Oct-07	CONS	Constellation Energy Comds Grp, Inc.	Monthly Accrual	140	6,770.25		6,770.25
Oct-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	50	3,350.00	-	3,350.00
Oct-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	200	9,450.00		9,450.00
Oct-07	MLCM	Merrill Lynch Commodities Inc	Monthly Accrual	69	4,216.00		4,216.00
Oct-07	SOUT	Southern Company Services, Inc	Monthly Accrual	14	2,056.23		2,056.23
Oct-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Sep 07	-	188.62	-	188.62
Oct-07	OVEC	Ohio Valley Electric Corporation	True-up Sep 07 Billing	-	46,212.70	(14,613.59)	31,599.11
Nov-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	69,088	1,448,637.19	1,395,118.33	2,843,755.52
Nov-07	MISO	Midwest Independent Transmission System Operator, Inc	Monthly Accrual	2,997	175,442.35		175,442.35
Nov-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	379	38,794.42		38,794.42
Nov-07	PJM	Pjm Interconnection Association	Monthly Accrual	210	8,573.47		8,573.47
Nov-07	AECI	Associated Elect Cooperative	Monthly Accrual	121	7,293.99		7,293.99
Nov-07	AEP	American Electric Power Service Corp.	Monthly Accrual	279	15,515.23		15,515.23
Nov-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	386	23,660.00		23,660.00
Nov-07	CITI	Citigroup Energy, Inc	Monthly Accrual	28	1,708.00		1,708.00
Nov-07	CONS	Constellation Energy Comds Grp, Inc.	Monthly Accrual	604	37,769.10		37,769.10
Nov-07	DTE	Dte Energy Trading, Inc.	Monthly Accrual	3	204.00		204.00
Nov-07	DECA	Duke Energy Carolinas, Llc	Monthly Accrual	16	1,152.00		1,152.00
Nov-07	EKPC	East Kentucky Power Cooperative	Monthly Accrual	465	27,899.21		27,899.21
Nov-07	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	624	34,477.53		34,477.53
Nov-07	MLCM	Merrill Lynch Commodities Inc.	Monthly Accrual	104	6,503.90		6,503.90
Nov-07	TEA	The Energy Authority	Monthly Accrual	88	6,137.43		6,137.43
Nov-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Oct 07		245.84	-	245.84
Nov-07	OVEC	Ohio Valley Electric Corporation	True-up Oct 07 Billing		(26,049.75)	99,513.95	73,464.20
Dec-07	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	70,431	1,476,797.21	1,441,627.45	2,918,424.66
Dec-07	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	528	37,787.66	-	37,787.66
Dec-07	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	188	18,751.41		18,751.41
Dec-07	PJM	Pjm Interconnection Association	Monthly Accrual	317	21,131.62		21,131.62
Dec-07	AECI	Associated Elect Cooperative	Monthly Accrual	2	136.00		136.00
Dec-07	AEP	American Electric Power Service Corp.	Monthly Accrual	231	15,485.11	-	15,485.11
Dec-07	CARG	Cargill- Alliant, Llc	Monthly Accrual	10	668.19		668.19
Dec-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Nov 07	-	217.04		217.04
Dec-07	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Nov 07	-	825.50		825.50
Dec-07	MISO	Midwest Independent Transmission System Operator, Inc	Prior Period Adjustment from Sep 08		21.52		21.52
Dec-07	EKPC	East Kentucky Power Cooperative	Prior Period Adjustment from Nov 07		(8,489.00)		(8,489.00)

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Energy	Demand	Total
Dec-07	CONS	Constellation Energy Comds. Grp. Inc.	Prior Period Adjustment from Nov 07		(32.07)		(32.07)
Dec-07	OVEC	Ohio Valley Electric Corporation	True-up Nov 07 Billing	-	(29,644.00)	530,445.92	500,801.92
Jan-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	81,377	1,706,312.94	1,627,678.52	3,333,991.46
Jan-08	MISO	Midwest Independent Transmission System Operator, Inc	Monthly Accrual	69	4,911.57	-	4,911.57
Jan-08	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	797	80,635.32		80,635.32
Jan-08	PJM	Pjm Interconnection Association	Monthly Accrual	391	25,304.45		25,304.45
Jan-08	AEP	American Electric Power Service Corp	Monthly Accrual	145	9,589.61	-	9,589.61
Jan-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	121	9,551.54		9,551.54
Jan-08	COBB	Cobb Electric Membership Corporation	Monthly Accrual	25	1,732.14		1,732.14
Jan-08	IMBL	Energy Imbalance	Monthly Accrual	148	12,827.80		12,827.80
Jan-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Dec 07	-	(14.92)		(14.92)
Jan-08	OVEC	Ohio Valley Electric Corporation	True-up Dec 07 Billing	-	43,214.61	38,479.91	81,694.52
Feb-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	61,488	1,289,280.39	1,470,464.52	2,759,744.91
Feb-08	MISO	Midwest Independent Transmission System Operator, Inc	Monthly Accrual	5,162	274,960.37		274,960.37
Feb-08	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	348	34,646.09		34,646.09
Feb-08	PJM	Pjm Interconnection Association	Monthly Accrual	4,938	301,548.22	-	301,548.22
Feb-08	AEP	American Electric Power Service Corp.	Monthly Accrual	302	21,576.00	-	21,576.00
Feb-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	75	5,325.00	-	5,325.00
Feb-08	COBB	Cobb Electric Membership Corporation	Monthly Accrual	366	25,915.00		25,915.00
Feb-08	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	40	2,720.00		2,720.00
Feb-08	FORT	Fortis Energy Marketing & Trading Gp	Monthly Accrual	6	450.00		450.00
Feb-08	TEA	The Energy Authority	Monthly Accrual	22	1,518.00	-	1,518.00
Feb-08	TVA	Tennessee Valley Authority	Monthly Accrual	299	18,896.00	-	18,896.00
Feb-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Jan 08	-	589.55		589.55
Feb-08	PJM	Pjm Interconnection Association	Prior Period Adjustment from Jan 08	4	137.16		137.16
Feb-08	OVEC	Ohio Valley Electric Corporation	True-up Jan 08 Billing	-	(135,539.41)	(421,186.41)	(556,725.82)
Mar-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	70,207	1,472,100.38	1,626,574.87	3,098,675.25
Mar-08	MISO	Midwest Independent Transmission System Operator, Inc.	Monthly Accrual	3,378	243,825.88		243,825.88
Mar-08	MCRS	Midwest Contingency Reserve Sharing Group	Monthly Accrual	898	91,464.69		91,464.69
Mar-08	PJM	Pjm Interconnection Association	Monthly Accrual	5,274	330,602.34		330,602.34
Mar-08	AEP	American Electric Power Service Corp.	Monthly Accrual	111	6,925.23		6,925.23
Mar-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	444	29,587.76	-	29,587.76
Mar-08	BREC	Big Rivers Electric Corp.	Monthly Accrual	135	11,801.18	-	11,801.18
Mar-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Feb 08	-	100.90	-	100.90
Mar-08	OVEC	Ohio Valley Electric Corporation	True-up Feb 08 Billing	-	10,133.27	(372,303.55)	(362,170.28)
Mar-08	OVEC	Ohio Valley Electric Corporation	True-up Dec 07 Billing			(358,325.16)	(358,325.16)
Apr-08	OVEC	Ohio Valley Electric Corporation	Monthly Accrual	69,836	1,464,321.25	1,575,165.31	3,039,486.56
Apr-08	MISO	Midwest Independent Transmission System Operator, Inc	Monthly Accrual	329	21,909.02		21,909.02

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Electronic Workpapers for Total Purchased Power Energy and Demand

General Ledger

Date	Counterparty ID	Counterparty Name	Description of Transaction	MW	Energy	Demand	Total
Apr-08	PJM	Pjm Interconnection Association	Monthly Accrual	140	13,582.97		13,582.97
Apr-08	CARG	Cargill- Alliant, Llc	Monthly Accrual	9	728.49		728.49
Apr-08	CONS	Constellation Energy Comds. Grp. Inc.	Monthly Accrual	64	4,566.01		4,566.01
Apr-08	IMBL	Energy Imbalance	Monthly Accrual	20	885.67		885.67
Apr-08	OMU	Owensboro Municipal Utilities	Monthly Accrual	-			
Apr-08	MCRS	Midwest Contingency Reserve Sharing Group	Prior Period Adjustment from Mar 08	-	1,492.91		1,492.91
Mar-08	PJM	Pjm Interconnection Association	Prior Period Adjustment from Mar 08		(119.69)		(119.69)
Apr-08	OVEC	Ohio Valley Electric Corporation	True-up Mar 08 Billing		(42,417.38)	(240,160.50)	(282,577.88)
Apr-08	OVEC	Ohio Valley Electric Corporation	Adjustment			(0.01)	(0.01)
May-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		2,874,230.27		2,874,230.27
Jun-07	Intercompany	Intercompany Purchases from KU	Native Load		10,696.65		10,696.65
Jun-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		2,883,223.34		2,883,223.34
Jul-07	Intercompany	Intercompany Purchases from KU	Native Load		13,826.34		13,826.34
Jul-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		3,559,912.47		3,559,912.47
Aug-07	Intercompany	Intercompany Purchases from KU	Native Load		21,063.96		21,063.96
Aug-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		1,696,608.76		1,696,608.76
Sep-07	Intercompany	Intercompany Purchases from KU	Native Load		209,405.70		209,405.70
Sep-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		1,756,015.72		1,756,015.72
Oct-07	Intercompany	Intercompany Purchases from KU	Native Load		124,648.10		124,648.10
Oct-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		4,306,892.75		4,306,892.75
Nov-07	Intercompany	Intercompany Purchases from KU	Native Load		190,520.17		190,520.17
Nov-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		3,010,654.55		3,010,654.55
Dec-07	Intercompany	Intercompany Purchases from KU	Off-System Sales		5,444,225.28		5,444,225.28
Jan-08	Intercompany	Intercompany Purchases from KU	Off-System Sales		6,174,146.08		6,174,146.08
Feb-08	Intercompany	Intercompany Purchases from KU	Off-System Sales		2,780,772.81		2,780,772.81
Mar-08	Intercompany	Intercompany Purchases from KU	Native Load		66,089.36		66,089.36
Mar-08	Intercompany	Intercompany Purchases from KU	Off-System Sales		5,317,883.09		5,317,883.09
Apr-08	Intercompany	Intercompany Purchases from KU	Off-System Sales		3,232,716.51		3,232,716.51
			Totals		$ 64,475,741.06	$ 17,326,451.15	$ 81,802,192.21

Louisville Gas & Electric

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Purchased Power Energy and Demand for the Month Ended May 31, 2007

PRE-MERGER PURCHASES				MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS			60966	$1,278,335.08	$1,441,614.12	$2,719,949.20
TOTAL PREMERGER PURCHASES				60966	$1,278,335.08	$1,441,614.12	$2,719,949.20

OTHER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	116	NL	$2,255.96	124	$3,041.67	$0.00	$3,041.67
MCRS	8	OSS	$785.71	326	$33,256.90	$0.00	$33,256.90
AECI				0	$0.00	$0.00	$0.00
AEP				197	$8,608.00	$0.00	$8,608.00
BP				0	$0.00	$0.00	$0.00
CARG				8	$592.00	$0.00	$592.00
CITI				0	$0.00	$0.00	$0.00
COBB				40	$2,640.00	$0.00	$2,640.00
CONS				150	$10,600.00	$0.00	$10,600.00
DTE				0	$0.00	$0.00	$0.00
EKPC				0	$0.00	$0.00	$0.00
FORT				329	$27,369.00	$0.00	$27,369.00
IMEA				0	$0.00	$0.00	$0.00
IMPA				0	$0.00	$0.00	$0.00
IMBL	DOLLARS RECORDED BY CORPORATE ACCOUNTING			0	$0.00	$0.00	$0.00
MLCM				252	$22,146.10	$0.00	$22,146.10
OVEC				0	$0.00	$0.00	$0.00
OMU				0	$0.00	$0.00	$0.00
PROG				75	$5,860.00	$0.00	$5,860.00
SOUT				0	$0.00	$0.00	$0.00
SEMP				0	$0.00	$0.00	$0.00
SEPA				7	$401.80	$0.00	$401.80
TEA				0	$0.00	$0.00	$0.00
TVA				0	$0.00	$0.00	$0.00
WESC				0	$0.00	$0.00	$0.00
WSTR				0	$0.00	$0.00	$0.00

Louisville Gas & Electric

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Purchased Power Energy and Demand for the Month Ended May 31, 2007

	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	1508	$114,515.47	$0.00	$114,515.47
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				4%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)	0		$0.00	NL
Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)				
SPLIT SAVINGS (LGE TO KU RATE BASE)			$0.00	NL
One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)				
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	86015	$2,874,230.27		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	$0.00
TOTAL	86015	$2,874,230.27	86,015	$2,874,230.27

OK

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS			MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	Apr-07	0	$17.99	$0.00	$17.99
SEPA (OMU)	reels between Non-UGen and UGen	Apr-07	0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0		$0.00	$0.00
TOTAL			0	$17.99	$0.00	$17.99

Louisville Gas & Electric

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Purchased Power Energy and Demand for the Month Ended May 31, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00
PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Apr 07 Billing	0	($104,152.69)	$108,607.60	$4,454.91
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($104,152.69)	$108,607.60	$4,454.91

Louisville Gas & Electric

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Purchased Power Energy and Demand for the Month Ended June 30, 2007

PRE-MERGER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS				72724	$1,524,876.83	$1,395,125.48	$2,920,002.31
TOTAL PREMERGER PURCHASES					72724	$1,524,876.83	$1,395,125.48	$2,920,002.31

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	45	NL	$3,468.45		361	$34,387.44	$0.00	$34,387.44
MCRS	316	OSS	$30,918.99		672	$87,367.56	$0.00	$87,367.56
AECI					463	$27,773.73	$0.00	$27,773.73
AEP					172	$10,601.22	$0.00	$10,601.22
BP					0	$0.00	$0.00	$0.00
CARG					98	$6,850.15	$0.00	$6,850.15
CITI					0	$0.00	$0.00	$0.00
COBB					43	$2,365.00	$0.00	$2,365.00
CONS					332	$21,947.53	$0.00	$21,947.53
DTE					117	$5,580.62	$0.00	$5,580.62
DECA					0	$0.00	$0.00	$0.00
EKPC					175	$1,600.00	$0.00	$1,600.00
FORT					1778	$136,306.00	$0.00	$136,306.00
IMEA					11	$950.62	$0.00	$950.62
IMPA					11	$950.62	$0.00	$950.62
KCPL					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
MLCM					25	$1,625.00	$0.00	$1,625.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SOUT					47	$2,629.78	$0.00	$2,629.78
SEMP					0	$0.00	$0.00	$0.00
SEPA					4	$229.60	$0.00	$229.60
TEA					0	$0.00	$0.00	$0.00
TPS					0	$0.00	$0.00	$0.00
TALT					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WESC					0	$0.00	$0.00	$0.00
WSTR					7	$434.00	$0.00	$434.00

Louisville Gas & Electric

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Purchased Power Energy and Demand for the Month Ended June 30, 2007

TOTAL PURCHASES OTHER THAN PREMERGER	4316	$341,598.87	$0.00	$341,598.87
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				10%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	173		$10,412.57	NI
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$284.06	NI
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	86778	$2,883,223.34		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL 173	$10,696.63
TOTAL	86951	$2,893,919.97	86,951	$2,893,919.97

OK

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS			MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	May-07	0	$2,338.81	$0.00	$2,338.81
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0		$0.00	$0.00
TOTAL			0	$2,338.81	$0.00	$2,338.81

Louisville Gas & Electric

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Purchased Power Energy and Demand for the Month Ended June 30, 2007

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of May 07 Billing	0	$4,063.37	($67,038.99)	($62,975.62)
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$4,063.37	($67,038.99)	($62,975.62)

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PRE-MERGER PURCHASES				MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS			65785	$1,379,379.88	$1,441,627.49	$2,821,007.37
TOTAL PREMERGER PURCHASES				65785	$1,379,379.88	$1,441,627.49	$2,821,007.37

OTHER PURCHASES				MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	2	NL	$75.78	426	$32,095.25	$0.00	$32,095.25
MCRS	424	OSS	$32,019.47	0	$0.00	$0.00	$0.00
AECI				0	$0.00	$0.00	$0.00
AEP				331	$30,538.71	$0.00	$30,538.71
BP				0	$0.00	$0.00	$0.00
CARG				0	$0.00	$0.00	$0.00
CITI				0	$0.00	$0.00	$0.00
COBB				0	$0.00	$0.00	$0.00
CONS				396	$40,791.00	$0.00	$40,791.00
DTE				0	$0.00	$0.00	$0.00
DECA				0	$0.00	$0.00	$0.00
EKPC				0	$0.00	$0.00	$0.00
FORT				437	$33,077.45	$0.00	$33,077.45
IMEA				0	$0.00	$0.00	$0.00
IMPA				0	$0.00	$0.00	$0.00
KCPL				0	$0.00	$0.00	$0.00
LMBL				0	$0.00	$0.00	$0.00
MLCM				0	$0.00	$0.00	$0.00
OVEC				0	$0.00	$0.00	$0.00
OMU				0	$0.00	$0.00	$0.00
PROG				154	$13,090.00	$0.00	$13,090.00
SEMP				0	$0.00	$0.00	$0.00
TEA				0	$0.00	$0.00	$0.00
TVA				0	$0.00	$0.00	$0.00
WESC				0	$0.00	$0.00	$0.00
WSTR				0	$0.00	$0.00	$0.00

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TOTAL PURCHASES OTHER THAN PREMERGER	1744	$149,592.41	$0.00	$149,592.41
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				30%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	298		$13,826.34	NL
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$0.00	NL
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	112054	$3,559,912.47		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	
			298	$13,826.34
TOTAL	112352	$3,573,738.81	112,352	$3,573,738.81
			OK	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS			MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	Jun-07	0	$14,505.94	$0.00	$14,505.94
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0		$0.00	$0.00
TOTAL			0	$14,505.94	$0.00	$14,505.94

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Jun 07 Billing	0	($619.69)	$254,799.19	$254,179.50
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	($619.69)	$254,799.19	$254,179.50

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PRE-MERGER PURCHASES		MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS	68010	$1,426,033.68	$1,441,627.24	$2,867,660.92
TOTAL PREMERGER PURCHASES		68010	$1,426,033.68	$1,441,627.24	$2,867,660.92

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	3599	0.10896	NL	$165,744.35	5178	$319,918.62	$0.00	$319,918.62
MCRS	1579	0.04780	OSS	$154,174.27	117	$12,011.93	$0.00	$12,011.93
PJM					0	$0.00	$0.00	$0.00
AECI					584	$53,064.21	$0.00	$53,064.21
AEP					266	$33,038.42	$0.00	$33,038.42
CARG					20	$1,200.00	$0.00	$1,200.00
CITI					0	$0.00	$0.00	$0.00
COBB					0	$0.00	$0.00	$0.00
CONS					334	$36,017.01	$0.00	$36,017.01
DTE					0	$0.00	$0.00	$0.00
DECA					0	$0.00	$0.00	$0.00
EKPC					126	$7,585.00	$0.00	$7,585.00
FORT					218	$17,474.39	$0.00	$17,474.39
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
KCPL					189	$17,010.00	$0.00	$17,010.00
IMBL	EM Acctg subsequently recorded in JE#188				63	$3,887.34	$0.00	$3,887.34
MLCM					174	$23,171.00	$0.00	$23,171.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
PROG					0	$0.00	$0.00	$0.00
SEMP					0	$0.00	$0.00	$0.00
TEA					132	$15,180.00	$0.00	$15,180.00
TALT					137	$17,839.75	$0.00	$17,839.75
TVA					0	$0.00	$0.00	$0.00
WESC					0	$0.00	$0.00	$0.00
WSTR					474	$58,120.02	$0.00	$58,120.02

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	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	8012	$615,517.69	$0.00	$615,517.69
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				12%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)	301		$20,994.41	NL
Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)				
SPLIT SAVINGS (LGE TO KU RATE BASE)			$69.55	NL
One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)				
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	45547	$1,696,608.76		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	
			301	$21,063.96
TOTAL	45848	$1,717,672.72	45,848	$1,717,672.72
			OK	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS			MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	Jul-07	0	$0.00	$0.00	$0.00
OMU (SEPA)	offset Non-Upen 4-5-07 adjustment		0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0	$0.00	$0.00	$0.00
			0		$0.00	$0.00
TOTAL			0	$0.00	$0.00	$0.00

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Jul 07 Billing	0	$54,723.35	($25,892.64)	$28,830.71
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL PRE-MERGER PURCHASE ADJUSTMENTS		0	$54,723.35	($25,892.64)	$28,830.71

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PRE-MERGER PURCHASES						MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS					66179	$1,387,641.27	$1,395,107.83	$2,782,749.10
TOTAL PREMERGER PURCHASES						66179	$1,387,641.27	$1,395,107.83	$2,782,749.10

OTHER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	797	0.06431	NL		$32,696.32	1967	$100,862.02	$0.00	$100,862.02
MCRS	1170	0.09440	OSS		$68,165.70	311	$31,044.64	$0.00	$31,044.64
PJM						0	$0.00	$0.00	$0.00
AECI						66	$4,261.33	$0.00	$4,261.33
AEP						643	$33,548.72	$0.00	$33,548.72
AMEM						96	$5,088.00	$0.00	$5,088.00
CARG						39	$2,418.21	$0.00	$2,418.21
CITI						0	$0.00	$0.00	$0.00
COBB						0	$0.00	$0.00	$0.00
CONS						296	$17,625.64	$0.00	$17,625.64
DTE						0	$0.00	$0.00	$0.00
DECA						0	$0.00	$0.00	$0.00
EKPC						0	$0.00	$0.00	$0.00
FORT						606	$46,720.08	$0.00	$46,720.08
IMEA						0	$0.00	$0.00	$0.00
IMPA						0	$0.00	$0.00	$0.00
IMBL	See Imbalance Split tab for recording instructions					15	$726.73	$0.00	$726.73
MLCM						0	$0.00	$0.00	$0.00
OVEC						0	$0.00	$0.00	$0.00
OMU						0	$0.00	$0.00	$0.00
PROG						24	$1,323.63	$0.00	$1,323.63
SEMP						0	$0.00	$0.00	$0.00
TEA						0	$0.00	$0.00	$0.00
TPS						0	$0.00	$0.00	$0.00
TAUT						0	$0.00	$0.00	$0.00
TVA						0	$0.00	$0.00	$0.00

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	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	4063	$243,619.00	$0.00	$243,619.00
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				16%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	5211		$205,743.51	NL
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$3,662.19	NL
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	55937	$1,756,015.72		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL 5,211	$209,405.70
TOTAL	61148	$1,965,421.42	61,148	$1,965,421.42

OK

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	NL	Aug-07	0	$181.17	$0.00	$181.17
MCRSG	price change	OSS	Aug-07	0	$200.72	$0.00	$200.72
TOTAL				0	$381.89	$0.00	$381.89

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS	MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)	0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)			$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE	0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES	0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS	0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Aug 07 Billing	0	$54,827.49	$100,763.89	$155,591.38
OVEC	Adjustment for Jun-07		($5.31)	$0.00	($5.31)
			$0.00	$0.00	$0.00
TOTAL		0	$54,822.18	$100,763.89	$155,586.07

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PRE-MERGER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS				60984	$1,278,712.51	$1,441,630.38	$2,720,342.89
TOTAL PREMERGER PURCHASES					60984	$1,278,712.51	$1,441,630.38	$2,720,342.89

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	1612	0.22723	NL	$84,663.40	1889	$133,548.63	$0.00	$133,548.63
MCRS	277	0.03905	OSS	$48,885.23	116	$11,629.92	$0.00	$11,629.92
PJM					5	$431.85	$0.00	$431.85
AECI					2	$124.00	$0.00	$124.00
AEP					809	$47,755.92	$0.00	$47,755.92
CARG					116	$7,449.79	$0.00	$7,449.79
CITI					0	$0.00	$0.00	$0.00
COBB					540	$23,923.00	$0.00	$23,923.00
CONS					140	$6,770.25	$0.00	$6,770.25
DTE					50	$3,350.00	$0.00	$3,350.00
EKPC					200	$9,450.00	$0.00	$9,450.00
FORT					0	$0.00	$0.00	$0.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
MLCM					69	$4,216.00	$0.00	$4,216.00
NIPS					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SOUT					14	$2,056.23	$0.00	$2,056.23
SEMP					0	$0.00	$0.00	$0.00
TEA					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

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	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	3950	$250,705.59	$0.00	$250,705.59
				27%
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)	3153		$121,941.72	NL
Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)				
SPLIT SAVINGS (LGE TO KU RATE BASE)			$2,706.38	NL
One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)				
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	137380	$4,306,892.75		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	
			3,153	$124,648.10
TOTAL	140533	$4,431,540.85	140,533	$4,431,540.85

OK

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	NL	Sep-07	0	$0.00	$0.00	$0.00
MCRSG	price change	OSS	Sep-07	0	$188.62	$0.00	$188.62
TOTAL				0	$188.62	$0.00	$188.62

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True up of Sep 07 Billing	0	$46,212.70	($14,613.59)	$31,599.11
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL		0	$46,212.70	($14,613.59)	$31,599.11

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PRE-MERGER PURCHASES		MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS	69088	$1,448,637.19	$1,395,118.33	$2,843,755.52
TOTAL PREMERGER PURCHASES		69088	$1,448,637.19	$1,395,118.33	$2,843,755.52

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	2370	0.10819	NL	$138,550.60	2997	$175,442.35	$0.00	$175,442.35
	627	0.02862	OSS	$36,891.75				
MCRS					379	$38,794.42	$0.00	$38,794.42
PJM					210	$8,573.47	$0.00	$8,573.47
AECI					121	$7,293.99	$0.00	$7,293.99
AEP					279	$15,515.23	$0.00	$15,515.23
CARG					386	$23,660.00	$0.00	$23,660.00
CITI					28	$1,708.00	$0.00	$1,708.00
COBB					0	$0.00	$0.00	$0.00
CONS					604	$37,769.10	$0.00	$37,769.10
DTE					7	$204.00	$0.00	$204.00
DECA					16	$1,152.00	$0.00	$1,152.00
EKPC					465	$27,899.21	$0.00	$27,899.21
FORT					624	$34,477.53	$0.00	$34,477.53
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
MLCM					104	$6,503.90	$0.00	$6,503.90
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SEMP					0	$0.00	$0.00	$0.00
TEA					88	$6,137.43	$0.00	$6,137.43
TVA					0	$0.00	$0.00	$0.00

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	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	6304	$385,130.63	$0.00	$385,130.63 16%
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				
INTERCOMPANY PURCHASES				
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	2592		$190,520.17	NL
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$0.00	NL
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	92515	$3,010,654.55		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL 2,592	$190,520.17
TOTAL	95107	$3,201,174.72	95,107	$3,201,174.72
			OK	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	NL	Oct-07	0	$0.00	$0.00	$0.00
MCRSG	price change	OSS	Oct-07	0	$245.84	$0.00	$245.84
TOTAL				0	$245.84	$0.00	$245.84

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Oct 07 Billing	0	($26,049.75)	$99,513.95	$73,464.20
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL		0	($26,049.75)	$99,513.95	$73,464.20

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PRE-MERGER PURCHASES		MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS	70431	$1,476,797.21	$1,441,627.45	$2,918,424.66
TOTAL PREMERGER PURCHASES		70431	$1,476,797.21	$1,441,627.45	$2,918,424.66

0	-	NL	$0.00		
528	0.20253	OSS	$37,787.66		

OTHER PURCHASES	MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	528	$37,787.66	$0.00	$37,787.66
MCRS	188	$18,751.41	$0.00	$18,751.41
PJM	317	$21,131.62	$0.00	$21,131.62
AECI	2	$136.00	$0.00	$136.00
AEP	231	$15,485.11	$0.00	$15,485.11
CARG	10	$668.19	$0.00	$668.19
CITI	0	$0.00	$0.00	$0.00
COBB	0	$0.00	$0.00	$0.00
CONS	0	$0.00	$0.00	$0.00
DTE	0	$0.00	$0.00	$0.00
EKPC	0	$0.00	$0.00	$0.00
FORT	0	$0.00	$0.00	$0.00
IMEA	0	$0.00	$0.00	$0.00
IMPA	0	$0.00	$0.00	$0.00
IMBL	0	$0.00	$0.00	$0.00
MLCM	0	$0.00	$0.00	$0.00
OVEC	0	$0.00	$0.00	$0.00
OMU	0	$0.00	$0.00	$0.00
SEMP	0	$0.00	$0.00	$0.00
TEA	0	$0.00	$0.00	$0.00
TVA	0	$0.00	$0.00	$0.00
WSTR	0	$0.00	$0.00	$0.00

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	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	1276	$93,959.99	$0.00	$93,959.99
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				16%
INTERCOMPANY PURCHASES KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	0		$0.00	NL
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$0.00	NL
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	188654	$5,444,225.28		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	$0.00
TOTAL	188654	$5,444,225.28	188,654	$5,444,225.28

OK

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS				MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	price change	NL	Nov-07	0	$217.04	$0.00	$217.04
MCRSG	price change	OSS	Nov-07	0	$825.50	$0.00	$825.50
MISO			Sep-05		$21.52	$0.00	$21.52
EKPC	price change for m	NL	Nov-07			$0.00	$0.00
EKPC	price change for m	OSS	Nov-07		($8,489.00)	$0.00	($8,489.00)
CONSTELL	decrease in mwh		Nov-07		($32.07)	$0.00	($32.07)
TOTAL				0	($7,457.01)	$0.00	($7,457.01)

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True up of Nov 07 Billing	0	($29,644.00)	$530,445.92	$500,801.92
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL		0	($29,644.00)	$530,445.92	$500,801.92

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PRE-MERGER PURCHASES		MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS	81377	$1,706,312.94	$1,627,678.52	$3,333,991.46
TOTAL PREMERGER PURCHASES		81377	$1,706,312.94	$1,627,678.52	$3,333,991.46

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	13	0.00107	NL	$170.17	69	$4,911.57	$0.00	$4,911.57
	56	0.00460	OSS	$4,741.40				
MCRS					797	$80,635.32	$0.00	$80,635.32
PJM					391	$25,304.45	$0.00	$25,304.45
AECI					0	$0.00	$0.00	$0.00
AEP					145	$9,589.61	$0.00	$9,589.61
CARG					121	$9,551.54	$0.00	$9,551.54
CITI					0	$0.00	$0.00	$0.00
COBB					25	$1,732.14	$0.00	$1,732.14
CONS					0	$0.00	$0.00	$0.00
DTE					0	$0.00	$0.00	$0.00
DECA					0	$0.00	$0.00	$0.00
EKPC					0	$0.00	$0.00	$0.00
FORT					0	$0.00	$0.00	$0.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
KCPL					0	$0.00	$0.00	$0.00
LMBL					148	$12,827.80	$0.00	$12,827.80
MLCM					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SOUT					0	$0.00	$0.00	$0.00
TEA					0	$0.00	$0.00	$0.00
TAUT					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

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Purchased Power Energy and Demand for the Month Ended January 31, 2008

	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	1696	$144,552.43	$0.00	$144,552.43
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				6%
INTERCOMPANY PURCHASES				
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	0		$0.00	NL
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$0.00	NL
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	202531	$6,174,146.08		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	$0.00
TOTAL	202531	$6,174,146.08	202,531	$6,174,146.08
			OK	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS					MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Tier 2 price change	NL-555015	Dec-07	(enter as 1 total &	0	$0.00	$0.00	$0.00
MCRSG	Tier 2 price change	OSS-555010	Dec-07	reclass to NL acct)	0	($14.92)	$0.00	($14.92)
MISO							$0.00	$0.00
EKPC	price change for m	NL	Nov-07				$0.00	$0.00
EKPC	price change for m	OSS	Nov-07				$0.00	$0.00
							$0.00	$0.00
TOTAL					0	($14.92)	$0.00	($14.92)

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
		0	$43,214.61	$38,479.91	$81,694.52
OVEC	True-up of Dec 07 Billing		$0.00	$0.00	$0.00
OVEC	0		$0.00	$0.00	$0.00
TOTAL		0	$43,214.61	$38,479.91	$81,694.52

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PRE-MERGER PURCHASES					MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS				61488	$1,289,280.39	$1,470,464.52	$2,759,744.91
TOTAL PREMERGER PURCHASES					61488	$1,289,280.39	$1,470,464.52	$2,759,744.91

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	5156	0.10652	NL	$274,252.11	5162	$274,960.37	$0.00	$274,960.37
MCRS	6	0.00012	OSS	$708.26	348	$34,646.09	$0.00	$34,646.09
PJM					4938	$301,548.22	$0.00	$301,548.22
AECI					0	$0.00	$0.00	$0.00
AEP					302	$21,576.00	$0.00	$21,576.00
AMEM					0	$0.00	$0.00	$0.00
CARG					75	$5,325.00	$0.00	$5,325.00
CITI					0	$0.00	$0.00	$0.00
COBB					366	$25,915.00	$0.00	$25,915.00
CONS					40	$2,720.00	$0.00	$2,720.00
DTE					0	$0.00	$0.00	$0.00
EKPC					0	$0.00	$0.00	$0.00
FORT					6	$450.00	$0.00	$450.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					0	$0.00	$0.00	$0.00
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$0.00	$0.00
SOUT					0	$0.00	$0.00	$0.00
TEA					22	$1,518.00	$0.00	$1,518.00
TVA					299	$18,896.00	$0.00	$18,896.00
WSTR					0	$0.00	$0.00	$0.00

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TOTAL PURCHASES OTHER THAN PREMERGER	11558	$687,554.68	$0.00	$687,554.68
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				10%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)	0		$0.00	NL
Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)				
SPLIT SAVINGS (LGE TO KU RATE BASE)			$0.00	NL
One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)				
PURCHASE OF FREED UP KU GEN BACK TO LGE	90222	$2,780,772.81		OSS
(INTERNAL REPLACEMENT)				
(Internal Economy matched w/gen)				
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	$0.00
TOTAL	90222	$2,780,772.81	90,222	$2,780,772.81
			OK	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS					MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Tier 2 price change	NL 555015	Jan-08	(Enter as 1 total &	0	$0.00	$0.00	$0.00
MCRSG	Tier 2 price change	OSS-555010	Jan-08	reclass to NL acct)	0	$589.55	$0.00	$589.55
MISO							$0.00	$0.00
EKPC	price change for in	NL	Nov-07				$0.00	$0.00
EKPC	price change for in	OSS	Nov-07				$0.00	$0.00
PJM	Volume increase		Jan-08		4	$137.16	$0.00	$137.16
TOTAL					4	$726.71	$0.00	$726.71

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00
PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Jan 08 Billing	0	($135,539.41)	($421,186.41)	($556,725.82)
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL		0	($135,539.41)	($421,186.41)	($556,725.82)

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PRE-MERGER PURCHASES						MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS					70207	$1,472,100.38	$1,626,574.87	$3,098,675.25
TOTAL PREMERGER PURCHASES						70207	$1,472,100.38	$1,626,574.87	$3,098,675.25

OTHER PURCHASES						MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	1374	0.04180	NL	$77,240.31		3378	$243,825.88	$0.00	$243,825.88
MCRS	2004	0.06097	OSS	$166,585.57		898	$91,464.69	$0.00	$91,464.69
PJM						5274	$330,602.34	$0.00	$330,602.34
AECI						0	$0.00	$0.00	$0.00
AEP						111	$6,925.23	$0.00	$6,925.23
AMEM						0	$0.00	$0.00	$0.00
CARG						444	$29,587.76	$0.00	$29,587.76
CITI						0	$0.00	$0.00	$0.00
COBB						0	$0.00	$0.00	$0.00
CONS						0	$0.00	$0.00	$0.00
DTE						0	$0.00	$0.00	$0.00
EKPC						0	$0.00	$0.00	$0.00
FORT						0	$0.00	$0.00	$0.00
IMEA						0	$0.00	$0.00	$0.00
IMPA						0	$0.00	$0.00	$0.00
BREC						135	$11,801.18	$0.00	$11,801.18
OVEC						0	$0.00	$0.00	$0.00
OMU						0	$0.00	$0.00	$0.00
TEA						0	$0.00	$0.00	$0.00
TVA						0	$0.00	$0.00	$0.00
XEWO						0	$0.00	$0.00	$0.00

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	MWH	INC. COST	FUEL	
TOTAL PURCHASES OTHER THAN PREMERGER	10240	$714,207.08	$0.00	$714,207.08
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				12%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE) Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)	1444		$54,917.53	NL
SPLIT SAVINGS (LGE TO KU RATE BASE) One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)			$11,171.83	NL
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	148525	$5,317,883.09		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	
			1,444	$66,089.36
TOTAL	149969	$5,383,972.45	149,969	$5,383,972.45

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS					MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Tier 2 price chang	NL-555012	Feb-08	(Enter as 1 total &	0	$0.00	$0.00	$0.00
MCRSG	Tier 2 price chang	OSS-555010	Feb-08	reclass to NL acct)	0	$100.90	$0.00	$100.90
MISO							$0.00	$0.00
EKPC	price change for m	NL	Feb-08				$0.00	$0.00
EKPC	price change for m	OSS	Feb-08				$0.00	$0.00
PJM	Volume increase		Feb-08		0	($119.73)	$0.00	($119.73)
TOTAL					0	($18.83)	$0.00	($18.83)

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INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		0	$0.00	$0.00	$0.00
PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Feb 08 Billing	0	$10,133.27	($372,303.55)	($362,170.28)
OVEC	True-up of December 07 Billing		$0.00	($358,325.16)	($358,325.16)
			$0.00	$0.00	$0.00
TOTAL		0	$10,133.27	($730,628.71)	($720,495.44)

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Purchased Power Energy and Demand for the Month Ended April 30, 2008

PRE-MERGER PURCHASES		MWH	ENERGY	FIXED CHARGES $	TOTAL $
OVEC	SURPLUS	69836	$1,464,321.25	$1,575,165.31	$3,039,486.56
TOTAL PREMERGER PURCHASES		69836	$1,464,321.25	$1,575,165.31	$3,039,486.56

OTHER PURCHASES					MWH	ENERGY $	FIXED CHARGES $	TOTAL $
MISO	301	0.00828	NL	$17,670.13	329	$21,909.02	$0.00	$21,909.02
MCRS	28	0.00077	OSS	$4,238.89	0	$0.00	$0.00	$0.00
PJM					140	$13,582.97	$0.00	$13,582.97
AECI					0	$0.00	$0.00	$0.00
AEP					0	$0.00	$0.00	$0.00
AMEM					0	$0.00	$0.00	$0.00
CARG					0	$728.49	$0.00	$728.49
CITI					0	$0.00	$0.00	$0.00
COBB					0	$0.00	$0.00	$0.00
CONS					64	$4,566.01	$0.00	$4,566.01
DECA					0	$0.00	$0.00	$0.00
EKPC					0	$0.00	$0.00	$0.00
FORT					0	$0.00	$0.00	$0.00
IMEA					0	$0.00	$0.00	$0.00
IMPA					0	$0.00	$0.00	$0.00
IMBL					20	$885.67	$0.00	$885.67
OVEC					0	$0.00	$0.00	$0.00
OMU					0	$0.00	$41.87	$41.87
TEA					0	$0.00	$0.00	$0.00
TVA					0	$0.00	$0.00	$0.00
WSTR					0	$0.00	$0.00	$0.00

Louisville Gas & Electric

CASE NO. 2008-00252
CASE NO. 2007-00564

Purchased Power Energy and Demand for the Month Ended April 30, 2008

TOTAL PURCHASES OTHER THAN PREMERGER	562	$41,672.16	$41.87	$41,714.03
Note> LEM total will be broken out between different management reporting segments within reconciliation section below				1%
INTERCOMPANY PURCHASES	MWH	INC. COST	FUEL	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)	0		$0.00	NL
Fuel cost of MWh sent to LGE for native load (INTERNAL ECONOMY)				
SPLIT SAVINGS (LGE TO KU RATE BASE)			$0.00	NL
One half the difference between KU gen (fuel) sent to LGE and the displaced LGE source which would have been used to supply the LGE local load. (Includes displaced LGE gen and purchases)				
PURCHASE OF FREED UP KU GEN BACK TO LGE (INTERNAL REPLACEMENT) (Internal Economy matched w/gen)	104301	$3,232,716.51		OSS
TOTAL LGE PURCH FROM KU FOR LGE INTERRUPTIBLE BUY THROUGHS	0	$0.00		NL
			Subtotal NL	$0.00
TOTAL	104301	$3,232,716.51	104,301	$3,232,716.51
			OK	

COMMON PURCHASE ADJUSTMENTS FROM PRIOR MONTHS					MWH	ENERGY	FIXED CHARGES	TOTAL
MCRSG	Tier 2 price change	NL-555015	Mar-08	(Enter as 1 total &	0	$0.00	$0.00	$0.00
MCRSG	Tier 2 price change	OSS-555010	Mar-08	reclass to NL acct)	0	$1,492.91	$0.00	$1,492.91
MISO							$0.00	$0.00
EKPC	price change for m	NL	Feb-08				$0.00	$0.00
EKPC	price change for m	OSS	Feb-08				$0.00	$0.00
PJM	Volume increase		Feb-08		0	$0.00	$0.00	$0.00
TOTAL					0	$1,492.91	$0.00	$1,492.91

Louisville Gas & Electric

CASE NO. 2008-00252
CASE NO. 2007-00564

Purchased Power Energy and Demand for the Month Ended April 30, 2008

INTERCOMPANY PURCH. ADJUSTMENTS FROM PRIOR MONTHS		MWH	ENERGY	SPLIT SAVINGS	
KU GEN FOR LGE NATIVE LOAD (KU SALE TO LGE)		0	$0.00		
SPLIT SAVINGS (LGE TO KU RATE BASE)				$0.00	
PURCHASE OF FREED UP KU GEN BACK TO LGE		0	$0.00		
TOTAL LGE PURCH FROM KU FOR LGE PREMERGER SALES		0	$0.00		
TOTAL PRE-MERGER ADJUSTMENTS		**0**	**$0.00**	**$0.00**	**$0.00**

PRE-MERGER PURCHASE ADJUSTMENTS		MWH	ENERGY	FIXED CHARGES	TOTAL
OVEC	True-up of Mar 08 Billing	0	($42,417.38)	($240,160.50)	($282,577.88)
OVEC	0		$0.00	$0.00	$0.00
			$0.00	$0.00	$0.00
TOTAL		**0**	**($42,417.38)**	**($240,160.50)**	**($282,577.88)**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 171

Responding Witness: William Steven Seelye

Q-171. With regard to LG&E electric Purchased Power expenses incorporated in the class cost of service study, please reconcile the two different Total System amounts referenced below:

a. Seelye Exhibit 26, page 13, "555 Purchased Power" of $81,802,192, and,

b. Seelye Exhibit 26, page 43, "Purchased Power Expenses" of $83,608,926.

Please include in this response all references, data, calculations, etc. as appropriate.

A-171. The Purchased Power Expenses amount shown on page 43 of $83,608,926 is incorrect. The amount shown on page 13, $81,802,192, is the correct amount for Account 555 – Purchased Power and should have been included on page 43.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 172

Responding Witness: Robert M. Conroy / William Steven Seelye

Q-172. With regard to LG&E Intercompany electric sales, please provide:

a. a detailed explanation along with all workpapers and analyses showing the pricing methodology (basis) and amount (units and dollars) for sales to affiliates, and,

b. if not provided in (a) above, please provide the detailed determination of test year Intercompany sales (units and dollars) by month and by affiliate.

A-172. a. Please see the response to Question Nos. 170(d), 114, and 115. The attachment to this response includes the Power Transaction Schedules from the monthly FAC Form B filings for the test year. The purchase and sales amounts (units and dollars) for intercompany transactions between KU and LG&E are contained on these schedules.

b. See part (a).

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: May 31, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components: Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	12,664,000		439,111.20	286,851.85	725,963.05
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	468,000		30,860.32	19,805.01	50,665.33
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	10,495,000		241,549.43	157,793.51	399,342.94
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	13,754,000		316,818.73	206,963.61	523,782.34
BP ENERGY COMPANY	BP	Economy	624,000		20,750.22	13,555.19	34,305.41
CARGILL- ALLIANT, LLC	CARG	Economy	8,942,000		219,597.47	143,453.28	363,050.75
CITIGROUP ENERGY, INC.	CITI	Economy	2,240,000		66,689.48	43,565.26	110,254.74
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	4,738,000		$128,289.04	83,805.54	$212,094.58
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	5,643,000		$125,602.13	82,122.04	$207,724.17
DTE ENERGY TRADING, INC.	DTE	Economy	415,000		12,671.41	8,277.67	20,949.08
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	998,000		24,514.60	16,014.30	40,528.90
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	7,670,000		194,447.24	127,023.75	$321,470.99
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	257,000		10,275.46	6,712.50	$16,987.96
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	275,000		10,987.55	7,177.68	18,165.23
ENERGY IMBALANCE	IMBL	Economy	23,000		1,391.20	908.80	2,300.00
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	6,317,000		149,038.50	97,360.23	246,398.73
PROGRESS ENERGY VENTURES INC.	PROG	Economy	1,379,000		35,514.48	23,200.03	58,714.51
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	848,000		20,569.69	13,437.26	34,006.95
THE ENERGY AUTHORITY	TEA	Economy	364,000		8,379.76	5,474.13	13,853.89
TENNESSEE VALLEY AUTHORITY	TVA	Economy	6,087,000		154,279.58	100,784.01	255,063.59
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	4,500,000		111,091.31	72,571.04	183,662.35
WESTAR ENERGY, INC.	WSTR	Economy	374,000		10,584.32	6,914.28	17,498.60
MISCELLANEOUS			-		17.99	(17.99)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	406,537,000		8,326,027.96	14.80	8,326,042.76
SUBTOTAL			495,612,000	0.00	10,659,059.07	1,523,767.78	12,182,826.85
TOTAL			495,612,000	-	10,659,059.07	1,523,767.78	12,182,826.85

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: June 30, 2007

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	7,108,000		177,557.20	137,582.79	315,139.99
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	332,000		20,052.45	19,502.31	39,554.76
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	4,015,000		88,179.96	68,327.53	156,507.49
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	9,626,000		240,102.55	186,046.97	426,149.52
BP ENERGY COMPANY	BP	Economy	144,000		5,220.29	4,045.01	9,265.30
CARGILL- ALLIANT, LLC	CARG	Economy	5,171,000		114,193.06	88,484.16	202,677.22
CITIGROUP ENERGY, INC.	CITI	Economy	592,000		15,053.89	11,664.71	26,718.60
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	4,762,000		131,607.07	101,977.66	233,584.73
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	14,876,000		377,085.56	292,147.91	669,233.47
DTE ENERGY TRADING, INC.	DTE	Economy	1,136,000		21,748.02	16,851.77	38,599.79
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	5,214,000		179,479.14	139,072.05	318,551.19
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	4,436,000		105,951.53	82,098.08	188,049.61
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	3,643,000		131,984.00	102,269.73	234,253.73
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	2,428,000		101,287.05	78,483.74	179,770.79
KANSAS CITY POWER & LIGHT	KCPL	Economy	1,489,000		40,868.34	31,667.43	72,535.77
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	2,692,000		66,300.74	54,444.98	120,745.72
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	2,336,000		61,867.93	47,939.28	109,807.21
THE ENERGY AUTHORITY	TEA	Economy	5,346,000		153,141.36	118,663.82	271,805.18
TENASKA POWER SERVICES CO.	TPS	Economy	619,000		13,061.21	7,049.78	20,110.99
TRANSALTA ENERGY MARKETING (U.S.) INC.	TALT	Economy	96,000		2,256.26	1,748.29	4,004.55
TENNESSEE VALLEY AUTHORITY	TVA	Economy	13,885,000		319,467.91	247,544.38	567,012.29
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	155,000		2,905.16	2,194.60	5,099.76
WESTAR ENERGY, INC.	WSTR	Economy	264,000		6,015.71	4,661.36	10,677.07
MISCELLANEOUS			-		2,338.81	(2,338.81)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	316,362,000		6,618,839.47	1,509.93	6,620,349.40
SUBTOTAL			406,727,000	0	8,996,564.67	1,843,639.46	10,840,204.13
TOTAL			406,727,000	0	8,996,564.67	1,843,639.46	10,840,204.13

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: July 31, 2007

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	10,915,000		328,308.03	262,324.98	590,633.01
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	389,000		22,491.73	18,327.45	40,819.18
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	3,139,000		71,879.78	57,438.02	129,317.80
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	17,631,000		434,140.00	346,914.55	781,054.55
BP ENERGY COMPANY	BP	Economy	244,000		6,385.96	5,102.92	11,488.88
CARGILL- ALLIANT, LLC	CARG	Economy	9,799,000		224,706.36	179,559.37	404,265.73
CITIGROUP ENERGY, INC.	CITI	Economy	585,000		17,743.57	14,178.62	31,922.19
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	2,463,000		54,790.96	43,782.61	98,573.57
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	16,292,000		394,502.76	315,241.04	709,743.80
DTE ENERGY TRADING, INC.	DTE	Economy	686,000		23,100.32	18,459.11	41,559.43
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	1,415,000		24,675.31	19,717.66	44,392.97
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	4,610,000		172,875.18	138,141.89	311,017.07
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	15,939,000		399,426.99	319,175.91	718,602.90
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	2,670,000		74,953.30	59,894.03	134,847.33
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	2,845,000		79,871.18	63,823.81	143,694.99
KANSAS CITY POWER & LIGHT	KCPL	Economy	781,000		29,027.43	23,195.38	52,222.81
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	3,868,000		112,850.15	90,176.80	203,026.95
PROGRESS ENERGY VENTURES INC.	PROG	Economy	902,000		26,358.48	21,062.66	47,421.14
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	6,016,000		159,825.89	127,714.40	287,540.29
THE ENERGY AUTHORITY	TEA	Economy	3,119,000		89,129.39	71,221.92	160,351.31
TENNESSEE VALLEY AUTHORITY	TVA	Economy	12,395,000		295,883.54	236,435.94	532,319.48
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	222,000		6,316.70	5,047.55	11,364.25
WESTAR ENERGY, INC.	WSTR	Economy	220,000		4,605.86	3,680.44	8,286.30
MISCELLANEOUS			-		14,505.94	(14,505.94)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	285,742,000		5,915,140.14	11.91	5,915,152.05
SUBTOTAL			402,887,000	-	8,983,494.95	2,426,123.03	11,409,617.98
TOTAL			402,887,000	-	8,983,494.95	2,426,123.03	11,409,617.98

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: August 31, 2007

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	2,927,000		134,951.37	59,277.66	194,229.03
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	133,000		9,941.57	4,374.16	14,315.73
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	5,000		85.42	37.53	122.95
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	7,920,000		311,074.49	136,640.08	447,714.57
CARGILL- ALLIANT, LLC	CARG	Economy	3,510,000		116,948.67	51,369.94	168,318.61
CITIGROUP ENERGY, INC.	CITI	Economy	96,000		2,679.58	1,177.00	3,856.58
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	1,337,000		43,389.07	19,058.73	62,447.80
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	5,300,000		158,315.96	69,540.59	227,856.55
DTE ENERGY TRADING, INC.	DTE	Economy	108,000		6,304.41	2,769.23	9,073.64
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	4,928,000		134,482.95	59,071.89	193,554.84
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	120,000		5,976.36	2,625.13	8,601.49
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	1,818,000		66,778.28	29,332.50	96,110.78
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	3,127,000		141,484.24	62,147.24	203,631.48
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	3,962,000		181,877.14	79,889.88	261,767.02
ENERGY IMBALANCE	IMBL	Economy	266,000		18,518.61	8,134.34	26,652.95
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	1,186,000		50,854.84	22,338.08	73,192.92
PROGRESS ENERGY VENTURES INC.	PROG	Economy	1,185,000		62,076.09	27,267.05	89,343.14
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	2,509,000		103,911.31	45,643.25	149,554.56
THE ENERGY AUTHORITY	TEA	Economy	824,000		31,341.20	13,766.68	45,107.88
TENNESSEE VALLEY AUTHORITY	TVA	Economy	11,220,000		330,967.45	145,378.08	476,345.53
WILLIAMS ENERGY MARKETING & TRADING CO	WESC	Economy	282,000		15,945.69	7,004.17	22,949.86
KENTUCKY UTILITIES COMPANY	KU	Economy	240,046,000		7,648,752.15	8.22	7,648,760.37
SUBTOTAL			292,809,000	-	9,576,656.85	846,851.43	10,423,508.28
TOTAL			292,809,000	-	9,576,656.85	846,851.43	10,423,508.28

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: September 30, 2007

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	2,186,000		53,303.59	32,060.65	85,364.24
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	102,000		6,522.67	3,923.21	10,445.88
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	746,000		16,662.47	10,022.01	26,684.48
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	6,210,000		166,373.01	100,068.82	266,441.83
CARGILL- ALLIANT, LLC	CARG	Economy	2,477,000		68,135.60	40,981.70	109,117.30
CITIGROUP ENERGY, INC.	CITI	Economy	586,000		13,958.47	8,395.65	22,354.12
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	1,251,000		33,355.30	20,062.29	53,417.59
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	4,274,000		113,479.40	68,254.75	181,734.15
DTE ENERGY TRADING, INC.	DTE	Economy	41,000		1,304.56	784.66	2,089.22
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	1,037,000		22,363.47	13,451.01	35,814.48
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	384,000		10,182.93	6,124.75	16,307.68
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	5,981,000		144,517.07	86,923.06	231,440.13
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	7,202,000		249,888.49	150,301.10	400,189.59
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	7,668,000		265,942.41	159,957.08	425,899.49
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	859,000		32,869.15	19,769.90	52,639.05
PROGRESS ENERGY VENTURES INC.	PROG	Economy	581,000		16,518.36	9,935.35	26,453.71
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	2,033,000		61,139.52	36,814.31	97,953.83
THE ENERGY AUTHORITY	TEA	Economy	863,000		21,906.95	13,176.43	35,083.38
TENASKA POWER SERVICES CO.	TPS	Economy	43,000		907.50	545.84	1,453.34
TRANSALTA ENERGY MARKETING (U.S.) INC.	TALT	Economy	373,000		16,891.54	10,159.78	27,051.32
TENNESSEE VALLEY AUTHORITY	TVA	Economy	15,932,000		392,753.62	236,230.58	628,984.20
MISCELLANEOUS			-		381.89	(381.89)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	211,086,000		4,578,650.03	251.76	4,578,901.79
SUBTOTAL			271,915,000	0.00	6,288,008.00	1,027,812.80	7,315,820.80
TOTAL			271,915,000	-	6,288,008.00	1,027,812.80	7,315,820.80

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: October 31, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components: Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	21,602,000		541,946.69	450,430.40	992,377.09
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	651,000		36,904.24	30,759.81	67,664.05
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	40,375,000		1,125,187.03	936,805.47	2,061,992.50
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	5,417,000		125,147.48	104,194.99	229,342.47
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	9,420,000		236,202.94	196,657.26	432,860.20
CARGILL- ALLIANT, LLC	CARG	Economy	12,254,000		299,455.68	249,320.08	548,775.76
CITIGROUP ENERGY, INC.	CITI	Economy	2,190,000		57,274.21	47,633.66	104,907.87
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	829,000		20,996.59	17,481.29	38,477.88
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	6,638,000		151,436.21	126,082.40	277,518.61
DTE ENERGY TRADING, INC.	DTE	Economy	1,980,000		57,304.14	47,710.13	105,014.27
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	394,000		15,650.55	13,030.30	28,680.85
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	3,619,000		99,319.17	82,690.91	182,010.08
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	2,319,000		92,779.79	77,246.38	170,026.17
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	2,473,000		98,787.77	82,248.47	181,036.24
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	2,598,000		80,833.28	67,299.97	148,133.25
NO. INDIANA PUBLIC SERVICE CO.	NIPS	Economy	46,000		1,581.94	1,317.09	2,899.03
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	2,166,000		53,499.89	44,542.81	98,042.70
THE ENERGY AUTHORITY	TEA	Economy	709,000		18,233.64	15,180.93	33,414.57
TENNESSEE VALLEY AUTHORITY	TVA	Economy	24,866,000		585,690.65	487,632.89	1,073,323.54
WESTAR ENERGY, INC.	WSTR	Economy	74,000		2,012.93	1,675.92	3,688.85
MISCELLANEOUS			-		188.62	(188.62)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	303,788,000		6,549,539.28	-	6,549,539.28
SUBTOTAL			444,408,000	-	10,249,972.72	3,079,752.54	13,329,725.26
TOTAL			444,408,000	-	10,249,972.72	3,079,752.54	13,329,725.26

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: November 30, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components: Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	9,744,000		285,611.59	139,340.57	424,952.16
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	626,000		43,227.73	21,089.39	64,317.12
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	27,960,000		801,043.93	390,803.18	1,191,847.11
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	2,478,000		66,153.20	32,273.98	98,427.18
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	4,088,000		117,864.76	57,502.37	175,367.13
CARGILL- ALLIANT, LLC	CARG	Economy	2,203,000		64,676.14	31,553.38	96,229.52
CITIGROUP ENERGY, INC.	CITI	Economy	1,522,000		40,776.25	19,893.40	60,669.65
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	323,000		8,872.48	4,328.60	13,201.08
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	2,857,000		77,217.58	37,671.95	114,889.53
DTE ENERGY TRADING, INC.	DTE	Economy	911,000		26,094.74	12,730.77	38,825.51
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	1,404,000		48,838.20	23,826.56	72,664.76
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	862,000		24,650.07	12,025.96	36,676.03
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	4,820,000		199,226.46	97,196.08	296,422.54
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	4,820,000		23,105.18	11,272.27	34,377.45
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	936,000		28,354.36	13,833.17	42,187.53
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	394,000		13,071.70	6,377.25	19,448.95
THE ENERGY AUTHORITY	TEA	Economy	339,000		9,518.81	4,643.92	14,162.73
TENNESSEE VALLEY AUTHORITY	TVA	Economy	29,830,000		807,943.76	394,169.37	1,202,113.13
MISCELLANEOUS			-		245.84	(245.84)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	364,089,000		6,696,698.20	982.12	6,697,680.32
SUBTOTAL			460,206,000	-	9,383,190.98	1,311,268.45	10,694,459.43
TOTAL			460,206,000	-	9,383,190.98	1,311,268.45	10,694,459.43

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: December 31, 2007

Company		Type of Transaction	KWH	Demand($)	Billing Components: Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	28,062,000		618,259.62	525,607.77	1,143,867.39
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	584,000		34,270.63	29,091.50	63,362.13
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	75,405,000		1,767,238.98	1,500,166.03	3,267,405.01
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	22,399,000		528,585.29	448,703.15	977,288.44
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	10,550,000		256,113.30	217,408.34	473,521.64
CARGILL- ALLIANT, LLC	CARG	Economy	5,137,000		130,909.31	111,125.72	242,035.03
CITIGROUP ENERGY, INC.	CITI	Economy	95,000		1,661.33	1,410.25	3,071.58
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	2,877,000		69,649.50	59,123.77	128,773.27
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	9,388,000		232,565.66	197,419.32	429,984.98
DTE ENERGY TRADING, INC.	DTE	Economy	561,000		20,734.70	17,601.18	38,335.88
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	6,473,000		190,113.68	161,598.56	351,712.24
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	1,273,000		35,998.41	30,558.17	66,556.58
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	1,109,000		36,713.19	31,164.94	67,878.13
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	1,847,000		63,655.11	320,023.51	383,678.62
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	1,510,000		54,003.45	45,842.21	99,845.66
SEMPRA ENERGY TRADING CORP.	SEMP	Economy	2,020,000		76,478.36	64,920.62	141,398.98
THE ENERGY AUTHORITY	TEA	Economy	281,000		9,253.38	7,854.96	17,108.34
TENNESSEE VALLEY AUTHORITY	TVA	Economy	29,381,000		713,027.01	605,271.21	1,318,298.22
WESTAR ENERGY, INC.	WSTR	Economy	467,000		13,616.58	11,558.77	25,175.35
MISCELLANEOUS			-		(7,674.05)	7,674.05	-
KENTUCKY UTILITIES COMPANY	KU	Economy	511,121,000		8,909,854.07	10.93	8,909,865.00
SUBTOTAL			710,540,000	-	13,755,027.51	4,394,134.96	18,149,162.47
TOTAL			710,540,000	-	13,755,027.51	4,394,134.96	18,149,162.47

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: January 31, 2008

Company		Type of Transaction	KWH	Demand($)	Billing Components Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	93,265,000		2,382,324.05	1,514,301.88	3,896,625.93
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	333,000		22,060.13	14,021.64	36,081.77
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	77,756,000		1,960,077.58	1,245,944.41	3,206,021.99
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	3,738,000		96,062.76	61,058.51	157,121.27
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	6,364,000		189,491.96	120,443.10	309,935.06
CARGILL- ALLIANT, LLC	CARG	Economy	4,400,000		133,907.09	85,112.76	219,019.85
CITIGROUP ENERGY, INC.	CITI	Economy	244,000		7,388.18	4,696.01	12,084.19
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	2,125,000		62,119.74	39,483.96	101,603.70
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	3,109,000		73,926.74	46,895.45	120,822.19
DTE ENERGY TRADING, INC.	DTE	Economy	190,000		6,498.08	4,130.25	10,628.33
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	428,000		11,721.41	7,450.26	19,171.67
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	2,547,000		104,761.47	66,587.50	171,348.97
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	904,000		32,467.33	20,636.58	53,103.91
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	601,000		23,102.76	14,684.35	37,787.11
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	789,000		28,547.59	18,145.16	46,692.75
KANSAS CITY POWER & LIGHT	KCPL	Economy	190,000		4,636.08	2,946.73	7,582.81
MERRILL LYNCH COMMODITIES INC.	MLCM	Economy	837,000		21,656.73	13,765.24	35,421.97
THE ENERGY AUTHORITY	TEA	Economy	202,000		4,402.11	2,798.02	7,200.13
TRANSALTA ENERGY MARKETING (U.S.) INC.	TALT	Economy	764,000		18,809.91	11,955.79	30,765.70
TENNESSEE VALLEY AUTHORITY	TVA	Economy	17,582,000		499,397.44	317,422.30	816,819.74
WESTAR ENERGY, INC.	WSTR	Economy	48,000		936.36	595.20	1,531.56
MISCELLANEOUS			-		(14.92)	14.92	-
KENTUCKY UTILITIES COMPANY	KU	Economy	541,939,000		10,770,545.12	-	10,770,545.12
SUBTOTAL			758,355,000	-	16,454,825.70	3,613,090.02	20,067,915.72
TOTAL			758,355,000	-	16,454,825.70	3,613,090.02	20,067,915.72

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: February 29, 2008

Company		Type of Transaction	KWH	Demand($)	Billing Components Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	32,770,000		900,570.39	682,601.46	1,583,171.85
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	183,000		10,780.96	8,171.60	18,952.56
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	45,685,000		1,168,583.85	885,746.47	2,054,330.32
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	3,067,000		78,757.43	59,695.44	138,452.87
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	1,113,000		26,269.71	19,911.55	46,181.26
AMEREN ENERGY MARKETING COMPANY	AMEM	Economy	148,000		4,265.68	3,233.23	7,498.91
CARGILL- ALLIANT, LLC	CARG	Economy	1,293,000		33,506.58	25,396.83	58,903.41
CITIGROUP ENERGY, INC.	CITI	Economy	151,000		4,608.95	3,493.43	8,102.38
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	599,000		14,836.50	11,245.55	26,082.05
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	687,000		15,943.84	12,084.89	28,028.73
DTE ENERGY TRADING, INC.	DTE	Economy	90,000		1,789.77	1,356.59	3,146.36
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	346,000		12,001.72	9,096.89	21,098.61
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	1,063,000		24,234.36	18,368.81	42,603.17
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	82,000		2,347.04	1,778.97	4,126.01
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	87,000		2,463.34	1,867.12	4,330.46
THE ENERGY AUTHORITY	TEA	Economy	63,000		1,432.94	1,086.13	2,519.07
TENNESSEE VALLEY AUTHORITY	TVA	Economy	3,908,000		108,582.65	82,301.93	190,884.58
WESTAR ENERGY, INC.	WSTR	Economy	99,000		3,882.11	2,942.47	6,824.58
MISCELLANEOUS			-		726.71	(726.71)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	359,434,000		7,525,413.70	-	7,525,413.70
SUBTOTAL			450,868,000	-	9,940,998.23	1,829,652.65	11,770,650.88
TOTAL			450,868,000	-	9,940,998.23	1,829,652.65	11,770,650.88

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: March 31, 2008

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	54,725,000		1,640,678.70	1,135,071.74	2,775,750.44
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	607,000		37,646.51	26,045.01	63,691.52
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	56,138,000		1,784,766.51	1,234,756.10	3,019,522.61
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	3,707,000		147,456.58	102,014.97	249,471.55
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	1,066,000		35,495.89	24,557.14	60,053.03
AMEREN ENERGY MARKETING COMPANY	AMEM	Economy	182,000		4,784.21	3,309.87	8,094.08
CARGILL- ALLIANT, LLC	CARG	Economy	3,562,000		113,447.53	78,486.47	191,934.00
CITIGROUP ENERGY, INC.	CITI	Economy	952,000		33,074.93	22,882.24	55,957.17
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	1,732,000		47,277.27	32,707.87	79,985.14
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	909,000		33,686.46	23,305.34	56,991.80
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	1,634,000		62,023.78	42,909.95	104,933.73
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	545,000		20,419.13	14,126.57	34,545.70
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	6,184,000		391,719.37	271,003.46	662,722.83
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	8,474,000		538,054.00	372,242.23	910,296.23
THE ENERGY AUTHORITY	TEA	Economy	961,000		32,252.67	22,313.39	54,566.06
TENNESSEE VALLEY AUTHORITY	TVA	Economy	19,414,000		516,766.96	357,515.19	874,282.15
MISCELLANEOUS			-		(18.83)	18.83	-
KENTUCKY UTILITIES COMPANY	KU	Economy	401,365,000		8,554,456.05	7,865.27	8,562,321.32
SUBTOTAL			562,157,000	-	13,993,987.72	3,771,131.64	17,765,119.36
TOTAL			562,157,000	-	13,993,987.72	3,771,131.64	17,765,119.36

Louisville Gas and Electric Company

POWER TRANSACTION SCHEDULE

Month Ended: April 30, 2008

Company		Type of Transaction	KWH	Billing Components: Demand($)	Fuel Charges($)	Other Charges($)	Total Charges($)
Sales							
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	MISO	Economy	25,709,000		720,862.94	657,689.22	1,378,552.16
MIDWEST CONTINGENCY RESERVE SHARING GROUP	MCRS	Economy	225,000		12,131.95	11,533.49	23,665.44
PJM INTERCONNECTION ASSOCIATION	PJM	Economy	53,305,000		1,439,208.31	1,306,461.09	2,745,669.40
ASSOCIATED ELECT COOPERATIVE	AECI	Economy	1,657,000		53,678.49	48,747.83	102,426.32
AMERICAN ELECTRIC POWER SERVICE CORP.	AEP	Economy	1,298,000		36,660.91	33,293.40	69,954.31
AMEREN ENERGY MARKETING COMPANY	AMEM	Economy	251,000		10,386.16	9,432.15	19,818.31
CARGILL- ALLIANT, LLC	CARG	Economy	2,916,000		92,664.02	84,152.34	176,816.36
CITIGROUP ENERGY, INC.	CITI	Economy	709,000		24,298.97	22,066.98	46,365.95
COBB ELECTRIC MEMBERSHIP CORPORATION	COBB	Economy	989,000		26,466.66	24,035.54	50,502.20
CONSTELLATION ENERGY COMDS. GRP. INC.	CONS	Economy	1,539,000		50,128.05	45,523.50	95,651.55
DUKE ENERGY CAROLINAS, LLC	DECA	Economy	3,224,000		73,153.62	66,434.07	139,587.69
EAST KENTUCKY POWER COOPERATIVE	EKPC	Economy	637,000		24,876.59	22,591.54	47,468.13
FORTIS ENERGY MARKETING & TRADING GP	FORT	Economy	1,030,000		33,573.46	30,489.55	64,063.01
ILLINOIS MUNICIPAL ELECTRIC AGENCY	IMEA	Economy	168,000		9,970.67	9,054.79	19,025.46
INDIANA MUNICIPAL POWER AGENCY	IMPA	Economy	260,000		14,880.03	13,513.21	28,393.24
THE ENERGY AUTHORITY	TEA	Economy	1,382,000		29,516.30	26,805.08	56,321.38
TENNESSEE VALLEY AUTHORITY	TVA	Economy	11,890,000		284,222.99	258,115.55	542,338.54
WESTAR ENERGY, INC.	WSTR	Economy	356,000		11,351.73	10,308.96	21,660.69
MISCELLANEOUS			-		1,492.91	(1,492.91)	-
KENTUCKY UTILITIES COMPANY	KU	Economy	350,222,000		6,667,782.60	499.60	6,668,282.20
SUBTOTAL			457,767,000	-	9,617,307.36	2,679,254.98	12,296,562.34
TOTAL			457,767,000	-	9,617,307.36	2,679,254.98	12,296,562.34

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 173

Responding Witness: William Steven Seelye

Q-173. With regard to Mr. Seelye's LG&E direct testimony, page 30, lines 8 through 13:

a. please provide all statistical studies that do and do not "indicate that temperature sensitive loads are less significant in the range of temperature between 60°F and 70°F,"

b. please provide all studies and references substantiating the statement: "cooling loads are often not significant until mean daily temperatures exceed 70°F, and heating loads are often not significant until mean daily temperatures drop below 60°F," and,

c. please provide all studies that indicate cooling loads are not significant until mean daily temperatures exceed 70°F, and/or heating loads are not significant until mean daily temperatures drop below 60°F.

A-173. Please see the response to Question No. 182.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 174

Responding Witness: William Steven Seelye

Q-174. With regard to Mr. Seelye's LG&E direct testimony, page 32, lines 22 and 23, should this sentence refer to "one" standard deviation, instead of "two"? If no, please reconcile with statement on lines 25 and 26 of page 26.

A-174. No. The *total* bandwidth is equal to two standard deviations centered on the mean, which comprises one standard deviation above and one standard deviation below the mean.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 175

Responding Witness: William Steven Seelye

Q-175. With regard to Mr. Seelye's LG&E direct testimony, page 32, lines 2 through 12, please provide a complete copy of the referenced Order.

A-175. See the response to Question No. 180.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 176

Responding Witness: William Steven Seelye

Q-176. With regard to Mr. Seelye's LG&E direct testimony, page 42, line 15, please explain in layman's terms:

a. what F-statistic means and relates to, and,

b. why a 0.50 level of significance was selected.

In addition, please provide support and references regarding the criteria for selecting an appropriate F-statistic level of significance.

A-176. In the context of Mr. Seelye's statement on page 42, line 15 of his testimony, the F-statistic refers to the "partial F-statistic" used add or remove variables in forward, backward and stepwise regression. In very general terms, the F-statistic compares the impact of adding or removing a variable in a regression model to a confidence interval given by an F-distribution. This is the most commonly used criterion for the addition or deletion of variables in stepwise regression and is the methodology used by SAS and other statistical software packages for determining whether a variable should be retained through the application of a stepwise regression procedure. A 0.50 level of significance is the default criterion utilized by SAS. See J.D. Jobson, *Applied Multivariate Data Analysis* (New York: Springer-Verlag, 1992).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 177

Responding Witness: William Steven Seelye

Q-177. Regarding Mr. Seelye's LG&E direct testimony, page 45, lines 17 and 18, please provide all analyses, studies, and observations supporting the statement: "We have long observed that sales patterns can be different on Mondays and Fridays than other days of the week."

A-177. This is a result that Mr. Seelye and other analysts he has worked with over the years have observed in modeling electric sales. Mr. Seelye did not retain the regression and other models he worked with over the years. The data utilized in this proceeding certainly indicate that the coefficients for the dichotomous Monday and Friday variables are frequently statistically significant. See Seelye Exhibit 17.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 178

Responding Witness: William Steven Seelye

Q-178. Regarding Mr. Seelye's LG&E direct testimony, page 43, line 22 through page 44, line 2, please provide all analyses, studies, and observations supporting the statement: "For many years, my colleagues and I have noticed that using a base of 70°F for determining cooling degree days produces a better fit than using a 65°F base temperature."

A-178. This is a result that Mr. Seelye and other analysts he has worked with over the years have observed in modeling electric sales. Mr. Seelye did not retain the regression and other models he worked with over the years. The data utilized in this proceeding certainly indicate that the coefficients for the HDD60 and CDD70 Monday and Friday variables are frequently more statistically significant than HDD65 and CDD65. See Seelye Exhibit 17.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 179

Responding Witness: William Steven Seelye

Q-179. Regarding Mr. Seelye's LG&E direct testimony, page 49, lines 10 and 11, please provide support for the statement: "a typical rule is that none of the VIF's should exceed 10."

A-179. See D. A. Belsley, E. Kuh, and R.E. Welsch, *Regression Diagnostics: Identifying Influential Data and Sources of Collinearity* (New York: John Wiley & Sons, 1980), and Chong Ho Yu, "An Overview of Remedial Tools for Collinearity in SAS," *Proceedings of the 2000 Western Users of SAS Software Conference*, pp. 196-201.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 180

Responding Witness: William Steven Seelye

Q-180. Regarding Mr. Seelye's LG&E direct testimony, page 52, lines 17 through 19, please provide all references and complete Commission Orders that "expressed concerns with using billing-cycle degree days . . . for purposes of calculating the electric temperature normalization adjustment."

A-180. See the Commission's Order in Case No. 10064, which is attached.

Commission's Order in Case No. 10064
Responding Witness – William Steven Seelye

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF GAS AND ELECTRIC RATES OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	CASE NO. 10064

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BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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O R D E R

On November 20, 1987, Louisville Gas and Electric Company ("LG&E") filed an application with the Commission requesting authority to increase its electric and gas rates for service rendered on and after December 20, 1987. The proposed rates would increase annual electric revenues by $37,794,000, an increase of 8.5 percent, and annual gas revenues by $12,073,000, an increase of 7.27 percent. These increases represent an annual increase in total operating revenues of $49,867,000, or 8.16 percent, based on normalized test year sales. This Order grants an increase in annual gas and electric revenues of $21,993,394 or 3.5 percent.

The Commission suspended the proposed rate increases until May 20, 1988 in order to conduct public hearings and investigations into the reasonableness of the proposed rates. A hearing was scheduled for March 22, 1988 for the purpose of cross-examination of the witnesses of LG&E and the intervenors. LG&E was directed to give notice to its consumers of the proposed rates and the scheduled hearing pursuant to 807 KAR 5:011, Section 8. A hearing to receive public comment and testimony was conducted on

March 7, 1988 at the Jefferson County Courthouse in Louisville, Kentucky.

The Commission granted motions to intervene filed by the Utility and Rate Intervention Division of the Office of the Attorney General ("AG"); Jefferson County ("County"); the City of Louisville ("City"); the Department of Defense of the United States ("DOD"); the Utility Ratecutters of Kentucky, Inc. and the Paddlewheel Alliance, referred to as Consumer Advocacy Groups ("CAG"); the Legal Aid Society, Inc. on behalf of Darlene Baker and Jacolyn Petty, residential customers of LG&E and the Fairdale Area Community Ministries, Inc., the West Louisville Community Ministries, Inc., the Sister Visitors Center, and the Inter-religious Coalition for Human Services, Inc., who assist low-income households ("Residential Intervenors"); and the groups of Alcan Aluminum Company, Ashland Oil Inc., Ford Motor Company, Frito-Lay, Inc., General Electric Company, B. F. Goodrich Chemical Group, Interez, Inc., Reynolds Metals Company, and Rohm and Haas Kentucky, Inc., the Kentucky Industrial Utility Customers ("KIUC").

The hearings for the purpose of cross-examination of the witnesses of LG&E and the intervenors were held in the Commission's offices in Frankfort, Kentucky, on March 22-25, 28-29, 1988 and April 4-8, 11-12, 14 and 18, 1988 with all parties of record represented. Briefs were filed May 9, 1988 and the information requested during the hearings has been submitted.

COMMENTARY

LG&E is a privately-owned electric and gas utility which distributes and sells electricity to approximately 311,600 consumers in Jefferson County, and in portions of Bullitt, Hardin, Meade, Oldham, Shelby, Spencer, and Trimble counties and distributes and sells natural gas to approximately 237,000 consumers in Jefferson County and in portions of Barren, Bullitt, Green, Hardin, Hart, Henry, LaRue, Marion, Meade, Metcalfe, Nelson, Oldham, Shelby, Trimble, and Washington counties.

TEST PERIOD

LG&E proposed and the Commission has accepted the 12-month period ending August 31, 1987 as the test period for determining the reasonableness of the proposed rates. In utilizing the historic test period the Commission has given full consideration to appropriate known and measurable changes.

VALUATION

LG&E presented the net original cost, capital, and reproduction cost as the valuation methods in this case. The Commission has given due consideration to these and other elements of value in determining the reasonableness of the proposed rates. As in the past, the Commission has given limited consideration to the proposed reproduction cost.

Net Original Cost

LG&E proposed a total company net original cost rate base of $1,345,749,137. Generally, the proposed rate base was determined in accordance with the Commission's decision in LG&E's last rate case. The net investment rate base has been adjusted to reflect the accepted pro forma adjustments to operation and maintenance expenses in the calculation of the allowance for working capital. As discussed further in the section of this Order relating to the extraordinary property losses, the net investment rate base has been reduced by $19,571,002 to reflect adjustments to the accumulated depreciation reserve and the deferred income tax accounts. The rate base has been increased by $72,780 to recognize 1 year's amortization of the unprotected excess deferred income taxes resulting from the reduction of the corporate tax rate in the Tax Reform Act of 1986 ("Tax Reform Act"). This is achieved by decreasing the deferred tax reserve account to reflect the amortization adjustment described in the section of this Order relating to Excess Deferred Taxes. All other elements of the net original cost rate base have been accepted as proposed by LG&E.

In LG&E's last rate case, the Commission placed LG&E on notice that the Federal Energy Regulatory Commission ("FERC") rulemaking procedure concerning the calculation of working capital would be considered in LG&E's future rate proceedings. FERC has not moved forward on this matter and at this time has not required a lead-lag study for the calculation of cash working capital. In this case, LG&E has determined the allowance for working capital in the same manner as in past rate cases with cash working capital calculated using the 45 day or 1/8 formula.

Thomas J. Prisco, on behalf of the DOD, recommended the use of the balance sheet approach to calculate working capital. His methodology was based upon correspondence from the National Association of Regulatory Utility Commissioners Annual Regulatory

Studies Program and various accounting books. The Commission agrees with the position of the DOD that consumers should not be required to pay rates which include an allowance for excess working capital. However, based on the evidence presented in this proceeding, the Commission is not convinced that the method offered by the DOD is an accurate representation of the balance sheet approach and, therefore, of LG&E's working capital needs. The Commission has, therefore, determined the allowance for working capital in the same manner as proposed by LG&E using the 45 day or 1/8 formula for cash working capital.

The net original cost rate base devoted to electric and gas operations is determined by the Commission to be as follows:

	Gas	Electric	Total
Total Utility Plant	$196,479,603	$1,702,353,408	$1,898,833,011
ADD:			
Materials & Supplies	1,443,870	46,126,080	47,569,950
Gas Stored Underground	22,166,664	-0-	22,166,664
Prepayments	341,417	1,431,429	1,772,846
Cash Working Capital	4,092,780	31,914,475	36,007,255
Subtotal	$ 28,044,731	$ 79,471,984	$ 107,516,715
DEDUCT:			
Reserve for Depreciation	72,817,435	416,540,389	489,357,824
Customer Advances	2,876,070	1,228,267	4,104,337
Accumulated Deferred Taxes	16,988,797	167,531,323	184,520,120
Investment Tax Credit (3%)	508,000	1,421,030	1,929,030
Subtotal	$ 93,190,302	$ 586,721,009	$ 679,911,311
NET ORIGINAL COST RATE BASE	$131,334,032	$1,195,104,383	$1,326,438,415

Capital

LG&E's Controller, M. Lee Fowler, proposed adjustments to LG&E's $1,362,822,255 end-of-test-year capital of $12,250,000. Long-term debt was adjusted to reflect "(1) the retirement of $12,000,000 of 4 7/8 percent First Mortgage Bonds; Series due September 1, 1987; (2) the scheduled redemption of $250,000 of 1975 Pollution Control Bonds due September 1, 1987; and (3) the refinancing of $49,000,000 of the 9.40 percent Pollution Control Bonds."[1] The refinancing of these Pollution Control Bonds did not affect the level of capital but rather the cost of this item. A further adjustment was made to capital to reflect discounts on preferred and common stock.[2]

Dr. Carl G. K. Weaver, an economist and principal with M. S. Gerber & Associates, Inc. and witness for the AG, proposed a capital balance of $1,246,106,059.[3] The difference between Dr. Weaver's proposed capital and Mr. Fowler's was in (1) Dr. Weaver's use of an October 31, 1987 capital balance as reported in LG&E's Financial and Operating Report; and (2) in the adjustments to reflect discounts on preferred stock and common equity.[4]

Lane Kollen, a utility rate and planning consultant with the firm Kennedy and Associates and witness for KIUC, proposed a

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1 Fowler Prepared Testimony, page 14.

2 Ibid., page 17.

3 Weaver Prepared Testimony, Exhibit CGW, Statement 24.

4 Ibid., pages 35-36.

capital balance of $1,289,422,255.[5] Mr. Kollen used LG&E's proposed adjusted capital balance, but made an additional adjustment to common equity to remove "$61.15 million in excess capitalization which is not utilized to support investment in utility property."[6]

Mr. Kollen provided three arguments for reducing common equity by the $61.15 million. First, because preferred stock has remained unchanged and the long-term debt increase of $51 million in pollution control bonds was invested in utility plant, it is the growth in common equity that has been used to finance short-term investments in non-utility plant since test year end of August 31, 1983.[7] Second, "LG&E has only debt and preferred stock directly attributable to utility operations and none whatsoever for non-utility operations."[8] Third, interest and other income from short-term investments is not flowed through to the ratepayers but is received below the line as a direct benefit to the shareholders.[9]

The process proposed by Mr. Kollen of isolating one asset which is not a part of rate base and reducing capital, without a complete evaluation of other assets and liabilities with regard to rate base and capital valuation is inappropriate. In order to

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5 Kollen Prepared Testimony, Exhibit LK-2.

6 <u>Ibid</u>., page 6.

7 <u>Ibid</u>., pages 8-9.

8 <u>Ibid</u>., page 9.

9 <u>Ibid</u>., page 10.

accept Mr. Kollen's adjustment, a complete reconciliation of the assets and liabilities would be necessary to determine appropriate additions and deletions of assets and liabilities to rate base and capital. None of the parties to this proceeding have attempted to make a complete reconciliation of rate base and capital. In the absence of such thorough analysis, the Commission cannot isolate and adjust selective items as proposed by Mr. Kollen. Moreover, the dollar relationship of rate base and capital as provided in this Order is approximately $4.5 million which is reasonable. The isolated adjustment proposed by Mr. Kollen would result in rate base exceeding capital by approximately $56 million. Therefore, Mr. Kollen's adjustment to capital has not been included for rate-making purposes herein.

The adjustments to the end-of-test-year capital proposed by LG&E reflect actual changes in LG&E's end-of-test-year capital which occurred on September 1, 1987 only 1 day after the end of the test period and should be accepted. In addition, the Commission has adjusted LG&E's capital by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. Concurrent with its adjustment to the rate base to remove the extraordinary losses, a similar adjustment must be made to capital. A company's net investment in utility operations and capital supporting utility operations should be equal, and rate-making steps should be undertaken to attempt to reach this equality. Since the losses do not relate specifically to any specific component of capital, the most equitable approach is to adjust capital on a pro rata basis. Therefore, the Commission is of the opinion that an adjusted capital balance of $1,331,001,253 is reasonable.

In determining capital the test-year-end Job Development Investment Tax Credit ("JDIC") has been allocated to each component of capital on the basis of the ratio of each component to total capital excluding JDIC, as proposed by LG&E. The Commission is of the opinion that this treatment is entirely consistent with the requirement of the Internal Revenue Service that JDIC receive the same overall return allowed on common equity, debt, and preferred stock.

Reproduction Cost

LG&E presented the reproduction cost rate base in Fowler Exhibit 9. Therein, LG&E estimated the value of plant in service, plant held for future use, and construction work in progress ("CWIP") at the end of the test year. The resulting reproduction cost rate base is $2,542,427,739 which includes electric facilities of $2,174,716,164 and gas facilities $367,810,575.

TRIMBLE COUNTY GENERATING STATION ("TRIMBLE COUNTY") - CWIP

In LG&E's last rate case, as well as the Order issued on October 14, 1985 in Case No. 9243, An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1, the Commission put LG&E on notice that the historical treatment of CWIP allowed in previous cases should not be taken as an indication that the treatment would continue indefinitely in future cases. In addition, due to the uncertainties surrounding the Trimble County project, the Commission initiated monitoring procedures to keep abreast of the

Trimble County activity. This monitoring contributed to the establishment of Case No. 9934, A Formal Review of the Current Status of Trimble County Unit No. 1.

In the Order in Case No. 9934 entered on July 1, 1988, the Commission found that 25 percent of Trimble County should be disallowed. In this proceeding, the Commission has heard evidence with regard to the rate-making treatment of Trimble County CWIP; however, there has been no specific testimony offered regarding the various options for rate-making treatment of a disallowance of 25 percent of the cost of Trimble County. Furthermore, in Case No. 9934, since the Commission's decision is being issued concurrently with this Order, there has been no specific investigation of the revenue requirement effects of a 25 percent disallowance of Trimble County. Therefore, the Commission has determined that another proceeding will be established to allow a full investigation of this issue. An Order establishing this case will be rendered in the immediate future.

In order to protect the interests of the consumers and assure that the disallowance will be recognized from the date of this Order, the Commission is of the opinion that all revenues associated with additions to CWIP since LG&E's last rate case should be collected subject to refund. The Trimble County CWIP included in rate base in LG&E's last rate case was $268 million and Trimble County CWIP has achieved a level of $382 million at the end of the test period in this case. Applying the overall rate of return allowed in this case to the increase in Trimble County CWIP of $114 million results in an annual provision of $11.4 million to be collected subject to refund. The final amount of disallowances will be determined in the forthcoming Trimble County CWIP case soon to be established and the current ratepayers will realize the benefits of the disallowance when an Order is issued in that case.

In this proceeding, as in LG&E's last two rate cases, the Commission has addressed the issue of continuing the practice of allowing CWIP in LG&E's rate base. While both LG&E and the intervenors have presented arguments supporting and opposing the practice of allowing a return on CWIP, neither side has presented any new arguments or evidence which has not already been considered by this Commission. Consequently, based on the evidence in this case, the Commission is of the opinion that the present regulatory treatment of allowing a cash return on CWIP should continue in light of the decision to complete Trimble County. However, the final amounts utilized for rate-making and revenue requirement determination will be decided in the future proceeding announced in this section of the Order.

RETIREMENTS OF SULFUR DIOXIDE REMOVAL SYSTEMS ("SDRS") AND GAS PLANT

As part of this case, the Commission Staff reviewed LG&E's accounting treatment for the retirement of SDRS and three underground storage fields ("gas fields"). The Staff gave LG&E notice through cross-examination and data requests that the accounting treatment utilized by LG&E ignored the impact these retirements had on LG&E's rate base and the return on that rate base.[10] LG&E

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[10] Response to the Commission Orders dated December 23, 1987, Item No. 42(a-e); dated January 15, 1988, Item No. 69; and Hearing Transcript, Vol. IV, pages 7, 13-19.

initially advised the Staff in 1986 that it planned to account for the abandoned gas fields as a normal retirement under the Uniform System of Accounts ("USoA"). The accounting treatment was investigated in this case because this was LG&E's first general rate case since these retirements had taken place.

LG&E stated that this accounting treatment was its usual procedure in accounting for abandonments and retirements.[11] In addition, LG&E determined that these entries resulted in a depletion of the depreciation reserve which was now deficient. LG&E proposed to revise upward the depreciation rates for underground gas plant to eliminate the deficiency. The revision was made in 1986, with the depreciation rate for underground gas plant increasing from 3.37 percent to 5.05 percent.[12]

The abandoned gas fields were comprised of several million dollars of undepreciated plant per the company's books. While most of the gas fields were being depreciated over approximately 30 years, significant portions of the gas fields had been in service less than 15 years. As a result of the abandonment, LG&E reported an income tax loss of $3,973,815[13] in 1985. Preliminary figures supplied by LG&E indicated that a book loss, at least as great as the tax loss, existed.[14]

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11 Response to the Commission Order dated December 23, 1987, Item No. 42(a), page 1 of 2.

12 Ibid., dated January 15, 1988, Item No. 69(f)(3), page 3 of 3.

13 1985 FERC Form No. 1, Annual Report of LG&E, page 261.

14 Response to the Commission Order dated January 15, 1988, Item No. 69(f)(1), page 2 of 37.

During 1986, Commission Staff obtained information from LG&E which reflected that early retirements of SDRS units were significant and had been accounted for in the same manner as the abandoned gas fields.[15] It was apparent that a depletion of the electric steam production plant depreciation reserve resulted. Since the accounting treatment for these early retirements results in a material impact on revenue requirements, the Commission is of the opinion that this subject is appropriately an issue in this case.

The subject of these early retirements and abandonments has been thoroughly explored through information requests and in cross-examination of LG&E witness, Mr. Fowler. From the information requests, it was determined that for the period 1984 through 1986, LG&E had incurred losses of $21,052,354 due to the early retirements of SDRS units and losses of $6,862,820 due to the abandonment of the gas fields in 1985.[16] If the electric and gas losses are combined, the total losses on these early retirements are $27,915,174. LG&E claimed tax losses on the SDRS units retired between 1984 and 1986 of $3,029,756.[17]

LG&E objected to the questioning of Mr. Fowler on the grounds that the accounting treatments utilized for the SDRS units and gas fields were not relevant to its rate application. LG&E observed that the events did not occur in the test year, and it believed

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[15] Ibid., Item No. 69(f)(2 and 3), page 1 of 3.

[16] Ibid., Item No. 69(f)(1), page 2 of 37.

[17] Ibid., Item No. 69(a), page 1 of 4.

that it was not a proper issue for consideration in this case.[18] The Commission finds that even though the actual retirements and abandonments did not occur in the test year, the subject is highly relevant to this rate case. The impact of retirements losses totaling $27,915,174 exists in the accumulated depreciation reserve and thus is reflected in the net original cost rate base. LG&E has already revised its depreciation rates for underground gas storage plant to offset a portion of the loss and seeks to reflect that change in this case. Moreover, the accounting treatment employed by LG&E does not properly disclose the impact of the early retirements and allows LG&E a full return on the net amount of the losses while the losses are being recovered through depreciation accruals.

LG&E's approach to the retirements transactions, on the surface, is simple and straightforward. While book losses generated by early retirements and abandonments can produce deficiencies in the accumulated depreciation reserve, the increasing of depreciation rates on existing plant will make up the deficiency. Mr. Fowler pointed out that, under LG&E's use of whole life, functional group depreciation, utility plant will often be depreciated beyond the estimated service life and thus can help reduce any existing deficiency.[19]

However, LG&E has failed to recognize that its approach allows the company to reap a double benefit at the ratepayers'

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[18] Hearing Transcript, Vol. III, pages 177-178.

[19] Ibid., Vol. IV, page 12.

expense. While plant is in service, a company will usually receive a return on the plant and recover the cost of the plant. This is accomplished through the return on the rate base and depreciation expense. LG&E seeks to retain this arrangement on plant that has been retired or abandoned. This approach not only allows for recovery of the inherent deficiency in accumulated depreciation through depreciation expense, but also allows a return on the loss by overstating the rate base. LG&E has maintained that its current treatment benefits its ratepayers by the reserve deficiencies being made up over several years, rather than recovered over a 3- to 5-year period. LG&E contends that 3 to 5 years is a normal amortization period for extraordinary losses, but Mr. Fowler could not cite a publication or pronouncement that supported this claim.[20]

The Commission recognizes that one of the problems which causes this situation is that general plant accounting instructions contained in the USoA does not specifically provide for the possibility of a loss occurring at the time of any retirement. There are three types of property losses provided for in the USoA: losses arising from the disposition of future-use utility plant; losses on the sale, conveyance, exchange or transfer of utility or other property to another; and extraordinary property losses. This last type of loss requires the creation of a deferred debit in Account No. 182, Extraordinary Property Losses.[21] The

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20 Ibid., Vol. III, pages 188-189; Vol. IV, pages 22-23, 51-52.

21 USoA, Electric and Gas Plant Instructions, Item No. 10, parts E and F.

amortization of the account over a set period of years is anticipated in USoA instructions.

In the absence of specific accounting treatment in the USoA, the Commission may utilize other authoritative accounting sources. The Commission generally attempts to minimize discrepancies between generally accepted accounting principles ("GAAP") and its prescribed accounting treatment. Under GAAP applied to non-utility business enterprises, the possibility of a loss occurring at the time of retirement of an asset is specifically recognized. Under those standards, when a major asset is retired from use, the cost and related accumulated depreciation are removed from the accounts, which is similar to the approach outlined in the USoA. However, under GAAP, the charge to accumulated depreciation is limited to the depreciation provided on the asset and since the depreciation expense charged over the estimated useful life of the asset is only an allocation of the cost based on an estimate, a gain or loss will normally be realized on disposal of the asset.

It is conceivable that in GAAP accounting for non-utility enterprises, the practice of group depreciation would exist in which case the entity would account for an asset retired from service in the same manner as prescribed in utility accounting. Thus, it is apparent that another discrepancy in dealing with this issue lies in the eligibility of an asset for group life depreciation. The Commission is of the opinion that the assets here, the gas fields and the SDRS units, are of sufficient value and identifiable enough to warrant individual asset accounting treatment for depreciation and retirement accounting. Thus, the arguments with regard to group depreciation are not valid.

Of the three types of treatment of losses available to LG&E under the USoA, the only applicable treatment is the extraordinary property loss. To be considered extraordinary, the transaction must be of significant effect, not typical or a customary business activity, and would not be expected to recur frequently or be considered as a recurring factor in the evaluation of the ordinary operating process of the business.[22] These restrictions are similar to those prescribed under GAAP. In Accounting Practices Board ("APB") Opinion 30, an extraordinary item is defined as a transaction which is of an unusual nature and has an infrequency of occurrence given the environment in which the business operates.[23] Under the current USoA, the use of extraordinary treatment must be approved by the Commission, upon the request of the company.

Based on the information contained in the record, the Commission finds that the early retirements and abandonments constituted extraordinary property losses, and that LG&E should have requested such treatment. The size of the book losses for the SDRS units and gas fields would be considered significant. LG&E has been an industry leader in SDRS technology, a technology which was new and for which service life history was nonexistent. Mr. Fowler stated at the hearing that the company's experience with SDRS units was

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22 Ibid., Item No. 7.

23 APB Opinion 30, paragraph 20.

unusual.[24] The gas fields were abandoned based on the recommendations of a consultant hired by LG&E.[25] While the USoA requires the company to seek Commission approval for the use of extraordinary treatment, the lack of such action on the part of LG&E causes the initiative to shift to the Commission.

It appears that LG&E has failed to recognize the impact its approach has on accounting and rate-making treatments. The use of revised depreciation rates on existing total utility plant is an example of the accounting impact. It is understandable that depreciation rates need to be revised from time to time due to changes in the actual service life history and technological advances. However, increasing the depreciation rates on existing plant to recover deficiencies created by early retirement or abandonment of major items of plant is not justifiable in this instance. If depreciation rates should be increased to make up deficiencies resulting from extraordinary property losses, once the deficiencies are made up the rates should be revised downward. With regard to the rate-making impact, the accumulated depreciation reserve is understated until the reserve is restored by the increased depreciation resulting from the depreciation rate revision. The understated accumulated depreciation reserve in turn causes the net original cost rate base to be overstated. Thus, if the revenue requirement is based on the return granted on

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24 Hearing Transcript, Vol. III, pages 179-180, 190-191.

25 Response to KIUC's Second Data Request filed February 1, 1988, Item No. 16.

rate base, the revenue required is inflated due to the overstated rate base.

In addition to the impact of the deficiencies in the accumulated depreciation reserve, there is also the issue of the rate-making treatment of deferred income taxes generated by the retired assets. LG&E was asked to provide the deferred income tax balances related to the SDRS units and the gas fields. For the gas fields, LG&E was able to respond that at the date of abandonment deferred income taxes totaled $3,059,100, and that $162,000 had been flowed back by the test year-end, for a balance of $2,897,100.[26] For the SDRS units, LG&E continually stated that this deferred income tax figure could not be readily determined due to the manner in which its deferred tax accounts were maintained. LG&E has identified the total SDRS deferred income tax balance as $4,910,100 at the date of retirement,[27] $5,146,000 at test year-end,[28] and $5,268,800 at calendar year-end 1987.[29] In addition, LG&E stated these figures included the impact of any flowbacks of these taxes. In calculating the balances, LG&E frequently speaks of "presumed retirement dates," and that in some cases, tax depreciation continues after retirement.[30] These

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[26] Supplemental Hearing Data Request, filed May 17, 1988, page 4.

[27] Response to the Commission Order dated January 15, 1988, Item No. 69(d)(1).

[28] Supplemental Hearing Data Request, filed May 17, 1988, page 2.

[29] Ibid., filed May 10, 1988, page 1.

[30] Ibid., filed May 10 and 17, 1988, page 1.

retirements have occurred, there is no presumption involved. Also, LG&E has not cited references to the Internal Revenue Code to support its claim that tax depreciation can be taken after the retirement of the depreciated asset. Based on the information supplied by LG&E, the Commission believes the most accurate deferred income tax balance for the SDRS units is $4,910,100, the reported balance at the time of the retirement.

In its brief, LG&E proposed that if the Commission required it to recognize the losses as extraordinary and establish regulatory assets, that the regulatory assets should be amortized over a period of 5 years.[31] However, Mr. Fowler stated that, utilizing a 5-year amortization period, the revenue requirements generated under the extraordinary loss proposal would be higher than those generated using LG&E's original accounting and rate-making treatment of the retirements.[32]

The Commission believes that the approach proposed by LG&E in this situation is not proper. The Commission believes that in the situation of the early retirement of the SDRS units and the abandonment of the gas fields, LG&E should have sought extraordinary property loss treatment for these transactions. LG&E's assumption that early retirements are offset by late retirements may be true for certain assets which qualify for group depreciation, but not in the current situation which demonstrates the basic problems of the assumption with regard to the plant retirements in question.

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31 LG&E Brief, filed May 9, 1988, page 44.

32 Hearing Transcript, Vol. IV, pages 14-15.

The dollar magnitude of these retirement losses should not be made up by LG&E by "over depreciating" current assets, since this would result in excessive recovery under ordinary rate-making practices and is not an appropriate criterion on which to base a change in depreciation rates.

Therefore, the Commission hereby requires the extraordinary property loss treatment for the losses experienced with the early retirement of the SDRS units and the abandonment of the gas fields. As such, the accumulated depreciation reserves for both the electric and gas plants should be credited $21,052,354 and $6,862,820, respectively. The debit should be to Account No. 182, Extraordinary Property Losses, with electric and gas subaccounts maintained. The deferred income tax accounts should be debited $4,910,100 for electric and $2,897,100 for gas. The corresponding credits will be to the appropriate subaccount of Account No. 182. The ratepayers of LG&E have provided the dollars represented in the deferred income tax balances. The netting of the total loss to be amortized recognizes this fact.

In determining a proper amortization period, the Commission has considered the undepreciated balance of the assets retired, the impact on operating expenses, and the ultimate effect on the ratepayers and stockholders. The Commission is of the opinion that an amortization period of 19 years is reasonable for the electric extraordinary property loss and that 18 years is reasonable for the gas extraordinary property loss. This represents an approximation of the number of years of the remaining service lives on the assets retired which LG&E had utilized for book depreciation purposes. Had LG&E's approach proposed in its Brief been utilized, with no change in the depreciation rates, it would have recovered the losses approximately over the same period of time. An annual amortization expense of $849,592 for the electric and $220,318 for the gas has been included for revenue requirement determination herein.

The company's proposal to increase the gas depreciation by $211,035 is unnecessary and the gas depreciation expense has been adjusted to reflect the depreciation expense based on the 3.37 percent depreciation rate in effect before the gas field abandonment. The income tax impacts of these adjustments have been included in the calculation of book income tax expense. The net-original cost rate base has been adjusted by $19,571,002 to reflect the accounting entries to the accumulated depreciation reserve and the deferred income tax accounts. The electric rate base has been reduced by a net amount of $16,142,254 reflecting the $21,052,354 increase to electric accumulated depreciation and reduced by the $4,910,100 reduction to electric deferred income taxes. The gas rate base has been reduced by a net amount of $3,428,748 reflecting the $6,862,820 increase to gas accumulated depreciation and reduced by the $2,897,100 reduction to gas deferred income taxes and the $536,972 reduction to gas depreciation expense due to the depreciation rate adjustment.

MANAGEMENT AUDIT OF LG&E

In August 1986, the Commission's Management Audit of LG&E ("Management Audit") was completed. The audit was performed by Richard Metzler and Associates, Inc. and Scott Consulting Group

("RM&A/Scott") under a statute enacted by the Kentucky General Assembly. According to the Executive Summary, the potential cost avoidance or reduction identified during the audit is probably in excess of $6 million to $7 million in annual recurring and $9 million to $10 million in one-time cost savings.[33] RM&A/Scott developed implementation action plans ("Action Plans") for each of the 146 recommendations and LG&E was directed to provide semi-annual reports to the Commission on the implementation of the recommendations.

This is LG&E's first request for a general increase in rates since the completion of the Management Audit. In prepared testimony, Robert L. Royer, President and Chief Executive Officer of LG&E, and Fred Wright, Senior Vice-President of Operations, noted that LG&E had incurred substantial expenditures to implement the Management Audit recommendations. The Commission demonstrated concern regarding the costs and benefits resulting from the Management Audit through the numerous information requests submitted to LG&E. LG&E was requested to provide a witness at the hearing for cross-examination regarding the Management Audit.

This section will focus on four general areas of the audit identified by the following subsections.

1. Closed Recommendations.
2. Management Information Systems.
3. Work Force - Compensation Recommendations.
4. Open Recommendations.

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[33] Management Audit of LG&E, Executive Summary, II-13.

Closed Recommendations

In response to the Commission Order dated January 15, 1988, F. L. Wilkerson, Vice-President of Corporate Planning and Accounting for LG&E, provided information regarding the cost and savings of 45 audit recommendations which have been implemented and closed.[34] The response indicated that the test year included $510,300 to $535,300 in costs associated with these recommendations and that the estimated recurring costs were in the order of $719,500 to $749,500. The estimated savings associated with these recommendations actually quantified in that response was related to only 2 of the 45 closed recommendations and totaled $167,000. During cross-examination, Mr. Wilkerson indicated that it is difficult to quantify the savings for this group of recommendations and that the savings, for the most part, were not measurable.[35] As a result, LG&E was requested to file additional information which would provide a description of the nature of the costs included in the test year, identify the type of savings or benefit and the functional area in which the savings will occur, and indicate whether the benefits will be one-time or recurring in nature.

The Commission has reviewed the information filed relevant to these closed recommendations and finds that the actions taken by LG&E in association with the implementation of these recommendations are in the interests of LG&E's consumers. The Commission is

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[34] Response to the Commission Order dated January 15, 1988, Item No. 5.

[35] Hearing Transcript, Vol. VIII, pages 194-195.

however, concerned with LG&E's failure to quantify the savings and/or benefits associated with implementation of audit recommendations and particularly with the level of estimated recurring costs. In future rate proceedings, LG&E should be better prepared to support the recurring costs associated with closed recommendations in order for the Commission to be able to better determine their reasonableness in light of the associated savings and/or benefits.

Management Information Systems

In response to Item Nos. 1(a) and (b) of the Commission Order dated December 23, 1987, LG&E provided a discussion of its efforts to develop or enhance its major management information systems. The actual development of most of these systems was begun prior to the Management Audit.[36] However, the Management Audit includes numerous recommendations relating to these systems.

The test year includes operating expenses of approximately $2,476,000 associated with development of these systems. LG&E has estimated that they will incur additional costs of $2,421,000 over the 12-month period ending August 31, 1988.[37] Additionally, LG&E has indicated that the estimated expenditures at the completion of the development of these systems will be $11,711,000 operating and maintenance costs and $2,327,000 capital costs.[38]

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36 Ibid., page 208.

37 Response to the Commission Order dated December 23, 1987, Item No. 1(a).

38 Response to Hearing Information Request, Item No. 3, Response 7.

The Executive Summary of the Management Audit addresses, in general terms, the status of LG&E's business systems and indicates that 3 to 5 years will be required to bring LG&E's computer-based systems up to par with the industry.[39] In response to a request for information made during the hearing, LG&E filed documentation indicating that the systems would be completed beginning in 1988 and continuing through 1991.[40] That response also indicated that the development of some of these systems began as early as 1983. Additional information in the record indicates these systems are still under development and that benefits that may result have not yet been realized. Further, LG&E has indicated that any savings or benefits are not likely to exceed the costs during the immediate future.[41]

LG&E was questioned regarding any cost-benefit analysis performed in connection with these systems and the appropriateness of expensing rather than capitalizing the cost of developing these systems. Cost-benefit analyses of the management information systems, though requested, have not been filed in this proceeding and it is not clear if LG&E has prepared updated cost-benefit analyses as projects progress.[42] Mr. Wilkerson indicated that LG&E felt that it was appropriate to expense the development costs

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39 Management Audit of LG&E, Executive Summary, II-7 to II-8.

40 Response to Hearing Information Request, Item No. 3, Response 7.

41 Response to the Commission Order dated December 23, 1987, Item No. 1(b).

42 Hearing Transcript, Vol. VIII, page 218.

of these systems because LG&E is paying for those costs in today's dollars, because the systems cost money up front, and because unless the company is willing to spend the money no savings will result. Mr. Wilkerson cited a paragraph relating to cost reduction penalties from the Executive Summary as support for LG&E's position.[43] This paragraph however does not address the accounting or rate-making treatment associated with the costs, and includes no prohibition in regard to capitalization of development costs.

The Commission is of the opinion that for the purpose of determining revenue requirements in this proceeding, the test-year operating expenses should be decreased by the $2,475,092 associated with the development costs of the management information systems. The management information systems are being developed to provide benefits to LG&E and its customers over an extended period time. LG&E should begin subsequent to the date of this Order to capitalize and amortize, over a reasonable time period, development costs associated with the management information systems. The costs incurred during and prior to the test year have been expensed during those accounting periods. Therefore, no adjustment to rate base is necessary. The rate-making treatment of costs, capitalized subsequent to the date of this Order, will be considered in future rate proceedings.

Work Force - Compensation Recommendations

The Management Audit contained numerous recommendations relating to the organization structure, work force, and compensation and benefits programs of LG&E. The Executive Summary noted that LG&E could produce annual payroll savings of at least $2.5 million by implementing work force recommendations exclusive of Trimble County considerations.[44] The Management Audit indicated that these savings can be accomplished by:

> . . . increasing organizational productivity through the establishment of work management systems, reducing layers of management, increasing spans of managerial control and revising the personnel skill mix . . .[45]

In addition, specific recommendations instructed LG&E to review the compensation and benefit programs and to annually review health insurance and other benefits programs.

These recommendations are of particular concern to the Commission for several reasons. First, the proposed $5,390,668 increase to test-year operating expenses for labor and labor-related costs was the largest single adjustment proposed by LG&E excluding the adjustments for electric weather normalization and fuel expenses. Second, LG&E was notified in its last rate proceeding, wherein it proposed an increase of $558,000 for Blue Cross-Blue Shield insurance, of the Commission's intended review in the next rate proceeding. In this case, $1,224,561 or approximately 23 percent of the proposed labor and labor-related increase is for health insurance. Third, the level of LG&E's employees has

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43 Ibid., pages 239-240.

44 Management Audit of LG&E, Executive Summary, II-13.

45 Ibid.

been steadily increasing, from 3,646 in 1985[46] to 3,920 on September 6, 1987 and to 3,988 on November 15, 1987.[47]

Moreover, when all of these work-force related recommendations are considered as a whole, they indicate the need for a thorough, comprehensive evaluation of LG&E's organizational structure, and compensation and benefit packages. According to LG&E, the review of the organizational structure, including work force considerations, has begun and LG&E should be able to meet the 3- to 5-year time frame for completion cited in the audit. The Commission is concerned with LG&E's progress in implementing the work-force reduction recommendation of the Management Audit. In August 1986, the Management Audit Report recommended that a reduction in LG&E's work force of 50 to 200 personnel over a 3- to 5-year period exclusive of the Trimble County construction should be accomplished. In response to the recommendation on October 31, 1987 LG&E promulgated its Human Resources Control Program essentially freezing the level of employment on that date and stating a company goal of reducing employment overall. Though LG&E is apparently implementing the planning mechanism called for in the Management Audit, the Commission is concerned with the continued expansion of its work force and the speed at which LG&E is implementing its employment control program. During the period from December 1986 to November 1987, LG&E expanded its work force

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46 Management Audit of LG&E, Chapter XI, Human Resources Management, Exhibit XI-10, Staffing Trends by Employee Group (1975-1985).

47 Response to the Commission Order dated January 15, 1988, Item No. 14.

exclusive of Trimble County from 3,162 to 3,210. The trend in employment is contrary to the intent of the auditors' recommendation and at the very least requires a more detailed explanation than has been provided by LG&E as to the reasons for the work force expansion. The Commission will continue to monitor the non-Trimble County level of employment in the future and will require LG&E to provide a complete explanation for any change in the work force on a semiannual basis. This initial report should be provided to the Management Audit Section starting October 31, 1988.

During the test year, LG&E developed a benefit improvement package for nonunion employees, granted the officer group salary increases greater than would normally have been considered and improved the supplemental benefits authorized for officers.

The improvements for the officer group were intended to address salary compression, and compensation and benefit levels lower than industry averages. LG&E has indicated that the incremental cost of the improvements for this group is between $40,900 and $50,200 for the test year. The benefit improvement package instituted by LG&E included changes in health insurance and group life insurance, and added a thrift-savings plan. This package is of particular concern to the Commission because of the impact on test year costs and the overall level of fringe benefits.

LG&E was notified in Case No. 8924, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated May 16, 1984, of the Commission's intention to review health insurance costs in the next rate proceeding. In addition, the Management Audit contains recommendations directing LG&E to evaluate the compensation and benefit programs and to review health insurance and other benefits programs to ensure cost effectiveness. Mr. Wilkerson, during cross-examination, indicated that the benefit improvement package was not instituted in response to the Management Audit, but for other reasons, among them, maintaining the nonunion benefits comparable to the union employees.[48]

William H. Hancock, Jr., Senior Vice-President of Administration and Secretary of LG&E, presented testimony regarding health insurance and other fringe benefits. He discussed the health insurance cost containment measures taken by LG&E and the newly instituted flexible medical benefit plan. Hancock Exhibit 1 indicates that the rate of increase after cost containment for Blue Cross-Blue Shield insurance was 1.4 percent compared to a rate of 12.8 percent prior to cost containment.[49] Hancock Exhibit 2 reflects an increase in average cost per participant of 29 percent from August 1983 to August 1987 as compared to an industry trend factor of 63 percent over 4 years.[50] These exhibits provide the basis of support regarding LG&E's attempts to control health insurance costs. However, for the 2 years immediately following the institution of the cost containment measures the rate of

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48 Hearing Transcript, Vol. VIII, pages 223-224.

49 Hancock Prepared Testimony, Exhibit 1.

50 Ibid., Exhibit 2.

increase is above 10 percent per year.[51] In addition, the basis of the 63 percent industry trend factor was a letter from an actuarial consultant[52] which neither defines the precise calculation of the factors nor the region considered. The only evidence by which the success of LG&E's cost control efforts can be compared to other utilities or companies in the area that LG&E serves or the state is this ambiguous letter from the actuarial consultant.

Mr. Hancock's testimony indicates that the annual reduction in medical benefits resulting from the flexible benefits program is approximately $500,000.[53] However, the savings are offset by a 3-year cash incentive payment to employees switching to the plan. The test-year operating expenses include $196,408 associated with the payment of the cash incentive for the first year. However, this is only the amount not paid in cash but contributed to the new thrift savings plan. The employees electing to receive actual cash payments received those payments in December 1987 after the end of the test period.

In the Management Audit Action Plan Progress Reports ("Progress Reports") submitted to the Commission in November 1986, LG&E indicated that the company was working with a consultant to evaluate alternate benefit packages and would submit a proposal to

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51 Response to the Commission Order dated December 23, 1987, Item No. 5(d).

52 Response to KIUC First Information Request dated January 14, 1988, Item No. 8, page 2.

53 Hancock Prepared Testimony, page 4.

senior management for consideration.[54] The record in this case contains no evidence that LG&E made any evaluations with regard to any fringe benefits other than health insurance. However, on April 1, 1987, LG&E instituted the new benefit improvement package which will increase LG&E's expenses.

The Commission stated its concern in LG&E's last rate case regarding the level of Blue Cross-Blue Shield insurance. Furthermore, the management auditors recommended that LG&E review, not only health insurance, but the total benefits package. The Commission's and the auditors' concern in this area would require that LG&E provide more adequate support than that which has been included in this proceeding to justify the cost increases to be borne by the ratepayers. Therefore, the Commission is of the opinion that the cost of the change in group life insurance, the cost of the thrift savings plan, and the cost of the cash incentive payments should not be borne by LG&E's ratepayers. The effect of these changes on LG&E's test year costs is specified in the later section of this Order dealing with the proposed labor and labor-related adjustments.

Open Management Audit Recommendations

During cross-examination, Mr. Wilkerson was asked to provide budget projections which reflect the future costs for the projects that were being implemented pursuant to the Management Audit. Mr. Wilkerson responded that the 90 or so open recommendations had not been identified in the budget process and were not readily

54 Management Audit Action Plans, November 1986, XI-8, page 2.

identifiable.[55] LG&E is hereby placed on notice that in future rate proceedings, the company should be prepared to identify and provide the costs associated with Management Audit recommendations. Due to LG&E's current inability to track these costs and its failure to adequately support, with proper documentation, the claim that post-test year costs will be incurred at the same level as the test year, the Commission finds that the costs associated with the open recommendations should not be included in the determination of revenue requirements.

The test year costs associated with these recommendations were provided in response to Item No. 1 of the Commission's Order dated January 15, 1988. The calculation of the amount disallowed, which is approximately $258,000, is included in a later section of this Order.

Summary

The Commission compliments LG&E on the progress it has made in the implementation of its Action Plans. The Commission continues to have confidence in the benefits that both LG&E and its consumers can derive from proper implementation of its Action Plans. However, the Management Audit, Action Plans, and Progress Reports do not absolve management from its responsibility to continuously monitor and document both the costs and benefits from implementing the recommendations of the management auditors. In future rate proceedings, LG&E should be better prepared to

[55] Hearing Transcript, Vol. IX, pages 76-77.

identify implementation costs, ongoing costs, as well as benefits resulting from implementation of its Action Plan.

REVENUES AND EXPENSES

For the test period, LG&E had actual net operating income of $118,858,318. LG&E originally proposed several pro forma adjustments to revenues and expenses to reflect more current and anticipated operating conditions which resulted in an adjusted net operating income of $111,795,250.[56] Subsequent to its original filing, LG&E proposed several correcting adjustments, which are addressed herein. The Commission is of the opinion that the proposed adjustments are generally proper and acceptable for rate-making purposes with the following modifications.

Temperature Normalization - Electric

LG&E proposed an adjustment to electric revenues and expenses for deviations from normal temperatures. The proposed adjustment would reduce operating income by $7,673,763 based on the assumption that the test year included an excess of 402 cooling degree days ("CDD") and a deficiency of 362 heating degree days ("HDD").

An electric temperature normalization adjustment has been proposed in each of LG&E's past three rate applications. In Case No. 8284, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated January 4, 1982, and Case No. 8616, General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company, final Order dated March 2, 1983, the adjustment was proposed by LG&E; however, in Case No.

56 Fowler Prepared Testimony, Exhibit 4.

8924, the adjustment was proposed by an intervenor. The Commission denied the proposed adjustments in each case. In his oral testimony, Patrick Ryan, a Load and Economic Research Analyst with LG&E, summarized the concerns expressed by the Commission in those past cases and stated that the methodology presented in this case addressed those concerns and was the most appropriate way to make this type of adjustment.[57]

This adjustment accounts for 15.4 percent[58] of LG&E's overall requested revenue increase. Additionally, Mr. Ryan has stated that if LG&E's rates are based on excess KWH sales, LG&E's only opportunity to recover its revenue requirement is if the test-year weather pattern occurs in each succeeding year.[59] However, this statement covers only one part of the Commission's concern with the proposed adjustment and the converse of this statement must also be considered. That is, if revenues are based on below normal sales, then consumers will be paying rates that may generate revenue in excess of authorized revenue requirements. Thus, prior to acceptance, it is imperative that the Commission determine if LG&E has accurately reflected the relationship of KWH sales and temperature.

LG&E's methodology begins with the definition of normal weather and the determination of the difference between normal (or expected) weather and actual test year weather. For purposes of

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57 Hearing Transcript, Vol. V, pages 9-11.

58 Ryan Prepared Testimony, page 4.

59 Ibid.

calculating the weather adjustment, actual and normal degree day data, the measures of weather used in this analysis were converted from a calendar month basis to that of billing cycles. Because LG&E bills its customers in cycles, it was necessary to calculate both billing cycle days and billing-cycle degree days to match weather data with sales data.

In determining normal billing-cycle degree days, LG&E used the National Oceanic and Atmospheric Administration's ("NOAA") 1951-1980, 30-year average degree day data. By using this average, LG&E has failed to include the degree day data from the most recent 7 years. The Commission is aware from a review of NOAA literature that the NOAA will prepare special HDD or CDD tabulations or other summaries which would include more recent data.[60] However, at the hearing, LG&E indicated that no attempt has been made recently to contact the NOAA to try to get more current degree day normals.[61] The Commission's language in its Order in Case No. 8616 clearly states that current data should be used to define normal degree days:

> A current [emphasis added] 30-year period provides accurate up-to-date information and at the same time is long enough to mitigate any abnormalities in weather conditions, whether they be yearly or cyclical.[62]

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60 Environmental Information Summaries, C-14, HDD and CDD Day Data, NOAA, Department of Commerce, USA.

61 Hearing Transcript, Vol. VI, pages 192-193.

62 Case No. 8616, final Order dated March 2, 1983, page 13.

LG&E's use of NOAA's published 1951-80 degree day data[63] as a "current" 30-year average ignores the impact that any recent temperatures may have had in defining normal degree days. The Commission is concerned that it may bias that information which is being considered as the standard for temperature normality.

In Exhibit 2 of his direct testimony, Mr. Ryan constructed 95 percent confidence intervals around the NOAA 1951-1980 30-year means. He asserts that since the annual total degree days and most of the monthly degree days fall outside of the confidence interval, the entire test year must be normalized for abnormal weather. In LG&E's effort to demonstrate that test year weather was abnormal, Mr. Ryan stated:

> Q. Since temperature is a random variable, can't you employ a statistical procedure to determine whether or not actual temperatures were statistically different from the historical average?
>
> A. Yes. This basically would involve the construction of a confidence interval around the mean of the weather variable. If the number of degree days actually incurred during the test period falls outside the confidence interval limits, they can be considered statistically different from the average.[64]

Though LG&E has used a confidence interval as a standard for testing normality, LG&E did not use the confidence interval for temperature adjustment purposes. Mr. Ryan adjusted each month's actual billing cycle temperature-sensitive load to a mean-determined temperature-sensitive load instead of to a

63 Climatography of the United States No. 81 (By State), Monthly Normals of Temperature, Precipitation, and Heating and Cooling Degree Days 1951-80, Kentucky.

64 Ryan Prepared Testimony, page 6.

temperature-sensitive load determined by the boundaries of a range of acceptable values constructed around the mean.

The Commission is of the opinion that there is adequate evidence to suggest that a range of temperatures and not a specific mean temperature is a more appropriate measure of normal temperatures. As long as the temperature falls within these bounds then it is inappropriate to adjust sales for temperature. However, if the temperature falls outside those bounds then it is appropriate to adjust sales to the nearest bound.

After determining normal weather and the departure of test year weather from normal, the methodology proposed by LG&E to determine weather-normalized sales involves estimating two components of total energy usage: baseload and temperature-sensitive load. LG&E's actual calculation of the weather normalization adjustment begins by determining the number of customers in each class for each month of the test year, as well as billing cycle days and billing-cycle degree days for each month of the test year. Billing cycle days were defined by Mr. Ryan to be the average number of days in all of LG&E's 21 billing districts for each month during the test year. Billing-cycle degree days were then defined to be the average number of degree days in each billing period for each month.

The Commission is concerned with the calculations of both billing cycle days and billing-cycle degree days. Mr. Ryan indicated on cross-examination that other LG&E personnel were specifically responsible for the calculations[65] and that these calculations assume an average and are not tied to the beginning and ending dates of district billing cycles.[66] This method of determining billing-cycle degree day fails to properly match customer load and their corresponding bills, because each billing cycle has discrete beginning and ending dates with specific degree days and customers associated with that period. Additionally, since no attempt was made to weight the billing-cycle degree days by the percentage of total customers included within each billing district, the results using billing-cycle degree days are not representative of the temperature's affect on electricity usage across billing districts unless each cycle includes approximately the same number of customers per class, an assumption which cannot be confirmed by LG&E.[67] Due to these problems and the lack of supporting evidence, the Commission finds that the method used to convert calendar month days and degree days into billing cycle days and degree days is inaccurate.

The accuracy of the billing cycle calculations is critical because these results are used in the calculation of the final temperature adjustment. Inaccuracies contained in LG&E's billing cycle calculations, therefore, render LG&E's entire electric temperature normalization adjustment unreliable and unacceptable.

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65 Hearing Transcript, Volume V, page 14.

66 Ibid., page 145.

67 Hearing Transcript, Volume V, pages 146-147.

As previously stated, LG&E separated total mWh sales into only two components: baseload and temperature-sensitive load. Residential baseload has been derived from the company's load research data. LG&E determined the daily residential baseload per customer based on the average of the 5 lowest days of daily energy usage from a selected sample of load research customers. For the test year this was determined to be 16.6 KWH per residential customer per day. To determine monthly total residential baseload, the 16.6 was then multiplied by the number of customers in each test year month. This product was then multiplied by monthly-billing cycle days. For the commercial sector, a weighted-average baseload was determined, which includes weekend and weekday usages.

The actual temperature-sensitive load was calculated by simply subtracting the actual estimated baseload per customer from the actual total load per customer. The number of actual billing-cycle degree days was then divided into the actual temperature-sensitive load to obtain the actual energy use per customer, per degree day. Normal temperature-sensitive load was then determined by multiplying the actual energy use per customer, per degree day times the number of customers times the normal number of billing-cycle degree days in that month. This normal temperature-sensitive load was then subtracted from actual temperature-sensitive load to determine the mWh sales adjustment.

Further, LG&E, in adopting its adjustment methodology, has failed to follow previous Commission orders to consider other variables in addition to temperature when normalizing sales. The methodology chosen by LG&E neglects to consider other factors (i.e., personal income, employment, humidity, wind, etc.) that may affect test-year electricity usage. LG&E has recognized that other factors may affect electricity sales but has not incorporated any of these factors in this adjustment.[68] By ignoring these variables LG&E's methodology does not accurately determine the actual relationship of electricity sales to degree days.

In his testimony, Mr. Ryan acknowledges the strong relationship between electricity usage and degree days,[69] as determined by a simple econometric model. Further, Mr. Ryan states that LG&E "is fully aware that variables other than weather affect electricity usage."[70]

The econometric modeling of temperature normalization is widely used by both the electric utility industry and regulatory agencies. During cross-examination, Dr. Carl Weaver, witness for the AG, recommended that to determine temperature-sensitive load, ". . . you should use a regression analysis but include more than one independent variable . . ."[71] Mr. Ryan admitted on cross-examination that to verify that relationships between loads and degree days existed on a class basis, regression analysis would be required.[72] However for the purpose of verifying these

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68 Ibid., Volume V, page 92.

69 Ryan Prepared Testimony, Exhibit 5.

70 Ibid., page 15.

71 Hearing Transcript, Vol. X, page 34.

72 Ibid., Vol. V, page 140.

relationships, Mr. Ryan has ignored those statistical techniques and instead relied upon "eyeballing" the temperature-sensitive load figures.[73] The primary use of an econometric or regression model in weather normalization is to adjust test year sales, which is the intended purpose of a weather normalization adjustment. During cross-examination, Mr. Ryan stated that there was no question in his mind regarding the accuracy of the relationship between degree days and KWH sales because he has been working with weather data and has made the type of computer runs that support the relationship. However, he further stated that the Commission has not seen those computer runs and that other than his assertion that loads per degree day look reasonable, nothing has been filed in the record of this case which verifies the accuracy of that relationship.[74] The Commission cannot allow an adjustment of over $7 million on such a nonspecific basis. In any case, if LG&E desires to propose an electric temperature adjustment in future rate applications, it should develop a methodology that will accurately and appropriately match the random effects of weather to electricity consumption. Further, LG&E should provide adequate support to verify the accuracy and appropriateness of any model presented. The Commission will require that LG&E provide documentation, including adequate statistical analysis, sufficient to support the accuracy of the relationships in the methodology developed and submitted in subsequent rate cases.

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73 Ibid., pages 141-142.

74 Ibid.

Stephen J. Baron of Kennedy and Associates proposed an alternative electric weather normalization adjustment on behalf of KIUC. In discussing the adjustment proposed by LG&E, Mr. Baron criticized several aspects of LG&E's model and concluded that LG&E's methodology was ". . . not precise and cannot be verified as to whether it is correct using actual monthly data."[75] Mr. Baron further stated that he believed that the most appropriate method to develop class weather normalization adjustments was by developing regression models utilizing load research data. No such analysis was presented in this case and Mr. Baron, therefore, determined that using the aggregate system sales and weather data supporting Ryan Exhibit 5 to develop system-wide sensitivity coefficients was the most appropriate way to correct LG&E's proposed adjustment. Mr. Baron then used these system-wide coefficients to adjust LG&E's class-by-class sales, revenue and expense adjustments.

Mr. Baron has recognized several important flaws in LG&E's methodology and attempts to correct these in order to calculate a more representative electric weather normalization adjustment. Mr. Baron's proposed adjustment, however, does not correct the problems presented by LG&E's methodology. By using the system company-wide data supporting Ryan Exhibit 5 (which represents a test year which has been characterized as abnormal) and then interpreting these into class-by-class adjustments, Mr. Baron has

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[75] Baron Prepared Testimony, filed February 16, 1988, page 14.

incorporated in his model the same inaccuracies and problems he noted in LG&E's model.

The Commission, therefore, finds that LG&E's proposed electric temperature adjustment should be denied for the following reasons:

1. LG&E's definition of normal degree days is based on 30-year data for the period 1951-1980, which does not include data for the most recent 7 years, including the test year.

2. The critical billing cycle calculations are inaccurate and do not reflect the actual degree days on either an actual or historic basis.

3. LG&E adjusted to a mean rather than to a range determined by a confidence interval.

4. LG&E has recognized only one variable that affects consumption.

5. LG&E did not accurately determine the relationship of KWH sales to degree days. LG&E simply estimated baseload and assigned the difference between total KWH sales and baseload to temperature-sensitive load.

6. LG&E has neither supported all of the assumptions nor supported the accuracy of its model.

The Commission is of the opinion that the electric weather normalization adjustment proposed by KIUC should be denied. The Commission cautions that alternative adjustments that suffer from the same inadequacies as the adjustments they are meant to replace are unacceptable.

Labor and Labor-Related Costs

LG&E proposed adjustments to increase the test-year operating expenses by $5,389,668 for labor and labor-related costs. The actual cost items and the proposed adjustments to combined gas and electric operations are as follows:

	Total
Wages and Salaries	$3,132,927
Pension Costs	34,698
Health Insurance	1,224,561
Dental Insurance	47,280
Group Life Insurance	148,914
Thrift Savings Plan	248,469
FICA Taxes	550,126
Unemployment Taxes:	
State	30,421
Federal	<26,728>
TOTAL	$5,390,668

Excluding the gas supply expense adjustment, the adjustment for labor and labor-related costs represents the largest adjustment to LG&E test-year operating expenses. In this case, as has been previously stated, the labor and labor-related costs are areas of concern for two reasons: the notice in Case No. 8924 that the Commission would analyze health insurance costs in LG&E's next rate case and the recommendations incorporated in the Management Audit regarding fringe benefits and work force considerations.

Wages and Salaries

LG&E proposed to increase wages and salaries by $3,132,927 in order to reflect wage increases granted during and subsequent to the test year. The first part of this adjustment reflects an increase of $784,852 to recognize the increases granted during the test year. The second part represents the increases granted in

October and November 1987, which results in an increase of $2,348,075. Generally, when utilities request adjustments to wages and salaries, a comparison is made between actual test year wages and salaries and a normalized or pro forma expense level. In this and recent proceedings, LG&E has not determined the adjustment to wages and salaries by the methodology described above. Mr. Fowler testified that LG&E did not follow this methodology because LG&E's test-year labor costs include overtime, shift differentials and other items.[76] Mr. Fowler further stated that LG&E was trying to compare wages on a straight-time basis, that overtime was not included in the adjustment and that the adjustment was very conservative.[77]

Mr. Kollen, on behalf of KIUC, agreed with the first part of the wage adjustment but recommended that the second part be denied in that it represents increases granted outside the test year.

LG&E's wages and salaries consist of various components including overtime pay, shift pay, and straight-time labor. Since LG&E has adjusted only the straight-time component, the Commission does agree that the adjustment is conservative. The Commission also recognizes that the second part of the proposed adjustment is based upon increases granted subsequent to the test period. However, the Commission has, in some circumstances, allowed adjustments of this nature for various reasons. Allowing this adjustment will provide a more accurate matching of wage expense to the

76 Hearing Transcript, Vol. III, page 130.

77 Ibid.

future rates which are intended to recover those wages. Additionally, the Commission notes that in Case No. 8616, which used a test year ended June 30, 1982, the Commission allowed LG&E to pass on wage increases granted in October and November 1982.[78] Therefore, the Commission is of the opinion that the full amount of the proposed adjustment to wages and salaries should be accepted.

Even though LG&E has adjusted only one component of wages and salaries, the Commission is concerned with LG&E's inability to provide the actual test year expense for each component of wages and salaries inasmuch as such information is necessary to accurately determine an adjustment to wages and salaries. During cross-examination, Mr. Fowler indicated that LG&E does not completely maintain the payroll records by employee classes[79] and in response to Commission data requests stated that,

> The automated payroll file by employee category is constantly changing as employees are added, deleted or transferred between categories and the data for prior periods is not retained. Thus, the annualized straight-time salaries of employees by categories can be determined for current employees, but such a calculation cannot be made for prior periods.[80]

LG&E is encouraged to incorporate the ability to determine the separate components of wages and salaries in the Management Information Systems being developed. The Commission, in future LG&E rate cases, will review the adjustments proposed for wages and

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78 Case No. 8616, final Order dated March 2, 1983, page 23.

79 Hearing Transcript, Vol. III, page 131.

80 Response to the Commission Order dated January 15, 1988, Item No. 8.

salaries while considering the actual test year-end levels of each element.

Group Life Insurance

LG&E proposed an adjustment of $148,914 to increase test-year operating expenses as a result of changes in the premium allowance for nonunion employees and to reflect the increased life insurance premiums resulting from the labor increase allowed in this case. In response to Item No. 16(d), page 10 of the Commission's Order dated November 12, 1987, LG&E provided the calculations to normalize the union and nonunion portions of this adjustment. The insurance benefit is equal to 125 percent of annual salary and the rate per $1,000 of insurance is $.59 for both categories of employees. For all employees, LG&E pays 100 percent of the premium on the first $5,000 of insurance. Prior to April 1, 1987, LG&E paid 75 percent of the premium for insurance in excess of the first $5,000 for all employees; however, on that date, LG&E, in accordance with the nonunion employees' benefit improvement package, began paying, for nonunion employees, 100 percent of the premium in excess of the first $5,000.

The adjustment proposed by LG&E reflects the change instituted in April for the nonunion employees; however, for simplicity, the calculation for union employees does not reflect the fact that LG&E pays 100 percent of the first $5,000 of insurance.[81] The Commission is of the opinion that the Group Life Insurance adjustment should be modified as determined in Appendix

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81 Response to the Commission Order dated December 23, 1987, Item No. 21, page 1.

B to this Order and as discussed below. The union employees' portion of the adjustment is calculated in a manner which does reflect that LG&E pays 100 percent of the premium for the first $5,000 of insurance and 75 percent of the amount over the first $5,000. Additionally, as previously discussed in the preceding Management Audit section of this Order, the nonunion employee portion has been calculated in the same manner as the union employees in order to recognize LG&E's benefit level prior to April 1, 1987. These changes result in a reduction of $40,534 to LG&E's proposed $148,914 adjustment. The Commission will, therefore, allow an increase in test-year operating expenses of $108,380 to reflect the increased costs associated with group life insurance.

Unemployment Taxes

LG&E proposed an adjustment to increase the expenses associated with federal and state unemployment taxes by $3,693. In his direct testimony, Mr. Fowler indicated that the adjustment resulted because of a higher wage base subject to these taxes; however, the decrease in the federal unemployment tax rate offset the increased wage rate and resulted in a negative adjustment for federal unemployment taxes.[82] As shown in Item No. 69(d)(1), the proposed adjustment relating to state unemployment taxes increases expenses by $30,421, while the adjustment related to federal unemployment taxes resulted in a decrease of $26,728.[83]

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[82] Fowler Prepared Testimony, page 10.

[83] Response to the Commission Order dated November 12, 1987.

In determining the amount of the adjustment, LG&E multiplied the base wage subject to unemployment tax by the total employees as of September 22, 1987 and multiplied this product by the applicable tax rate. LG&E provided the total number of employees at the end of several payroll periods in response to a Commission Information Request.[84] In that response, LG&E indicated that there were 3,920 employees as of September 6, 1987, which is the payroll period nearest the end of the test period. During cross-examination, Mr. Fowler indicated that the level of employees used in the adjustment was based on the September 22, 1987 payroll period because that was the approximate date the calculation was performed.[85] Additionally, Mr. Fowler stated that this calculation utilized a 0.6 percent federal unemployment tax rate in anticipation of a proposed change in that rate. Ultimately the change was not effected, thereby leaving the tax rate at 0.8 percent.

The Commission is of the opinion that it is more appropriate to use the number of employees in the payroll period nearest the end of the test year and the federal tax rate actually in effect in the calculation of this adjustment. Therefore, the Commission has, in Appendix C, recalculated this adjustment using 3,920 as the base number of employees and 0.8 as the federal unemployment tax rate. This recalculation results in increases to the test-year federal and state unemployment tax expense of $8,914 and

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84 Ibid., dated January 15, 1988, Item No. 14(c).

85 Hearing Transcript, Vol. III, page 136.

$21,573, respectively. The net effect is an increase to test-year operating expense of $30,487.

Thrift Savings Plan

LG&E proposed an adjustment to increase the test-year operating expense by $248,469 to reflect the normalized expense associated with the thrift savings plan instituted April 1, 1987 in the nonunion employee benefit improvement package. As previously discussed in the Management Audit section, the Commission has disallowed the expenses associated with this item. Therefore, the Commission has reduced operating expense by $180,668 which represents the actual test year expense associated with the thrift savings plan.

Health Insurance

LG&E proposed an adjustment of $1,224,561 to increase the test year level of health insurance expense. Testimony regarding this adjustment was presented by Mr. Hancock. Mr. Hancock also addressed the measures taken by LG&E to control medical benefit costs in response to the final Order in Case No. 8924.

As noted previously in the Management Audit section of this Order, the Commission will allow the proposed increase relating to the expense for the actual health insurance plans, but will not allow LG&E to include the expense relating to the cash incentive payments. According to Item No. 16(d), page 8,[86] the actual test year expense for health insurance was $7,781,922. This amount included $196,408 relating to the cash incentive payments. The

86 Response to the Commission Order, dated November 12, 1987.

remaining $7,585,514 was subtracted from the pro forma operating expense relating to the actual insurance plans of $8,810,075 to arrive at the proposed adjustment of $1,224,561. The Commission, after reflecting the $196,408 decrease associated with the cash incentive payments, has increased the test-year operating expenses by $1,028,153 to recognize the increased health insurance costs.

Adjustment to Annualize Year-End Electric Volumes of Business

John Hart, Vice-President of Rates and Economic Research for LG&E, proposed an adjustment to reflect the increased costs associated with serving the level of customers at the end of the test year. The proposed adjustment, as amended by Mr. Hart, increased test-year operating revenues by $3,531,357 and test-year operating expenses by $1,860,852. The net effect is a proposed increase in test-year operating income of $1,675,005.

To determine the adjustment to operating revenue, the excess of customers served at test year-end over the test-year average customers was multiplied by an average revenue per customer. The average revenue per customer was determined using the actual revenues from sales to ultimate consumers adjusted to reflect the present rates for a full year, the transfers between rate schedules and normal temperatures. The Commission has previously determined that the proposed electric temperature normalization adjustment should be denied. Therefore, the proposed adjustment to electric operating revenues has been increased to $3,627,565 as calculated by the Commission to reflect the disallowance of the adjustment for normal temperature.

To determine the adjustment to operating expenses, Mr. Hart calculated a cost per KWH of electricity and multiplied that cost by the excess of test year-end customers over test-year average customers. As Mr. Hart explained during cross-examination, this is a traditional calculation made by LG&E[87] which has previously been accepted by the Commission. In performing the calculation in this manner, LG&E has treated all operation and maintenance expenses as variable costs, costs that will increase proportionately with each additional KWH sold. LG&E has not provided conclusive evidence that this is an accurate relationship of all operating expenses to KWH sales. As Mr. Hart admitted during cross-examination, customer accounting expenses, customer service and information expenses, and some portion of administrative and general expenses would vary with the number of customers and not with KWH sales.[88] In response to an information request, LG&E stated that an argument could be made for calculating the expense adjustment based on the company's operating ratio.[89] During cross-examination, Mr. Hart indicated that this approach was not used because he was being conservative in his approach and that his approach had been used for a number of years by LG&E.[90]

The Commission is of the opinion that the approach used by LG&E does not provide an accurate determination of the increase in

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[87] Hearing Transcript, Vol. I, page 194.

[88] Ibid., Vol. VI, pages 194-195.

[89] Response to the Commission Order dated January 15, 1988, Item No. 24.

[90] Hearing Transcript, Vol. VI, page 200.

the level of expenses associated with serving additional customers and that it would be more appropriate to use an adjusted operating ratio. The Commission has accepted similar methods to adjust expenses to reflect year-end customers for other companies under its jurisdiction. An appropriate ratio of expenses to sales for use in this case should be 39.84 percent. The calculation of this ratio and the expense adjustment is included in Appendix D of this Order. In determining this ratio, actual test year wages and salaries have been subtracted from actual test year operation and maintenance expenses. It is not appropriate to include wages and salaries in this calculation because the amount of those costs to be included in future rates has previously been adjusted and reflects test year-end employees and post-test-year wage rates. Additionally, the amount of sales to other utilities, which is a net amount, has been deducted from total actual electric operating revenues.

The Commission is of the opinion that this method more accurately reflects the relationship of expenses to sales than the approach used by LG&E. Therefore, the Commission finds that the adjustment to LG&E's electric operating and maintenance expenses should be an increase of $1,445,222. The net effect of this adjustment is a decrease to test-year operating expenses of $2,182,343 or $507,338 above the net amount proposed by LG&E. The Commission advises LG&E that this issue will be considered in future rate proceedings.

Provision for Uncollectible Accounts

LG&E proposed an increase of $250,000 to the test year provision for uncollectible accounts based on its analysis of the appropriate total annual provision. The total provision and the increase were allocated between electric and gas based on the percentage of gross revenues from ultimate consumers for the preceding calendar year. While the Commission finds the proposed increase acceptable, it is concerned about LG&E's use of an allocation method based on revenues instead of actual electric or gas uncollectible account charge-off history. The amounts recorded for electric and gas provisions for uncollectible accounts were not based on the history of uncollectible charge-offs because LG&E did not maintain records of charge-offs by department.[91] LG&E should develop and maintain a record of actual uncollectible charge-offs by department and should utilize that information in adjusting the provision for uncollectible accounts in future rate proceedings.

Depreciation Expense

LG&E proposed to increase depreciation expense by $2,408,809 in order to annualize the test year expense. Of the total adjustment, $2,197,774 was for electric and $211,035 was for gas. Included in the gas depreciation calculations was the depreciation expense for gas underground storage property. The depreciation for this portion of the gas plant was computed using a rate of 5.05 percent. As has been discussed in the section of this Order

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91 Response to the Commission Order dated December 23, 1987, Item No. 40.

relating to retirements of SDRS and gas plant, LG&E revised its depreciation rates for gas underground storage property in order to recover the losses incurred when it abandoned three underground storage fields.[92] If LG&E had computed annual depreciation expense using a rate of 3.37 percent, which was in use before the abandonment, there would be a reduction of $536,972 in gas plant depreciation.[93] Because the Commission has decided to treat the abandonment loss as extraordinary, the use of the higher depreciation rate is unnecessary. The Commission has reduced the test-year depreciation expense for the gas plant by $325,937 to reflect the rate of 3.37 percent on gas storage plant. The Commission has accepted the electric depreciation adjustment. Therefore, the total increase to depreciation expense allowed herein is $1,871,837.

Advertising Expense

LG&E proposed to remove $267,278 from its test-year advertising expenses, which represented expenditures which were not allowable for rate-making pursuant to 807 KAR 5:016. The prohibited advertising expenses include promotional, political, and institutional advertising. At the hearing, LG&E witness, Mr. Wilkerson, introduced a schedule of promotional advertising expenses which had not been included in LG&E's original

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92 Hearing Transcript, Vol. IV, page 21.

93 Response to KIUC Second Data Request, filed February 1, 1988, Item No. 16.

adjustment, and indicated these expenses should also be removed.[94] The additional promotional advertising expenses totaled $52,960. The Commission has accepted both of the advertising adjustments proposed by LG&E, and has reduced advertising expenses by a total of $320,238. The $267,278 in reductions to the electric and gas operations are accepted as proposed; in addition, the $52,960 has been allocated, $40,779 to electric and $12,181 to gas, based on LG&E's reported allocation methods for such costs.

Membership Dues

During the test year, LG&E paid membership dues to the Edison Electric Institute ("EEI") of $164,390 and to the Coalition for Environmental Energy Balance ("CEEB") of $5,800. In addition, LG&E paid $20,760 to EEI as its annual assessment for an acid precipitation study. LG&E included these expenditures in adjusted test-year operating costs.

LG&E was asked to enumerate the benefits of EEI membership and provide any cost-benefit analysis performed concerning membership. LG&E was also asked to provide a breakdown of the EEI dues based on EEI activities. In its responses, LG&E indicated it had not and could not perform cost-benefit analysis of its membership.[95] While providing a listing of benefits, the listing was general in nature and did not document any specific benefits

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94 Hearing Transcript, Vol. VIII, pages 185-191 and Wilkerson Exhibit 1.

95 Response to the Commission Order dated December 23, 1987, Item No. 36(d), page 2 of 7.

received by LG&E's ratepayers.[96] LG&E was asked to describe the nature of CEEB and why it was a member. LG&E provided a general description of the activities of CEEB and explained that the CEEB activities were compatible with LG&E's mission.[97] However, LG&E's responses did not indicate any direct benefits to its ratepayers from CEEB membership.

The Commission is aware that the payment of membership dues to organizations such as EEI and CEEB have received differing regulatory treatment across the country in recent years. The Commission takes notice of two recent cases which involved situations similar to the one the Commission faces in this case. In a case before the Missouri Public Service Commission, EEI dues were disallowed in their entirety because there was no way to quantify the benefits accorded ratepayers and shareholders from membership in the association.[98] In a case before the Massachusetts Department of Public Utilities, the assertion that EEI membership provided numerous and substantial benefits to electric ratepayers did not relieve a utility of its duty to prove that the dues represented a reasonable operating expense and the dues were disallowed.[99]

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96 Ibid., Item No. 36(c), pages 1 and 2 of 7.

97 Response to CAG First Data Request, filed February 8, 1988, Item No. 15.

98 Arkansas Power and Light Company, 74 PUR4th 36 (1986), Case Reference ER-85-265.

99 Western Massachusetts Electric Company, 80 PUR4th 479 (1986), Case Reference DPU 85-270.

In this case, LG&E has failed to show that its membership in EEI and CEEB is of direct benefit to its ratepayers. Therefore, the Commission has excluded all EEI and CEEB costs in the amount of $170,190 from allowable operating expenses for rate-making. This issue will be reconsidered in future cases if LG&E can document that the costs of membership dues provide a direct benefit to the ratepayers.

The Commission recognizes the growing concern in this country over the problems of acid rain. Studies, such as the one being performed by EEI, could provide valuable information in the resolution of this problem. The Commission finds that the EEI acid precipitation study could provide future benefits to LG&E and its ratepayers. Therefore, the Commission has included the $20,760 annual assessment as an allowable rate-making expense.

Excess Deferred Taxes - Tax Reform Act of 1986

In Case No. 9781, The Effects of the Federal Tax Reform Act of 1986 on the Rates of Louisville Gas and Electric Company, Order dated June 11, 1987, the Commission explored the issue of excess deferred taxes resulting from the change in tax rates under the Tax Reform Act. The Commission stated that the accelerated amortization of the unprotected excess deferred taxes would be considered in future rate proceedings.[100] In response to a data request LG&E provided the amount of unprotected excess deferred taxes available for accelerated amortization.[101] In addition, LG&E

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[100] Case No. 9781, final Order dated June 11, 1987, page 10.

[101] Response to the Commission Order dated December 23, 1987, Item No. 30.

provided a calculation of a deferred tax deficiency arising from an increase in the state corporate tax rate. LG&E took the position that the federal excess deferred taxes should be offset by the state deficiency in accordance with the Commission Order in Case No. 8616.[102] Mr. Kollen, on behalf of KIUC, has recommended that the unprotected excess deferred taxes as of August 31, 1987 be offset by the same proportion of the state tax deficiency and be returned to the ratepayers as a 1-year credit to base rates.[103] At the hearing, LG&E indicated that the original information filed could violate the normalization requirements of the Tax Reform Act and subsequently filed an amended calculation.

The Commission is of the opinion that the unprotected excess deferred taxes of $4,749,500 as of August 31, 1987,[104] the test year-end, should be offset by the full state tax deficiency of $4,385,600 and amortized over 5 years for rate-making purposes. The effect of this decision is an annual reduction in income tax expense in the amount of $72,780. This amount has been allocated to gas and electric operations in proportion to the existing deferred tax reserve after the adjustment for early retirements with $6,703 allocated to gas operations and $66,077 to electric operations. The rate base has been increased by a like amount to recognize the first year's amortization. LG&E should transfer the excess and deficiency to separate accounts in order that they can

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102 Ibid.

103 KIUC Brief, May 9, 1988, pages 30-33.

104 Response to Hearing Data Request, filed May 9, 1988, Excess Deferred Federal Income Taxes as of December 31, 1987.

be readily identified in future rate proceedings. The Commission is of the opinion that this method is in keeping with the position established in Case No. 8616[105] and does not represent a change of Commission practice.

Management Audit Adjustments

LG&E proposed an adjustment to reflect the recovery of the cost of the Management Audit over a 3-year period. The effect of this adjustment is to increase operating expenses by $194,000. The proposed adjustment allocates $44,620 to gas operations and $149,380 to electric operations. Pursuant to KRS 278.255, the agreement between LG&E, RM&A/Scott and the Commission stated that the cost of the audit would be an allowable expense for rate-making purposes. The Commission, therefore, has accepted the adjustment as proposed by LG&E.

The $2,475,092 test-year cost of the management information systems discussed in the Management Audit section of this Order has been allocated by the Commission to gas and electric and operations in the same proportion as the cost of the Management Audit. The adjustments decrease the test-year operating expenses in the gas department by $569,271 and by $1,905,821 in the electric department.

As previously discussed in the Management Audit section, the Commission has disallowed $258,040 associated with the test-year cost of open management audit recommendations. The test-year cost of $1,477,900 of these recommendations was detailed by LG&E in

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[105] Case No. 8616, final Order dated March 2, 1983, pages 20-21.

response to a data request.[106] Commission review of this response indicates that $1,166,900 of these costs have been capitalized or included in the disallowed cost of the management information systems. An additional $52,960 was included by Mr. Wilkerson at the hearing as additional disallowed advertising and has been included in that adjustment, as amended. The remaining $258,040 is based on the following recommendations as detailed in the response to a data request and has been allocated to gas and electric operations as indicated below:[107]

Recommendation	Gas	Electric	Total
V-5	$11,969	$ 40,071	$ 52,040
XI-3	3,220	10,780	14,000
XIV-1	-0-	12,000	12,000
XVI-1, 2, 3	53,000	-0-	53,000
XVIII-1, 2, 3, 5	29,210	97,790	127,000
TOTAL	$97,399	$160,641	$258,040

Recommendations XIV-1 and XVI-1, 2, and 3 have been identified as specific to either gas or electric operations. The other recommendations were allocated to gas and electric operations in the same manner as the cost of the Management Audit.

The total effect of these adjustments is to decrease operating expenses by $2,539,132. The decrease in gas operations is $622,050 and in electric operations is $1,917,082.

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106 Response to the Commission Order dated January 15, 1988, Item No. 1.

107 Ibid.

Storm Damage Expenses

LG&E has proposed an adjustment to amortize, over a 3-year period, unrepresentative storm damage expenses incurred during July 1987. This proposed adjustment would decrease test year operations and maintenance expenses by $976,896.

Listed below are actual storm damage expenses for the past 5 calendar years as indicated by LG&E:[108]

Year	Amount
1982	$ 442,375
1983	448,465
1984	332,705
1985	1,670,904
1986	722,355

The actual test-year storm damage expenses were $3,189,909, an amount greater than in any 3 of the past 5 calendar years. After the proposed adjustment is reflected, the test year would still include $2,213,013 in storm damage expenses.

Mr. Fowler of LG&E stated at the hearing that over a 2-week period LG&E's service area was hit by a series of very extensive and unusual storms.[109] Mr. Fowler indicated in his prepared testimony that the company considers these expenses to be legitimate, reimbursable costs.[110] However, LG&E recognized that the recovery of costs of this magnitude might overstate the level of expenses during a normal 12-month period and has, therefore,

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108 Response to the Commission Order dated December 23, 1987, Item No. 25(e).

109 Hearing Transcript, Vol. III, page 116.

110 Fowler Prepared Testimony, page 12.

proposed an adjustment to amortize these costs over a 3-year period.[111]

During redirect examination, Mr. Fowler stated:

> If the Commission takes the position that you cannot recover these costs, we can certainly reduce these costs very easily by allowing the customer to stay off five weeks instead of two weeks or one week, by doing the repairs during normal business hours with our regular employees.[112]

Mr. Fowler further stated during recross-examination that he believed that LG&E should make every effort to restore service but should the Commission exclude costs incurred for the benefit of the customer, there is a point beyond which the company would have to consider the extent of its efforts. He further stated that if ". . . the stockholders are going to have to eat the expenses, there would become a point where maybe a day or two delay would not seem unreasonable."[113]

In determining a reasonable level of operating expenses and an appropriate rate of return, the Commission considers both the risks of the shareholders and the appropriate cost of service to be borne by a utility's ratepayers. In the present case, LG&E argues that the expenses were incurred for the benefit of the ratepayers. However, the stockholders were unable to earn a return until service had been restored. Clearly, expeditious restoration of service is of benefit to both ratepayers and stockholders.

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[111] Ibid.

[112] Hearing Transcript, Vol. IV, page 54.

[113] Ibid., pages 145-146.

The random occurrence of severe storm damage cannot be accurately predicted. This can be seen from the historical calendar year experience noted above. LG&E has focused on only 1 month of the test year in determining that the $1,465,344 abnormal expense incurred in July should be amortized. Mr. Fowler indicated during cross-examination that the 1985 storm damage expense of $1,670,904 was abnormal.[114] Yet, he proposed to include $1,724,565 as an on-going or normal level of storm damage expenses in addition to the amortization of the abnormal July expense of $488,448. The Commission is of the opinion that the test year should include only a reasonable level of storm damage expenses. The proposed adjustment does not render the test period expense representative for rate-making purposes, but projects a level of expense that is clearly abnormal in relation to the historical storm damage expense as indicated by LG&E. The Commission has, on past occasions, determined a reasonable level of expenses by utilizing a historical average and reaffirms that policy. In this case, the average of the test year and the 4 previous calendar years results in an allowable average of $1,272,868 and a decrease in test year expenses of $1,917,041. The Commission finds that this does not deny recovery but merely establishes a reasonable level of expense for the period in which rates will be in effect. In addition, LG&E should continue to make every effort to restore service as soon as possible.

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[114] Ibid., Vol. III, pages 121-123.

Interest Synchronization

The Commission has applied the cost rates applicable to the long-term debt and short-term debt components of the capital structure in order to compute an interest adjustment. The debt components utilized in this computation reflect the effects of the JDIC allocation and reductions to capital structure due to the extraordinary property losses discussed in this Order. Using the adjusted capital structure allowed herein, the Commission has computed an interest adjustment of $122,093 which results in a reduction to income taxes of $47,353.

After applying the combined state and federal income tax rate of 38.785 percent to the accepted pro forma adjustments, the Commission finds that combined operating income should be increased by $25,109 to $118,883,427.

The adjusted net operating income is as follows.

	Gas	Electric	Total
Operating Revenues	$52,020,765	$460,363,195	$512,383,960
Operating Expenses	44,532,659	348,967,874	393,500,533
ADJUSTED NET OPERATING INCOME	$ 7,488,106	$111,395,321	$118,883,427

RATE OF RETURN

Capital Structure

Mr. Fowler proposed an adjusted end-of-test-year capital structure containing 46.17 percent debt, 9.40 percent preferred stock, and 44.43 percent which reflect the adjustments discussed in the Capital section of this Order.

Dr. Weaver, witness for the AG, proposed a capital structure containing 46.20 percent debt, 9.47 percent preferred stocks, and 44.33 percent common equity. As stated in the Capital section of this Order, the difference between Dr. Weaver's proposed capital structure and Mr. Fowler's was the result of the date used by Dr. Weaver in determining capital structure and in the adjustments to reflect discounts on preferred stock and common equity.[115]

Mr. Kollen, witness for KIUC, proposed a capital structure containing 48.55 percent debt, 9.89 percent preferred stock and 41.56 percent common equity based on his proposed adjusted capital.

The Commission has determined LG&E's adjusted capital structure for rate-making purposes to be as follows:

	Amount	Percent
Debt	$ 614,484,032	46.17
Preferred Stock	125,170,510	9.40
Common Equity	591,346,711	44.43
	$1,331,001,253	100.00

In determining the capital structure, the Commission has accepted the adjustments to capital proposed by LG&E and has used the capital ratios reflected as of September 1, 1987. As previously stated, the test-year-end JDIC has been allocated to each component of the capital on the basis of the ratio of each component to total capital, excluding JDIC, as proposed by LG&E and in accordance with past Commission treatment of this item. In

[115] Weaver Prepared Testimony, pages 35-36.

addition, the total capital has been reduced by $19,571,002 to reflect the extraordinary property losses, which are explained in another section of this Order. The losses have been allocated on the basis of the ratio of each capital component to the total capital.

Cost of Debt

Mr. Fowler proposed a cost of 8.09 percent for preferred stock which was based on the embedded rate as of August 31, 1987.[116] Dr. Weaver recommended an 8.02 percent rate for preferred stock. The difference between Mr. Fowler's and Dr. Weaver's proposed cost of preferred stock was that Dr. Weaver did not reduce the book value of the outstanding preferred stock by the issuing expense.[117] The Commission is of the opinion that issuance costs should be reflected in the cost of preferred stock. Therefore, the Commission is of the opinion that the reduction in book value of the outstanding preferred stock by the issuing expense is proper and that the 8.09 percent rate reflects the true costs of the preferred stock to LG&E.

Mr. Fowler further testified that LG&E's end-of-test year embedded cost of long-term debt was 7.62 percent and reflects adjustments for the retirement of $12,000,000 of First Mortgage Bonds, Series due September 1, 1987, a sinking fund requirement of $250,000 of 1975 Series A pollution control bonds, and the replacement of 1982 Series B (9.40 percent) pollution control

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116 Fowler Prepared Testimony, page 17.

117 Weaver Prepared Testimony, page 36.

bonds with 1987 Series A (6.876 percent) bonds.[118] Dr. Weaver proposed a cost of debt of 7.51 percent which was based upon October 31, 1987 data.[119] The Commission is of the opinion that long-term cost of debt is 7.62 percent based on the end-of-test-year adjusted data.

Cost of Equity

Dr. Charles E. Olson, President of H. Zinder and Associates and witness for LG&E, recommended a return on equity in the range of 13.75 to 14.25 percent.[120] Dr. Olson's recommendation was based on a discounted cash flow ("DCF") analysis of LG&E. In addition, he utilized both a risk premium analysis and a DCF study of nine electric companies as a check on his estimate of LG&E's DCF cost of equity.

In the LG&E DCF analysis, Dr. Olson used (1) a dividend yield of 7.78 percent based on a dividend of $2.66 and a 6-month high/low average stock price of $34.188; and (2) an estimated dividend growth rate of 5.0 to 5.5 percent based on LG&E's 5-year earnings per share growth rate.[121] This resulted in an overall DCF estimate of 12.78 to 13.28 percent. Dr. Olson performed a risk premium analysis as his first check on his LG&E's DCF estimate. The "premium" that investors required over bond yields was estimated at 3.5 percent. This was higher than the 2.6 percent

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118 Fowler Prepared Testimony, Exhibit 5.

119 Weaver Prepared Testimony, page 37.

120 Olson Prepared Testimony, page 30.

121 Ibid., pages 17-22.

premium from Dr. Olson's source of information, a Paine Webber Mitchell Hutchins, Inc. publication titled "Electric Utility Industry - Electric Utility Analyst Survey" (April 19, 1985).[122] The 3.5 percent risk premium was added to LG&E's current bond yield of 10.1 percent resulting in a 13.6 percent required return. Dr. Olson's second check was based on a DCF analysis of nine electric utility companies and resulted in an average return on equity of 12.79 to 13.29 percent.[123] In addition, Dr. Olson increased his estimates by approximately 8.0 percent to allow for flotation costs and market pressure to arrive at his recommended range of 13.75 to 14.25 percent.[124]

Mr. Royer of LG&E recommended that a return on equity in the range of 13.8 to 14.8 percent is necessary to maintain the financial integrity of LG&E and to fund internal growth at 4.0 to 5.0 percent.

Dr. Weaver recommended a cost of equity in the range of 11.5 to 12.5 percent based on a DCF analysis and used the earnings/ price ratio approach as a means to gain additional information. He applied the DCF model to LG&E and a group of four comparable companies using 1987 data and 1978-1980 historical data. Dr. Weaver developed his growth rates using the earnings retention ratio times return on equity (b x r) method. Dr. Weaver's results showed a cost of equity of 10.33 percent for the comparable

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122 Ibid., pages 25-26.

123 Ibid., page 28.

124 Ibid., page 29.

companies and 10.20 percent for LG&E in 1987, and a 13.58 percent and 11.58 percent for 1978-1980, respectively. Dr. Weaver's earnings/price ratio approach averaged 13.04 percent and were higher than his 1987 DCF results, but were closer to the 1978-1980 DCF estimates on the return on equity. Dr. Weaver recommended that no allowances be made for flotation costs or market pressure.

Dr. Jay B. Kennedy, a principal in Kennedy and Associates and witness for KIUC, recommended an 11.75 percent return on equity with a range of 11.34 to 12.21 percent. Dr. Kennedy's proposal was based on a DCF analysis on LG&E. He also performed a DCF analysis on a comparison group of five utilities and a risk premium analysis for verification. His ranges on return on equity were from the results of his DCF analysis and showed LG&E with an average 11.34 percent return on equity and the comparison group with an average 12.21 percent return on equity.[125] Dr. Kennedy's risk premium estimate was based on the difference between the comparison group's average bond yield of 10.02 percent for the July 1987 to December 1987 period, and the DCF cost of equity of 12.21 percent for the comparison group. This risk premium of 2.19 percent was then added to LG&E's long-term debt of 9.82 for a risk premium cost of equity of 12.01 percent.[126] Dr. Kennedy made no allowances for flotation costs or market pressure; however, he suggested that any future costs of issuing common stock be

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125 Kennedy Prepared Testimony, page 40.

126 Ibid., page 41.

measured and recovered externally as a cost of providing service, and levelized over a 30-year period at the weighted cost of capital.

Mr. Kinloch stated that LG&E's rate of return should be 12.0 percent assuming that LG&E no longer receives CWIP, but only 11.0 percent if they are allowed to continue receiving CWIP. Mr. Kinloch's recommendation was based on "current trends from around the nation on recent cases."[127]

The Commission has an obligation to allow LG&E an opportunity to earn a rate of return which will allow it to continue to maintain its financial integrity. In making its determination, the Commission finds that Dr. Olson has basically ignored his own data on growth estimates as provided in his testimony and, therefore, rejects his recommendation of a 14.0 percent return on equity in that it is in excess of an investor's required rate of return. In addition, the Commission also finds that Dr. Weaver's use of the b x r method, if earnings have been inadequate in the past, can understate the growth rate component and, thus, the investor's required return in the DCF analysis. The lower growth rate derived from the b x r method results in a lower allowed return which could result in lower earnings and a lower retention ratio and then a still lower growth rate component and so on. A downward trend could develop and thus weaken the financial integrity of LG&E. The Commission further finds that Dr. Kennedy's failure to give proper weight for the current volatile economic conditions

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[127] Kinloch Prepared Testimony, page 13.

results in an understatement of the investor's required rate of return.

Therefore, the Commission having considered all of the evidence, including recent volatile economic conditions, is of the opinion that a return on equity in the range of 12.25 to 13.25 percent is fair, just, and reasonable. A return on equity in this range would allow LG&E to attract capital at a reasonable cost to insure continued service and provide for necessary expansion to meet future requirements, and also would result in the lowest possible cost to ratepayers. A return of 12.75 percent will best meet the above objectives.

Rate of Return Summary

Applying rates of 7.62 percent for debt, 8.09 percent for preferred stock, and 12.75 percent for common equity to the capital structure approved herein produces an overall cost of capital of 9.94 percent. The Commission finds this overall cost of capital to be fair, just, and reasonable.

REVENUE REQUIREMENTS

The Commission has determined that LG&E needs additional annual operating income of $13,463,256 to produce a rate of return of 12.75 percent on common equity based on the adjusted historical test year. After the provision for state and federal income taxes, there is an overall revenue deficiency of $21,993,394 which is the amount of additional revenue granted herein. The net operating income necessary to allow LG&E the opportunity to pay its operating expenses and fixed costs and have a reasonable amount for equity growth is $132,346,683. A breakdown between gas and electric operations of the required operating income and the increase in revenue allowed herein is as follows.

	Total	Gas	Electric
Net Operating Income Found Reasonable	$132,346,683	$13,103,981	$119,242,702
Adjusted Net Operating Income	118,883,427	7,488,106	111,395,321
Net Operating Income Deficiency	13,463,256	5,615,875	7,847,381
Additional Revenue Required	21,993,394	9,174,017	12,819,377

The additional revenue granted herein will provide a rate of return on the net-original cost rate base of 9.98 percent and an overall return on total capitalization of 9.94 percent.

The rates and charges in Appendix A are designed to produce gross operating revenues, based on the adjusted test year, of $644,797,735. These operating revenues include $469,555,007 in electric revenues and $175,242,728 in gas revenues.

OTHER ISSUES

"Benchmark" Treatment of Operation and Maintenance Expenses

KIUC proposed a reduction of test-year operating and maintenance expenses totaling $25,771,000, which it claimed reflected the excessive expense growth above inflation and sales growth experienced by LG&E. The amount of reduction was determined utilizing a "benchmark" calculation presented by KIUC witness, Mr. Kollen. Mr. Kollen took the pro forma operation and maintenance expenses for the test year in LG&E's last general rate case and multiplied the amounts by an overall growth factor to arrive at a benchmark level of operation and maintenance expenses.[128] These figures were compared to the pro forma operation and maintenance expenses for the current test year, and the difference calculated. Mr. Kollen's analysis was restricted to non-fuel operation and maintenance expenses. In his prepared testimony, Mr. Kollen indicates that the $25,771,000 in operation and maintenance expenses over his benchmark calculation clearly shows that the growth in those expenses is out of control.[129] He advocates that the Commission adopt some form of cost containment, like the benchmark, as an incentive for LG&E.[130]

During the hearing, Mr. Kollen was cross-examined extensively about his benchmark approach. Mr. Kollen frequently referred to the Florida Public Service Commission ("Florida PSC") utilizing a benchmark approach similar to his proposal. While Mr. Kollen testified that the Florida PSC uses a benchmark approach in all general rate proceedings, he could not cite a rule, regulation, practice, or order which required such a filing.[131] While advocating the benchmark as a means of total operation and maintenance expense containment, Mr. Kollen readily accepted the fact that some functional areas of operation and maintenance expenses could continue to increase in exchange for reduction in

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128 Kollen Prepared Testimony, Exhibit LK-5 and Hearing Transcript, Vol. XI, pages 91-92.

129 Kollen Prepared Testimony, page 14.

130 Ibid., page 18.

131 Hearing Transcript, Vol. XI, pages 97-98.

other areas.[132] In computing the overall growth factor, Mr. Kollen used the change in the sales growth in his calculations although his testimony was that the Florida PSC uses the change in the customer growth.[133]

In its brief, KIUC stated that,

> . . . there is substantial evidence [emphasis added] indicating that the requested level of O & M expense is excessive even when given a liberal recognition of inflation and sales growth. In the absence of specific data [emphasis added] provided by the Company, the Commission should determine the reasonable level of recurring operation and maintenance expense using a benchmark methodology similar to that developed and utilized by the Kentucky Commission two cases ago.[134]

The Commission does not understand how there can be "substantial evidence" while at the same time be an "absence of specific data." In the case which KIUC has referenced to support the benchmark approach, the increase to wages and salaries was denied because of an evaluation of existing economic conditions; therefore, the Consumer Price Index was used as a substitute for the percent of wage increase allowed for rate-making purposes.[135] Thus, the example referred to differs significantly from the proposed benchmark as put forth by KIUC.

The benchmark approach to establishing a fair and reasonable level of expenses may be a useful tool in instances where the data is not available to make specific adjustments, or in abbreviated

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132 Ibid., pages 100-102.

133 Ibid., page 103.

134 KIUC Brief, filed May 9, 1988, page 47.

135 Case No. 8616, final Order dated March 2, 1983, pages 22-23.

filings or annual earnings adjustment cases allowed by some state regulatory bodies where time constraints are present. However, the Commission in its general rate proceedings, applies the standards of known and measurable as well as fair and reasonable in making adjustments to the historical test period. In this case, many adjustments have been made to reduce historical test year expenses where costs were deemed to be excessive, non-recurring, or otherwise inappropriate for rate-making purposes. The Commission believes that this approach is much more accurate and results in a more reasonable level of operating expenses. The case presented by KIUC on this issue is not conclusive. The Commission has decided not to use the benchmark approach proposed by KIUC in this general rate proceeding.

Gas Cost of Service

In accordance with the Commission's Order of May 29, 1987 in Administrative Case No. 297, An Investigation of the Impact of Federal Policy on Natural Gas to Kentucky Consumers and Suppliers, the Company prepared and filed a fully distributed, embedded gas cost of service study. The study's sponsor, Randall Walker, LG&E's Coordinator of Rates and Tariffs, described the methodology in his testimony,

> In order to allocate costs among the classes of service on the basis of cost incurrence and to determine the relative contribution that each class makes to the overall return on net gas rate base, costs were first assigned to functional groups, then classified as to demand, commodity, or customer-related, and finally, allocated to the classes of service.[136]

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136 Walker Prepared Testimony, page 2.

The study shows that the residential class is being subsidized by all other rate classes of gas service.[137] According to this Exhibit, the adjusted return for the test year for residential service is a negative 0.79 percent, for nonresidential service, 11.93 percent, Fort Knox, 16.5 percent, and seasonal off-peak Rate G-6, 66.34 percent. LG&E stated in its brief that "such an imbalance is undesirable and should be improved."[138] As a result, LG&E is proposing rates which will result in a more equitable recovery of costs, thus reducing the differential in class rates of return. The Residential Intervenors contend that the reason for the residential class's negative return is that the study overstates the costs incurred by the residential class.[139] One example of overstated costs offered by the Residential Intervenors involves the method in which the costs of distribution mains are allocated. LG&E uses the zero-intercept methodology to classify the costs of distribution mains as either demand or customer related. "This methodology again disproportionately assigns costs to the residential class based on a theoretical system design which has no basis in reality."[140] Also critical of LG&E's use of the zero-intercept methodology was the DOD whose witness, Suhas P. Patwardhan, conversely charges that "use of the Company method

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137 Ibid., Exhibit 1, page 4.

138 LG&E Brief, May 9, 1988, page 64.

139 Residential Intervenors Brief, May 9, 1988, page 14.

140 Ibid., pages 14-15.

will result in favorable treatment for small usage customers as opposed to large usage customers."[141] Mr. Patwardhan feels that the use of a minimum-system method would result in a more favorable rate of return performance from large users such as Fort Knox.

The Commission is convinced that the zero-intercept method is theoretically sound and less subjective than the minimum system method, in which a minimum size main must be subjectively chosen in order to determine the customer component.

For the purpose of determining cost causation, LG&E separates its customers into four classes of service, Rate G-1-residential, Rate G-1-nonresidential, Fort Knox and Rate G-6-Seasonal Off-Peak service. This particular breakdown of rate classes evokes this criticism by the KIUC:

> Although LG&E has presented a "cost-of-service study," it is not appropriate because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service.[142]

KIUC further contends that the Company's study is contrary to the Commission's guidelines set forth in its Order in Administrative Case No. 297. On pages 42-43 of that Order, the following guidelines are stated, "The Commission prefers that the (cost of service) studies be disaggregated to the greatest extent possible."

Pursuant to its criticism of LG&E's gas cost of service study, KIUC, through its witness Kenneth Eisdorfer, presented an

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141 Patwardhan Prepared Testimony, page 7.

142 KIUC Brief, May 9, 1988, page 87.

alternative study. Mr. Eisdorfer's study disaggregates the Non-residential Rate G-1 category, used by LG&E, into Commercial G-1, Industrial G-1 (Sales), and Industrial G-1 (Transportation). Further, he disaggregates LG&E's Rate G-6 into Sales and Transportation classes of service. His study allocates gas stored underground exclusively to sales service. Otherwise, all cost assignment methodologies are identical to LG&E's.[143]

The Commission is of the opinion that KIUC's assertion that the Company did not fully disaggregate the various classes of service is a valid concern. The Commission will require LG&E to specifically address this issue in the gas cost of service study it files in its next rate case.

Except as described above, the Commission finds that the gas cost of service filed by LG&E provides an adequate starting point for rate design and should be used as the guide for the allocation of revenues to the customer classes.

Electric Cost of Service

LG&E filed an embedded time-differentiated cost of study that used a base-intermediate-peak ("BIP") method to allocate production and transmission demand related costs to costing periods and to customer classes. The methodology used by LG&E was essentially the same as has been used in the last two rate cases with the exception that some of the demand allocators were adjusted to account for temperature-sensitive demand. James W. Kasey,

[143] Eisdorfer Prepared Testimony, page 11.

Coordinator of Rate Research for LG&E, sponsored the embedded cost of service study.

There was considerable concern expressed by the Residential Intervenors, County and CAG with the results of the electric cost of service study. Mr. Kinloch indicated his opposition to LG&E's use of the zero-intercept method for allocating distribution system costs between energy and customer related costs. He stated, "The use of a minimum system calculation assumes that all customers are the same, and that each customer contributes equally to the minimum system requirement."[144] He further contended that customers living in older neighborhoods were closer to generation stations with more fully depreciated infrastructure and contribute less to costs of the distribution system. Mr. Kinloch concluded that the minimum distribution grid costs should be allocated based on energy and recovered through a KWH charge.[145]

The Residential Intervenors expressed concern with LG&E's proposal to include weather normalization adjustment in its cost of service study. The Residential Intervenors contend that they are doubly affected by weather normalization because "the company <u>increased</u> the residential contribution to system peak demand over actual test year contribution to reflect a lower than 'normal' demand,"[146] plus "the company's proposed weather normalization reduced the revenues attributed to the residential class by $8.5

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[144] Kinloch Prepared Testimony, page 29.

[145] <u>Ibid</u>., page 30.

[146] Residential Intervenors Brief, page 12.

million."[147] Thus, the residential class rate of return is reduced to 6.25 percent for the adjusted test year which was below the system average of 8.67 percent. Therefore, the Residential Intervenors proposed that the, ". . . company cost of service study should not be used to assign a greater percentage of any increase to the residential than that assigned to the system as a whole."[148]

The Commission in its Order in Case No. 8924 accepted LG&E's proposed cost of service study's methodology. The Commission continues to be of the opinion that LG&E's BIP methodology is appropriate. Furthermore, the Commission will continue to accept the zero-intercept methodology for the allocation of distribution costs between customer and demand components of the cost of service study. This method is theoretically superior to the alternative proposed by the Residential Intervenors.

Though the Commission is of the opinion that LG&E's cost of service methodology is acceptable, the Commission has serious concerns with the class rate of return results. In this case, LG&E's witness testified that, ". . . the summer and winter system peaks used in this analysis were temperature normalized,"[149] and ". . . several of the demand allocation factors were normalized for the effects of temperature . . ."[150] In a previous section of

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[147] Ibid., page 13.

[148] Ibid., page 13.

[149] Kasey Prepared Testimony, Exhibit 1, page 7.

[150] Ibid., page 11.

this Order the Commission rejected the temperature normalization adjustment. The use of temperature normalized allocators and the temperature normalization adjustment of the winter and summer peaks result in improper allocations of costs to various classes, distorting class rate of return. Therefore, the Commission will reject the cost of service study for use as the basis for the allocation of revenues to the classes. Instead, the Commission will allocate the increase in revenue to each rate class in proportion to its overall increase in rates.

RATE DESIGN

Street Lighting

The City expressed concern about the financial impact of the proposed increased cost of the 400-watt mercury vapor street light with a wood pole. The Commission understands the concerns of the City and recognizes that inequities exist in the tariffs for mercury vapor street lights and the high pressure sodium vapor lights because the rates do not currently reflect cost of service. The Commission agrees with the analysis that LG&E prepared to reflect the movement toward cost-based rates in the street lighting structure. As the Commission has reduced the requested revenue increase by LG&E in this case, the Commission has also adjusted the rates of individual units in the street lighting tariff, which reflects a gradual movement to cost-based rates. The Commission advises the City and LG&E that LG&E should again analyze and update its street lighting tariff in its next rate case.

Disconnect and Reconnection Charge/Monthly Customer Charge

Mr. Kinloch, representing the County and the CAG, stated that the low income customers would be adversely affected by the proposed increases in the disconnect and reconnection charge ("fee") and the monthly customer charge ("charge").[151] Mr. Kinloch stated that the fee applies generally to the bills of the customers that are least able to pay the fee; that the fee is a cost of doing business; that all utilities, such as Louisville Water Company in Louisville and Jefferson County, do not charge such a fee; and that new customers are not charged a hookup fee. The Commission has considered the testimony of Mr. Kinloch and recognizes that this type of a fee by its nature will affect customers experiencing financial difficulties. The fee recovers a cost of business created by a minority of customers. Although Louisville Water Company may not exercise its right to charge this fee, that right is still in its rules and regulations. The Commission does not find that disconnect/reconnect service charges upon the customers creating the need for these services to be comparable to the provision of hookup service at no charge to every customer. While the Commission is sensitive to the concerns of those experiencing financial hardship, it recognizes that a fee of this type allocates costs to cost causers and is a fair and reasonable component of an electric utility rate design. The Commission has and will continue to consider the effects of this charge. In this case, the Commission has adjusted the proposed $4

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151 Kinloch Prepared Testimony, page 22.

increase to $2 to reflect the approximate percent of decrease of LG&E's overall requested increase. The fee is to increase from $12 to $14.

Mr. Kinloch recommended that the monthly residential customer charge for electric service be reduced below the current monthly charge of $3.16 to $2.35 and the residential rate design be changed to a flat rate for the winter months and an inverted block rate for the summer months. Similarly, Mr. Kinloch recommended that the proposed monthly customer charge for gas services be reduced from $5.50 to $3.85. The Commission has accepted the cost of service methodologies proposed by LG&E for the Electric and Gas Divisions but has rejected the proposed weather normalization included in the Electric Division's cost of service study. Mr. Kinloch did not propose a complete cost of service analysis for either the Electric or Gas Division, and the proposed inverted block rate for electric is not a cost-based rate. The rate design as proposed by LG&E has been accepted in the past by the Commission.

The Commission is of the opinion that LG&E's proposed residential rate design appropriately reflects its costs and is fair to all parties. Therefore, considering the objectives of cost-based rates and rate continuity, the Commission has relied on LG&E's proposal in determining approved residential rates.

<u>Off-System Sales</u>

George Gerasimou, witness for KIUC, recommended that the Commission investigate the feasibility of flowing total revenue associated with off-system sales through the monthly fuel adjustment clause ("FAC").[152] He did not propose any adjustment to revenues or expenses in this case related to his proposed treatment of off-system sales. FAC revenues and expenses are reviewed in 6-month hearings under the Commission's regulation 807 KAR 5:056. That regulation is under review in Administrative Case No. 309, An Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056. The Commission is of the opinion that any revision to the FAC regulation should have been presented to the Commission for review in that case.

Revenue Increase Allocation

LG&E based its proposed allocation of revenue increase on its cost of service studies. The Commission has previously rejected the proposed electric cost of service analysis for reasons stated elsewhere in this Order; therefore, the Commission will allocate the allowed electric revenue increase in the proportions of the revised normalized class revenue to the total revised normalized revenue, as illustrated below.

	Revised Normalized Revenue	Percent	Allocation of Revenue Increase
Residential	$172,914,195	38.313	$ 4,900,514
General Service	66,230,541	14.675	1,877,040
Large Commercial	89,790,252	19.895	2,544,717
Large Industrial	91,697,158	20.317	2,598,694
Special Contracts	24,078,953	5.335	682,386
Street and Outdoor Lighting	6,611,828	1.465	187,384
Total Sales Customers	$451,322,927	100.000	$12,790,735
Other Electric Revenue	5,412,703		28,642
Total Electric Operating Revenue	$456,735,630		$12,819,377

152 Gerasimou Prepared Testimony, page 6, A16.

The Commission has accepted the gas temperature normalization and the other revenue adjustments as proposed by LG&E in the $166,068,711 total normalized gas operating revenues. The reduction in the allowed Gas Division revenue increase from the proposed revenue increase will be allocated among those rate classes that LG&E proposed revenue increases. LG&E proposed an extremely large percent increase to the monthly customer charge. The Commission is of the opinion that the proposed customer charges should be reduced to maintain rate continuity. Therefore, all of the reduction in proposed gas revenue increase is allocated to the customer charge. The allocation of the revenue increase is as follows.

Rate Class	Normalized Revenue	Allocation of Revenue Increase
Rate G-1		
Total Residential	$ 89,443,656	$ 8,394,853
Total Non Residential	55,672,127	2,085,578
Rate G-6	13,601,930	<1,324,103>
Rate G-7	106,520	<10,953>
Rate G-8		-0-
Fort Knox Contract	5,783,136	-0-
Total Sales and Transportation	$164,607,369	$ 9,145,375
Other Revenues	1,461,342	28,642
Total Gas Operating Revenues	$166,068,711	$ 9,174,017

Economic Development Rate

LG&E, through its witness, Fred Wright, has proposed an Economic Development Rate ("EDR") to be administered as a rider to LG&E's Large Commercial Rate - LC, Large Commercial Time-of-Day

Rate - LC-TOD, Industrial Power Rate - LP, and Industrial Power Time-of-Day Rate - LP-TOD. Mr. Wright described the purpose of this proposed rate in the following statements:

> LG&E strives to broaden the base of customers over which to spread its fixed costs, in order to keep its retail gas and electric rates as low as practicable so as to remain competitive for new business . . . The EDR is designed to stimulate the creation of new jobs and capital investment both by encouraging existing large commercial and industrial companies to remain in the area and to expand, and by making it more attractive for new companies to move into our service area.[153]

The proposed rate offers companies in the above rate classes, who increase their electric load demand by at least 1,000 Kilowatts over the base year load demand, a reduction to the billing demand during the 8 monthly billing periods from October through May in accordance with the following table:

Time Period	Reduction to Billing Demand
First 12 Months	50%
Second 12 Months	40%
Third 12 Months	30%
Fourth 12 Months	20%
Fifth 12 Months	10%
After 60 Months	0%

For purposes of this rider, the base year is defined as the most recent 12-month calendar year period ending before the effective date of this rider.

Mr. Wright further explains that, "Incentive rates are becoming increasingly common in utility rate tariffs in areas against which the Louisville area must compete."[154] In addition, Mr.

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153 Wright Prepared Testimony, page 3.

154 Wright Prepared Testimony, page 5.

Wright testified that "it (EDR) should not contribute unnecessarily to the Company's future capacity requirements but, rather should improve the Company's electric system load and capacity factors by encouraging growth in a customer class that has a higher load factor."[155] Several parties in this proceeding expressed concern with LG&E's proposed EDR. Mr. Kinloch testified that, although he was not opposed to economic development and the creation of jobs, he is concerned about the mechanism by which LG&E has proposed to address these issues -- the EDR. The first point of concern he raised is that "the EDR rate is below cost of service pricing."[156] Secondly, he expressed apprehension about the potential for success of the EDR and concern with the lack of formal evaluation proposed by LG&E. Finally, Mr. Kinloch addresses the effect, he feels, the EDR will have on LG&E's low-income customers. "While there may be some benefit for a younger low-income customer who is unemployed, the EDR rate will provide absolutely no benefit for elderly customers on fixed incomes."[157] Mr. Kinloch likens the EDR to a lifeline rate proposed for industry instead of to the low-income customers. He suggests that the Commission approve the EDR only if LG&E offers a lifeline rate to elderly customers on fixed incomes.

The Residential Intervenors, during the cross examination of Mr. Wright, raised the concern with the manner in which LG&E will

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[155] Ibid., page 6.

[156] Kinloch Prepared Testimony, page 45.

[157] Ibid., page 47.

determine the normality of whether base year demand, above which an additional one megawatt will qualify an LC, LC-TOD, LP, or LP-TOD rate customer for the EDR. Specifically, they were concerned with whether there were unusual circumstances in the base year that would cause a customer's demand to be lower than it would normally be.[158] Mr. Wright responded that each qualifying customer must convince LG&E that he has created jobs and capital investment, and that no unusual circumstances exist in the base year. LG&E did not propose, nor does the EDR rider address, the mechanism by which either of these conditions will be satisfied.

Throughout the record in this case, LG&E has maintained a dual purpose in proposing the EDR: creating additional load, and creating new jobs and new capital investment. The Commission believes that the two purposes are complements. However, the Commission also believes that the concern raised by the intervenors, that LG&E has proposed no mechanism in its EDR to determine that both of these purposes are being addressed, is valid.

The Commission also finds merit with the following concerns raised by the intervenors and its Staff regarding the EDR:

1. The possibility that the EDR is priced below cost of service.

2. The lack of any formal evaluation by LG&E of the effects of the EDR if it is implemented.

3. The effect the EDR will have on LG&E's other ratepayers.

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158 Hearing Transcript, Vol. II, page 222.

4. The fact that the EDR rider does not specify how to determine if base year demand is abnormal or how to determine the effect of the EDR on job creation and capital investment.

5. Whether the EDR should be implemented via a tariff or by special contracts.[159]

There has been a substantial increase in the number of economic development/incentive rates filed with the Commission by both electric and gas utilities during the past year. The purpose of these tariffs, according to the utilities, is to increase the amount of energy sold and/or to expand the level of capital investment and employment in the sponsoring utility's service area. Though the rate designs may vary drastically by utility, they typically provide demand discounts for new and expanding industries within the utility's service area for some specified time period, typically 5 years.

At the current time, the Commission has before it, in addition to LG&E's proposed EDR rider, several economic development/incentive rate proposals. Each of the various tariffs and contracts will require a Commission decision for implementation. Because of the potential volume of tariff and contract filings and their impact on the utility and their customers, the Commission is of the opinion that a consistent policy should be developed on tariff filing and reporting requirements.

The Commission finds that the concerns raised by the parties in the instant case, the number of tariffs and contracts presently

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159 Hearing Transcript, Vol. II, pages 251-253 and 255-256.

under consideration, and the potential implications of these proposals necessitate that utilities which offer economic development/incentive rates to existing or potential customers must satisfy the following requirements, prior to Commission approval of the proposed rate:

1. Each utility should be required to provide an affirmative declaration and evidence to demonstrate that it has adequate capacity to meet anticipated load growth each year in which an incentive tariff is in effect.

2. Each utility should be required to demonstrate that all variable costs associated with the transaction during each year that the contract is in effect will be recovered and that the transaction makes some contribution to fixed costs. Furthermore, the customer-specific fixed costs associated with adding an economic development/incentive customer should be recovered either up front or as a part of the minimum bill over the life of the contract.

3. Each utility that offers an economic development rate should be required to document and report any increase in employment and capital investment resulting from the tariff and contract. These reports should be filed on an annual basis with the Commission.

4. Each utility that intends to offer economic incentive rates should be required to file a tariff stating the terms and conditions of its offering. Furthermore, each utility should be required to enter into a contract with each customer which specifies the minimum bill, estimated annual load, and length of

contracting period. No contract should exceed 5 years. All contracts shall be subject to the review and approval of the Commission.

5. Each utility should be required to include a clause in its contract that states that the tariff will be withdrawn when the utility no longer has adequate reserve to meet anticipated load growth.

6. Each utility should be required to demonstrate that rate classes that are not party to the transaction should be no worse off than if the transaction had not occurred. Under special circumstances, the Commission will consider utility proposals for contracts that share risk between utility shareholders and other ratepayers. However, if a utility proposes to charge the general body of ratepayers for the revenue deficiency resulting from the EDR through a risk-sharing mechanism then the utility will be required to demonstrate that these ratepayers should benefit in both the short- and long-run. In addition, at least one-half of the deficiency will be absorbed by the stockholders of the utility and will not be passed on to the general body of ratepayers. The amount of the deficiency will be determined in future rate cases by multiplying at least one-half of the billing units of the EDR contract(s) by the tariffed rate that would have been applied to customer(s) if the EDR contract(s) had not been in effect.

The Commission is of the opinion that these restrictions on economic development/incentive rates will provide a means for protecting other ratepayers while still providing LG&E, other utilities, and industrial development specialists the opportunity to use lower rates to attract industry.

Furthermore, the Commission is of the opinion and finds that the EDR rider proposed by LG&E is partially consistent with Requirement 4 above. However, the rider must be revised to include language making it completely consistent with all of the above requirements. Therefore, LG&E should withdraw the EDR rider in its present form and refile it within 30 days after all revisions have been made.

<u>Cogeneration and Small Power Production Tariffs</u>

Pursuant to the Order in Case No. 8566, Setting Rates and Terms and Conditions of Purchase of Electric Power from Small Power Producers and Cogenerators by Regulated Electric Utilities, LG&E filed tariffs reflecting its proposed avoided energy and capacity costs. Robert Lyon, Manager of System Planning and Budgets, sponsored the avoided cost studies and tariffs. In preparing estimates of avoided energy costs, LG&E used "its more detailed production costing model, PROMOD III, in place of the EBASCO model (MARCOST 80)." Similarly, in preparing estimates of avoided capacity costs, "computer models used in the Company's recent capacity expansion study were used, viz., EGEAS (Electric Generation Expansion Analysis System) and TALARR (Total and Levelized Annual Revenue Requirements)." Both models are widely accepted and used in the electric utility industry.

In preparing its estimate of avoided capacity costs, LG&E used, "[T]wo twenty-year strategic expansion plans . . ." One plan assumed qualifying facilities with 75,000 KW capacity with an availability of 70 percent and no capacity costs while the other plan did not. The use of Qualifying Facility ("QF") capacity by LG&E resulted in both cancellation and deferment of combustion turbine capacity in its 20-year planning cycle. The difference in the present worth of revenue requirements ("PWRR") between the two plans represented the avoided capacity costs of QF capacity since only the fixed costs of plant ownership were considered in the PWRR analysis. Using a levelized annual revenue requirement of $1,910,000 and assuming 70 percent availability and must run QF operational characteristics, Mr. Lyon proposed a capacity purchase payment of 4.15 mills per KWH. Finally, Mr. Lyon indicated that a QF would have to contract for 20 years to qualify for the proposed capacity purchase payment. In addition, LG&E proposed that each QF be required to post a bond to insure that capacity will be offered for the duration of the contract.

In preparing its avoided energy costs, LG&E used essentially the same method as it used in preparing its estimates in Case No. 8566. Using PROMOD III, LG&E estimated its avoided energy costs at 2.04 cents per KWH. Mr. Lyon indicated that LG&E would apply this avoided energy cost to all QF purchases regardless of whether it was under a 20-year contract or not. He further indicated that LG&E would update its estimates of avoided energy costs and its energy purchase rates annually, and avoided capacity costs and capacity purchase rates updates biannually. Finally, Mr. Lyon indicated that the revised rates would apply to all QF purchases.

The Commission is of the opinion and finds that the proposed rates resulting from the avoided costs are consistent with the

Commission's Order in Case No. 8566. Furthermore, the rates reflect LG&E avoided costs and should be adopted. However, the Commission does intend to continue to monitor LG&E bonding requirements to insure that the requirements do not discourage or hinder QF development.

Natural Gas Tariffs

KIUC proposes that LG&E's gas tariffs be revised to reflect the costs incurred by the utility in serving different customers.[160] KIUC states that the cost of service study LG&E has submitted is deficient "because it fails to evaluate cost causation with respect to firm industrial sales customers as distinct from firm commercial sales customers and transportation service as distinct from sales service."[161] KIUC states that the result of LG&E's revenue proposals for transportation customers will be to earn from these classes an excessive rate of return. KIUC's proposed solution is to utilize the cost of service study presented by its witness, Mr. Eisdorfer.

KIUC's conclusions are based upon the differences between its cost of service study and the one submitted by LG&E. The Commission discusses the two studies elsewhere in this Order in the section entitled Gas Cost of Service, wherein the Commission concludes that these issues raised by KIUC are a valid concern. However, the Commission has decided to have LG&E disaggregate the various classes of service more fully in the gas cost of service

160 KIUC Brief, filed May 9, 1988, page 87.

161 Ibid., page 86.

study it files in its next rate case. Therefore, it would be inappropriate to order any tariff changes the support for which would require a greater disaggregation between classes than that accepted by the Commission in LG&E's cost of service study.

KIUC also proposes that certain changes be made to LG&E's proposed tariff Rate T applicable to gas transportation service. KIUC states that the proposed language ". . . does not conform with Mr. Hart's representation . . . that transportation service provided under Rate T would be firm and that the language should be corrected by substituting the word "converted" for the word "reduction . . ."[162] KIUC also believes that certain language under the "availability" part of this tariff should be changed to conform to certain provisions in the Order issued in Administrative Case No. 297. Specifically, KIUC argues that the language should clearly state: LG&E has the obligation to tell a prospective transportation customer why it cannot transport gas; and the burden of proof is on LG&E to show that capacity does not exist on its system to transport gas.[163]

The Commission is of the opinion that the proposed language in LG&E's gas tariffs is sufficient to allow a prospective gas customer to understand the services offered and their terms and conditions. The Commission also finds that it is unnecessary for LG&E to substitute the word "converted" for the word "reduction" in the Rate T tariff. LG&E's proposed language allows its

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162 Hearing Transcript, Vol. VI, page 93.

163 _Ibid._, page 94.

transportation customers to receive transportation service under Rate T as long as LG&E's D-1 and D-2 billing demands from its pipeline supplier are reduced in an amount corresponding to the volumes of gas transported. The Commission understands KIUC's point to be that an end-user through its supplier may request a reduction or conversion of some portion of its supply in order to increase the amount of transportation it can utilize. LG&E agrees that an end-user may request either a reduction or conversion.[164] However, in either case, LG&E must receive a reduction in its billing demands which represent the reduced or converted sales volumes. Otherwise, LG&E's non-transportation customers would ultimately pay the billing demands for those sales volumes not purchased by such an end-user.

Regarding the "availability" section of the Rate T tariff, the Commission does not view the current language as relieving LG&E of its burden of proof. LG&E agrees with the points raised by KIUC.[165] However, the Commission is of the opinion that the language should be clarified to provide prospective transportation customers in a clearer understanding of LG&E's responsibilities. Therefore, LG&E should revise the language in the "availability" section of the Rate T tariff to more clearly comply with the Order issued in Administrative Case No. 297.

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164 Hearing Transcript, Vol. VI, pages 78-79.

165 Ibid., pages 85-86.

Effective Date of New Rates

LG&E's proposed rates were filed with an effective date of December 20, 1987. Pursuant to KRS 278.190(2), the Commission suspended the operation of the proposed schedules for a period of 5 months, until May 20, 1988. On May 19, 1988, LG&E filed a motion stating that if the Commission has not ruled on its rate application by May 20, 1988, LG&E would forego its right to place the proposed rates in effect subject to refund provided that the new rates when authorized will be made effective on May 20, 1988. None of the intervenors objected to this motion and the Commission granted it by Order issued May 20, 1988.

In accordance with that Order, the rates authorized herein are being made effective for service rendered on and after May 20, 1988. With respect to a surcharge to permit LG&E to recover the new rates from May 20, 1988 through the effective date of this Order, LG&E's motion proposed that the surcharge be applied to billings spread over an extended period of time not to exceed December 31, 1988. On June 20, 1988, the Commission received a letter from LG&E proposing that the surcharge be applied only to billings for one month. The Residential Intervenors notified the Commission on June 28, 1988 that it objected to LG&E's proposed modification. The Commission is of the opinion that LG&E should file a surcharge plan within 30 days from the date of this Order. All parties will then be afforded 15 days to file comments on the plan.

SUMMARY

The Commission, after consideration of the evidence of record and being advised, is of the opinion and finds that:

1. The rates in Appendix A are the fair, just, and reasonable rates for LG&E and will produce gross annual revenues based on adjusted test year sales of approximately $644,776,975.

2. The rate of return granted herein is fair, just, and reasonable and will provide for the financial obligations of LG&E with a reasonable amount remaining for equity growth.

3. The rates proposed by LG&E would produce revenue in excess of that found reasonable herein and should be denied upon application of KRS 278.030.

4. The proposed EDR tariff rider should be withdrawn and resubmitted for review when the revisions discussed herein have been made.

IT IS THEREFORE ORDERED that:

1. The rates in Appendix A be and they hereby are approved for service rendered by LG&E on and after May 20, 1988.

2. The rates proposed by LG&E be and they hereby are denied.

3. The proposed EDR tariff rider shall be resubmitted when LG&E has made necessary revisions.

4. Within 30 days from the date of this Order, LG&E shall file with the Commission its revised tariff sheets setting out the rates approved herein.

5. LG&E shall file a surcharge plan within 30 days of the date of this Order and intervenors shall have until 15 days thereafter to file comments.

Done at Frankfort, Kentucky, this 1st day of July, 1988.

By the Commission

ATTEST:

Forest M. Skaggs

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988.

The following rates and charges are prescribed for the customers in the area served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

ELECTRIC SERVICE

RESIDENTIAL RATE
(RATE SCHEDULE R)

RATE:

Customer Charge: $3.25 per meter per month.

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

First 600 kilowatt-hours per month	6.023¢ per Kwh
Additional kilowatt-hours per month	4.717¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month	6.593¢ per Kwh

WATER HEATING RATE
(RATE SCHEDULE WH)

RATE: 4.761¢ per kilowatt-hour.

Minimum Bill $2.05 per month per heater

GENERAL SERVICE RATE*
(RATE SCHEDULE GS)

RATE:

Customer Charge:

$3.85	per meter per month for single-phase service
$7.70	per meter per month for three-phase service

Winter Rate: (Applicable during 8 monthly billing periods of October through May)

All kilowatt-hours per month 6.454¢ per Kwh

Summer Rate: (Applicable during 4 monthly billing periods of June through September)

All kilowatt-hours per month 7.232¢ per Kwh

Minimum Bill:

The minimum bill for single-phase service shall be the customer charge.

The minimum bill for three-phase service shall be the customer charge; provided, however, in unusual circumstances where annual kilowatt-hour usage is less than 1,000 times the kilowatts of capacity required, Company may charge a minimum bill of not more than 98 cents per month per kilowatt of connected load.

SPECIAL RATE FOR ELECTRIC SPACE HEATING SERVICE RATE SCHEDULE GS

RATE:

For all consumption recorded on the separate meter during the heating season the rate shall be 4.726¢ per kilowatt-hour.

Minimum Bill:

$6.90 per month for each month of the "heating season." This minimum charge is in addition to the regular monthly minimum of Rate GS to which this rider applies.

LARGE COMMERCIAL RATE (RATE SCHEDULE LC)

Applicable:

In all territory served.

Availability:

This schedule is available for alternating current service to customers whose monthly demand is less than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $16.90 per delivery point per month.

Demand Charge:

	Secondary Distribution	Primary Distribution
Winter Rate: (Applicable during 8 monthly billing periods of October through May)		
All kilowatts of billing demand	$7.25 per Kw per month	$5.61 per Kw per month
Summer Rate: (Applicable during 4 monthly billing periods of June through September)		
All kilowatts of billing demand	$10.33 per Kw per month	$8.42 per Kw per month

Energy Charge:

All kilowatt-hours per month 3.272¢

LARGE COMMERCIAL TIME-OF-DAY RATE

Availability:

This schedule is available for alternating current service to customers whose monthly demand is equal to or greater than 2,000 kilowatts and whose entire lighting and power requirements are purchased under this schedule at a single service location.

RATE:

Customer Charge: $17.20 per delivery point per month

Demand Charge:

Basic Demand Charge
Secondary Distribution $3.68 per Kw per month
Primary Distribution $1.99 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge

Summer Peak Period	\$6.66 per Kw per month
Winter Peak Period	\$3.54 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 3.272¢ per Kwh

Winter-Peak Period is defined as weekdays, except holidays as recognized by company, from 6 AM to 10 PM local time, during the 8 monthly billing periods of October through May.

INDUSTRIAL POWER
(RATE SCHEDULE LP)

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is less than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage.

RATE:

Customer Charge: \$41.70 per delivery point per month

Demand Charge:

	Secondary Distribution	Primary Distribution	Transmission Line
All kilowatts of billing demand	\$8.99 per Kw per month	\$7.02 per Kw per month	\$5.86 per Kw per month

Energy Charge:

All kilowatt-hours per month 2.832¢ per Kwh

INDUSTRIAL POWER TIME-OF-DAY RATE
(RATE SCHEDULE LP-TOD)

Applicable:

In all territory served.

Availability:

This schedule is available for three-phase industrial power and lighting service to customers whose monthly demand is equal to or greater than 2,000 kilowatts, the customer to furnish and maintain all necessary transformation and voltage regulatory equipment required for lighting usage. As used herein the term "industrial" shall apply to any activity engaged primarily in manufacturing or to any other activity where the usage for lighting does not exceed 10% of total usage. Company reserves the right to decline to serve any new load of more than 50,000 kilowatts under this rate schedule.

RATE:

Customer Charge: $42.55 per delivery point per month

Demand Charge:

Basic Demand Charge:

Secondary Distribution	$5.26 per Kw per month
Primary Distribution	$3.30 per Kw per month
Transmission Line	$2.10 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Peak Period Demand Charge:

Summer Peak Period	$5.51 per Kw per month
Winter Peak Period	$2.92 per Kw per month

Applicable to the highest average load in kilowatts recorded during any 15-minute interval of the peak period, as defined herein, in the monthly billing period, but not less than 70% of the maximum demand similarly determined for any of the four billing periods of June through September within the 11 preceding months; nor less than 50% of the maximum demand similarly determined during any of the 11 preceding months.

Energy Charge: 2.832¢ per Kwh

Summer-Peak Period is defined as weekdays, except holidays as recognized by Company, from 9 AM to 11 PM local time, during the 4 monthly billing periods of June through September.

Winter-Peak Period is defined as weekdays, except holidays as recognized by Company, from 6 AM to 10 PM local time during the 8 monthly billing periods of October through May.

Power Factor Provision

The monthly demand charge shall be decreased .4% for each whole one percent by which the monthly average power factor exceeds 80% lagging and shall be increased .6% for each whole one percent by which the monthly average power factor is less than 80% lagging.

OUTDOOR LIGHTING SERVICE
(RATE SCHEDULE OL)

RATES:

Overhead Service Mercury Vapor	Rate Per Light Per Month
100 watt*	$6.92
175 watt	7.89
250 watt	8.98
400 watt	11.03
400 watt floodlight	11.03
1000 watt	20.38
1000 watt floodlight	20.38
High Pressure Sodium Vapor	
150 watt	$9.89
150 watt floodlight	9.89
250 watt	11.73
400 watt	12.55
400 watt floodlight	12.55
Underground Service Mercury Vapor	
100 Watt - Top Mounted	$12.00
175 Watt - Top Mounted	12.83
High Pressure Sodium Vapor	
100 Watt - Top Mounted	$14.14

* Restricted to those units in service on 5-31-79.

Special Terms and Conditions:

Company will furnish and install the lighting unit complete with lamp, fixture or luminaire, control device and mast arm. The above rates for overhead service contemplate installation on an existing wood pole with service supplied from overhead circuits only; provided, however, that when possible, floodlights served hereunder may be attached to existing metal street lighting standards supplied from overhead service. If the location of an existing pole is not suitable for the installation of a lighting unit, the Company will extend its secondary conductor one span and install an additional pole for the support of such unit. The customer to pay an additional charge of $1.62 per month for each such pole so installed. If still further poles or conductors are required to extend service to the lighting unit, the customer will be required to make a non-refundable cash advance equal to the installed cost of such further facilities.

PUBLIC STREET LIGHTING SERVICE
(RATE SCHEDULE PSL)

RATE:

TYPE OF UNIT

Overhead Service	Support	Rate Per Light Per Year
100 Watt Mercury Vapor (open bottom fixture)(1)	Wood Pole	$74.57
175 Watt Mercury Vapor	Wood Pole	88.03
250 Watt Mercury Vapor	Wood Pole	100.76
400 Watt Mercury Vapor	Wood Pole	121.45
400 Watt Mercury Vapor (2)	Metal Pole	174.02
400 Watt Mercury Vapor Floodlight	Wood Pole	121.45
1000 Watt Mercury Vapor	Wood Pole	228.43
1000 Watt Mercury Vapor Floodlight	Wood Pole	228.43
150 Watt High Pressure Sodium	Wood Pole	107.36
150 Watt High Pressure Sodium Floodlight	Wood Pole	107.36
250 Watt High Pressure Sodium	Wood Pole	129.36

400 Watt High Pressure Sodium	Wood Pole	136.21
400 Watt High Pressure Sodium Floodlight	Wood Pole	136.21
<u>Underground Service</u>		
100 Watt Mercury Vapor Top Mounted		121.65
175 Watt Mercury Vapor Top Mounted		133.73
175 Watt Mercury Vapor	Metal Pole	179.67
250 Watt Mercury Vapor	Metal Pole	192.87
400 Watt Mercury Vapor	Metal Pole	228.09
400 Watt Mercury Vapor	Alum. Pole	228.09
400 Watt Mercury Vapor on State of KY Aluminum Pole		137.14
100 Watt High Pressure Sodium Top Mounted		133.73
250 Watt High Pressure Sodium Vapor	Metal Pole	245.48
250 Watt high Pressure Sodium Vapor	Alum. Pole	245.48
250 Watt High Pressure Sodium Vapor on State of KY Aluminum Pole		127.19
400 Watt High Pressure Sodium Vapor	Metal Pole	264.89
400 Watt High Pressure Sodium Vapor	Alum. Pole	264.89
1500 Lumen Incandescent (3)	8-1/2' Metal Pole	99.01
6000 Lumen Incandescent (3)	Metal Pole	131.99

(1) Restricted to those units in service on 5/31/79
(2) Restricted to those units in service on 1/19/77
(3) Restricted to those units in service on 3/1/67

STREET LIGHTING ENERGY RATE
(RATE SCHEDULE SLE)

RATE:

4.021¢ per kilowatt-hour

TRAFFIC LIGHTING ENERGY RATE
(RATE SCHEDULE TLE)

RATE:

5.327¢ per kilowatt-hour

Minimum Bill:

$1.45 per month for each point of delivery.

INTERRUPTIBLE SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Availability:

This rider is available for interruptible service to any customer whose interruptible demand is at least 1,000 kilowatts.

Contract Demand:

The contract shall be for a given amount of firm demand which shall be billed at the appropriate standard rate schedule demand charge. Any excess monthly demands above this firm demand shall be considered as interruptible demand.

Rate:

The monthly bill for service under this rider shall be determined in accordance with the provisions of Rate LC, Rate LC-TOD, Rate LP or Rate LP-TOD, except there shall be an interruptible demand credit determined in accordance with one of the following categories of interruptible service:

Interruptible Service Categories	Maximum Annual Hours of Interruption	Monthly Demand Credit ($/Kw/Mo)
1	150	1.18
2	200	1.57
3	250	1.94

The interruptible demand credit shall be applied to the monthly billing demand in excess of the firm contract demand (but not less than 1,000 kilowatts) determined in accordance with the billing demand provision under the applicable rate schedule, except in the case of service under Rate LC-TOD or Rate LP-TOD. The interruptible credit shall be applied to the billing demands as determined for the peak periods only.

Interruption of Service:

The Company will be entitled to require customer to interrupt service at any time and for any reason upon providing at least 10 minutes prior notice. Such interruption shall not exceed 10 hours duration per interruption.

Penalty for Unauthorized Use:

In the event customer fails to comply with a Company request to interrupt either as to time or amount of power used, the customer shall be billed for the monthly billing period of such occurrence at the rate of $15.00 per kilowatt of monthly billing demand. Failure to interrupt may also result in the termination of the contract.

Term of Contract:

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

Applicability of Terms:

Except as specified above, all other provisions of Rate LC, Rate LC-TOD, Rate LP and Rate LP-TOD shall apply.

SUPPLEMENTAL OR STANDBY SERVICE

Applicable:

To Large Commercial Rate LC, Rate LC-TOD, Industrial Power Rate LP and Rate LP-TOD.

Rate:

Electric service actually used each month will be charged for in accordance with the provisions of the applicable rate schedule; provided, however, that the monthly bill shall in no case be less than an amount calculated at the rate of $5.61 per kilowatt applied to the contract demand.

Special Terms and Conditions:

d. In the event customer's use of service is intermittent or subject to violent fluctuations, the Company will require customer to install and maintain at his own expense suitable equipment to satisfactorily limit such intermittence or fluctuations.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-1

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SMALL POWER PRODUCTION AND COGENERATION
PURCHASE SCHEDULE
SPPC-II

Rates for Purchases from
Qualifying Facilities

Capacity component per kilowatt-hour delivered .415¢

Term of Contract:

For contracts which cover the purchase of energy only, the term shall be one year and shall be self-renewing from year to year thereafter, unless cancelled by either party on one year's written notice.

For contracts which cover the purchase of capacity and energy, the term shall be 20 years.

SPECIAL CONTRACT FOR ELECTRIC SERVICE
ARICO ALLOYS AND CARBIDE SPECIAL CONTRACT

Demand Charge

Primary Power (28,500 Kw)	$11.37 per Kw per month
Secondary Power (Excess Kw)	$5.69 per Kw per month
Demand Credit for Primary Interruptible Power (24,500 Kw)	$1.94 per Kw per month
Energy Charge All KWH	2.005¢ per KWH

SPECIAL CONTRACT FOR ELECTRIC SERVICE
E. I. DUPONT DE NEMOURS SPECIAL CONTRACT

Demand Charge

$11.02 per Kw of billing demand per month

Energy Charge

2.128¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
FORT KNOX SPECIAL CONTRACT

Demand Charge

Winter Rate:
(Applicable during 8 monthly billing periods of October through May)

All Kw of Billing Demand — $6.24 per Kw per month

Summer Rate:
(Applicable during 4 monthly billing periods of June through September)

All Kw of Billing Demand — $8.42per Kw per month

Energy Charge: All Kwh per month — 2.742¢ per Kwh

SPECIAL CONTRACT FOR ELECTRIC SERVICE
LOUISVILLE WATER COMPANY SPECIAL CONTRACT

Demand Charge

$7.53 per Kw of billing demand per month

Energy Charge

2.261¢ per Kwh

GENERAL RULES

Charge for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will be made to cover disconnection and reconnection of electric service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Residential and general service customers may request and be granted a temporary suspension of electric service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of electric service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

GAS SERVICES

The Gas Supply Cost component in the following rates has been adjusted to incorporate all changes through PGA 8924-R.

GENERAL GAS RATE
G-1

Curtailment Rules

Delete specific reference.

Availability:

Available for general service to residential, commercial and industrial customers.

Rate:

Customer Charge:

$4.55 per delivery point per month for residential service
$9.25 per delivery point per month for non-residential service

Charge Per 100 Cubic Feet:

Distribution Cost Component	10.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	37.802¢

Off-Peak Pricing Provision:

The "Distribution Cost Component" applicable to monthly usage in excess of 100,000 cubic feet shall be reduced by 5.0 cents per 100 cubic feet during the 7 monthly off-peak billing periods of April through October. The first 100,000 cubic feet per month during such period shall be billed at the rate set forth above.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE G-1

Availability:

Available to any customer who takes gas service under Rate G-1 and who has installed and in regular operation a gas burning summer air conditioning system with a cooling capacity of three tons or more. The special rate set forth herein shall be applicable during the 5 monthly billing periods of each year beginning with the period covered by the regular June meter reading and ending with the period covered by the regular October meter reading.

Rate:

The rate for "Summer Air Conditioning Consumption," as described in the manner hereinafter prescribed, shall be as follows:

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.820¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.802¢

All monthly consumption other than "Summer Air Conditioning Consumption" shall be billed at the regular charges set forth in Rate G-1.

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheets No. 12, 13 and 14 of this Tariff.

SEASONAL OFF-PEAK GAS RATE G-6

Curtailment Rules

Delete specific reference.

Availability:

Available during the 275-day period from March 15 to December 15 of each year to commercial and industrial customers using over 50,000 cubic feet of gas per day who can be adequately served from the Company's existing distribution system without impairment of service to other customers and who agree to the complete discontinuance of gas service for equipment served hereunder and the substitution of other fuels during the 3-month period from December 15 to March 15. No gas service whatsoever to utilization equipment served hereunder will be supplied or permitted to be taken under any other of the Company's gas rate schedules during such 3-month period. Any gas utilization equipment on customer's premises of such nature or used for such purposes that gas service thereto cannot be completely discontinued during the period from December 15 to March 15 will not be eligible for service under this rate, and gas service thereto must be segregated from service furnished hereunder and supplied through a separate meter at the Company's applicable standard rate for year-around service. This rate shall not be available for loads which are predominantly space heating in character or which do not consume substantial quantities of gas during the summer months.

Rate:

Customer Charge: $20.00 per delivery point per month

Charge Per 100 Cubic Feet:

Distribution Cost Component	5.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	32.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Minimum Bill:

The customer charge.

Prompt Payment Provision:

The monthly bill will be rendered at the above net charges (including net minimum bills when applicable) plus an amount equivalent to 1% thereof, which amount will be deducted provided bill is paid within 15 days from date.

RATE FOR UNCOMMITTED GAS SERVICE
G-7

Rate:

Charge Per 100 Cubic Feet:

Distribution Cost Component	4.300¢
Gas Supply Cost Component	26.982¢
Total Charge Per 100 Cubic Feet	31.282¢

The "Gas Supply Cost Component" as shown above is the cost per 100 cubic feet determined in accordance with the Gas Supply Clause set forth on Sheet Nos. 12, 13 and 14 of this Tariff.

Incremental Pricing:

Delete from Tariff.

DUAL-FUEL OFF-PEAK GAS SPACE HEATING RATE
G-8

Service to be supplied under G-1.

SUMMER AIR CONDITIONING SERVICE UNDER GAS RATE
G-8

Service to be supplied under G-1.

GAS TRANSPORTATION SERVICE/STANDBY
RATE TS

Availability:

Available to commercial and industrial customers served under Rates G-1 and G-6 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any transportation service hereunder will be conditioned on the Company being able to retain or secure adequate standby quantities of natural gas from its supplier. In addition, transportation service hereunder shall be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

Rate:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

	G-1	G-6
Distribution Charge Per Mcf	$1.0820	$0.5300
Pipeline Supplier's Demand Component	.4671	.4671
Total	$1.5491	$0.9971

The "Distribution Charge" applicable to G-1 monthly quantities in excess of 100 Mcf shall be reduced by $.50 per Mcf during the 7 off-peak billing periods of April through October. The first 100 Mcf per month during such period shall be billed at the rate set forth above.

Pipeline Supplier's Demand Component:

Average demand cost per Mcf of all gas, including transported gas, delivered to Company by its pipeline supplier as determined from Company's quarterly Gas Supply Clause.

Standby Service:

Company will provide standby quantities of natural gas hereunder for purposes of supplying customers' requirements should customer be unable to obtain sufficient transportation volumes. Such standby service will be provided at the same rates and under the same terms and conditions as those set forth in the Company's applicable rate schedule under which it sells gas to customer.

Receipts and Deliveries:

Customer shall not cause quantities of gas to be delivered to Company's system which exceed the quantities delivered to the customer's place of utilization by more than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof.

GAS TRANSPORTATION SERVICE
RATE T

Applicable:

In all territory served.

Availability:

Available to commercial and industrial customers served under Rate G-7 who consume at least 50 Mcf per day at each individual point of delivery, have purchased natural gas elsewhere, obtained all requisite authority to transport such gas to Company's system through the system of Company's natural gas supplier, and request Company to utilize its system to transport, by displacement, such customer-owned gas to place of utilization. Any such transportation service hereunder shall be conditioned on the Company being granted a reduction in D-1 and D-2 billing demands by its pipeline supplier corresponding to the customer's applicable transportation quantities. In addition, transportation service hereunder will be subject to the terms and conditions herein set forth and to the reserved right of Company to decline to initiate such service whenever, in Company's sole judgment, the performance of the service would be contrary to good operating practice or would have a detrimental impact on other customers served by Company.

Rate:

In addition to any and all charges billed directly to Company by other parties related to the transportation of customer-owned gas, the following charges shall apply:

Administrative Charge: $90.00 per delivery point per month.

Distribution Charge Per Mcf: $0.43

Receipts and Deliveries:

Customer will deliver or cause to be delivered daily and monthly quantities of natural gas to Company's system which correspond to the daily and monthly quantities delivered hereunder by Company to customer's place of utilization and, in no case, shall the variation in quantities be greater than 5%. Any imbalance between receipts by Company on behalf of customer and quantities delivered to customer shall be corrected as soon as practicable, but in no event shall imbalance be carried longer than 60 days.

Special Terms and Conditions:

(1) Service under this rider shall be performed under a written contract between customer and Company setting forth specific arrangements as to volumes to be transported by Company for customer, points of delivery, methods of metering, timing of receipts and deliveries of gas by Company, and any other matters relating to individual customer circumstances.

(2) At least 10 days prior to the beginning of each month, customer shall provide Company with a schedule setting forth daily

volumes of gas to be delivered into Company's system for customer's account. Customer shall give Company at least 24 hours prior notice of any subsequent changes to scheduled deliveries. Customer shall cause gas delivered into Company's system for customer's account to be as nearly as practicable at uniform daily rates of flow, and deliveries of such gas by Company to customer hereunder will also be effected as nearly as practicable on the same day as the receipt thereof. Company will not be obligated to utilize its underground storage capacity for purposes of this service.

(3) In no case will Company be obligated to supply greater quantities hereunder than those specified in the written contract between customer and Company.

(4) Volumes of gas transported hereunder will be determined in accordance with Company's measurement as set forth in the general rules of this Tariff.

(5) All volumes of natural gas transported hereunder shall be of the same quality and meet the same specifications as that delivered to Company by its pipeline supplier.

(6) Company will have the right to curtail or interrupt the transportation or delivery of gas to any customer hereunder when, in the Company's judgment, such curtailment is necessary to enable Company to maintain deliveries to residential and high priority customers or to respond to an emergency.

(7) Should customer be unable to deliver sufficient volumes of transportation gas to Company's system, Company will not be obligated hereunder to provide standby quantities for purposes of supplying such customer requirements.

Applicability of Rules:

Service under this Rider is subject to Company's rules and regulations governing the supply of gas service as incorporated in this Tariff, to the extent that such rules and regulations are not in conflict with nor inconsistent with the specific provisions hereof.

GAS SUPPLY CLAUSE
GSC

Applicable to:

All gas sold.

Gas Supply Cost Component (GSCC): (PGA) 8924-R)

Gas Supply Cost	27.043¢
Gas Cost Actual Adjustment (GCAA)	0.241
Gas Cost Balance Adjustment (GCBA)	(0.269)
Refund Factors (RF) continuing for 12 months from the effective date of each or until Company has discharged its refund obligation thereunder:	
Refund Factor Effective August 1, 1987 from 8924-O (0.020)	
Refund Factor Effective November 1, 1987 from 8924-P (0.013)	
Total of Refund Factors Per 100 Cubic Feet	(0.033)
Total Gas Supply Cost Component Per	26.982¢

The monthly amount computed under each of the rate schedules tp which this Gas Supply Clause is applicable shall include a Gas Supply Cost Component per 100 cubic feet of consumption calculated for each 3-month period in accordance with the following formula:

GSCC = Gas Supply Cost + GCAA + GCBA + RF

where:

Gas Supply Cost is the expected average cost per 100 cubic feet for each 3-month period determined by dividing the sum of the monthly gas supply costs by the expected deliveries to customers. Monthly gas supply cost is composed of the following:

(a) Expected total purchases at the filed rates of Company's wholesale supplier of natural gas, plus

(b) Other gas purchases for system supply, minus

(c) Portion of such purchase cost expected to be used for non-Gas Department purposes, minus

(d) Portion of such purchase cost expected to be injected into underground storage, plus

(e) Expected underground storage withdrawals at the average unit cost of working gas contained therein.

(GCAA) is the Gas Cost Actual Adjustment per 100 cubic feet which compensates for differences between the previous quarter's expected gas cost and the actual cost of gas during that quarter.

(GCBA) is the Gas Cost Balance Adjustment per 100 cubic feet which compensates for any under- or over-collections which have occurred as a result of prior adjustments.

(RF) is the sum of the Refund Factors set forth on Sheet No. 12 of this Tariff.

Company shall file a revised Gas Supply Cost Component (GSCC) every 3 months giving effect to known changes in the wholesale cost of all gas purchases and the cost of gas deliveries from underground storage. Such filing shall be made at least 30 days prior to the beginning of each 3-month period and shall include the following information:

(1) A copy of the tariff rate of Company's wholesale gas supplier applicable to such 3-month period.

(2) A statement, through the most recent 3-month period for which figures are available, setting out the accumulated costs recovered hereunder compared to actual gas supply costs recorded on the books.

(3) A statement setting forth the supporting calculations of the Gas Supply Cost and the Gas Cost Actual Adjustment (GCAA) and the Gas Cost Balance Adjustment (GCBA) applicable to such 3-month period.

To allow for the effect of Company's cycle billing, each change in the GSCC shall be placed into effect with service rendered on and after the first day of each 3-month period.

In the event that the Company receives from its supplier a refund of amounts paid to such supplier with respect to a prior period, the Company will make adjustments in the amounts charged to its customers under this provision, as follows:

(1) The "Refundable Amount" shall be the amount received by the Company as a refund less any portion thereof applicable to gas purchased for electric energy production. Such refundable amount shall be divided by the number of hundred cubic feet of gas that Company estimates it will sell to its customers during the 12-month period which commences with implementation of the next gas supply clause filing, thus determining a "Refund Factor."

(2) Effective with the implementation of the next Gas Supply Clause filing, the Company will reduce, by the Refund Factor so determined, the Gas Supply Cost Component that would otherwise be

applicable during the subsequent 12-month period. Provided, however, that the period of reduced Gas Supply Cost Component will be adjusted, if necessary, in order to refund, as nearly as possible, the refundable amount.

(3) In the event of any large or unusual refunds, the Company may apply to the Public Service Commission for the right to depart from the refund procedure herein set forth.

GENERAL RULES

Charges for Disconnecting and Reconnecting Service:

23. A charge of $14.00 will made to cover disconnection and reconnection of gas service when discontinued for non-payment of bills or for violation of the Company's rules and regulations, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

Customers under General Gas Rate G-1 may request and be granted a temporary suspension of gas service. In the event of such temporary suspension, Company will make a charge of $14.00 to cover disconnection and reconnection of gas service, such charge to be made before reconnection is effected. If both gas and electric services are reconnected at the same time, the total charge for both services shall be $14.00.

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of Adjustment
for
Group Life Insurance

	Amount	Insurance Coverage		Rate	Month	Total Amount
Union Employees:						
A. For first $5,000 of Coverage						
2,459 employees X $5,000	$12,295,000	100%	$12,295,000	.59/1000	12	$ 87,048
B. For additional coverage						
Wages & Salaries	74,634,771	125	93,293,464			
Increase in Salaries - 4%	2,985,390	125	3,731,738			
			97,025,202			
LESS: First $5,000			12,295,200			
			$84,730,002	.44/1000	12	447,372
Union Subtotal						$534,420
Nonunion Employees:						
A. For first $5,000 of Coverage						
1,242 employees X $5,000	6,210,000	100	6,210,000	.59/1000	12	43,968
B. For additional coverage						
Wages & Salaries	39,545,720	125	49,432,150			
Increase in Salaries	275,825	125	344,781			
			$49,776,931			
LESS: First $5,000			6,210,000			
			$43,566,931	.44/1000	12	230,028
Nonunion Subtotal						$273,996
TOTAL						$808,416
Operating Portion @ 72%						582,060
LESS: Test Year Amount per Books						473,680
NET ADJUSTMENT						$108,380

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of
Federal and State Unemployment for
Test Year Ended August 31, 1987

	Federal Unemployment	State Unemployment
Total Employees as of 9/6/87	3,920	3,920
Base Wage	$ 7,000	$ 8,000
Wages Subject to Tax	$27,440,000	$31,360,000
Rate/KIUC Information Request No. 2	.8%	1.2%
Tax	$ 219,520	$ 376,320
Operating Percentage	72%	72%
	$ 158,054	$ 270,950
Operating Tax for Test Year Ended 8/31/87		
January-December 1986	149,039	298,447
January-August 1986	<145,554>	<291,919>
January-August 1987	145,655	242,849
TEST YEAR UNEMPLOYMENT	$ 149,140	$ 249,377
ADJUSTMENT	$ 8,914	$ 21,573
Electric - 77%	6,864	16,611
Gas - 23%	2,050	4,962
	$ 8,914	$ 21,573

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 10064 DATED JULY 1, 1988

Commission Calculation of Year-End Volumes of Business Expense Adjustment

Total Expenses	$255,400,862 [1]
Wages & Salaries:	
Test Year Actual	<66,332,568>[2]
	$189,068,294
Total Electric Operations Revenues	$476,397,820 [3]
Sales to Other Utilities	<1,877,587>[4]
	$474,520,233

Ratio = $\frac{\$189,068,294}{474,520,233}$ = 39.84%

Revenue Increase Per Adjustment	$ 3,627,565
	.3984
	$ 1,445,222
Net Adjustment:	
Revenues	$ 3,627,565
Expenses	4,445,222
	$ 2,182,343

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1 Hart Exhibit 6, page 3, lines 1-6; August 31, 1987 Monthly Report, page 19.

2 Response to the Commission Order dated November 12, 1987, Item No. 16(d), page 2.

3 Hart Prepared Testimony, Exhibit 1, Column 5.

4 *Ibid*.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 181

Responding Witness: William Steven Seelye

Q-181. With regard to Mr. Seelye's LG&E direct testimony, page 53, lines 14 through 17:

a. please provide a specific reference to where the FERC predominance methodology is discussed later in this testimony. Note: if this discussion was inadvertently omitted, please explain and discuss the FERC predominance methodology in this response, and,

b. please provide reference to FERC cases, rules, and/or procedures discussing and utilizing the "FERC predominance methodology."

A-181. a. Under the FERC predominance methodology, production operation and maintenance accounts that are predominantly fixed, i.e. expenses that the FERC has determined to be predominantly incurred independently of kilowatt hour levels of output are classified as demand-related. Production operation and maintenance accounts that are predominantly variable, i.e., expenses that the FERC has determined to vary predominantly with output (kWh) are considered to be energy related. In the cost of service study, demand-related accounts are functionally assigned using the PROFIX vector and energy-related accounts are functionally assigned using the PROVAR vector.

b. The predominance methodology has been accepted in FERC proceedings for over 25 years and is a standard methodology for classifying production operation and maintenance expenses. For example, see *Public Service Company of New Mexico* (1980) 10 FERC ¶ 63,020, *Illinois Power Company* (1980), 11 FERC ¶ 63,040, *Delmarva Power & Light Company* (1981) 17 FERC ¶ 63,044, and *Ohio Edison Company* (1983) 24 FERC ¶ 63,068.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 182

Responding Witness: William Steven Seelye

Q-182. With regard to LG&E Seelye Exhibit 17, please provide all detailed SAS output reports including diagnostic statistics, confidence intervals, number of observations, coefficients, etc.

A-182. The requested data is provided on CD.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 183

Responding Witness: William Steven Seelye

Q-183. Please provide all SAS stepwise selection and output reports generated during Mr. Seelye's LG&E electric weather normalization analysis.

A-183. See response to Question No. 182.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 184

Responding Witness: William Steven Seelye

Q-184. With regard to LG&E Seelye Exhibit 17, page 1, please explain what timing and size metrics the coefficients measure in terms of usage. In other words, do the coefficients relate to daily or monthly usage, sample size, or total class usage? If sample size, please explain in detail and provide all workpapers, analyses, and spreadsheets used to adjust from sample to population amounts.

A-184. The coefficients relate to total class daily usage.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 185

Responding Witness: William Steven Seelye

Q-185. Please provide all weather related data for all weather stations in LG&E's (or its Kentucky affiliates) possession (whether utilized or not in this case) in electronic format. Please provide in Microsoft Excel format if available. If not available in Excel format, please provide in ASCII, common delineated or fixed field format with all fields labeled or identified. In this response, include all weather stations for which data is available, all periods in which data in available, and all weather characteristics available (e.g., HDD, CDD, Max Temp, Min Temp, wind, etc.).

A-185. The requested information is being provided on CD.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 186

Responding Witness: William Steven Seelye

Q-186. Please identify the weather station(s) utilized by Mr. Seelye to conduct his LG&E electric weather normalization analyses.

A-186. Mr. Seelye utilized the Standiford Field (SDF) weather station.

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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 187

Responding Witness: William Steven Seelye

Q-187. Please provide all source documents, analyses, and spreadsheets supporting Seelye LG&E Exhibit 15.

A-187. See response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 188

Responding Witness: William Steven Seelye

Q-188. With regard to Seelye LG&E Exhibit 17, please provide all input data (as selected) for each model in electronic format. Please provide in Microsoft Excel format if available. If Excel format is not available, please provide in ASCII common delineated or field format with all fields labeled or identified.

A-188. See response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 189

Responding Witness: William Steven Seelye

Q-189 With regard to Seelye LG&E Exhibit 18:

a. please provide the Exhibit in executable Excel format (include all linked files); and,

b. using Index 1 (Residential Rate RS), month 5 as an example, please explain in detail how the "CDD70" value of -4369.87 was obtained as well as how the "max temp" value of -6230.33 was obtained. In this response, please also explain how the load data sample was applied to the entire class (population).

A-189. a. See response to PSC-2 Question No. 48.

b. The value of -4369.87 was obtained by multiplying (i) the difference between the normal CDD70 plus one standard deviation (47 + 37 = 84) and actual CDD70 (= 96) (or 84 – 96 = -12) by (ii) the CDD70 coefficient for month 5 (= 364.156), which results in -4369.87. The value of -6230.33 was obtained by multiplying (i) the difference between the normal max temp plus one standard deviation (2368.4 + 105.4 = 2473.8) and actual max temp (= 2511) (or 2473.8 – 2511 = -37.2) by (ii) the max temp coefficient for month 5 (= 167.482), which results in -6230.33. The load data for entire population (either stratified from a sample or from census data) was to derive the coefficients and to calculate the normalization adjustments.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 190

Responding Witness: William Steven Seelye

Q-190. With regard to Mr. Seelye's LG&E direct testimony, page 41, lines 9 through 15, please explain in detail whether Mr. Seelye utilized the entire sample load research data available, or a subset of all sampled load research data observations (customer) in conducting his weather normalization regression analyses. If a subset of the total sampled load research data was utilized, please explain and provide all analyses showing how the selected sample reasonably reflects the usage characteristics of the class.

A-190. The entire sample load research data was utilized.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 191

Responding Witness: William Steven Seelye

Q-191. With regard to the LG&E Direct Testimony of Mr. Seelye, page 17, line 22 through page 18 line 4 and LG&E Exhibit 10, please provide all workpapers, data, electronic computer models and spreadsheets, assumptions, calculations, etc. that show how the proposed class revenue percentage increases and the corresponding revenue dollar increases were determined.

A-191. See response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 192

Responding Witness: William Steven Seelye

Q-192. Please provide a listing of the LG&E gas rate schedules that are included in each of the customer classes presented in the gas CCOSS; i.e., Residential Gas Service, Commercial Gas Service, Industrial Gas Service, As-Available Gas Service, Firm Transportation, and Special Contracts.

A-192. Rate RGS, Rate CGS, Rate IGS, Rate AAGS, Rate FT, and Special Contracts. See Seelye Exhibit 11.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 193

Responding Witness: William Steven Seelye

Q-193. With regard to the LG&E direct testimony of Mr. Seelye, page 80, line 18 through page 86, Line 4; and Exhibit 32, pages 14 and 15, please provide all workpapers, data, electronic computer models and spreadsheets, assumptions, calculations, etc. showing how each of the allocation and functionalization factors used in the CCOSS was developed. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-193. See response to PSC-2 Question No. 48. Hard copies are not provided due to the volume of data requested.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 194

Responding Witness: William Steven Seelye

Q-194. With regard to the LG&E direct testimony of Mr. Seelye, page 86, Footnote 6/, please explain and provide all source documents, workpapers, spreadsheets, assumptions, calculations, etc. that show the basis for each "cost weighting factor" referenced in Footnote 6/ of Mr. Seelye's LG&E direct testimony. Please provide in hard copy as well as in Microsoft readable electronic format (preferably Microsoft Excel).

A-194. See response to PSC-2 Question No. 48. Hard copies are not provided due to the volume of data requested.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 195

Responding Witness: William Steven Seelye

Q-195. With regard to the LG&E direct testimony of Mr. Seelye, page 86, lines 6 through 9, please provide an executable computer spreadsheet of Seelye LG&E Exhibit 35, gas Zero Intercept Analysis.

A-195. See response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 196

Responding Witness: William Steven Seelye

Q-196. With regard to the LG&E direct testimony of Mr. Seelye, Exhibits 33 and 34, please provide an executable computer spreadsheet of Mr. Seelye's LG&E gas class cost of service study (Exhibits 33 and Exhibit 34).

A-196. See response to PSC-2 Question No. 48.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
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Response to Initial Request for Information of the Attorney General
Dated August 27, 2008

Question No. 197

Responding Witness: William Steven Seelye

Q-197. Please provide LG&E Seelye Exhibit 11 in executable Microsoft Excel format.

A-197. See response to PSC-2 Question No. 48.