COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF	)	
KENTUCKY UTILITIES COMPANY AND	)	
LOUISVILLE GAS AND ELECTRIC	)	**CASE NO. 2018-00304**
COMPANY FOR AN ORDER APPROVING	)	
THE ESTABLISHMENT OF REGULATORY	)	
LIABILITIES AND REGULATORY ASSETS	)	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
AND LOUISVILLE GAS AND ELECTRIC COMPANY
TO
ATTORNEY GENERAL'S INITIAL DATA REQUESTS FOR INFORMATION
DATED OCTOBER 1, 2018

FILED: OCTOBER 15, 2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15th day of October 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett
Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 15th day of October 2018.

Judy Schooler
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

JK Wolfe

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12 day of October 2018.

Judy Schooler

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 1

Responding Witness: Christopher M. Garrett / John K. Wolfe

Q-1. Reference the Application at page 6, wherein the Companies describe the number of wires and poles damaged across the utilities' service territories.

a. Provide, with as much specificity and description as reasonably possible, the geographic areas, distribution lines, distribution areas, cities, etc. where the damage from the July 20, 2018 storms to the Companies' system were focused. If reasonably possible, provide specific line names, or, if parallel to roads, the name of those roads or streets and the zip code where those lines are located.

b. Based on the specificity or descriptions provided in response to 1(a), above, provide the costs, both O&M and capital, broken out by geographic area, distribution line, distribution area, city, etc. If reasonably possible, compare the costs related to the July 20, 2018 Storms per geographic area, distribution line, distribution area, city, etc. to the annual expense or average annual expense of those same areas for the past 10 years.

c. Provide an analysis of the extent of outages occurring as a result of the subject storm on the twenty (20) worst-performing circuits for each KU and LG&E.

A-1.

a. See attached. Attachment 1 for KU and Attachment 2 for LG&E contain a listing of distribution circuits which experienced one or more outages as a result of the July 20, 2018 severe weather, sorted by company, local area, and substation.

b. See attached. The Companies do not maintain storm recovery costs to the level of detail described in the request. The attachment contains LG&E's and KU's annual O&M and Capital storm costs for 2008 - 2017.

c. The July 20, 2018 severe weather outbreak produced 2,149 outage events on the LG&E and KU distribution systems. Only 6.5% (140) of these outage events occurred on the twenty distribution circuits which contributed the most to system SAIFI for each Company over the previous five-year period. The following tables list these circuits and the number of outages resulting from the July 20th severe weather event.

LG&E Circuits

Substation	Circuit	July 20th Storm Outage Events
DIXIE	DX1222	5
HARRODS CREEK	HK1234	4
MILL CREEK - LGE	MC1261	0
NACHAND	NA1266	0
DIXIE	DX1223	0
CENTERFIELD	CF1204	0
BRECKENRIDGE	BR1181	2
CLIFTON	CL1232	0
DEL PARK	DE1410	0
WATTERSON	WT1210	0
OXMOOR	OX1274	13
HARRODS CREEK	HK1243	0
INTERNATIONAL	IN1291	3
BRECKENRIDGE	BR1177	8
SEMINOLE	SM1235	0
SOUTH PARK	SP1116	0
SEMINOLE	SM1233	2
SOUTH PARK	SP1115	1
HIGHLAND	HI1105	0
TAYLOR	TA1130	13
	Total	51

KU (Kentucky) Circuits

Substation	Circuit	July 20th Storm Outage Events
FRANKFORT	3411	0
Earlington - Oak Hill (Sec 3B)	3418	0
REYNOLDS	0044	1
JOYLAND	0099	4
LANSDOWNE SWITCHING	0126	4
HOPEWELL	0286	5
SHANNON RUN	0868	11
PICADOME 12KV	0112	1
EVARTS	4476	0
CALLOWAY	0311	0
RICHMOND 2	2313	1
BRYANT ROAD	0874	3
HARLAN 12KV	4406	3
LOUDON AVENUE	0127	5
ROGERS GAP	0451	1
FARISTON	0217	1
VERSAILLES BYPASS	0509	21
PINEVILLE	0301	4
LANSDOWNE SWITCHING	0024	10
LANSDOWNE SWITCHING	0106	14
	Total	89

DANOC
CAMPBELLSVILLE
CAMPBELLSVILLE 1
0233
2203
2205
2234
CAMPBELLSVILLE INDUSTRIAL
0207
COLUMBIA
0209
COLUMBIA SOUTH
2208
GREENSBURG
2213
LEBANON CITY
2216
LEBANON WEST
0218
SPRINGFIELD
2226
UNION UNDERWEAR
2228
DANVILLE
ATOKA
2100
BUENA VISTA
2104
2106
DANVILLE EAST
2113
DANVILLE NORTH
2123
HARRODSBURG EAST
2131
HARRODSBURG INDUSTRIAL
2133
KENTUCKY STATE HOSPITAL
2138
SALVISA
2150
SHAKERTOWN
2151
STANFORD

0156
VAKSDAHL AVENUE
0280
EAROC
BARLOW
CLINTON 12KV
1316
EARLINGTON
DOZIER HEIGHTS
0816
EARLINGTON
1476
MANNINGTON
1802
EDDYVILLE
EDDYVILLE
0560
FREDONIA
1508
GREENVILLE
CENTRAL CITY SOUTH
1650
ECHOLS
1903
GREENVILLE NORTH
1327
HARTFORD
1911
SHAVERS CHAPEL
1609
MORGANFIELD
MORGANFIELD INDUSTRIAL
1763
STURGIS
1728
UNIONTOWN
1742
ELIOC
ELIZABETHTOWN
BLACK BRANCH ROAD
2477
CLARKSON
2404
EASTVIEW
2406
2408

HODGENVILLE
2431
HORSE CAVE
2432
2434
2435
MUNFORDVILLE
2442
RADCLIFF
2448
RINEYVILLE
2334
SONORA
2457
2458
WOODLAWN
2231
LEXOC
LEXINGTON NORTH
BELT LINE
0036
0129
BRYANT ROAD
0149
0150
0151
0873
0874
0904
0905
DONERAIL
0104
0105
EASTLAND
0182
FMC
0120
HAEFLING
0055
0059
0060
HALEY
0045
0046
HUGHES LANE
0037
0063

HUME ROAD
0191
0193
0194
IBM
0103
0110
0140
INNOVATION DRIVE
0591
0592
0595
0596
JOYLAND
0025
0047
0071
0099
0599
LEXINGTON PLANT
0001
0003
0004
0006
0007
LIBERTY ROAD
0042
0091
0092
0095
LOUDON AVENUE
0127
PROCTOR AND GAMBLE
0068
RACE STREET
0014
0015
0030
SPINDLETOP
0082
LEXINGTON SOUTH
AMERICAN AVENUE
0009
0090
0144
ASHLAND AVENUE
0048

0049
0050
0111
0187
BUCHANAN
0005
CLAYS MILL
0146
0147
0148
GE LAMP WORKS
0032
0094
HIGBY MILL DISTRIBUTION
0023
1071
HIGH BRIDGE
0590
KENTUCKY RIVER
0043
KUNKEL
0026
LAKESHORE
0132
0133
0134
0135
0195
LAKESHORE SUB
LANSDOWNE
0024
0033
0106
0118
0126
LEXINGTON WATER COMPANY
0011
0016
0039
0109
0130
MOUNT TABOR
0027
PARKERS MILL
0051

0074
0083
0100
0939
PICADOME
0062
0080
0112
0158
0232
REYNOLDS
0069
0188
SCOTT STREET
0018
SHUN PIKE
0581
STONEWALL
0096
0097
0098
TRAFTON AVENUE
0077
0078
0079
0088
VILEY ROAD
0041
0116
0159
VINE STREET
0021
0125
WEST HIGH STREET
0054
WILMORE
0585
0586
WILSON DOWNING
0081
MIDWAY NORTH
ADAMS
0452
0453
DELAPLAIN
0401
FORKS OF ELKHORN

0405
0406
GEORGETOWN
0425
0426
0427
HOOVER 1
0411
LEMONS MILL
0440
NEWTOWN LEXOC
0431
OXFORD
0470
PEPPER PIKE
0460
0461
ROGERS GAP
0450
0451
SHADRACK
0475
0476
STAMPING GROUND
0481
MIDWAY SOUTH
ALEXANDER
0500
0501
0515
FLORIDA TILE
2505
KUHLMAN
KUHLMAN SUB
LAWRENCEBURG
0160
2515
2516
2517
2518
MIDWAY
0503
0504
0516
SHANNON RUN
0867
0868

VERSAILLES
0505
0506
VERSAILLES BYPASS
0507
0508
0509
0510
0511
VERSAILLES WEST
0512
0513
0514
LONOC
LONDON
CARON
0212
0213
CORBIN EAST
0276
0277
0279
CORBIN US STEEL
0288
FARISTON
0217
HOPEWELL
0285
0286
LONDON
0200
0201
0203
0205
MANCHESTER
0250
MANCHESTER SOUTH
0253
0254
SOMERSET
LIBERTY
0552
REVELO
0577
WAITSBORO
0533
WAYNESBURG

0546
0547
WHITLEY CITY
0576
MAYOC
MAYSVILLE
BUTLER
0950
CARNTOWN
0947
0948
FALMOUTH
0796
FLEMINGSBURG
0960
KENTON
0921
0924
SHARON
0935
WEDONIA
0966
0967
MOREHEAD
FARMERS
0615
MOREHEAD WEST
0616
0617
SALT LICK
0612
0613
MOUNT STERLING
A O SMITH
0607
0608
CAMARGO
0603
0604
0605
0659
EWINGTON
0646
0647
0969
MOUNT STERLING
0600

0601
OWINGSVILLE
0610
0611
PARIS
CARLISLE
0877
0879
CYNTHIANA
0853
CYNTHIANA SOUTH
0881
DETROIT HARVESTER
0801
0802
KAWNEER
0856
NEWTOWN MAYOC
0430
PARIS 12KV
0795
0805
0806
PINOC
HARLAN
CATRONS CREEK
4427
CATRONS CREEK SUB
CAWOOD
0418
DAYHOIT
0414
DAYS BRANCH
0493
HARLAN
4406
4407
HARLAN Y
0413
4412
HIGHSPLINT
0484
HOLMES MILL
0491
KENTENIA
0422

0423
ROBBINS
0487
SHAWNEE GAS
4402
SHAWNEE GAS SUB
VERDA
4480
MIDDLESBORO
CALLOWAY
0311
DEER BRANCH
0319
MELDRUM
0390
MIDDLESBORO 1
0364
0365
MIDDLESBORO 2
0355
0356
0360
MILL CREEK KU
0315
0316
PINEVILLE
0300
0301
0302
0303
STINKING CREEK
0313
0314
STRAIGHT CREEK
0317
RICOC
RICHMOND
BRODHEAD
2103
DARK HOLLOW
0337
IRVINE
2303
MOUNT VERNON
2146
PAINT LICK
2309

PINE HILL
2147
2149
RED HOUSE
2312
RICHMOND
2237
2326
2329
RICHMOND 2
2313
RICHMOND SOUTH
2321
2323
2324
WACO
0331
WINCHESTER
BEATTYVILLE CITY
2300
BOONE AVENUE
0639
0640
0769
PARKER SEAL
0630
ROCKWELL
0626
0627
0628
SYLVANIA
0847
0849
WINCHESTER WATER
0641
0642
SHEOC
CARROLLTON
BEDFORD
0700
CARROLLTON
0709
SHELBYVILLE
EMINENCE
2500
2502
2535

FAIRFIELD
2503
FINCHVILLE
2504
LAGRANGE EAST
2472
2509
2511
LOCKPORT
2532
SHELBYVILLE
2519
2520
SHELBYVILLE EAST
2522
SHELBYVILLE SOUTH
2524
2526
SIMPSONVILLE
2527
2541
TAYLORSVILLE
2529

ALGONQUIN
DIXIE
DX1220
DX1221
DX1222
DX1223
SEVENTH STREET
SE0004
AUBURNDALE
ASHBOTTOM
AS1417
KENWOOD
KE1155
KE1156
KE1157
KE1158
KE1159
CANE RUN
FARNSLEY
FA1123
FA1148
FA1149
FA1215
FAIRDALE
MANSLICK
MK1292
MK1295
MK1296
MK1299
SOUTH PARK
SP1114
SP1115
SP1117
LOUISVILLE (DOWNTOWN)
CROP
CB0001
CB0002
CB0003
EIGHTH STREET
EI0002
MAGAZINE
MG0417
MG1329
PIRTLE
PI0002
PI0003

WESTERN
WE0001
WE0006
LOUISVILLE (WEST)
GRAND
GD0002
NEWBURG / BUECHEL
BISHOP
BI1219
BI1220
ETHEL
ET1169
ET1170
ET1172
ET1173
OKOLONA
FERN VALLEY
FV1134
FV1135
FV1137
FV1138
FV1141
FV1143
FV1477
OKOLONA
OK1273
OK1274
OK1275
SMYRNA
SY1251
SY1252
SY1253
SY1255
PRP
INTERNATIONAL
IN1290
IN1291
PLEASURE RIDGE
PL1270
PL1271
PL1274
TERRY
TE1243
TE1246
TE1247
SHIVELY
SHIVELY

SH1284
STEWART
SW1184
SW1186
SW1187
SW1188
SW1190
SW1191
SOUTH DIXIE
BRANDENBURG
BB1103
WEST POINT
WP1104
SOUTH PRESTON
MUD LANE
ML1281
ML1282
ML1283
ML1284
ML1285
ML1287
ML1288
ML1289
SHEPHERDSVILLE
SV1121
SV1122
U OF L / GERMANTOWN
FLOYD
FL1496
LOCUST
LO1190
LO1192
LO1193
SEMINOLE
SM1232
SM1233
SM1363
VALLEY STATION
ASHBY
AB1202
AB1204
AB1205
AB1207
MILL CREEK SWITCHING
MC1261
MC1262
ANCHORAGE

COLLINS
CO1192
CO1195
CO1196
CO1197
FREYS HILL
FH1209
FH1210
FH1213
FH1214
OLD HENRY
OH1170
OH1173
WORTHINGTON
WO1179
WO1182
WO1184
BROWNSBORO RD
CLIFTON
CL1226
CL1229
CL1230
CL1232
HILLCREST
HC1290
HC1291
HC1292
HC1293
HC1294
HC1434
TAYLOR
TA1105
TA1106
TA1130
TA1132
TA1133
TA1134
TA1138
TA1172
TA1173
CRESTWOOD
CENTERFIELD
CF1202
CF1203
CRESTWOOD
CRESTWOOD SUB
CW1222

CW1224
CW1225
CW1226
CW1228
EOC CENTRAL
DAHLIA
DA1238
DA1239
DA1240
DA1241
DA1242
DA1243
HIGHLAND
HI1101
HI1102
HI1104
HI1105
NACHAND
NA1265
NA1266
NA1268
NA1272
FERN CREEK
FAIRMOUNT
FM1257
FM1259
FM1260
FM1261
FM1262
WATTERSON
WT1151
WT1209
WT1210
WT1212
HURSTBOURNE
BLUEGRASS PARKWAY
BY1278
BY1281
BY1283
HURSTBOURNE
HB1142
HB1144
HB1148
HB1150
JEFFERSONTOWN
JT1120
JT1123

JT1124
JT1125
JT1126
JT1127
LYNDON
LYNDON
LY1111
LY1163
LYNDON SOUTH
LS1241
LS1243
LS1244
LS1245
MIDDLETOWN
AIKEN
AK1290
AK1291
AK1292
AK1296
EASTWOOD WEST
EW1241
EW1242
WHAS
WH1115
WH1116
PROSPECT / GOSHEN
HARMONY LANDING
HL1155
HL1156
HL1157
HL1158
HARRODS CREEK
HK1233
HK1234
HK1235
HK1238
HK1241
HK1243
SKYLIGHT
SK1127
SK1128
ST MATTHEWS
BRECKENRIDGE
BR1176
BR1177
BR1181
BR1185

BR1351
BR1352
OXMOOR
OX1273
OX1274
OX1279
PLAINVIEW
PV1250
PV1251
PV1253
PV1254

Historical Storm Costs

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Electric Distribution										
LG&E										
Capital	9,458,355	10,590,745	681,541	3,680,005	1,210,459	1,099,026	2,706,998	2,234,328	1,317,667	1,174,483
O&M	30,008,003	49,216,775	1,535,593	14,866,414	4,364,361	5,432,638	9,069,912	4,844,214	2,304,503	2,267,174
KU										
Capital	3,477,527	20,090,201	2,112,120	1,476,370	1,370,523	2,117,293	3,904,290	2,509,857	2,469,658	2,303,982
O&M	9,155,653	71,098,926	2,626,598	3,998,403	4,348,856	2,410,744	6,840,824	3,606,330	2,841,206	2,532,603
Transmission										
LG&E										
Capital	437,145	715,221	95,738	335,943	347,245	6,744	98,919	71,716	95,288	153,409
O&M	9,516	121,998	30,665	55,878	48,652	41,154	295,181	143,350	83,641	99,240
KU										
Capital	504,757	17,172,039	808,500	1,212,009	1,584,025	1,325,537	1,278,428	1,212,621	923,044	818,409
O&M	122,735	1,193,151	161,669	324,000	501,093	344,374	393,671	588,286	307,552	176,143
Total										
LG&E										
Capital	9,895,500	11,305,966	777,279	4,015,948	1,557,704	1,105,770	2,805,917	2,306,043	1,412,955	1,327,892
O&M	30,017,518	49,338,773	1,566,258	14,922,292	4,413,013	5,473,792	9,365,093	4,987,564	2,388,144	2,366,414
KU										
Capital	3,982,284	37,262,240	2,920,620	2,688,380	2,954,548	3,442,830	5,182,718	3,722,478	3,392,701	3,122,391
O&M	9,278,389	72,292,078	2,788,266	4,322,403	4,849,950	2,755,118	7,234,495	4,194,615	3,148,758	2,708,747

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 2

Responding Witness: John K. Wolfe

Q-2. Do the Companies breakout distribution vegetation management expense by geographic area, distribution line, distribution area, city, etc. in a manner similar to that requested in 1(a)? If so, describe how specific or detailed the Companies' annual vegetation management plans or expense are.

A-2. No. The Companies manage distribution line clearing budgets and expenses at the company level.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 3

Responding Witness: Christopher M. Garrett / John K. Wolfe

Q-3. Reference the Application at page 6, wherein the Companies describe the number of wires and poles damaged across the utilities' service territories.

a. How many of the 1,200 damaged wires were due to vegetation interfering with distribution wires or interfering otherwise with the distribution system?

i. Do the Companies have available the estimated remaining useful life of the approximately 1,200 wires that were damaged during the July 2018 Storm? If so, provide same.

b. How many of the 200 damaged poles were due to vegetation interfering with distribution poles or interfering otherwise with the distribution system?

i. Do the Companies have available the estimated remaining useful life of the approximately 200 poles that were damaged during the July 2018 Storm? If so, provide same.

A-3.

a. Specific causes of downed conductor are not consistently tracked within the Outage Management System (OMS) during major storm events. Causes can range from vegetation within and outside of the right-of-way, lightning strikes, and strong winds.

i. The Company uses group depreciation for wire and does not maintain useful life at specific locations.

b. Specific causes of damaged poles are not consistently tracked within the OMS during major storm events. Causes can range from vegetation within and outside the right-of-way, lightning strikes, and strong winds.

i. The Company uses group depreciation for poles and does not maintain useful life at specific locations.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 4

Responding Witness: Christopher M. Garrett

Q-4. Reference the Application at page 6, wherein the Companies describe the July 2018 Storm as compared to other damaging storms.

a. Provide support for the statement that "the July 2018 Storm ranks among the top five most damaging storms to hit the KU and LG&E system."

b. Provide the storm-related operations and maintenance expense, excluding normal operations expenses currently embedded in base rates, for the at least four (4) other storms referenced in the above statement. These amounts should be provided in dollar value in the year incurred.

   i. Further, for the at least four (4) other storms referenced on page 6, provide the amount related to normal storm-related operations expenses embedded in base rates for each company at the time of each storm-related occurrence. These amounts should be provided in dollar value in the year incurred.

c. Did the Companies request and receive deferral accounting for each of the at least four (4) other storms referenced on page 6 of the Application?

   i. If the answer to 4(c) is in the affirmative, provide the case numbers of each matter where deferral accounting was requested and approved.

   ii. If not, explain why deferral accounting was not requested in those other instances.

A-4. See response to PSC 1-3.

KENTUCKY UTILITIES COMPANY
AND
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Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 5

Responding Witness: Christopher M. Garrett

Q-5. Reference the Application at page 8, wherein the Companies reference the amount of incremental operations and maintenance expense from the level embedded in base rates.

a. Provide the incremental level for this expense, or any expense, above the level embedded in base rates which causes the Companies to request deferral accounting. This response should provide an indication of what incremental level of an expense above that embedded in base rates (on an absolute, relative or percentage basis) causes the Companies to request deferral accounting as opposed to an incremental level the Companies deem to be a reasonable deviation from that embedded in rates and in line with the risk they take in providing service, and thus lead them to conclude not to request deferral accounting. If the Companies have in their possession any formal or informal guidance or policy documents on this subject, provide same.

b. Other than the requested deferral accounting for a regulatory liability resulting in the reduction of the state income tax expense herein, have the Companies in the past twenty (20) years requested the establishment of regulatory liabilities when the Companies experienced an expense less than the level embedded in base rates? If so, provide the case number for each instance the Companies have requested or received this deferral accounting treatment.

A-5.

a. The Companies do not use the standard identified in the request for information to determine whether to use deferral accounting. Instead, the Companies determine whether to use deferral accounting on a case-by-case basis depending on the facts and circumstances of the expense and accounting guidance and regulatory orders. Deferral accounting is a long-standing and well-established accounting practice in accordance with Generally Accepted Accounting Principles ("GAAP"). For guidance regarding deferral accounting, the Companies use FASB's Accounting Standards Codification 980-340-25-1, *Recognition of Regulatory Assets*, and the Commission's

Orders on regulatory asset accounting.[1] The Commission's Orders in Case No. 2016-00180 placed all jurisdictional utilities on notice that they should seek prior Commission approval for regulatory asset treatment of major storm expenses.[2] The Companies have used deferral accounting in a wide variety of circumstances, including to distribute proceeds to customers.[3]

b. Over the last twenty years, the Companies have recorded regulatory liabilities on a case-by-case basis depending on the facts and circumstances in regulatory proceedings before the Commission. The creation of a comprehensive list would require original work, but recent filings include matters related to refined coal and debt financings. The Companies' regulatory filings are a matter of public record on the Commission's website.

[1] *See e.g.*, *In the Matter of: Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with the Two 2015 Major Storm Events*, Case No. 2016-00180, Orders (Ky. PSC Nov. 3, 2016 & Dec 12, 2016).
[2] *Id.*
[3] *See e.g.*, *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance into Refined Coal Agreements*, *For Proposed Accounting and Fuel Adjustment Clause Treatment and for Declaratory Ruling*, Case No. 2015-00264, Order (Ky. PSC Nov. 24, 2015).

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 6

Responding Witness: Christopher M. Garrett / John K. Wolfe

Q-6. Reference the Application, Exhibit 4.

a. Provide a breakout of the cost category "Miscellaneous."

b. Provide the name of contractors, the contract rate(s) for each contractor, and the billing and expense information that supports the total of $5,045,102 in the cost category "Contractor Labor."

c. Confirm that the Companies anticipated no costs for the cost category "Materials" under "Normal Operations."

d. Provide a breakout of the cost category "Materials" between poles, wires, transformers, etc.

A-6.

a. See response to PSC 1-8b.

b. See attached. The attachment is updated through September 30, 2018 (consistent with the updated Exhibit 4 in response to PSC 1-8e). Contractor rates are calculated by taking the "all-in cost" divided by the total number of hours worked. All-in costs include expense items such as labor, lodging, equipment, etc. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

c. All materials charged to the storm were incremental costs.

d. The breakout of materials is shown below, updated through September 30, 2018 (consistent with the updated Exhibit 4 in response to PSC 1-8e).

Material Description	**LG&E**	**KU**
Tools & Hardware	$ 13,584	$ 52,839
Warehouse Support Labor	4,554	28,397
Connectors	7,151	24,463
Consumables	6,312	11,020
Fuel	0	11,498
Fuses	1,372	4,983
Fleet Maintenance Parts	151	1,160
Total Materials	**$ 33,124**	**$ 134,360**

CONFIDENTIAL INFORMATION REDACTED

Contractor	Work Function	Rate	Estimated Cost
ARC American	Linemen	$ [redacted]	$ [redacted]
Asplundh Construction	Linemen	$ [redacted]	$ [redacted]
Asplundh Tree Experts	Tree Trimmers	$ [redacted]	$ [redacted]
AWP	Traffic Control	$ [redacted]	$ [redacted]
B&B Electric	Linemen	$ [redacted]	$ [redacted]
Blue Grass Energy	Linemen	$ [redacted]	$ [redacted]
Bowlin Energy	Linemen	$ [redacted]	$ [redacted]
Bray	Inspector	$ [redacted]	$ [redacted]
CC Power	Linemen	$ [redacted]	$ [redacted]
CE Power	Substation	$ [redacted]	$ [redacted]
CN Utility Tree Service	Tree Arborists	$ [redacted]	$ [redacted]
Davis H. Elliot	Linemen	$ [redacted]	$ [redacted]
Delta Services	PSRT	$ [redacted]	$ [redacted]
Dynamic Utility	Linemen	$ [redacted]	$ [redacted]
Fishel	PSRT	$ [redacted]	$ [redacted]
Five Star	Linemen / PSRT	$ [redacted]	$ [redacted]
Groves Construction	Linemen	$ [redacted]	$ [redacted]
Intren	Linemen	$ [redacted]	$ [redacted]
J Y Legner	Back office	$ [redacted]	$ [redacted]
Just Engineering	Bird Dog / Dispatcher	$ [redacted]	$ [redacted]
Meade	Linemen	$ [redacted]	$ [redacted]
Miller Construction	Linemen	$ [redacted]	$ [redacted]
MJ Electric	Linemen	$ [redacted]	$ [redacted]
Nelson Tree Service	Tree Trimmers	$ [redacted]	$ [redacted]
Ops Plus	PSRT	$ [redacted]	$ [redacted]
Phillips Tree Service	Tree Trimmers	$ [redacted]	$ [redacted]
PieperLine	Linemen	$ [redacted]	$ [redacted]
Pike	Linemen	$ [redacted]	$ [redacted]
Quality Resources	Bird Dog	$ [redacted]	$ [redacted]
Reed Electric	UG Contractor	$ [redacted]	$ [redacted]
Southeast Power	Linemen	$ [redacted]	$ [redacted]
Storm Services	Linemen	$ [redacted]	$ [redacted]
Townsend Tree Service	Tree Trimmers	$ [redacted]	$ [redacted]
TruCheck	PSRT	$ [redacted]	$ [redacted]
United Electric	Linemen / PSRT	$ [redacted]	$ [redacted]
Willis Lane Construction	Linemen	$ [redacted]	$ [redacted]
Wright Tree Service	Tree Trimmers	$ [redacted]	$ [redacted]
		Total	$ [redacted]
		Sales Taxes	$ [redacted]
		Total Outside Services	**$ 5,434,277**

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 7

Responding Witness: John K. Wolfe

Q-7. Reference the Application at page 7 and the September 28, 2018 Errata filing.

a. Provide the time period referenced in the statement, "the Companies' installation of Distribution Automation ("DA") through August 2018 has resulted in the avoidance of 16,763 service interruptions and a total of more than 6.3 million outage minutes."

i. Provide support, including workpapers in native Excel format, used to calculate these amounts.

ii. Over the same time period referenced in response to 7(a), above, how many outage minutes and service interruptions have the Companies' customers experienced?

iii. For the DA referenced in the Errata filing, provide the capital and O&M expense (on-going and one-time) related to the investment, installation and maintenance spent to date, by year. Any response should include at least 10 years of data, but preferably, the entirety of the life of the DA referenced in the Errata filing.

b. Confirm that the customer interruptions and customer outage minutes for the July 20, 2018 Storm are excluded from the Companies' ordinary determination of certain reliability indices, such as SAIDI and SAIFI.

i. For the past 10 years, provide the SAIDI, SAIFI, and CAIDI calculations for each of the Companies, separately, calculating separately the metrics including only Normal Days, but also the calculations using Major Event Days and Catastrophic Days. Provide the criteria and standards used to determine Major Event Days and Catastrophic Days.

A-7.

a. The Companies began tracking DA related data upon completion of the first DA project recloser installation in July 2017.

i. See the attachment being provided in Excel format. DA reliability data are determined by comparing reliability outcomes resulting from DA recloser operations to reliability outcomes had the recloser not been in place.

ii. LG&E and KU (KY) customers have experienced 302,437,118 outage minutes and 1,171,383 service interruptions from July 2017 through August 2018 due to distribution system outages.

iii. The Distribution Automation project began in 2017. The following table provides spend through September 2018.

Type	2017	2018
Capital	$10,715,760	$20,301,274
O&M Expense	$42,569	$72,804

b. It is confirmed that customer interruptions and customer outage minutes for the July 20, 2018 Storm are excluded from the Companies' ordinary determination of certain reliability indices, such as SAIDI and SAIFI.

i. The Companies adopted the IEEE 1366 standard for determination of a Major Event Day in 2009. IEEE 1366 does not define an objective methodology that can be applied universally to achieve acceptable results related to Catastrophic Days. Thus, consistent with industry reporting and benchmarking practices, the Companies do not distinguish a Catastrophic Day from a Major Event Day in their calculations.

Below are the reliability metrics, including and excluding Major Event Days, from 2008 through 2017. The results show improving reliability trends particularly since inception in 2010 of the Companies' reliability and resiliency programs in response to the 2008 Ike Wind Storm and 2009 Kentucky Ice Storm. LG&E SAIDI and SAIFI excluding Major Event Days have improved by 32% and 31.5%, respectively, while KU (Kentucky) SAIDI and SAIFI excluding Major Event Days have improved by 26% and 30%, respectively.

	LG&E					
	Excluding Major Events			Including Major Events		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2008	94.30	1.042	90.48	3823.19	2.246	1701.88
2009	90.20	0.941	95.83	2845.01	2.073	1372.61
2010	105.87	1.220	86.78	105.87	1.220	86.78
2011	94.36	1.046	90.25	604.93	1.667	362.92
2012	97.11	1.153	84.24	150.91	1.443	104.61
2013	78.50	0.933	84.10	147.39	1.136	129.74
2014	73.75	0.897	82.23	158.62	1.156	137.21
2015	74.45	0.927	80.30	119.10	1.123	106.06
2016	73.03	0.861	84.82	89.70	0.936	95.83
2017	71.93	0.835	86.11	90.81	0.912	99.57
	KU (Kentucky)					
	Excluding Major Events			Including Major Events		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2008	73.28	0.748	97.92	438.74	1.195	367.00
2009	102.06	0.937	108.93	2786.58	1.962	1420.57
2010	89.83	0.948	94.72	89.83	0.948	94.73
2011	100.55	0.989	101.63	148.14	1.085	136.59
2012	95.15	0.847	112.39	120.23	0.932	129.00
2013	82.79	0.752	110.08	94.45	0.795	118.81
2014	79.28	0.752	105.46	156.54	1.000	156.54
2015	78.10	0.773	100.99	102.13	0.893	114.37
2016	99.40	0.858	115.85	106.18	0.882	120.39
2017	66.51	0.661	100.64	92.89	0.739	125.70

The attachment is being provided in a separate file in Excel format.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 8

Responding Witness: John K. Wolfe

Q-8. Reference the Application at pages 9-10. Have the Companies studied the previous instances where storm damage expense has been so extraordinary to require the Companies' request for regulatory accounting to learn from the mistakes or characteristics that lead to such occurrences?

a. If so, provide all such reviews and studies.

b. If the Companies have not reviewed or studied such previous instances, state so.

A-8. The Companies have studied their response to storms for which they have requested regulatory asset treatment in recent years. The Companies, however, dispute the assertion in the request that any "mistakes or characteristics" led to the storm damage. As with all areas of their business, the Companies continue to seek improvement, but are unable to prevent all damage caused by storms of increasing severity.

a. Following the Hurricane Ike Windstorm in 2008 and the Ice Storm in 2009, the Companies contributed to the Commission's *Report on the September 2008 Wind Storm and the January 2009 Ice Storm* ("Report"), which can be viewed at https://psc.ky.gov/IkeIce/Report.pdf. Following those storms, the Companies also responded to the Commission's Recommendations from the Report ("Companies' Response"). The Report and the Companies' Response are attached.

b. See response to part a.

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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

March 1, 2010

RE: Joint Responses of Kentucky Utilities Company and Louisville Gas and Electric Company to Recommendations in Kentucky Public Service Commission Report on the September 2008 Wind Storm and the January 2009 Ice Storm

Dear Mr. DeRouen:

Enclosed please find and accept an original and ten (10) copies of the Joint Responses of Kentucky Utilities Company and Louisville Gas and Electric Company to the applicable Recommendations from the Kentucky Public Service Commission Report on the September 2008 Wind Storm and the January 2009 Ice Storm dated November 19, 2009.

In addition, the Companies agree with and support the findings and recommendations listed in items C1 through C8.

Should you have any questions, please contact me at your convenience.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	A1
Recommendation Statement:	The Commission strongly recommends that all jurisdictional utilities avail themselves of opportunities to participate in emergency planning exercises. The Commission also encourages organizers of such exercises to solicit utility participation.
Person Responsible:	David Guy, Director System Restoration

II. RECOMMENDATION STATUS

X COMPLETE (Considered complete and part of continuing operations.)
___ ONGOING (The implementation of this recommendation is in progress.)
___ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies welcome opportunities to participate in all available emergency planning exercises. Currently the Companies conduct internal drills several times annually and participate in drills organized by the Kentucky Division of Emergency Management, Southern Gas Association and the Southeastern Electric Exchange Mutual Assistance group. Most recently, the Companies participated in the Chemical Stockpile Emergency Preparedness Plan (CSEPP) drill held in central Kentucky.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	A2
Recommendation Statement:	Utilities should exchange and update emergency contact information on at least an annual basis in order to maintain adequate lines of communication.
Person Responsible:	David Guy, Director System Restoration

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies frequently communicate with the Kentucky Division of Emergency Management and local emergency management officials across the Commonwealth. Contact numbers have been recently exchanged and updated, and the Companies will proactively update contact information at least annually. The Companies support and participate in the Governor's workshops and attend quarterly Emergency Management Agency meetings in many of the counties across the state.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

I. RECOMMENDATION REFERENCE

Recommendation No.	A3
Recommendation Statement:	Utilities should arrange to have access to satellite telecommunications during emergencies.
Person Responsible:	David Guy, Director System Restoration

II. RECOMMENDATION STATUS

X COMPLETE (Considered complete and part of continuing operations.)
___ ONGOING (The implementation of this recommendation is in progress.)
___ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies have satellite phones for use during emergencies. The Companies also have five fixed satellite installations located in the Lexington and Louisville Distribution Control Centers, Simpsonville and Dix Dam Transmission Control Centers, and Earlington. The Mobile Command Center has full satellite data capability.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	A4
Recommendation Statement:	All owners of underground facilities should be members of Kentucky 811, the state underground utility location service.
Person Responsible:	David Huff, Director Distribution Operations

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies are members of Kentucky 811. LG&E participates fully. KU participates in 13 counties in central Kentucky, including Fayette County and surrounding counties, where membership is a cost effective approach to facilitate line locating requests. KU continues to evaluate the cost benefit of 811 membership in the rural areas with limited underground facilities.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	A5
Recommendation Statement:	Any utility wishing to recover unreimbursed storm restoration expenses should request Commission authorization to defer such expenses as soon as practical.
Person Responsible:	Lonnie Bellar, VP State Regulation and Rates

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

On October 27, 2008 KU and LG&E each filed applications[1] seeking authority to establish regulatory assets based on their operation and maintenance costs incurred in connection with restoring electric service to its customers following the September 14, 2008 windstorm that hit much of Kentucky in the wake of Hurricane Ike. The Commission, having considered the evidence of record, on December 22, 2008, issued an order granting both KU and LG&E the request to establish a regulatory asset based on the cost each company incurred for storm damages and service restoration due to the windstorm which much of Kentucky experienced on September 14, 2008, in the aftermath of Hurricane Ike. However, the Commission also found that these related costs should not be considered for rate recovery until the Commission has completed its review of the utilities' disaster preparedness and storm restoration efforts. Pursuant to the Commission's Order in each Companies proceeding, on May 4, 2009, KU and LG&E filed the final accounting entries for the final costs related to the wind storm that had been made in each Companies records.

[1]Case No. 2008-00457, Application of Kentucky Utilities Company for an Order Approving the Establishment of a Regulatory Asset.; Case No. 2008-00456, Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

On April 30, 2009 KU and LG&E each filed applications[2] seeking authority to establish regulatory assets based on their operation and maintenance costs incurred in connection with restoring electric service to its customers following the 2009 ice storm and subsequent wind storm that impacted much of Kentucky from January 26, 2009 through mid-February 2009. The Commission, having considered the evidence of record, on September 30, 2009, issued an order granting both KU and LG&E the request to establish a regulatory asset based on the cost each company incurred for storm damages and service restoration due to the winter storm occurring January 26, 2009 through February 14, 2009. However, the Commission also found that these related costs would not be considered for rate recovery until the Commission has completed its review of the disaster preparedness and storm restoration efforts of the utilities under its jurisdiction. Pursuant to the Commission's Order in each Companies proceeding, on December 18, 2009, KU and LG&E filed the final accounting entries for the final costs related to the winter storm that had been made in each Companies records.

KU and LG&E each respectively filed applications[3] on January 29, 2010 requesting an adjustment to the base rates. Included in this request is an adjustment to recover the deferred operating and maintenance expenses that KU and LG&E incurred as a result of the windstorm that occurred in September 2008. The adjustment to operating expenses represents the Companies proposal to amortize this regulatory asset over a five year period and to reverse the timing differences between the impact of recording the regulatory asset in the test year and recording the related costs prior to the test year. In addition, an adjustment to recover the deferred operating and maintenance expenses that KU and LG&E incurred as a result of the winter storm that occurred in January and February 2009 is also included in this request. The Companies propose to amortize this regulatory asset over a five year period.

[2]Case No. 2009-00174, Application of Kentucky Utilities Company for an Order Approving the Establishment of a Regulatory Asset.; Case No. 2009-00175, Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset

[3] Case No. 2008-00548, Application of Kentucky Utilities Company for and Adjustment of its Electric Base Rates.; Case No. 2009-00549, Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rates.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

I. RECOMMENDATION REFERENCE

Recommendation No.	B1
Recommendation Statement:	Jurisdictional utilities should consider upgrading to heavy loading standards in some circumstances. For example, it may be beneficial to shorten span lengths when building lines in treed areas, thus improving the ability of those lines to sustain the weight of fallen vegetation.
Person Responsible:	Nelson Maynard, Director Electric Reliability

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

As concluded in the report, the Companies believe that overhead lines for utilities in Kentucky should continue to be designed to the NESC "medium" loading standard and should not be required to satisfy standards for a "heavy" loading zone. The Companies' overhead distribution facilities meet, at a minimum, the medium loading standards and it is estimated that a majority of their overhead lines also meet the "heavy" loading standard. The Companies believe that the extreme ice and wind loading and resulting extensive damage to trees caused the majority of damage in the 2008 and 2009 storms and this damage would have occurred even if lines were upgraded to "heavy" loading standards. The Companies will continue to routinely evaluate the reliability of circuits and will consider, in appropriate circumstances, upgrading to heavy loading, eliminating hazard trees and other strategies to improve performance of select circuits.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B2
Recommendation Statement:	All utilities should use their routine system evaluations as an opportunity to evaluate the need for and potential effectiveness of system hardening, and to implement those system hardening practices where indicated. Utilities should track outage data for those portions of their systems that have undergone system hardening in order to determine the overall effectiveness of system hardening practices in preventing outages on those circuits. All jurisdictional utilities should evaluate system circuits serving critical infrastructure such as hospitals, police stations, emergency response facilities, drinking water system facilities, fuel locations, and predetermined lodging or staging facilities used during storm restoration and evaluate the potential effectiveness of hardening those critical circuits.
Person Responsible:	Nelson Maynard, Director Electric Reliability

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

Following the 2008 Wind Storm and the 2009 Winter Storm, the Companies engaged Davies Consulting, Inc. to provide options for further improving the reliability of their electrical system. The report by Davies Consulting, Inc. was previously provided to the Commission in connection with its investigation of utilities' responses to the 2009 Winter Storm ("Davies Report"). One recommendation in the Davies Report was the implementation of an Enhanced "Hazard Tree" Program further described in the response to recommendation B5. As an integral part of system hardening, the companies have proposed implementation of such a program upon approval of the "hazard tree" rate adjustment included in Reference Schedule 1.20 of Rives Exhibit 1 of the Application of KU and LG&E for and adjustment of their base rates.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

The Companies will continue to routinely evaluate the reliability performance of circuits, including those serving critical infrastructure, and implementing improvements when warranted. The Companies will continue to track performance after improvements are implemented to measure effectiveness over time.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

I. RECOMMENDATION REFERENCE

Recommendation No.	B3
Recommendation Statement:	Utilities should continue their current practice of placing new facilities underground when the cost differential is recovered through a contribution in aid of construction. Utilities also should continue to replace existing overhead facilities with underground facilities when the requesting party pays the conversion costs.
Person Responsible:	Denise Simon, Director Distribution Operations

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies will continue their current practice of placing new facilities underground when the cost differential is recovered through a contribution in aid of construction. The Companies will also continue to replace existing overhead facilities with underground facilities when the requesting party pays the conversion costs.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and tbe January 2009 Ice Storm
Dated November 19, 2009**

I. RECOMMENDATION REFERENCE

Recommendation No.	B4
Recommendation Statement:	All electric utilities should assess the effectiveness of undergrounding existing service drops as a means of mitigating outages due to extreme weather events. Utilities should consider, on an ongoing basis, the feasibility of undergrounding other overhead facilities that have shown themselves over time to be particularly prone to weather-related outages. Utilities should evaluate the impacts on their systems and their customers of placing all new service drops underground, where feasible.
Person Responsible:	Tom Jessee, Director Asset Management

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Davies Report (referenced in the response to recommendation B2 above) recommended consideration of a pilot program to convert a limited number of overhead residential services to underground in order to verify the cost of conversions, determine acceptance by residential customers, and evaluate reductions in outage frequency and length of time to restore in storm and non-storm conditions. The pilot would consist of converting approximately 500 overhead residential services. It would be implemented in areas where access and vegetation increase the likelihood of frequency and duration of outages.

The Companies plan to begin this pilot program in 2010 with conversion complete in 2012. A minimum of two years will be required to monitor performance after the conversion is complete. At the end of the study period, the Companies will evaluate the results to determine whether undergrounding services is cost-effective. This evaluation will also consider the impact of undergrounding all new services, though it should be noted that the majority of new services are already installed underground at the request of customers.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

As described in the response to recommendation B2, the Companies routinely evaluate reliability performance of circuits. Undergrounding will be considered along with other strategies, including hazard tree removal, for circuits subject to frequent outages.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B5
Recommendation Statement:	All jurisdictional electric utilities should take steps to increase removal of such hazard trees and those steps are to be reported to the PSC as updates to utility vegetation management plans.
Person Responsible:	Nelson Maynard, Director Electric Reliability

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies currently have a "hazard tree" program that is focused on removing dying, diseased, or weakened trees that provide an imminent threat to electric infrastructure. As referenced in the response to recommendation B2, the Davies Report recommends implementation of an Enhanced "Hazard Tree" Program to aggressively seek permission from property owners to remove additional "hazard trees" from outside the right of way. The scope of the program depends on the willingness of the property owners to allow removal of these "hazard trees" from their property. The report estimates that there are approximately 80,000 "hazard trees" adjacent to the distribution right of way. The Companies estimate, with greater cooperation from the property owners, they would be able to secure permission to remove up to 50% of the "hazard trees" over a 5 year period. As an integral part of system hardening, the Companies have proposed implementation of such a program upon approval of the "hazard tree" rate adjustment included in Reference Schedule 1.20 of Rives Exhibit 1 of the Application of KU and LG&E for and adjustment of their base rates.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B6
Recommendation Statement:	Electric utilities should conduct regular audits and inspections of pole routes to ensure continued compliance with applicable standards, including evaluations of structure loadings and facility clearances. In instances in which the pole-route owner determines that third-party attachments are inappropriate or unsafe, the Commission expects the attaching party to be notified of the specific location(s) and details for each area of concern, and advised of the precise procedures necessary to correct the deficiency. If the identity of the attaching party cannot be obtained, or the attaching party refuses to engage in actions necessary to correct the deficiency, the utility may take steps, in accordance with its pole attachments tariff, to remove the attachments. The Commission expects attaching parties to notify the pole-route owner of each specific intention to make attachments and to seek approval of such attachments pursuant to governing agreements or tariffs prior to placement. Such required notifications include circumstances where additional facilities will be placed in pole-attachment space already occupied pursuant to an approved pole-attachment arrangement.
Person Responsible:	Nelson Maynard, Director Electric Reliability

II. RECOMMENDATION STATUS

_____ COMPLETE (Considered complete and part of continuing operations.)
__X__ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the Septemher 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

III. ACTION TAKEN ON RECOMMENDATION

The Companies routinely conduct inspections of pole routes to ensure continued compliance with applicable codes and standards, including facility clearances. In instances in which the Companies determine that third-party attachments are inappropriate or unsafe, the attaching party is notified of the specific location(s) and details for each area of concern, and advised of the procedures necessary to correct the deficiency. Additionally, the Companies have processes in place to effectively manage installation of new attachments ensuring compliance with appropriate codes and standards. The Companies expect to incorporate an evaluation of structure loading into their wood pole inspection program.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B7
Recommendation Statement:	The Commission will amend its regulations to clarify that on-the-ground inspections are to be the primary method of system inspection. In the interim, the Commission recommends that jurisdictional utilities use on-the-ground inspections as the primary means of system inspection.
Person Responsible:	Ed Staton, Director Transmission David Huff, Director Distribution Operations

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II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
____	ONGOING (The implementation of this recommendation is in progress.)
X	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies currently employ comprehensive distribution and transmission inspection programs. The plans incorporate safety, regulatory compliance, customer (landowner) impacts, and reliable operation. Due to the nature of the system, transmission lines are inspected with a combination of aerial and on-the-ground patrols which include climbing, ground-line and steel corrosion inspections.

For the distribution system, on-the-ground patrols are used as the primary method of inspection. Aerial patrol is not a primary means of inspection for distribution. Distribution is often located in no fly zone urban areas. Distribution is on lower profile shorter poles and the right of way is more congested, which makes aerial patrols impractical. Ground patrols are also preferable in inspecting distribution equipment such as transformers and service connections to the customer.

Transmission lines currently are ground patrolled in urban and other areas deemed to be "no-fly zones". Aerial patrol is primarily utilized across the remainder of the transmission system and is a highly technical operation involving both the pilot and a trained patrolman, each of which undergo specific training for transmission line inspections. Aerial inspections are

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

more efficient and allow a more comprehensive inspection providing an up close three dimensional view of every structure, focusing the inspection on the part of a structure that is most susceptible to "deterioration", the wood cross-arms and braces. Wood cross-arms and braces generally "deteriorate" first on the top, as a result of constant exposure to sun and weather elements. Also, insulators and conductors can be more thoroughly viewed with an aerial inspection. Aerial patrol allows for multiple comprehensive inspections during the year of the transmission system. In summary, the current program allows the companies to inspect the transmission system (which traverses a very diverse geographic footprint with substantially different terrains) multiple times each year. The Companies believe the addition of mandatory on-the-ground inspection of the entire transmission system introduces additional costs, with limited reliability benefits. The Companies are open to and invite more discussion with KPSC staff concerning mandatory on-the-ground patrols of transmission lines.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

I. RECOMMENDATION REFERENCE

Recommendation No.	B8
Recommendation Statement:	Jurisdictional electric utilities should conduct formal post-restoration inspections subsequent to any future major outage event and report their findings as may be directed by the Commission.
Person Responsible:	Nelson Maynard, Director Electric Reliability

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

Upon completion of restoration efforts following significant weather events, the Companies currently conduct post-restoration inspections of their electric distribution systems. Qualified personnel visually inspect each impacted electric circuit, from the substation to the customer.

The focus of post-restoration inspections includes identification of:

- Unsafe conditions remaining on the electric system;
- Visible damage necessitating follow-up work to repair;
- Debris, equipment, or materials needing removal;
- Vegetation canopy, hangover, or contact issues requiring correction; and
- Third party property damages requiring refurbishment.

All inspections are documented on a circuit print, and a standardized inspection summary form. Work requests or packets are developed and assigned to field resources to resolve all identified deficiencies. Post storm inspections are important to prevent additional outages and to eliminate unsafe conditions, however all damage is not visible and future outages related to the original storm can occur.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B9
Recommendation Statement:	In all future weather-related outages, electric utilities should accurately record the number of overhead and underground service drops requiring separate repairs in order to restore service.
Person Responsible:	Nelson Maynard, Director Electric Reliability

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

When reconnection of service is required, the Companies will track and record the number of customer service drops that have damage to customer owned service equipment during major weather-related events.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B10
Recommendation Statement:	Every jurisdictional electric utility should acquire an OMS.
Person Responsible:	David Huff, Director Distribution Operations

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II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies completed implementation of an OMS in 2004. The OMS continues to be an integral part of outage determination and prioritization of restoration activities.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B11
Recommendation Statement:	Utilities with an OMS should ensure that the OMS electrical model is kept current so that it can accurately make outage predictions and also accurately keep track of which customers are out and which are restored.
Person Responsible:	Tom Jessee, Director Asset Management

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies have processes in place to keep the electric model in the OMS up to date. Each week all circuits with changes are extracted from the Geospatial Information System (GIS) and translated into the OMS.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B12
Recommendation Statement:	Every jurisdictional electric utility company should contact the NWS office covering its service area to establish e-mail notification of conference calls conducted in advance of anticipated severe weather events and participate in such calls when notified. Jurisdictional utilities should plan to attend the meeting with the NWS.
Person Responsible:	David Guy, Director System Restoration

II. RECOMMENDATION STATUS

X COMPLETE (Considered complete and part of continuing operations.)
___ ONGOING (The implementation of this recommendation is in progress.)
___ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies have established email notification of and participated in NWS conference calls since 2005. This includes the Paducah, Louisville and Jackson Kentucky offices. The Wilmington, Ohio, Charleston, West Virginia and Morristown, Tennessee offices (which also cover parts of Kentucky and Virginia) currently do not have conference calls; however, the Companies are in contact with them as needed.

The Companies also attended the NWS meeting at the KPSC Offices on Friday, January 8, 2010.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B13
Recommendation Statement:	Utilities that do not have sufficient personnel to devote solely to logistical support during a major outage event should take steps to determine as part of their emergency planning whether such logistical support personnel are available through mutual aid assistance or other sources, and, if so, how such personnel can be best utilized.
Person Responsible:	Mark Schmitt, Director Supply Chain

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies' personnel is sufficient to devote solely to logistical support during major outage events.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B14
Recommendation Statement:	Electric utilities should examine their Emergency Response Plans to ensure that they have adequate provisions for either dedicated fuel tankers or other fuel sources during emergency restoration operations.
Person Responsible:	Mark Schmitt, Director Supply Chain

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies have two mechanisms to secure and dispense dedicated fuel in a restoration effort. As part of its normal operation, the Companies have established a network of service stations across the entire service territory where fuel can be obtained. In an emergency restoration event these stations are used by responding resources.

For a "large" restoration response, established contracts are in place with multiple suppliers of unleaded and diesel fuel. The primary suppliers are located in the Louisville area but can be, and have been, dispatched throughout the entire service territory.

Fuel distribution is in the form of stationary "stations" as well as mobile tankers. Stationary "stations" are typically utilized in crew staging areas where large numbers of vehicles are maintained. Mobile tankers can be located at strategic locations where a concentrated number of vehicles are working or have easy access. These vehicles remain in the affected restoration area for the duration of the event are staffed full-time and are replenished by mobile tankers from the supplier's home base.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B15
Recommendation Statement:	IOUs should monitor insurance markets for the development of catastrophic coverage and other potentially applicable products. As such products become available, the IOUs should evaluate the cost-effectiveness of obtaining coverage.
Person Responsible:	Dan Arbough, Treasurer

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies continue to monitor the insurance markets for potential sources of insurance to cover costs associated with storm damage. A consultant has been retained to perform an analysis of expected transmission and distribution losses on the Companies system associated with the 2009 ice storm. The results of this study, which are expected later this year, will then be used to determine whether commercial insurers are willing to underwrite the risk at a reasonable cost.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B16
Recommendation Statement:	Electric utilities should take the necessary steps to improve customer access to customer service functions. Utilities should review their disaster response plans and make any changes needed to provide for adequate staffing of customer service functions during outages, including cross-training of employees to supplement consumer service staff, extending consumer service hours and providing for third-party backup if necessary. Utilities should provide for backup power in order to maintain call center operations in the event that the utility offices lose power.
Person Responsible:	Butch Cockerill, Director Revenue Collection

II. RECOMMENDATION STATUS

__X__ COMPLETE (Considered complete and part of continuing operations.)
_____ ONGOING (The implementation of this recommendation is in progress.)
_____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies have business recovery plans in place for the customer service office locations. Company management reviews these plans annually. The Companies also have historically supplemented customer service staff and extended regular business hours during major outage events, and are positioned to continue this practice in the future. The Companies operate the residential call center as a "virtual call center" because facilities in Louisville, Lexington and Pineville have the infrastructure and staffing in place to allow routing of customer calls among all three centers in a manner transparent to the customer. The business call center also operates virtually between the Louisville and Lexington office locations. Backup generation is in place for both the Louisville and Lexington facilities should these offices lose power. Finally, the Companies utilize a third party service to assist with call overflow should the Companies' call centers be unable to accommodate the call volume for any reason. The third party service permits automated reporting of outages and interfaces with the Company outage reporting tools, so that the entire outage-reporting process is transparent to the customer.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B17
Recommendation Statement:	Electric distribution utilities should include on their Web sites a section specifically for outage information. On an ongoing basis, this section should include information for customers regarding electric safety and disaster preparedness. During major outages, the Web site should be used to provide information on the location of outages, restoration efforts and expected duration of outages. At a minimum, the information should be specific to county or, in urban areas, ZIP code. Information should be presented on a map if possible and should be updated at least daily. Utilities should post press releases on the Web site as well.
Person Responsible:	David Huff, Director Distribution Operations

II. RECOMMENDATION STATUS

____ COMPLETE (Considered complete and part of continuing operations.)
__X__ ONGOING (The implementation of this recommendation is in progress.)
____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies maintain a section specifically for outage information on their Web site. This section includes information for customers regarding electric safety and disaster preparedness. Press releases are posted on the Web site as well.

The Companies are near completion of an initiative to make outage maps available online to the public showing current power outage conditions across the service territories. The user will be able to view this information by "location" (outage event), county or ZIP code. Different information is displayed depending on the view; it includes the number of customers affected, the number of customers served, date, time the outage was reported and the estimated restoration time. Outage information will be updated at least daily.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B18
Recommendation Statement:	All utilities should examine the possibility of establishing their own accounts with Twitter.com, Facebook.com or any similar social networking services, utilize these services as a means of disseminating outage-related information and inform their customers about the availability of information via these services.
Person Responsible:	Chris Whelan, Director Communications & Brand Mgt

II. RECOMMENDATION STATUS

X	COMPLETE (Considered complete and part of continuing operations.)
	ONGOING (The implementation of this recommendation is in progress.)
	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies created a Twitter account in May 2009 and currently have 550 followers. The account is used to tweet about storms, outages and other important information about the business.

**KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

**Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009**

I. RECOMMENDATION REFERENCE

Recommendation No.	B19
Recommendation Statement:	Utilities which currently utilize automated outage reporting via telephone should explore the possibility of using the same systems to deliver restoration information to consumers on a targeted basis. The Commission also recommends that utilities explore the possibility of developing such outbound information services based on e-mails or text messages to wireless devices designated by customers.
Person Responsible:	Butch Cockerill, Director Revenue Collection

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies currently utilize automated outbound calling in the restoration process. If a customer calls to report an outage, the Companies have a system in place that permits an automated return call to be placed to that customer when the restoration is complete. The process allows company staff to designate which customers receive return calls and the time at which the calls are released. In 2010, the Companies are exploring the technology options available for providing restoration information updates via outbound calling, text message, or email as designated by the customer.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B20
Recommendation Statement:	Electric utilities should include service entrance repair information on their Web sites and, for the investor-owned utilities, in at least two bill inserts per year. Electric cooperatives are also encouraged to include service entrance repair information in monthly publications or, if feasible, in at least two bill inserts per year.
Person Responsible:	Chris Whelan, Director Communications & Brand Mgt

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies have had service repair information on their Web site for a number of years. The information includes a graphic and description of the masthead as well as the steps to take if the customer's masthead is damaged.

The Companies have traditionally included this information in a bill insert once a year and now have plans to communicate this information through a dedicated bill insert at least twice per year.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B21
Recommendation Statement:	Utilities should provide customers with information about outage reporting procedures. At a minimum, this should include: • The number or numbers to call to report an outage. • The availability, if any, of outage reporting via e-mail or text message from wireless devices. • An explanation of automated outage reporting, if applicable, and why it is important that customers use it. • A request that every customer who loses power calls to report an outage, but that customers make only one such report. • Instructions on when a call to 911 is appropriate and when it is not.
Person Responsible:	Chris Whelan, Director Communications & Brand Mgt

II. RECOMMENDATION STATUS

____ COMPLETE (Considered complete and part of continuing operations.)
__X__ ONGOING (The implementation of this recommendation is in progress.)
____ DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

The Companies currently provide the numbers to report an outage in several ways. These include printing on the top of the customer bills, inclusion in the customer newsletters, posting on the corporate Website, listing in the telephone book, and presentation of the numbers through the news media at the onset of outage events. The Companies have also started accepting outage reporting on the Website through the customer self-serve functionality.

The process of reporting an outage through the automated phone system is explained in detail on the Website and is periodically included in the customer newsletters. Additionally, during an outage, the media is reminded that customers are to report their outages and that reporting it once is sufficient.

Call center representatives inform customers at the beginning of a call that if an event is dangerous or life threatening then they should call 911. This information will also be posted on the Website.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Kentucky Public Service Commission
Report on the September 2008 Wind Storm and the January 2009 Ice Storm
Dated November 19, 2009

I. RECOMMENDATION REFERENCE

Recommendation No.	B22
Recommendation Statement:	Utilities should inform customers when severe weather or other circumstances require large numbers of bills to be based on estimates instead of actual readings. This information should be incorporated into utility communications regarding safety and other outage-related topics.
Person Responsible:	Butch Cockerill, Director Revenue Collection

II. RECOMMENDATION STATUS

____	COMPLETE (Considered complete and part of continuing operations.)
X	ONGOING (The implementation of this recommendation is in progress.)
____	DISAGREE (The Companies do not agree with this recommendation.)

III. ACTION TAKEN ON RECOMMENDATION

A customer's bill currently indicates when an estimated reading has occurred. The Companies are developing a message which will print directly on the customer's bill advising them that their usage has been estimated due to storm restoration work. This message would only be placed on those customers' bills where service was estimated. In addition, the Companies will note on the website that customer bills may be based upon estimates instead of actual readings in the event of severe weather or other circumstances.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 9

Responding Witness: John K. Wolfe

Q-9. Reference the Application generally. Have the Companies observed any material similarities between the different areas affected by the July 2018 Storm, such as types of poles or wires, topography, or the vicinity of vegetation or specific types of vegetation, etc.?

a. If so, provide and describe same, including a response indicating the efforts the Companies are taking to protect customers from similar instances, including the costs resulting thereof.

A-9. Multiple rounds of widespread severe weather were experienced across the Companies' impacted service areas. Harder hit areas experienced wind speeds between 60 and 70 mph. Affected circuits were constructed and maintained according to NESC and the Companies' construction standards. Affected facilities typically involved overhead construction with wood poles and crossarms.

a. Beginning in 2010, in response to the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm, KU/LG&E Electric Distribution Operations has focused on improving distribution system reliability and resiliency by increasing capital investments in circuit hardening, critical asset contingency, aging infrastructure replacement, and grid intelligence technologies. Annual investments related to distribution system reliability and resiliency improvement have increased from about $1.5 million in 2005 to nearly $55 million in 2017. These initiatives have produced significant system wide improvements in LG&E and KU SAIDI (22%) and SAIFI (26%) between 2010 and 2017.

   See attached. The KU/LG&E Electric Distribution Operations Distribution Reliability and Resiliency Improvement Program includes information related to previous and planned EDO reliability and resiliency programs and investments.

Electric Distribution Operations

Distribution Reliability & Resiliency Improvement Program

LG&E® KU®
PPL companies

August 2018

Contents

Tables

Figures

Executive Summary

As stewards of the LG&E and KU electric distribution system, Electric Distribution Operations (EDO) is responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers. Acting upon this responsibility and consistent with industry trends, EDO has focused on improving distribution system reliability and resiliency by increasing capital investments in circuit hardening, critical asset contingency, aging infrastructure replacement, and grid intelligence technologies. These initiatives have produced significant improvements in LG&E and KU SAIDI (22%) and SAIFI (26%) between 2010 and 2017 as well as LG&E and KU's customer satisfaction ratings which have improved by 35 percent and 9 percent, respectively.

To continue these improving trends, this Distribution Reliability and Resiliency Improvement Program (DRRIP) provides nearly $465 million total capital investment and $30 million in total expenses during 2019 through 2023 focused on the strategies shown below.

- System reliability and contingency investments to meet increasing customer expectations respective to service availability
- Investments in aging infrastructure to continue long term service reliability
- Advanced grid intelligence to meet evolving customer expectations and align with industry trends
- Respond to outage events in an efficient and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times
- Technology which enhances business processes, reduces cycle times, and expands communications with customers.

Specific investment and operating initiatives evaluated and prioritized through EDO's investment selection methodology are provided in the DRRIP and in EDO's 2019 Business Plan (BP). These initiatives include the following:

- Continued development and enhancement of a centralized grid operation strategy
- Continuation and extension of automation on the distribution system;
- Continued funding for the distribution substation transformer contingency program;
- Continuation of existing reliability improvement programs; and
- Continued expansion of existing aging infrastructure replacement programs.

In summary, this DRRIP delivers prudent investment and operating strategies to ensure continued improvement in LG&E and KU's reliability and customer satisfaction performance by advancing grid intelligence, providing for increased operational control and flexibility, prudently replacing aging assets, and building additional contingency into critical assets.

1.0 Background

1.1 LG&E and KU Performance and Investments

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) serve nearly 1.3 million customers, and consistently rank high in customer satisfaction among utilities. LG&E serves 411,000 electric customers in Louisville and 9 surrounding counties, and KU serves 553,000 electric customers in 77 Kentucky counties and five Virginia counties.

LG&E and KU participate in multiple industry accepted customer satisfaction surveys, the most recognizable of which is administered by J.D. Power, which evaluates several key indices. The 2017 J.D. Power Electric Utility Residential Customer Satisfaction Study placed KU first and LG&E second in residential customer satisfaction among Midwest midsize utilities. Both utilities achieved first quartile rankings in categories such as Power Quality and Reliability, Billing and Payment, Price, Corporate Citizenship, Communication, and Customer Service. While each category drives customer satisfaction to some degree, satisfaction with a utility's Power Quality and Reliability was the most significant factor in determining overall customer satisfaction. LG&E and KU results are shown in Figure 1 below. Areas of significant improvement compared to the 2016 survey are circled.

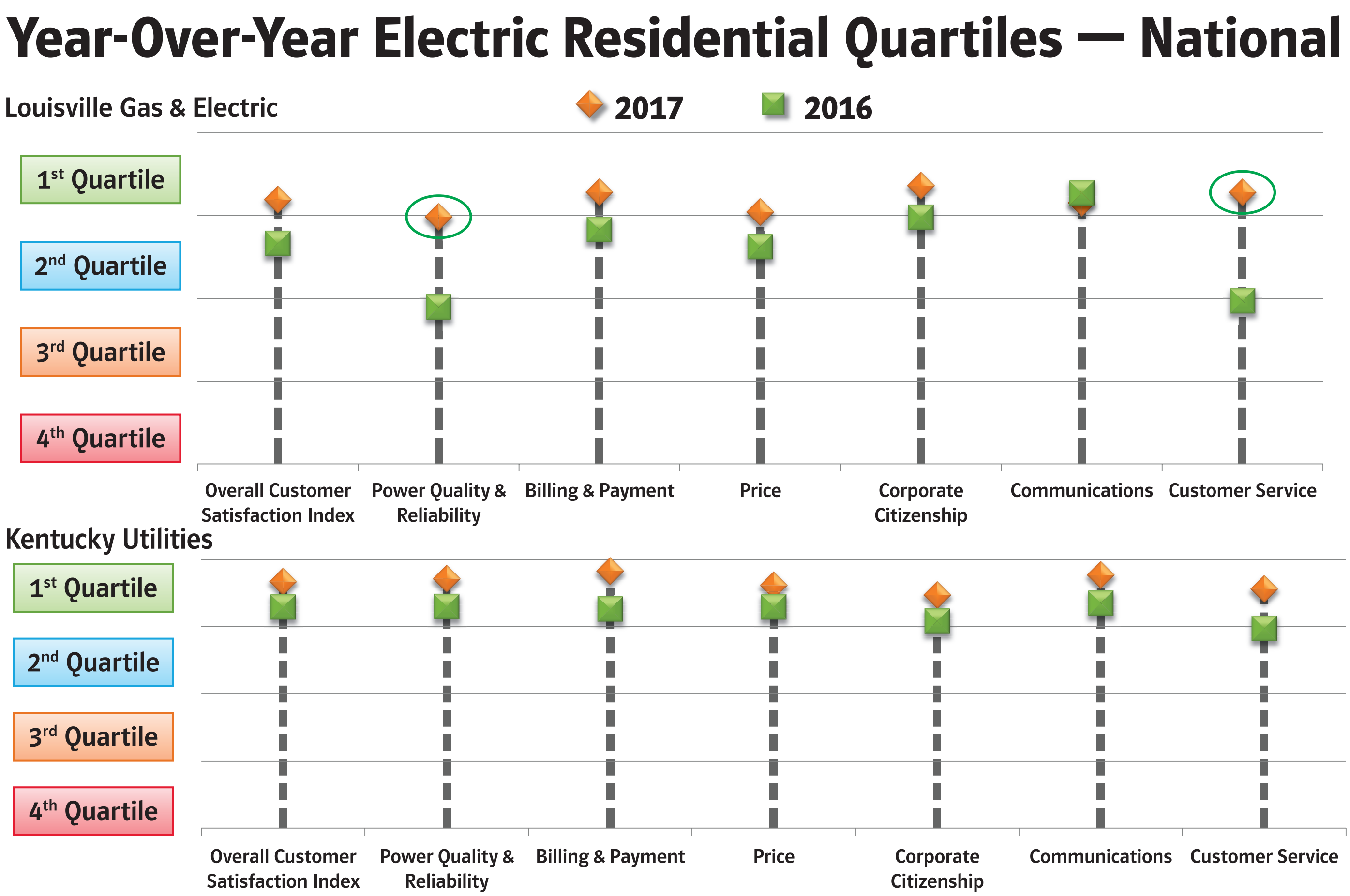

Figure 1: J.D. Power 2017 Electric Utility Residential Customer Satisfaction Study

Electric Distribution Operation's (EDO) primary benchmarking surveys for reliability performance[1] within the electric industry are REDACTED - Third Party Confidentiality Agreement Figures 2–5 display LG&E and KU SAIDI and SAIFI performance against REDACTED - Third Party Confidentiality Agreement performance thresholds since 2006.

1. Since 2010, and consistent with the utility industry, LG&E and KU has tracked and reported electric reliability indices as defined by the Institute of Electrical and Electronics Engineers (IEEE) standard P1366, "Guide for Electric Distribution Reliability Indices." The general acceptance of these metrics by the industry makes them useful as benchmarks and as long-term average system performance measures. They are also useful tools to help guide decision making respective to sustaining or enhancing reliability performance.
   The primary IEEE 1366 performance metrics tracked and benchmarked by LG&E and KU are:
   - System Average Interruption Frequency Index (SAIFI) — calculated by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is interruptions per customer.
   - System Average Interruption Duration Index (SAIDI) — calculated by summing the customer-minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during that period. The resulting unit is minutes.

REDACTED - Third Party Confidentiality Agreement

Figure 2: LG&E and KU Distribution SAIDI performance against REDACTED - Third Party Confidentiality Agreement[2]

REDACTED - Third Party Confidentiality Agreement

Figure 3: LG&E and KU Distribution SAIFI performance against REDACTED - Third Party Confidentiality Agreement

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[redacted]

REDACTED - Third Party Confidentiality Agreement

[redacted]

Figure 4: LG&E and KU Distribution SAIDI performance against REDACTED - Third Party Confidentiality Agreement[4]

REDACTED - Third Party Confidentiality Agreement

[redacted]

Figure 5: LG&E and KU Distribution SAIFI performance against REDACTED - Third Party Confidentiality Agreement[5]

4. Includes distribution lines and substations SAIDI, and excludes Major Event Days.

5. Includes distribution lines and substation SAIFI, and excludes Major Event Days.

LG&E and KU's SAIDI and SAIFI performance ranked in first quartile [redacted], and upper second quartile [redacted], prior to the 2008 Hurricane Ike Wind Storm and 2009 Kentucky Ice Storm. Immediately following these storms, the most significant outage events in the combined utilities' histories,[6] LG&E and KU's actual and comparative reliability performance (Figures 2–5) and customer satisfaction levels declined. Moreover, LG&E and KU customer satisfaction levels reached historically low levels between 2009 and 2011.

In response to the historical storms and reduced customer satisfaction levels, EDO studied alternatives for enhancing electric system resiliency[7] to guard against similar extensive system damages and long duration outages for customers. From this study, EDO implemented several system reliability and resiliency enhancement programs in 2010, including a Pole Inspection and Treatment Program (PITP) and Hazard Tree Program. EDO also increased investments in circuit hardening reliability programs that had proven valuable over time, namely the Circuits Identified for Improvement (CIFI) program. In subsequent years, EDO allocated incremental funding for Aging Infrastructure Replacement (AIR) and Distribution Substation Transformer Contingency (N1DT) programs.

EDO's increased investments in reliability and resiliency produced significant improvements in LG&E and KU SAIDI (22%) and SAIFI (26%) between 2010 and 2017. Additionally, LG&E and KU's customer satisfaction ratings improved by 35 percent and 9 percent, respectively. EDO attributes much of its realized reliability improvements to its CIFI program. Between 2010 and 2017, EDO completed circuit hardening on 234 LG&E and KU circuits which were targeted for the CIFI program based on historical Customers Interrupted (CI).

When the CIFI program was initiated, EDO understood that eventually, the same investment would yield progressively smaller reliability benefit per dollar invested. As the CIFI program progressed, the average annual SAIFI contribution of circuits targeted for the program steadily decreased, indicating reduced opportunity to realize further step improvements in SAIFI through the existing program. Realizing this, EDO assessed alternative investment strategies for achieving step improvements in reliability and customer satisfaction. As a result of EDO's assessment, and upon receiving CPCN approval in 2017, LG&E and KU began its Distribution Automation (DA) program.

Figure 6 displays EDO's electric distribution system reliability and resiliency capital investment allocations between 2005 and 2017.

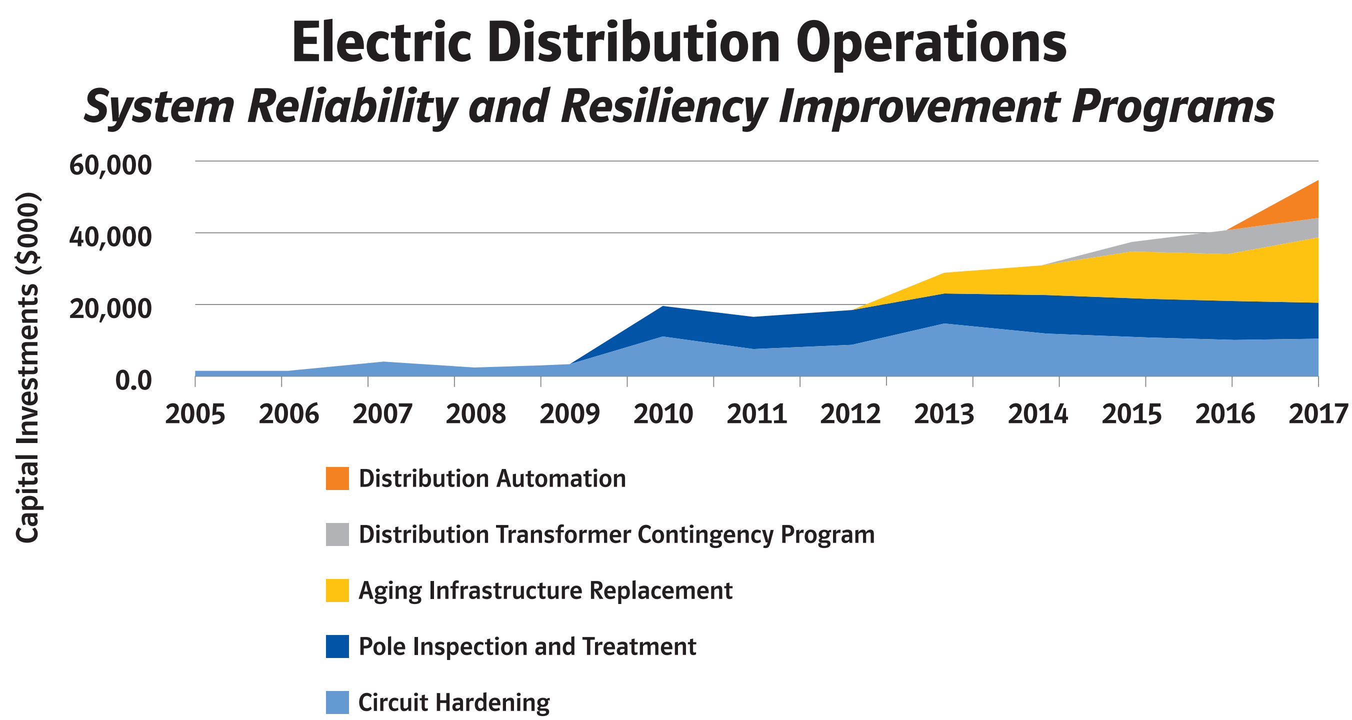


Figure 6: LG&E and KU electric distribution service reliability and system resiliency capital investment programs (2005-2017).

6. The 2009 Kentucky Ice Storm ranks as the largest outage event in LG&E and KU history — 654k customer outages on 8. 7k outage events; Hurricane Ike ranks second — 480k customers affected, on 6.1k outage events.

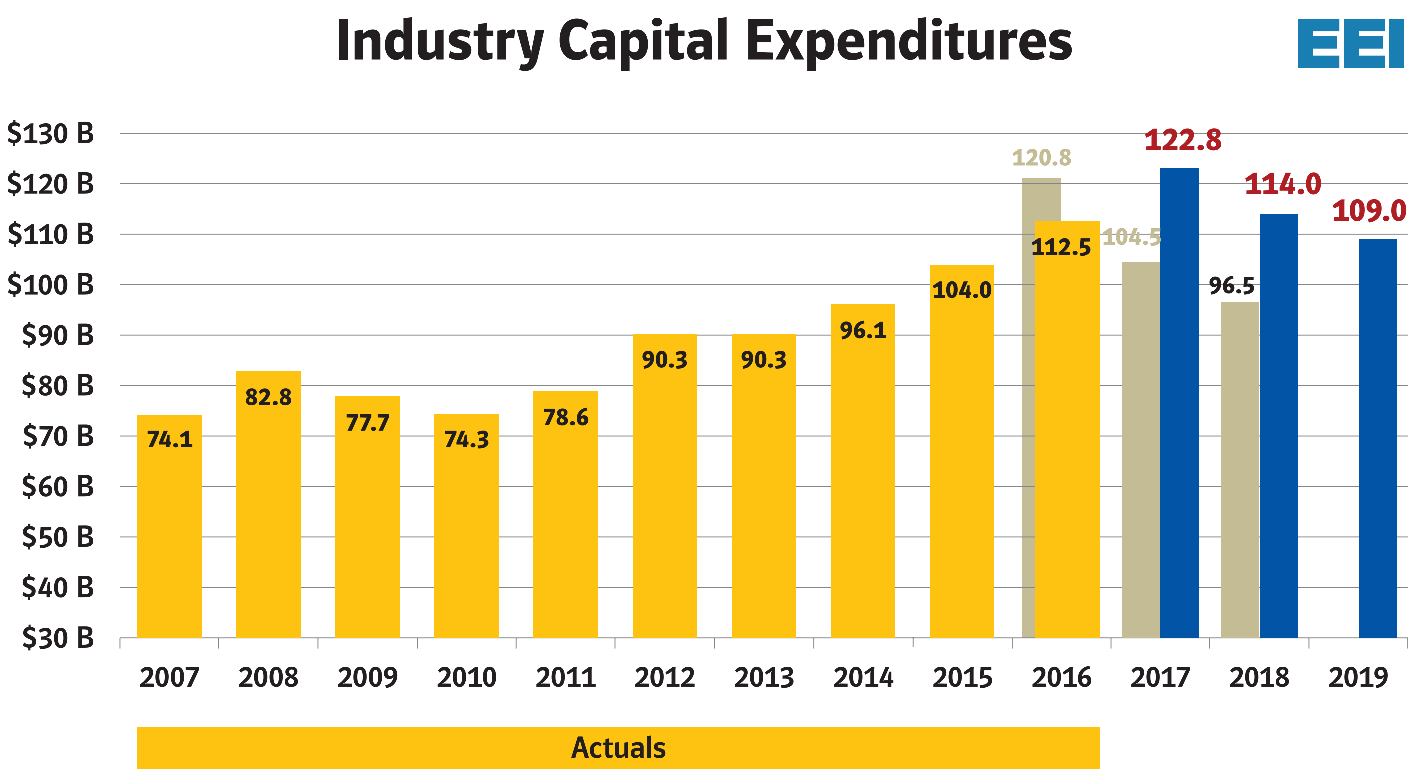
7. Definition: ***Resilience*** is defined as "robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event."
Source: National Association of Regulatory Utility Commissioners, Resilience in Regulated Utilities; Miles Keogh, Christina Cody, NARUC Grants and Research — with support from DOE; November 2013.

1.2 Industry Perspective

Results from REDACTED - Third Party Confidentiality Agreement benchmarking studies demonstrate continuous improvement and a compression of quartile reliability performance levels. REDACTED - Third Party Confidentiality Agreement [redacted] enhanced reliability performance characteristics are being attributed to vastly increased capital investments and modernization of electric distribution systems across the industry.

In addition to its customer service and reliability performance benchmarking studies, EDO routinely surveys the electric industry to identify emerging and advancing technologies for improving distribution resiliency and reliability. Over the past decade, most leading electric utilities have focused on improving distribution reliability by increasing capital investments in circuit hardening and critical asset contingency. More recent trends in the industry point to accelerated investment strategies in grid intelligence technologies in response to increasing customer expectations for reliable power, and the proliferation of distributed energy resources (DER).

During EEI's February 7, 2018 Wall Street Briefing, Richard McMahon, Vice President, Energy Supply and Finance discussed Industry Investment and Financial Overview. The Industry Capital Expenditure and Projected Functional Capital Expenditure information he shared is shown in Figures 7 and 8 below. Based on EEI's analysis, annual capital investments in U.S. investor owned electric utilities have increased by 52% over the last ten years, and are projected to remain above $100 billion through 2019 (Figure 7).



Notes: Total company spending of U.S. Investor-Owned Electric Utilities, consolidated at the parent or appropriate holding company. Projections based on publicly available information and extrapolated for companies reporting fewer than three projected years (0.1% and 2.5% of the industry for 2018 and 2019, respectively.

Source: EEI Finance Department, company reports, S&P Global Market Intelligence (August 2017).

Figure 7: Annual Capital Expenditures of U.S. Investor Owned Utilities.[8]

8. Edison Electric Institute (EEI) — Delivering America's Energy Future; Electric Power Industry Outlook; Edison Electric Institute Wall Street Briefing; February 2018; New York, NY; http://eei.org/issuesandpolicy/finance/wsb/Documents/EEI_WSB_Presentation.pdf.

Further, it is important to note that in recent years, the capital investment across the industry is being shifted from generation to power delivery (i.e., transmission and distribution). In 2017, the percent of investor owned utility capital investments in distribution increased to 29% from 27% of total investment, when compared to 2016 capital allocations (Figure 8).

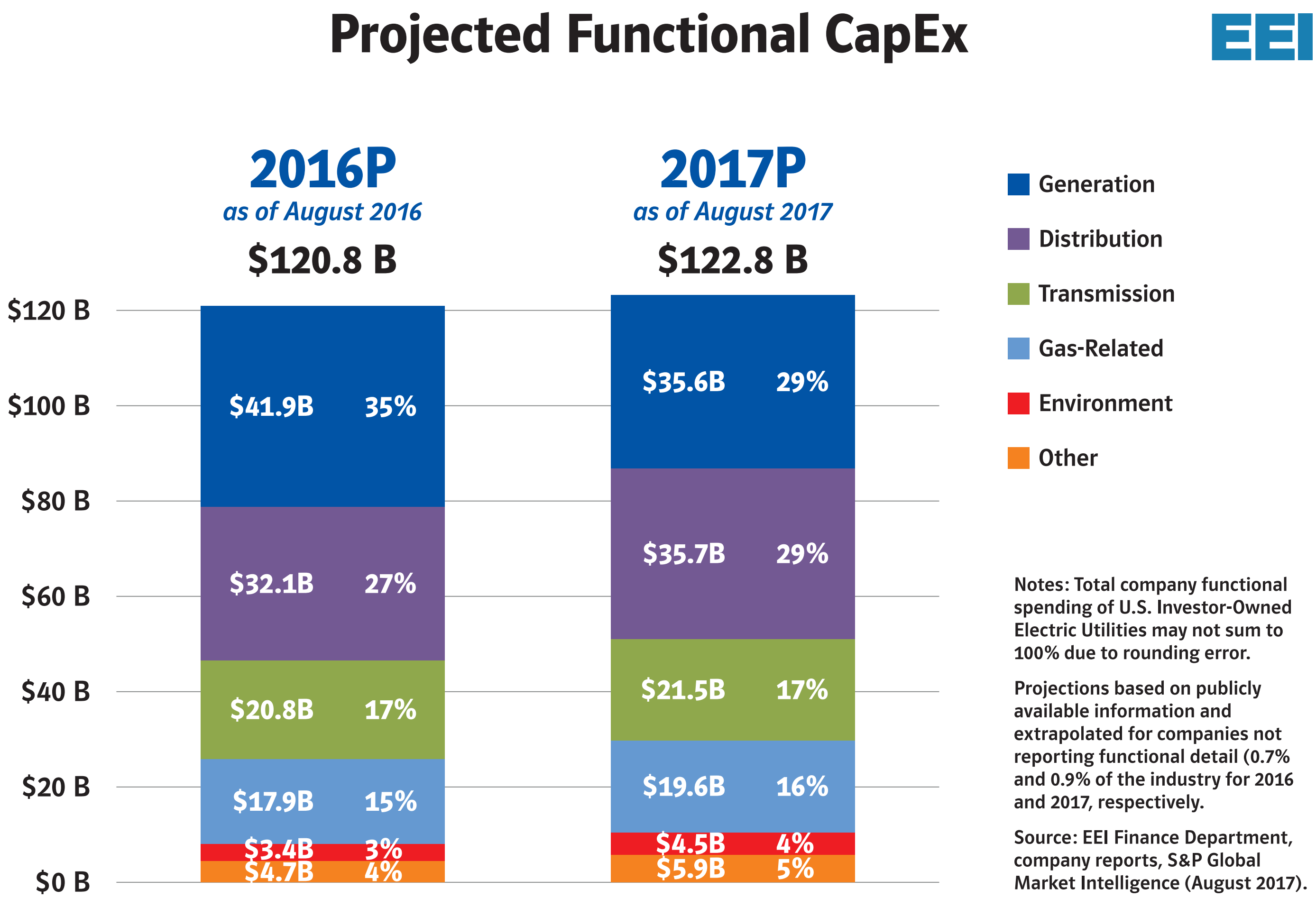


Figure 8: Projected Functional CapEx.[9]

The American Recovery and Reinvestment Act (ARRA) has been a primary contributor and stimulant of increased investments in electric utility distribution assets since 2009. President Obama signed the ARRA into law on February 17, 2009. The ARRA was implemented primarily to stimulate the economy, but included specific measures and funding designated to encourage private utility investment towards advancing grid intelligence and modernization. Approximately $4.5 billion was allocated to the Department of Energy (DOE) for Smart Grid Investment Grant (SGIG), Smart Grid Demonstration Program (SGDP), Energy Storage Demonstration (ESD), Smartgrid Workforce Development and other miscellaneous programs. The SGIG program was funded at $3.4 billion. Grants under this program were awarded to approximately 99 utilities, and resulted in joint (public-private) investments of $8 billion for DOE approved smart grid projects. The DOE Office of Electricity Delivery and Energy Reliability managed each SGIG project to ensure performance remained on schedule and on budget. In December, 2016, the DOE released its final SGIG report. Figure 9 displays the final SGIG program overview.

9. Edison Electric Institute (EEI) — Delivering America's Energy Future; Electric Power Industry Outlook; Edison Electric Institute Wall Street Briefing; February 2018; New York, NY; http://eei.org/issuesandpolicy/finance/wsb/Documents/EEI_WSB_Presentation.pdf.

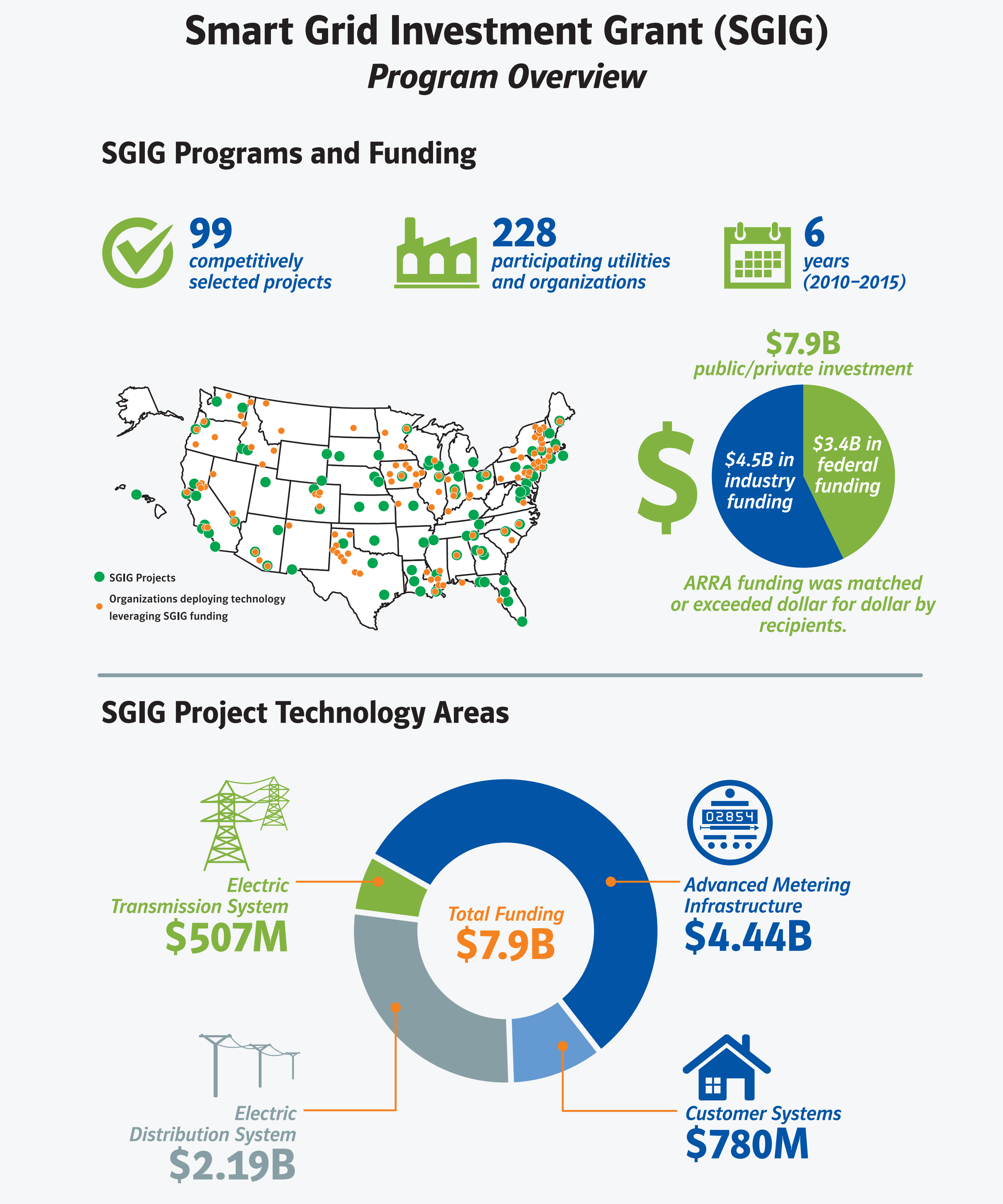


Figure 9: SGIG Program Overview.[10]

10. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability; p6; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

Demonstrated smart grid technology benefits cited in the final report include:

- Fewer and shorter outages that result in less inconvenience and lower outage costs for customers.
- Improved grid resilience to extreme weather events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.
- Faster and more accurate outage location identification for improved repair crew dispatching and service restoration, reducing operating costs, truck rolls, and environmental emissions.
- More effective equipment monitoring and preventative maintenance that reduce operating costs and the likelihood of equipment failures, make more efficient use of capital assets, and result in fewer outages.[11]

Finally, the DOE's final SGIG report referenced smart grid investments in the U.S. as a whole. "In all, the U.S. electricity industry as a whole spent an estimated $24.97 billion for smart grid technology deployed from 2010 through 2015 (excluding transmission system technologies).[12] Smart grid investments under the ARRA accounted for nearly a third of spending during this period. The rate of expenditures was highest in 2010–2012, following the spirit of ARRA to stimulate the economy. This infusion of technologies is catalyzing continued industry investment over the next several years as smart grid technologies continue to mature."[13] Total U.S. smart grid investments are shown graphically in Figure 10 below.

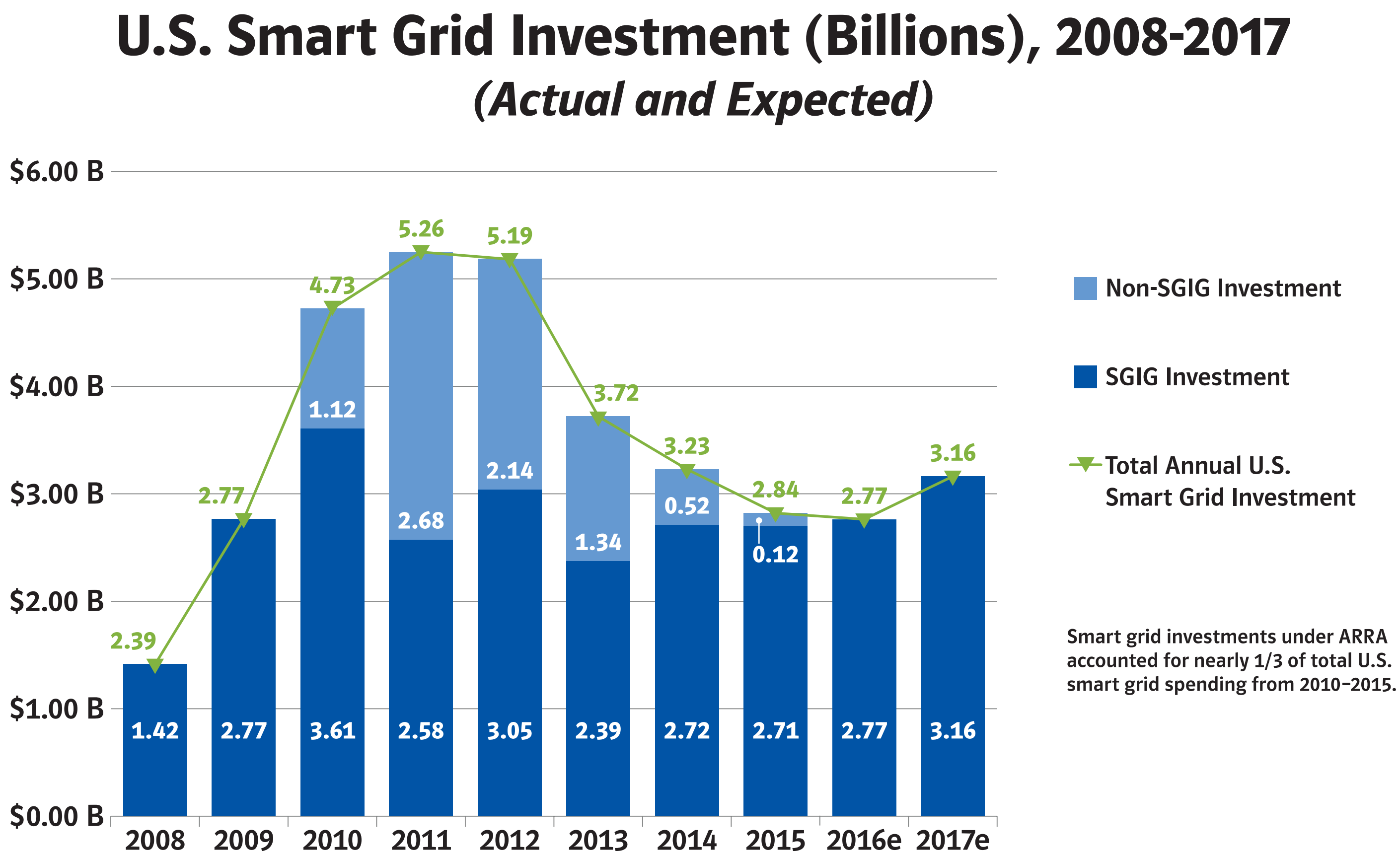


Figure 10: U.S. Smart Grid Investment.[14]

11. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability;p7; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

12. Bloomberg New Energy Finance, U.S. Smart Grid and Smart Metering Forecasts, prepared for the U.S. Department of Energy (February 17, 2016).

13. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability;p34; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

14. Smart Grid Investment Grant Program Final Report December 2016; U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability;p34; https://www.smartgrid.gov/files/Final_SGIG_Report_20161220.pdf.

1.3 Recent Investments into System Improvement

As referenced previously, following the historical storms and outage events of 2008 and 2009, EDO broadened and enhanced its portfolio of distribution system reliability and resiliency programs. These incremental investment and expense programs were designed to replace aging infrastructure, provide additional system contingency and flexibility, and harden the grid against physical exposures. Table 1 provides a summary of EDO's distribution reliability and resiliency centered programs that were expanded between 2010 and 2018.

Table 1: EDO Primary Incremental System Reliability and Resiliency Improvement Programs

	Program Description	2010	2011	2012	2013	2014	2015	2016	2017	2018 (Forecast)
	(Dollars in Thousands)									
Capital	Distribution Automation								$ 10,715	$ 28,330
	Circuit Hardening/Reliability	$ 10,856	$ 7,273	$ 8,486	$ 14,484	$ 11,826	$ 10,692	$ 10,086	$ 10,318	$ 14,505
	Pole Inspection & Treatment Program	$ 8,568	$ 8,965	$ 9,680	$ 8,436	$ 10,723	$ 11,000	$ 10,758	$ 10,134	$ 11,901
	Aging Infrastructure Replacement				$ 5,838	$ 8,167	$ 13,063	$ 13,105	$ 18,137	$ 22,202
	N1DT Contingency Program						$ 2,632	$ 6,635	$ 5,628	$ 10,714
	DSCADA Expansion									$ 1,957
	Total Capital	**$ 19,424**	**$ 16,238**	**$ 18,166**	**$ 28,758**	**$ 30,716**	**$ 37,387**	**$ 40,584**	**$ 54,932**	**$ 89,609**
Expense	Hazard Tree Mitigation	$ 1,088	$ 5,852	$ 5,392	$ 5,020	$ 5,110	$ 5,458	$ 4,655	$ 2,896	$ 4,195
	Pole Inspection and Treatment	$ 328	$ 301	$ 472	$ 515	$ 631	$ 542	$ 277	$ 375	$ 490
	Total Expenses	**$ 1,416**	**$ 6,153**	**$ 5,864**	**$ 5,535**	**$ 5,741**	**$ 6,000**	**$ 4,932**	**$ 3,271**	**$ 4,685**

Table 1: EDO incremental system reliability and resiliency program funding — 2010–2018

- ***Circuit Hardening/Reliability —*** system hardening investments (includes CIFI), targeted at circuits with high customer interruptions and pockets of poor performance; increased from $2M in 2008 to nearly $15M in 2018.
- ***Pole Inspection and Treatment (PITP) —*** program provides for annual inspection, treatment, reinforcement, and replacement, where necessary, of approximately 7% of LG&E and KU's wooden distribution poles. Expense allocations also provide for pole numbering, and anchor, grounding, and other ancillary maintenance.
- ***Aging Infrastructure Replacement (AIR) —*** programs provide for targeted replacement of critical distribution assets considered beyond their life expectancy and experiencing increasing failure or declining reliability rates. Primary assets included in this category are paper-insulated lead-covered cable, underground substation exit cables, legacy and problematic distribution circuit breakers, load tap changers, and pad mounted switchgears.
- ***Distribution Substation Transformer Contingency Program (N1DT) —*** program initiated in 2015 provides added contingency for critical substation transformers, targeting power transformer additions, circuit upgrades, distribution system enhancements, and mobile or spare transformer purchases.
- ***Distribution Automation (DA) —*** program initiated in 2017 to yield step-improvement in reliability performance and customer satisfaction, through enablement of remote monitoring and control, circuit segmentation, and "self-healing" of select electric distribution system circuits.
- ***Hazard Tree Mitigation —*** program targets trimming or removal of out of right-of-way trees, with noticeable decay or damaged limbs; funding levels were enhanced substantially in late 2010, with annual hazard tree expense allocations of approximately four to six million dollars annually since 2011.

2.0 2019 EDO Business Plan Reliability and Resiliency Strategy

As stewards of the LG&E and KU electric distribution system, EDO is responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers. The EDO 2019 Business Plan delivers a prudent system reliability and resiliency strategy which sustains this responsibility. The following assumptions adopted in the plan are founded on customer satisfaction surveys and industry intelligence.

- Customer reliance on electricity will continue to increase, with advancement of end use technologies and electrification of nearly everything. Accordingly, customer expectations respective to electric service safety, reliability, and quality will continue to evolve.
- Expectations for system resiliency and outage responsiveness will continue to grow in the face of increased grid vulnerabilities linked to severe and extreme weather, threats of cyber and physical attacks, and interference from wildlife and vegetation.
- Across the industry, customers, regulators, and community leaders will continue to push for modernization of the electric grid, effective interconnection of distributed energy resources, increased operational flexibility, and enhanced customer communications

In accordance with its Business Plan, EDO will address these ongoing issues and continue to deliver increasing value to its customers via the following initiatives:

- Invest in system reliability and contingency to meet increasing customer expectations respective to service availability
- Investment in aging infrastructure to continue long term service reliability
- Advance grid intelligence to meet evolving customer expectations and align with industry trends
- Respond to outage events in an efficient and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times
- Invest in and deploy technology which enhances business processes, reduces cycle times, and expands communications with customers.

Strategies and programs developed to enhance and sustain these initiatives are detailed in the remainder of this paper.

3.0 Centralized Grid Operations Strategy

EDO must continuously evaluate its operating strategies to increase efficiencies in day to day operations and in outage response. The recently approved Distribution Automation (DA) program provides enabling technology for development of an enhanced grid operations model. EDO is standardizing distribution grid operations with the current Oracle Network Management System (NMS) for integrating outage management and distribution management. Connectivity to field devices will utilize the OSI Systems, Incorporated (OSI) Monarch Supervisory Control and Data Acquisition (SCADA) platform, leveraging OSI's built-in interfaces with the Oracle NMS. SCADA functionality will include access to existing substation telemetry currently available in the transmission system's OSI Energy Management System (EMS), addition of SCADA capability at existing substations currently without SCADA, Distribution Automation (DA) reclosers, and capacitor controllers.

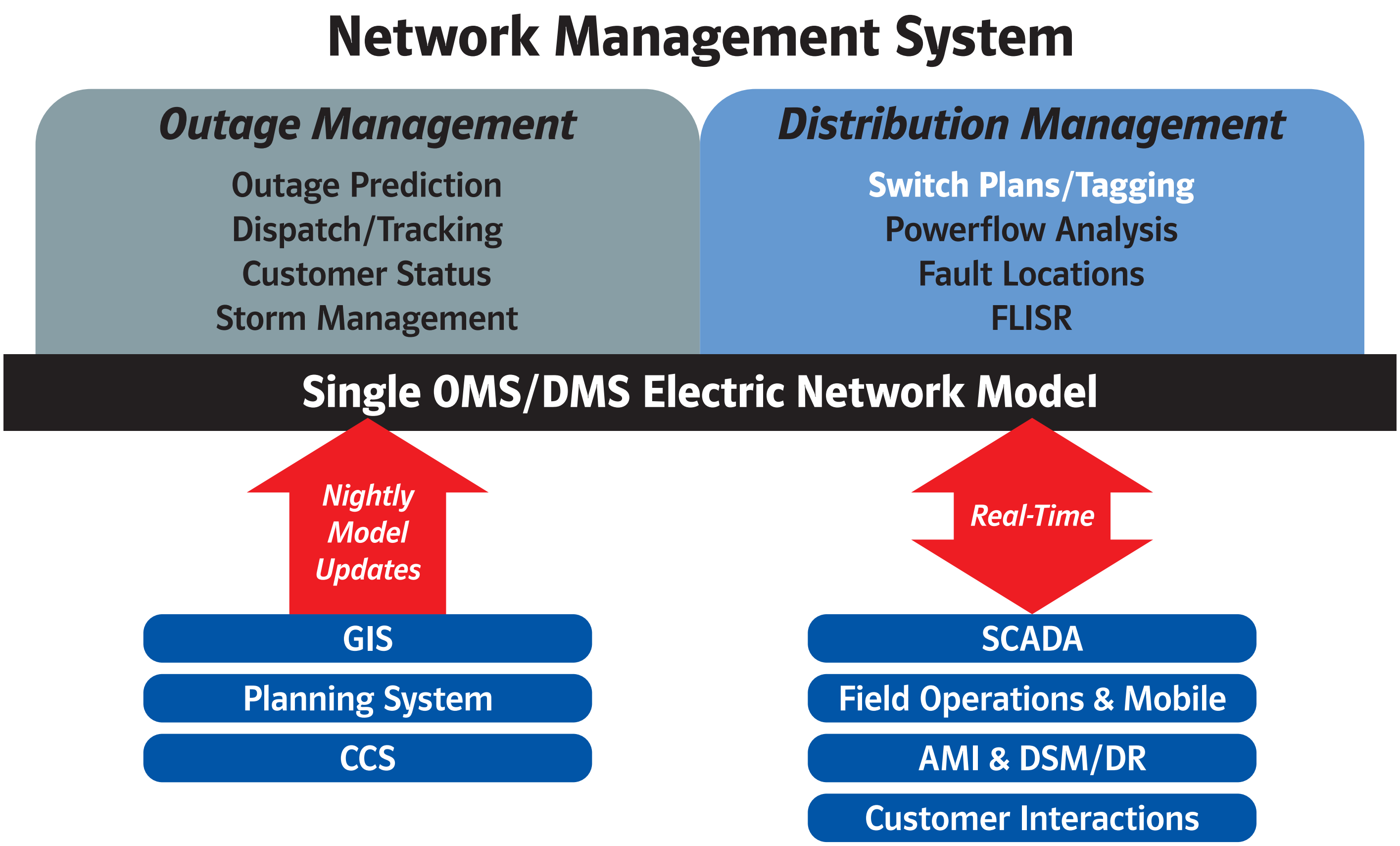


Figure 11: Centralized Grid Operation Systems.

In conjunction with the DA program, consolidation of two Distribution Control Centers (DCC) into one location presents the Company with a unique opportunity to standardize business processes and develop a centralized approach that will allow for 24x7 monitoring and control of the grid across LG&E and KU. This Centralized Grid Operations approach will enable the Company to proactively meet customers' expectations while positioning EDO to support future technologies such as Advanced Meter Systems (AMS) and Distributed Energy Resources (DER).

Today's customers are becoming less accepting of service interruptions or even momentary interruptions of less than five minutes. In order to manage these customer expectations, EDO is increasing the number of intelligent devices that can remotely communicate with the centralized grid operations group, DCC, allowing them to proactively monitor, control, and dispatch trouble crews even before customers may be aware of the problem. Key to the success of a centralized grid operating strategy is the implementation of a Distribution Management System (DMS), whereby advanced applications provide map based situational awareness capability, outage information, real-time power flow calculations, alarming, and fault identification and location. EDO's advanced DMS will provide FLISR (fault location, isolation, and service restoration) capability, the ability for the system to automatically isolate faulted distribution facilities and reroute power to minimize customer outage durations.

Future initiatives will focus around Centralized Grid Operations which will leverage a Distribution Management System as the focal point of LG&E and KU's overall capital model. Resiliency programs, circuit hardening, N1DT, and advancement of DA will be part of this overall EDO strategy.

4.0 Investment Strategy

Prudent investment strategies are fundamental to advancement of EDO's business plan initiatives. Results of analysis completed during EDO's 2018 planning process for the 2019 business plan indicated priority should be placed in the following areas:

- Continued development and enhancement of a centralized grid operation strategy
- Continuation, acceleration and extension of automation on the distribution system;
- Continued funding for the distribution substation transformer contingency program;
- Continuation of existing reliability improvement programs; and
- Continued expansion and in some cases, acceleration, of existing aging infrastructure replacement programs.

These investment strategies will continue to advance grid intelligence, provide for increased operational control and flexibility, assure continued improvement in reliability performance and power quality, and build additional contingency into critical assets. These strategies also align with industry best practices and are comprehensive, continual, and flexible.

4.1 Investment Selection Methodology

In 2011, EDO began using an Asset Investment Strategy (AIS) decision-support model and supporting business processes to help evaluate and prioritize distribution investment programs. The model and processes enable EDO to evaluate and prioritize proposed investments based on 1) a set of custom benefit criteria defined by EDO subject matter experts; and 2) estimated costs of proposed projects. The AIS prioritization algorithm sorts proposed investments based on a benefit/cost ratio, which in turn allows EDO to determine the best allocation of capital spending. EDO's management team then applies other criteria, such as resource availability and seasonality of work, to determine the ultimate set of investment projects to include in EDO's Business Plan.

As part of its annual business plan development, EDO has used the AIS approach to evaluate traditional reliability and asset replacement investment programs. During the 2016 business planning process, EDO utilized AIS and available industry data to assess DA against its existing portfolio of system reliability and resiliency capital programs, and concluded that DA provided LG&E and KU the best option for making step improvements in reliability performance, and maintaining or improving upon its relative peer group standing in reliability benchmarks. The 2018 business planning process continued to support this conclusion.

In order to get the most value for the investment in the N1DT contingency program, LG&E and KU expanded the AIS evaluation framework to include at-risk power transformers based on benefit/cost, which also identified the most vulnerable transformers that need to be addressed. Considerations include: the number of customers affected by a transformer failure, the amount of load at risk, the length of time to replace the capacity, the amount of time during the year the load is at risk, the age and health of the transformer, and the impact a long term outage may have on the surrounding community and critical infrastructure. Scaling factors were applied to the inputs to calculate the total benefit. This benefit was then divided by total project cost to determine the benefit/cost ratio.

In addition to these programs, 2018 AIS analysis indicated priority should be given to Distribution SCADA expansion and accelerated or expanded aged asset replacement.

4.2 Reliability and Resiliency Programs

Table 2 provides a summary of EDO's strategic 2019-2023 reliability and resiliency capital and expense programs.

Table 2: EDO Primary Incremental System Reliability and Resiliency Improvement Programs

	Program Description	2019	2020	2021 (Dollars in Thousands)	2022	2023
Capital	Distribution Automation	$ 28,243	$ 23,974	$ 20,974		
	Circuit Hardening/Reliability	$ 17,963	$ 16,727	$ 22,088	$ 18,292	$ 18,954
	Pole Inspection & Treatment Program	$ 12,278	$ 12,646	$ 13,026	$ 13,417	$ 13,820
	Aging Infrastructure Replacement	$ 35,303	$ 33,594	$ 33,611	$ 16,179	$ 15,743
	N1DT Contingency Program	$ 14,997	$ 6,931	$ 17,691	$ 14,370	$ 9,000
	Distribution Automation Expansion				$ 4,250	$ 5,750
	DSCADA Expansion	$ 4,936	$ 4,998	$ 5,085	$ 5,000	$ 5,000
	Total Capital	**$ 113,720**	**$ 98,870**	**$ 112,475**	**$ 71,508**	**$ 68,266**
Expense	Hazard Tree Mitigation	$ 5,609	$ 5,026	$ 5,873	$ 5,265	$ 5,265
	Pole Inspection and Treatment	$ 506	$ 520	$ 535	$ 542	$ 558
	Total Expenses	**$ 6,115**	**$ 5,546**	**$ 6,408**	**$ 5,807**	**$ 5,823**

Table 2: EDO 2019-2023 Reliability and Resiliency Improvement Programs.

EDO's proposed investment strategy provides for continued funding of the existing circuit hardening (including CIFI and the Hazard Tree Program), PITP, and AIR programs. These existing programs continue to deliver system reliability and resiliency improvements. Any substantial shifts in funding away from them would increase outages, and decrease operational contingency. Program continuation is necessary to deliver maintenance, replacement, or upgrade on LG&E and KU system components not yet addressed and circuits not well suited for distribution automation (due to limited circuit ties, etc.). For example, the CIFI program has addressed only 234 of LG&E and KU's 1800 circuits. Over time, remaining circuits will ultimately require circuit hardening and aging infrastructure replacement to maintain and/or improve reliability performance. Likewise, the PITP has addressed only 394,028 of 672,596 (58.5%) LG&E and KU distribution poles. More than 16,000 poles have been replaced under this program, and the contribution of pole related outages to SAIDI has dropped by approximately 32% on completed circuits. The remaining LG&E and KU distribution poles also need to be addressed under the program, and subsequent inspection cycles will be needed as the poles continue to age.

4.2.1 Distribution Substation Transformer Contingency Program

The N1DT Contingency Program is a 15-year program that began in 2015 and will continue to be implemented through 2029. The purpose of the program is to enhance the LG&E and KU customer experience through improved reliability and reduced exposure to low probability, high consequence, and long duration service interruptions due to failure of a substation power transformer. Since the inception of the N1DT program in 2015, the number of transformers considered "at risk" has been reduced from 484 to 462 across KU and LG&E. This reduction of 24 transformers is a 5% improvement in the substation transformer related long term outage exposure to the electric distribution system.

4.2.2 Distribution Automation Expansion

Phase one of DA began in July 2017 and consists of a $112 million capital investment that will install 1,400 electronic SCADA connected reclosers and target approximately 360 (20%) distribution circuits and 50% of LG&E and KU customers. Phase one was initially planned to complete in 2022, but current acceleration efforts will likely see completion sometime in 2021. Through July 2018, EDO installed nearly 360 electronic reclosers which resulted in 6,281,428 avoided outage minutes including more than 16,763 avoided interruptions.

DA will continue expansion during 2022–2023 in order to provide centralized control capabilities along with DA's reliability benefits to all distribution circuits having a total of at least 500 customers and a serviceable circuit tie for switching (40% of all circuits, 70% of customers). Total DA investment will amount to approximately $144 million and the total number of reclosers installed will increase from 1,400 to about 1,900.

4.2.3 Substation SCADA Expansion

EDO has identified an opportunity to expand SCADA capabilities to KU substations across the state. Currently, approximately 20% of circuits in the KU service territory are equipped with SCADA connectivity - accounting for approximately 30% of KU customers (including ODP). Lack of SCADA capabilities to monitor and control these facilities is an operational hindrance to daily duties and delays circuit restoration following an outage event.

The expansion of SCADA capabilities will allow the Distribution Control Center, the centralized grid operator, to have the necessary information to identify outages and take remedial measures in real-time. Under this program, approximately 570 additional circuits will be upgraded and connected to SCADA by 2024. To accomplish this, over 150 legacy breakers and 300 electromechanical relays will be upgraded to modern technology — serving as an enabler for EDO's overall centralized grid operator strategy. Under this program, approximately 85% - 90% of all KU and ODP customers will be served from a SCADA connected circuit by 2024.

There are many overall benefits to substation SCADA capabilities. These benefits can be grouped into four categories: Operational Efficiencies, Emergency Response, Enhanced Worker Safety, and Improved System Data. Detailed below are each of these categories, along with the benefits they bring to the distribution system:

- ***Operational Efficiencies:*** Expanded SCADA functionality in KU and ODP substations provides DCC and field resources with the ability to know the status of station breakers quickly during an emergency, after an interruption, and during normal operations. The microprocessor relays that will be installed in substations will allow control center system operators to identify possible fault locations through the use of the DMS. Field personnel will then be directly dispatched to the trouble area identified, leading to faster restoration times and more efficient use of field resources. These efficiencies are estimated to reduce targeted circuit outages by 30 minutes on average. System operators will also be able to control breakers and components such as reclosers from the DCC, reducing the need for crews to visit the substation before and after performing live line work. Additionally, the feature rich microprocessor relaying will provide alarming and diagnostics data to system operations. Of significance is battery monitoring and alarming, which today is unavailable and places stations at significant risk for breaker failure operation and total loss of a station.
- ***Emergency Response:*** With the ability to remotely control substation assets, system operators will be able to quickly respond in times of emergency (e.g. 911 calls) and coordination during the restoration of a Transmission outage — providing for improved public safety and equipment protection. This is a valuable benefit, as response to such events can be time consuming and requires dispatching a person physically to the substation(s) to de-energize equipment.
- ***Enhanced Worker Safety:*** The upgraded relays bring a unique feature that enhances the safety for Company and contract crews performing live line maintenance. These advanced relays offer a "Hot Line Tag" (HLT) feature that goes above and beyond current practices for protecting line crews at the circuit breaker. The HLT option, when enabled, makes the device more sensitive to faults

resulting in faster clearing times and potentially reducing impacts of arc flash situations.

- ***Improved System Data:*** Capturing data will enhance Distribution's and Transmission's abilities to analyze real-time situations and have the best information to make decisions. For Distribution, circuit loading data will provide the operator information to know if an overload is occurring and/or other circuits' conditions in the area if action is required. Transmission Operations will benefit from additional system data to further improve State Estimator and Power Flow results — two analyses that drive operator action on the transmission system. System data will also be extremely beneficial for Distribution Planning to compare and optimize planning models with the actual, coincidental circuit data, aiding in capital project prioritization.

4.2.4 Aged Asset Replacement

LG&E and KU will continue investments targeted toward aged asset replacement. The LG&E and KU Distribution system is comprised of a mix of old and new equipment. On the system, old equipment that is well beyond its designed operating life is being relied on to reliably and effectively serve customers. While this equipment has performed well over the years, the Companies believe proactive replacement is the prudent alternative to maintain reliable service, advance distribution system operations, and effectively manage costs. As such equipment on the system ages, risk of failure rises. For the company to effectively manage operational costs, these devices must be replaced proactively rather than upon failure. Failures of these types of equipment typically result in long duration outages, additional associated equipment damage, and more expensive installation costs. Additionally, equipment such as this requires extensive periodic and preventative maintenance practices compared to its modern day equivalent technology. Proactively replacing these aged assets allows the company to more effectively manage capital and operational costs.

During 2018, EDO's Asset Management department performed a study to evaluate all asset classes pertaining to electric distribution equipment and determine if the current asset replacement strategies adequately mitigate potential asset failures. This evaluation took into account overall condition and reliability of each asset class to estimate the likelihood of failure. Further, consideration was given to distribution system criticality and potential customer impact of each asset class to infer consequences associated with asset failure. Asset condition was evaluated via technologies such as infrared scans, dissolved gas analysis, power factor testing and internal inspection results. Asset reliability and performance was reflected through review of maintenance history and failure rates. Assessment of asset class probabilities of failure and associated consequences enabled development of an overall risk profile identifying asset classes at greatest risk for failure and in most need of replacement. The resulting replacement priority was compared to existing asset replacement programs to identify potential need for acceleration of current programs and to establish new programs if needed.

Oil filled substation breakers, electromechanical relays, and copper and copper-clad overhead conductor were found to have a need for prudent, proactive replacement. The current replacement program addressing oil filled substation breakers will be accelerated based on the study results. The LG&E and KU systems contain over 180 substation oil filled circuit breakers. These breakers are 50+ years old and beyond their designed in-service life.

The LG&E and KU systems contain more than 5,900 electromechanical relays. In addition to the risk associated with failure, electromechanical relays are simple in design and limit the companies' ability to advance distribution system operations. As part of a strategy to move to a more centralized, smarter distribution system, the replacement of these relays with more advanced microprocessor relays is needed. These relays will provide the additional information needed to better leverage existing IT systems - allowing operators and field technicians to more quickly locate faults and restore service following an outage.

In addition to aging substation assets, distribution lines contain assets near end of life as well. Equipment such as copper and copper-weld conductor is a legacy construction method that requires preventative attention. These conductors become brittle over time and are subject to break when contacted by vegetation. Detailed design and engineering is required to cost effectively replace this equipment. It is not feasible to replace upon failure, as a typical installation may be hundreds of feet long.

5.0 Summary

As stewards of the LG&E and KU electric distribution system, EDO is responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers. LG&E and KU's recent reliability and resiliency investment strategies and programs have resulted in steady improvements in customer satisfaction and reliability performance since 2010 and are consistent with industry best practice. To meet evolving customer expectations respective to electric service safety, reliability, and quality, EDO's 2018 DRRIP and 2019-2023 Business Plan provide for the following high-level investment strategies.

- Continued development and enhancement of a centralized grid operation strategy
- Continuation and extension of automation on the distribution system;
- Continued funding for the distribution substation transformer contingency program;
- Continuation of existing reliability improvement programs; and
- Continued expansion of existing aging infrastructure replacement programs.

These investment strategies will continue to advance grid intelligence, provide for increased operational control and flexibility, assure continued improvement in reliability performance and power quality, and build additional contingency into critical assets. These strategies also align with industry best practices and are comprehensive, continual, and flexible.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 10

Responding Witness: Christopher M. Garrett

Q-10. Reference the Application, pages 3-6. Confirm that where applicable, the Companies have treated the resulting effects of a lower Kentucky income tax rate in the same manner as the Commission provided for the reduction in the Federal income tax rate in its September 28, 2018 Order in Case No. 2018-00034.

a. If not confirmed, for those issues that are applicable, explain what differences the Companies provided for in this matter that the Commission ordered differently in its Order.

A-10. The Companies in this case have treated the recording of state excess accumulated deferred income taxes ("ADIT") as a regulatory liability consistent with the recording of federal excess ADIT in Case No. 2018-00034. The Companies are proposing to amortize the state excess ADIT regulatory liability in a consistent manner as the federal case with one exception. The Companies propose to begin returning state excess ADIT as part of their pending base rate cases rather than through a separate billing credit such as the TCJA surcredit.

The Companies are also treating state tax savings related to the various rate mechanisms in a consistent manner whereby tax savings are being returned to customers through the various mechanisms' procedural provisions.

The primary difference in this case from Case No. 2018-00034 is that the state income tax *expense* savings resulting from the lower tax rate are not being established as part of the regulatory liability. The Companies propose to address the non-mechanism related savings as part of their pending base rate cases rather than through a separate billing credit such as the TCJA. This will ensure all aspects of state tax reform are appropriately considered, including the sizable increase in sales tax. This treatment is consistent with prior state tax reform cases as discussed in the application.

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 11

Responding Witness: John K. Wolfe / Daniel K. Arbough

Q-11. Reference the Kentucky PSC Report, "Ike and Ice," ("the Report") accessible at the link below.

a. At p. 83, the report states: ". . . the PSC recommends that jurisdictional utilities should consider upgrading to heavy loading standards in some circumstances. For example, it may be beneficial to shorten span lengths when building lines in treed areas, thus improving the ability of those lines to sustain the weight of fallen vegetation."

   i. Have the companies undertaken any studies since the date of the Report's publication regarding whether any portions of their transmission and/or distribution systems should be upgraded to heavy loading standards?

b. Further at p. 83, the Report states: "The Commission recognizes that many utilities evaluate the appropriateness of system hardening practices for particular areas or circuits that suffer repeated weather-related outages. The Commission recommends that all utilities use their routine system evaluations as an opportunity to evaluate the need for and potential effectiveness of system hardening, and to implement those system hardening practices where indicated. Utilities should track outage data for those portions of their systems that have undergone system hardening in order to determine the overall effectiveness of system hardening practices in preventing outages on those circuits. All jurisdictional utilities should evaluate system circuits serving critical infrastructure such as hospitals, police stations, emergency response facilities, fuel locations, and predetermined lodging or staging facilities used during storm restoration and evaluate the potential effectiveness of hardening those critical circuits."

   i. Provide copies of all studies or analyses undertaken following the Report's publication to this effect. Provide examples of any system hardening the Companies may have incorporated into their transmission and/or distribution grids. Provide copies of data tracking reliability in areas undergoing any such system hardening.

c. At p. 123, the Report states: ". . . the Commission recommends that investor-owned utilities should monitor insurance markets for the development of catastrophic coverage and other potentially applicable products. As such products become available, the IOUs should evaluate the cost-effectiveness of obtaining such coverage."

i. Provide copies of any and all studies, reports or analyses the Companies may have conducted in which they evaluate the cost-effectiveness of obtaining such coverage.

ii. If the Companies have not conducted cost-effectiveness studies, state so.

A-11.

a.i. The Companies responses to the Commission's Ike and Ice Reports are attached to Question No. 8a. Please also see the LG&E and KU Transmission System Improvement Plan Annual Report (June 1, 2018) on file with the Commission and produced as an attachment to this request.

b.i. See the Companies' response to Kentucky Public Service Commission Report on the September 2008 Wind Storm and the January 2009 Ice Storm Dated November 19, 2009 Recommendation number B2 attached to Question No. 8a.

See also the *Electric Distribution Operations Distribution Reliability and Resiliency Improvement Program* attachment referenced in Question No. 9a.

See also the *2016 Transmission System Improvement Plan* attached to this response

c.i. See the response to PSC 1-7.

c.ii. See the response to PSC 1-7.

LG&E and KU
Transmission System Improvement Plan Annual Report

Filed Pursuant to Paragraph 9 of Order entered June 22, 2017 In Case No. 2016-00370 and Paragraph 8 of Order entered June 22, 2017 in Case No. 2016-00371

June 1, 2018

Prepared by:

Table of Contents

Table of Tables

Table of Figures

1. Executive Summary

In connection with their 2016 applications for adjustment of base rates and for issuance of certificates of public convenience and necessity, Kentucky Utilities Company ("KU") (Case No. 2016-00370) and Louisville Gas & Electric Company ("LG&E") (Case No. 2016-00371) submitted a spending plan for improvement of their combined transmission system. This plan, entitled the Transmission System Improvement Plan ("TSIP"), projected $108.3 Million in spending on reliability investments over a five year period from 2017-2021, and $430 Million in system integrity and modernization investments over the same time period.

In its orders entered on June 22, 2017, the Kentucky Public Service Commission ("PSC") approved stipulated settlements in both cases with certain modifications, resolving the applications filed by KU and LG&E (collectively, the "Companies"). The Orders approved the spending contained in the TSIP, and required that the Companies file an annual report starting June 1, 2018, detailing TSIP spending for the preceding reporting period, the criteria used to prioritize transmission projects, the impact on system reliability and other benefits to the Companies' customers resulting from the investments, and outlining proposed spending for the following year.[1]

This report is submitted pursuant to the PSC's directive. It shows that the Companies are following through on their proposed investments in the transmission system, both to increase the reliability of the system now, and to modernize the system to ensure it performs safely and resiliently for many years to come. The report further illustrates how the Companies are using inspection cycles and planned outages to maximize the efficiency of asset replacements and minimize customer impact. Improvements in reliability can already be seen for specific lines on which system infrastructure investments have been made.

The Companies anticipate that spending on certain TSIP-related programs in 2018 will continue to exceed the forecasts made when the TSIP was first created. These increases are primarily driven by the condition of assets found during inspections. The Companies are continually responding to new information and changed circumstances in determining the timing and priority of these investments into the transmission system. Through flexibility and the ability to change program priorities and investments based on inspection data, risk assessment, and scheduled outages, the Companies are best able to efficiently conduct asset replacements and carry out the objectives of the TSIP: securing the

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[1] PSC Order June 22, 2017, Case No. 2016-00370, at 28-29; PSC Order June 22, 2017, Case No. 2016-00371, at 30-31, 35.

existence of a modern, reliable, safe and resilient transmission system now and in the future.

2. 2017 TSIP Spending Report

2.1 Overall Spending Comparison versus TSIP

The following table sets forth the Companies' combined actual spending for TSIP-related improvements in 2017 versus the projections in the TSIP:

Table 1: LG&E and KU Combined 2017 TSIP Projection vs. Actual ($MM)

	TSIP 2017 Projection	**2017 Actual**	**Variance ($)**
O&M Total:	$10.2	$9.9	($0.3)
Capital Total:	$82.3	$105.0	$22.7
Total:	$92.5	$114.9	$22.4

The following tables show the same spending comparison broken down by LG&E and KU, respectively:

Table 2: LG&E 2017 TSIP Projection vs. Actual ($MM)

	TSIP 2017 Projection	**2017 Actual**	**Variance ($)**
O&M Total:	$1.7	$1.6	($0.1)
Capital Total:	$9.3	$14.8	$5.5
Total:	$11.0	$16.4	$5.4

Table 3: KU 2017 TSIP Projection vs. Actual ($MM)			
	TSIP 2017 Projection	**2017 Actual**	**Variance ($)**
O&M Total:	$8.5	$8.3	($0.2)
Capital Total:	$73.0	$90.3	$17.3
Total:	$81.5	$98.6	$17.1

As these tables reflect, combined spending for Operations & Maintenance (O&M) programs in the TSIP was within two percent the Companies' projections, while capital spending exceeded original TSIP projections. The increase in capital spending compared to TSIP projections is primarily attributable to accelerated replacement of line equipment and substation equipment based on inspection results and the Companies' ability to take advantage of planned outages and other work to accelerate the timing of replacements of certain aging transmission infrastructure.

2.2 2017 Spending on Reliability Projects

The following table shows how the Companies allocated 2017 spending on reliability projects compared to 2017 projections in the TSIP:

Table 4: LG&E and KU Combined 2017 TSIP Reliability Project Forecast vs. Actual ($MM)			
	TSIP 2017 Projection[2]	**2017 Actual**	**Variance ($)**
O&M for TSIP Projects (Veg. Mgmt, Switch Maintenance, Corrosion Protection)[3]	$10.2	$9.9	($0.3)

[2] These projections appear in Table 5 of the TSIP Document, attached as Exhibit PWT-2 to Paul Thompson's Direct Testimony in both Case No. 2016-00370 and 2016-00371.

[3] Corrosion protection is shown as an O&M expense in Table 6 of the TSIP Document.

Line Sectionalizing (Capital):	$9.6	$8.5	($1.1)

The Companies' spending on O&M reliability projects was very close to what the Companies projected in the TSIP. Spending on line sectionalizing, a capital project to improve system reliability, was under budget primarily due to a design improvement that reduced costs compared to original estimates.

2.3 2017 Spending on System Integrity and Modernization Projects

The following table contains a breakdown of the Companies' actual 2017 spending on system integrity and modernization projects compared to the Companies' forecast in the TSIP:

Table 5: LG&E and KU Combined 2017 TSIP System Integrity Project Forecast vs. Actual ($MM)

	TSIP 2017 Projection[4]	**2017 Actual**	**Variance ($)**
Line Equipment	$48.6[5]	$68.2	$19.6
Underground Lines	$3.2	$1.7	($1.5)
Substation Equipment	$11.4[6]	$16.8	$5.4
Substation P&C Systems	$9.5	$9.9	$0.4
Total System Integrity:	**$72.7**	**$96.6**	**$23.9**

[4] These projections appear in Table 6 of the TSIP Document, attached as Exhibit PWT-2 to Paul Thompson's Direct Testimony in both Case No. 2016-00370 and 2016-00371.

[5] Separately shown as line equipment, line switches, and overhead lines in Table 6 of the TSIP Document.

[6] Separately shown as circuit breakers, insulators, line arresters, and coupling capacitors in Table 6 of the TSIP Document.

As summarized in this table, total 2017 spending on transmission system integrity and modernization projects under the TSIP exceeded the Companies' projections by $23.9 Million. The bulk of the additional spending is attributable to the Companies' accelerated replacement of line equipment, in particular, wood poles.

2.3.1. Line Equipment

Historically, the Companies conducted system-wide aerial inspections for damage to or deterioration of poles in the transmission system. Starting in 2013, in part in response to evolving Commission regulations regarding inspections, the Companies began performing more detailed pole inspections and initiated a cycled approach to those inspections. Wood poles are now inspected every six years and steel poles are inspected every twelve years. Pole inspections now include detailed visual observation, sounding, and, when possible, climbing of the poles to observe their condition.

The more detailed ground inspections have been successful in identifying more poles in need of replacement. The Companies budgeted for 650 pole replacements in calendar year 2017 based on historical data. However, inspections in 2017 using the methods described above yielded a higher number of poles in need of replacement. To manage the increased need for pole replacements, the Companies replaced 952 poles in 2017 versus the planned 650, contributing to additional spending toward line equipment compared to the budget projected in the TSIP.

At the end of 2017, there were roughly 2,900 poles in the transmission system slated for replacement. 2018 is the final year of the first six-year cycle for wood pole replacements. When the first cycle is completed, the Companies expect the replacement rate to stabilize as many of the more deteriorated or damaged poles will have been identified in the first cycle. In the meantime, the Companies will continue expending resources in pole replacement to manage and ultimately reduce the backlog of poles identified for replacement based on ground inspection data.

While 2017 spending for replacement of overhead lines was below TSIP projections, the Companies were actually able to replace *more* lines than expected due to lower cost design solutions implemented during line replacement work, resulting in increased efficiencies. Specifically, the Companies were able to use more guyed structures instead of self-supporting structures in line replacements. KU achieved further efficiencies by replacing static wire on the Rosine – Leitchfield line while crews were replacing poles on that line.

2.3.2. Underground Lines

The Companies' actual spending for replacement of undergrounds lines in 2017 was roughly half of TSIP projections. Conflicts with other underground utilities during installation of transmission conduit contributed to delays and deferred some of this planned spending to 2018.

2.3.3. Substation Equipment

Spending on replacement of substation equipment, including circuit breakers, insulators, line arresters, and coupling capacitors exceeded TSIP projections by $5.3 Million in 2017. Due to lower spending in Transmission in programs outside of the TSIP, the Companies took advantage of an opportunity to focus more resources on replacing substation equipment as part of previously-scheduled work. For example, the Companies replaced a total of 61 circuit breakers in 2017 compared to planned replacement of 37 breakers, largely during planned outages. Effective use of planned outages lowers the overall risk to the system and lowers overall costs to replace equipment.

3. Criteria Used to Prioritize Projects

There is not a "one size fits all" approach to prioritizing reliability or system integrity projects contained in the TSIP. The Companies must be nimble and adapt their approach to asset replacement to respond to changed circumstances. For example, planned substation outages allow the Companies to accelerate replacement of equipment at that substation without causing additional impact to customers. Furthermore, overall system resiliency is best achieved when certain related equipment (such as breakers, insulators, and line arrestors) are replaced simultaneously. The Companies can maximize efficiency in asset replacement when they have flexibility to determine how such replacements are prioritized and when they occur.

Prioritization within each program or asset class depends on the impact of failure on the Companies' customers, the type of asset, the age and condition of the asset, past performance and maintenance history, or some combination of these factors. This section describes the various projects contained in the TSIP and the general criteria used to prioritize those projects.

3.1 Reliability Programs

3.1.1. Prioritizing Vegetation Management Activity

As the Companies reported in testimony and related materials filed in the 2016 rate cases, in 2016 the Companies began transitioning their line clearing and vegetation management programs on 345kV and higher lines from a just-in-time approach to a 5-year cycled approach. Starting in mid-2017, the Companies began the first cycle for lines operating below 345kV. Because the complete cycle will take five years to implement, the Companies have continued with aerial inspections to identify potential line interference and hazard trees, and those inspections are still the primary method of prioritizing vegetation management activities. Potential customer impact and the occurrence of other work, such as pole and conductor replacements, is also a factor.

Once the first five year cycle is complete, prioritization of line clearing will be based primarily on the established cycle, while off-cycle work will continue to be prioritized through inspection programs.

3.1.2. Prioritizing Line Switch Maintenance

As part of the TSIP, the Companies have established a detailed annual inspection cycle for all automated and motor operated line switches. All remaining manual switches will be inspected every other year. The results of these inspections allow the Companies to repair switches as necessary or to prioritize switches for replacement. The cycles for the inspections themselves were established based on experience and typical industry practices.

3.1.3. Prioritizing Line Sectionalizing

Line sectionalizing involves installation of in-line breakers or switches to decrease customer exposure to outages on long transmission lines with multiple load taps. Priority for lines to receive this new equipment is based on the length of the line, the total customer impact in the event of an outage, and past performance of the line in terms of outage frequency and duration.

3.2 System Integrity Programs

3.2.1. Prioritizing Line Equipment Projects

Prioritization of line equipment (including poles), line switches, and overhead lines is based primarily upon analysis of field inspection data and the condition of the asset. For example, inspection data for poles reflects the overall condition of the poles, and those showing a greater degree of damage or deterioration are prioritized for replacement sooner than poles in better condition. Other factors that can influence the priority of replacement of line equipment, line switches, and overhead lines are field-notes captured during inspection, past performance of the circuit on which the equipment operates, extent of customer impact in the event of equipment or line failure, and other work planned on the circuit which may allow the Companies the opportunity to replace line equipment without further service interruption.

3.2.2. Prioritizing Substation Equipment Projects

Circuit breakers are mechanical switching devices subject to mechanical failure and are sometimes difficult to keep in adjustment. The TSIP targets replacement of 12 345kV breakers, 40 138kV or 161kV breakers, and 125 69kV breakers over the five year period. Replacements are prioritized using a number of factors, including past maintenance history, environmental risks (risk of oil release), age, availability of replacement parts, results of diagnostic test results, and potential customer impact of breaker failure.

Substation insulators are used to isolate energized conductors and switching equipment from ground. Replacement of substation insulators contemplated by the TSIP targets both cap and pin and hollow post insulators. Cap and pin insulators typically fail when their cement joints deteriorate and allow separation of components. Most hollow post insulator failures are attributable to water ingress to the hollow portion of the insulator. Replacements are prioritized by the timing of scheduled work on related breakers, potential customer impact of failure, and in some cases, visual inspection.

Line arresters protect transmission equipment by limiting transient overvoltage typically caused by lightning strikes or switching. Porcelain or silicon carbide components on older line arresters are prone to failure and resulting outages. Replacement of line arresters is performed in connection with replacement of other substation assets and is not individually prioritized.

Coupling capacitors couple a signal from a power line carrier to the transmission line. Their failure is difficult to predict. Replacements are prioritized based primarily on customer impact of failure, age and type of equipment.

3.2.3. Prioritizing Substation Protection and Control Systems

Protection and Control (P&C) Systems refer to a class of equipment used to identify power system disturbances, stop system degradation, restore the system to a normal state, and minimize the impact of disturbance. P&C equipment is typically contained inside a substation control house and includes relay panels, remote terminal units (RTUs), power line carriers, digital fault recorders, and batteries.

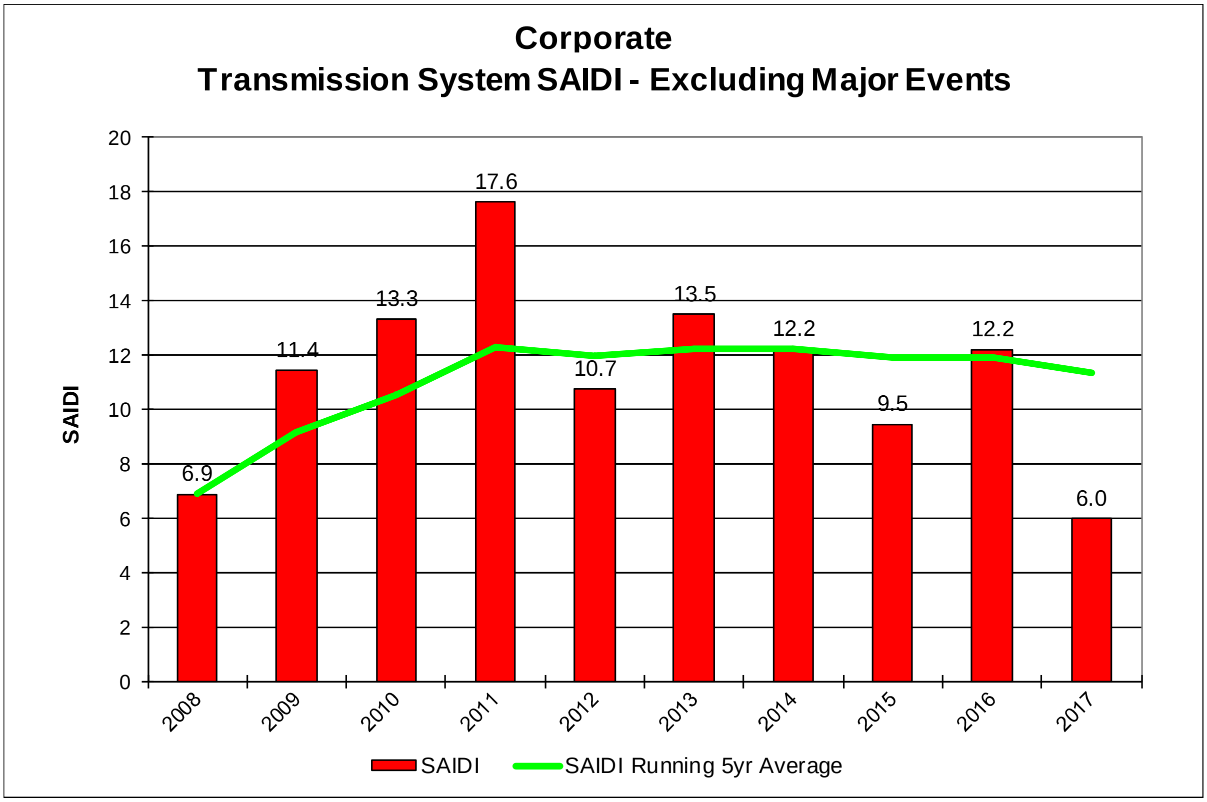
Replacement of the control house itself is prioritized based on the overall condition of the control house and the equipment inside. Replacement of relays and RTUs are prioritized primarily based on past performance and obsolescence. Power line carriers and digital fault recorders are replaced based on past maintenance history, and new digital fault recorders are added based on the need to improve data on a particular circuit. Batteries are replaced based upon their age and/or condition.

4. Impact on System Reliability and Other Benefits

4.1 System-Wide Reliability Performance

Transmission System Average Interruption Duration Index ("SAIDI") is used as a metric to track transmission reliability impact on customers. SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and system. Based on industry standard, major event days such as a severe wind storm are excluded from this metric. SAIDI can be influenced by a number of factors, including weather events which do not meet the "major events" threshold for exclusion and the number and duration of planned outages. The following graphic shows the Companies' combined transmission system SAIDI for the past ten years:

Figure 1: Combined Transmission SAIDI 2008-2017



As this figure demonstrates, the Companies' combined 2017 transmission reliability performance was favorable compared to recent years as measured by SAIDI, resulting in just 6.0 minutes of average service interruption per customer. Combined transmission SAIDI for calendar year 2018 through May is 1.44 minutes, more than one minute lower than the same period in 2017. These data show a positive trend in improvement of transmission system reliability, and the Companies expect that the upgrades and improvements included in the TSIP are contributing to and will continue to contribute to that positive trend.

4.2 Reliability Benefits on Specific Lines

Since the implementation of the TSIP, the Companies have made TSIP-related upgrades to a total of 26 circuits. While there is not enough history for most of these circuits to determine impact on overall reliability, the Companies have noted immediate and significant improvements in reliability resulting from TSIP investments on certain lines.

4.2.1 Beattyville to West Irvine

In 2016, KU added a motor operated switch and in 2017 added automation at the Irvine tap point for this line. From 2012 until the time this switch was installed, this circuit experienced fourteen (14) sustained events and accounted for 2.7 minutes of SAIDI for an average SAIDI of 0.19 minutes per event. After these projects were completed, this circuit experienced four (4) sustained events, but collectively those events accounted for only 0.03 minutes of SAIDI impact for an average SAIDI of 0.008 minutes per event.

4.2.2 Lexington to Pisgah

The Lexington to Pisgah line was previously KU's worst performing transmission line in terms of system outages and duration. The line experienced eleven (11) sustained events and contributed 8.6 minutes of SAIDI since 2012. In 2016, KU added two circuit breakers at the Parker's Mill station and motor operated switches at the Parker's Mill tap point. Several miles of the line were replaced and rebuilt. Since the completion of these improvements, there have been no outage events on the line.

4.2.3 Carrollton to Owen County

The Carrollton to Owen County line was historically a poor SAIDI performer. This line experienced eight (8) sustained events and contributed 2.66 minutes of SAIDI since 2012 for an average SAIDI of 0.53 minutes per event. At the end of 2015, KU added a breaker to sectionalize this line into two segments. Since that time, there has only been one (1) event resulting in 0.39 minutes of SAIDI for an average SAIDI of 0.39 minutes per event. The SAIDI impact of this single event would have been much more severe without the additional breaker.

4.3 Reliability Benefits of Cycled Vegetation Management and Hazard Tree Removal

As set forth above, the Companies are in the midst of implementing a 5-year line clearing cycle for transmission lines. Cycled line clearing began on high voltage lines (345kV and 500kV) in 2016 and is now being performed on lower voltage lines (161kV, 138kV, and 69kV). Inspections of lines which have already been cleared under the cycle reveal more uniform line clearance as compared to the previous just-in-time approach, in which significant variations in vegetation encroachment on a single line were sometimes observed. As completion of the first five-year cycle progresses, the Companies expect to see improved reliability, particularly during severe weather events, through uniform maintenance of established transmission corridors.

In 2017 the Companies also completed hazard tree patrols on over 1,000 transmission miles across the transmission system. These patrols identified roughly 1,800 ash trees scheduled for removal. Hazard trees pose a risk of line interference and resulting service disruption. Early identification and removal of hazard trees improves the overall reliability of the transmission system and mitigates the risk of tree-related outages.

4.4 Other Benefits of TSIP Projects

Replacement of aging transmission assets not only contributes to system reliability now, but also improves the resiliency and reliability of the transmission system long into the future. Many of the assets being replaced under the TSIP were past their useful life and obsolete. Replacement parts for these aging assets are costly and difficult to obtain, and do not necessarily extend the life of the assets. Replacement assets installed under the programs outlined in the TSIP employ modern technology which enhances the overall safety and resiliency of the system. For example, replacement relays installed in the Companies' substations contain microprocessors which capture valuable data used in fault analysis and outage prevention. This equipment enables the Companies to more accurately identify a fault location and reduce the number of faults where an initiating cause cannot be identified.

Furthermore, many of the lines being improved were previously designed for medium loading under the National Electrical Safety Code ("NESC"). New equipment installed on these lines is designed for heavy loading under the NESC, improving the ability of the line to withstand weather events such as wind and ice. For example, while most of the poles being replaced on the transmission system are wood, most of the replacement poles are steel. Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles. This approach is typical in the industry for transmission structures, particularly in areas where woodpeckers are common.

Replacement of aging infrastructure also reduces the risk and potential impact of environmental contamination. Circuit breakers containing oil are being replaced with modern equipment that does not contain oil, reducing the amount of oil in the transmission system and thus reducing environmental risks posed thereby.

In summary, the investments being made consistent with the TSIP provide long lasting benefits to system resiliency, public and employee safety, and operational efficiency in addition to improving overall system reliability.

5. 2018 Projected TSIP Spending

The following table shows the Companies' combined projected 2018 spending on projects included in the TSIP:

Table 6: LG&E and KU Combined TSIP Projections vs. 2018 Forecast ($MM)

	TSIP Projection for 2018	Current 2018 Forecast[7]	Variance ($)
O&M Total:	$14.3	$14.3	$0.0
Capital Total:	$88.4	$108.5	$20.1
Total:	$102.7	$122.8	$20.1

As with 2017, 2018 projected spending for O&M projects is expected to track near the Companies' projections in the TSIP. Also like 2017, the forecast for 2018 spending on system integrity and modernization projects (capital projects) is expected to exceed the Companies' initial projections. The primary drivers for the projected variance are the same as those applicable to 2017 spending: increased need to replace aging or deteriorated line equipment identified through inspections and other risk analysis, and increased ability to take advantage of planned outages on certain lines and substation equipment.

[7] Forecast includes actual spending through April 2018.

Transmission System Improvement Plan (2017–2021)

PPL companies

Contents

Tables

Figures

1. Executive Summary

LG&E and KU operates the largest electric transmission system in Kentucky with 952,000 retail customers. In addition, the company serves more than 125,000 electric customers either directly or through interconnects with other smaller distribution companies (cooperatives) and municipal utility systems. The system spans more than 5,000 line miles with voltages from 69kV to 500kV.

Since the LG&E and KU merger in 1998, the transmission systems of both utilities have been jointly planned, operated and maintained in accordance with regulations and generally accepted practices within the industry. However, due to dissimilar geography, the two systems vary significantly in both design and performance. KU transmission is mostly rural, with low customer density, long circuits and more infrastructure required to serve customers. The LG&E system is more compact, with built-in redundancy and circuit ties, serving a mostly urban customer base in and around Louisville. These inherent characteristics in the two system designs drive the difference in reliability performance, with the LG&E transmission system performing in the first quartile, while the KU transmission system is in the fourth quartile among utilities as measured by annual duration of customer outages.

Because LG&E and KU infrastructure was built mostly between the 1950s and 1980s, a significant portion of the system is aging past its assumed useful life and must be replaced in order to ensure system integrity over the long term. Major weather events in 2008 and 2009 revealed an increase in duration of transmission-related customer outages across the system.

In 2010, LG&E and KU joined the newly formed North American Transmission Forum (NATF). NATF benchmarking studies against the industry indicated the LG&E and KU transmission system was experiencing a higher-than-average number of outages compared to other utilities. These findings led the company to formalize its reliability performance monitoring functions to better understand the reliability drivers with the intention of developing improvement plans. This focus uncovered that KU and LG&E have similar number of outages per mile of transmission line, but that outage restoration time at KU is longer than LG&E. The analysis also determined that the sustained outages are primarily caused by tree interference and equipment failure; while momentary outages are driven primarily by weather, but are significantly affected by tree interference and equipment failure.

LG&E and KU leadership recognizes that customer expectations are changing and understands that to keep pace, the company must increase its investment to improve reliability and maintain system integrity, while minimizing the impact on the cost to customers. The company believes that, through targeted investment, it can bring the KU transmission system to the top of the third or even the bottom of the second quartile for reliability (from the current fourth-quartile ranking), while maintaining the first-quartile performance of the LG&E transmission system.

Through a combination of carefully selected capital and O&M reliability programs, the company proposes to invest $108.3 million ($67.8 million in O&M and $40.5 million in capital) over the next five years (2017-2021) to target improving reliability performance by 3–6 SAIDI minutes (excluding major event days). The key reliability programs include enhanced vegetation management, switch maintenance and circuit sectionalizing through installation of in-line breakers and switches.

In order to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure, the company proposes to invest approximately $429.5 million over a five-year period (2017–2021). This investment will focus on a more aggressive replacement of critical line and substation assets and upgrades to the protection and control systems.

2. Case for Action/Performance Objectives/Strategy

2.1. Background

2.1.1. LG&E and KU System Characteristics

Kentucky Utilities Company (KU) is a regulated electric utility, based in Lexington, Kentucky, serving customers in 77 Kentucky counties and five counties in Virginia (under the name Old Dominion Power — ODP). Louisville Gas and Electric Company (LG&E) is a regulated electric and natural gas utility, based in Louisville, Kentucky, serving Louisville and 16 surrounding counties. In 1998, the utilities' operations were merged together after LG&E Energy acquired KU Energy. Today, LG&E and KU together operate the largest transmission system in Kentucky. The transmission system serves more than 952,000 retail customers, and more than 125,000 electric customers connected either directly or through interconnects with other smaller distribution companies (cooperatives) and municipal utility systems. While a large number of customers are in the Lexington and Louisville metropolitan areas, a significant portion of the line mileage of the transmission system is used to provide electrical service to the rural customer base spread across the Commonwealth. LG&E and KU service territory is provided in Figure 1.

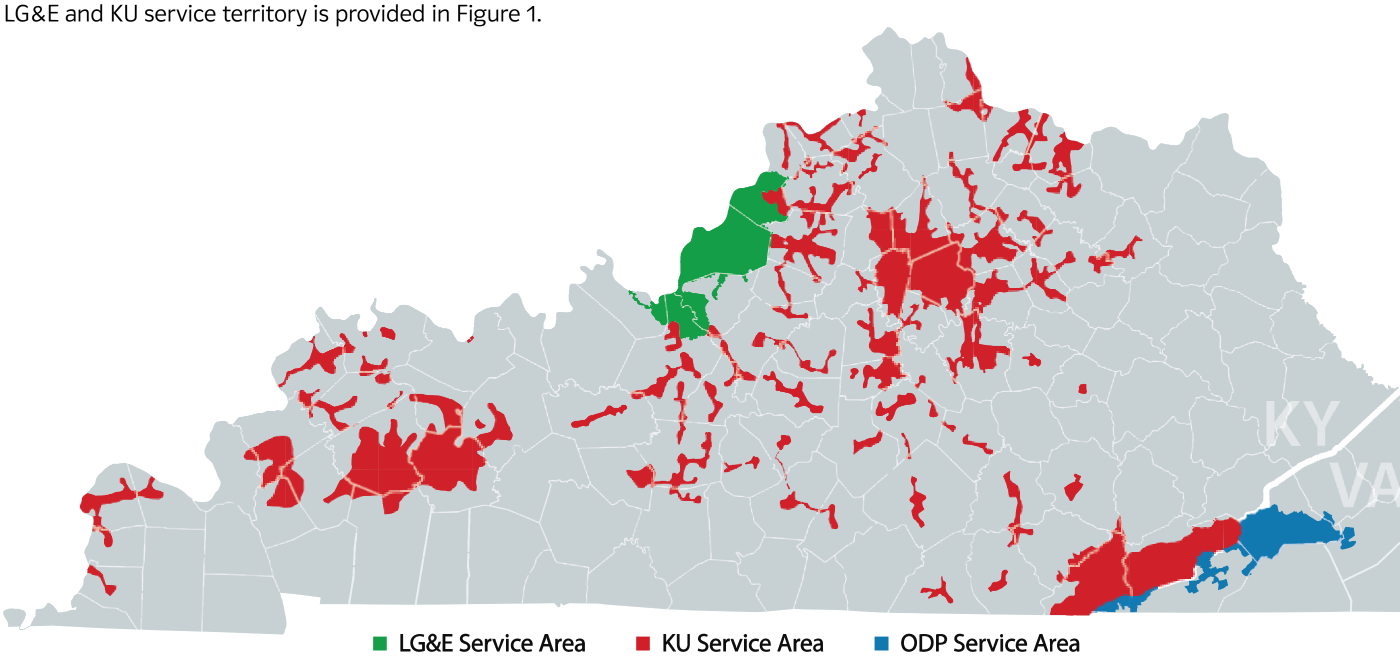


Figure 1: LG&E and KU service territory map.

Table 1 provides a summary of the key LG&E and KU transmission system characteristics and assets by operating voltage.

Table 1: LG&E and KU Transmission System Characteristics

		69kV	138kV	161kV	345kV	500kV	Total
LG&E and KU — Total	Retail Customers*	775,000	176,000	1,000	1	0	952,001
	Circuits/Line Segments	248	134	31	43	2	458
	OH Circuit Miles	2,755	1,344	646	674	57	5,476
	UG Line Miles	6	5	0	0	0	11
	Substations (high end voltage)	57	60	32	18	2	169
	Transformers	0	81	32	22	2	137
	Circuit Breakers	642	417	81	95	3	1,238
	Poles/Structures	29,000	8,700	3,600	2,700	200	44,200
KU System	Retail Customers	505,000	41,000	1,000	1	0	547,001
	Circuits/Line Segments	178	70	29	16	2	295
	OH Circuit Miles	2,468	1,009	530	499	57	4,563
	UG Line Miles	3	1	0	0	0	4
	Substations (high end voltage)	43	40	31	9	2	125
	Transformers	0	54	31	9	2	96
	Circuit Breakers	476	213	80	43	3	815
	Poles/Structures	24,200	6,300	3,200	2,100	200	36,000
LG&E System	Retail Customers	270,000	135,000	0	0	0	405,000
	Circuits/Line Segments	70	64	2	27	0	163
	OH Circuit Miles	287	335	116	175	0	913
	UG Line Miles	3	4	0	0	0	7
	Substations (high end voltage)	14	20	1	9	0	44
	Transformers	0	27	1	13	0	41
	Circuit Breakers	166	204	1	52	0	423
	Poles/Structures	4,800	2,400	400	600	0	8,200

* Count of retail customers either served directly at the designated voltage or by a distribution substation connected to that voltage.

Table 1: LG&E and KU transmission system characteristics.

Prior to the LG&E and KU merger in 1998, each transmission system was planned, designed, operated and maintained in accordance with regulations and typical industry practices and in a manner that met the unique needs of its respective customers and service area.

Following the merger, LG&E and KU reorganized and integrated transmission planning, operational and maintenance processes. However, the design of each utility transmission system remained the same, and LG&E and KU continued to design and install new infrastructure in a manner compatible with legacy systems.

2.1.2. Age of Transmission Infrastructure

Based on available asset information, the company has analyzed the age and condition of its transmission assets. As can be seen in Figure 2, and in line with other utilities, a large portion of LG&E and KU's assets were installed between 1950 and 1980, with significant portions constructed prior to 1950 still in service.

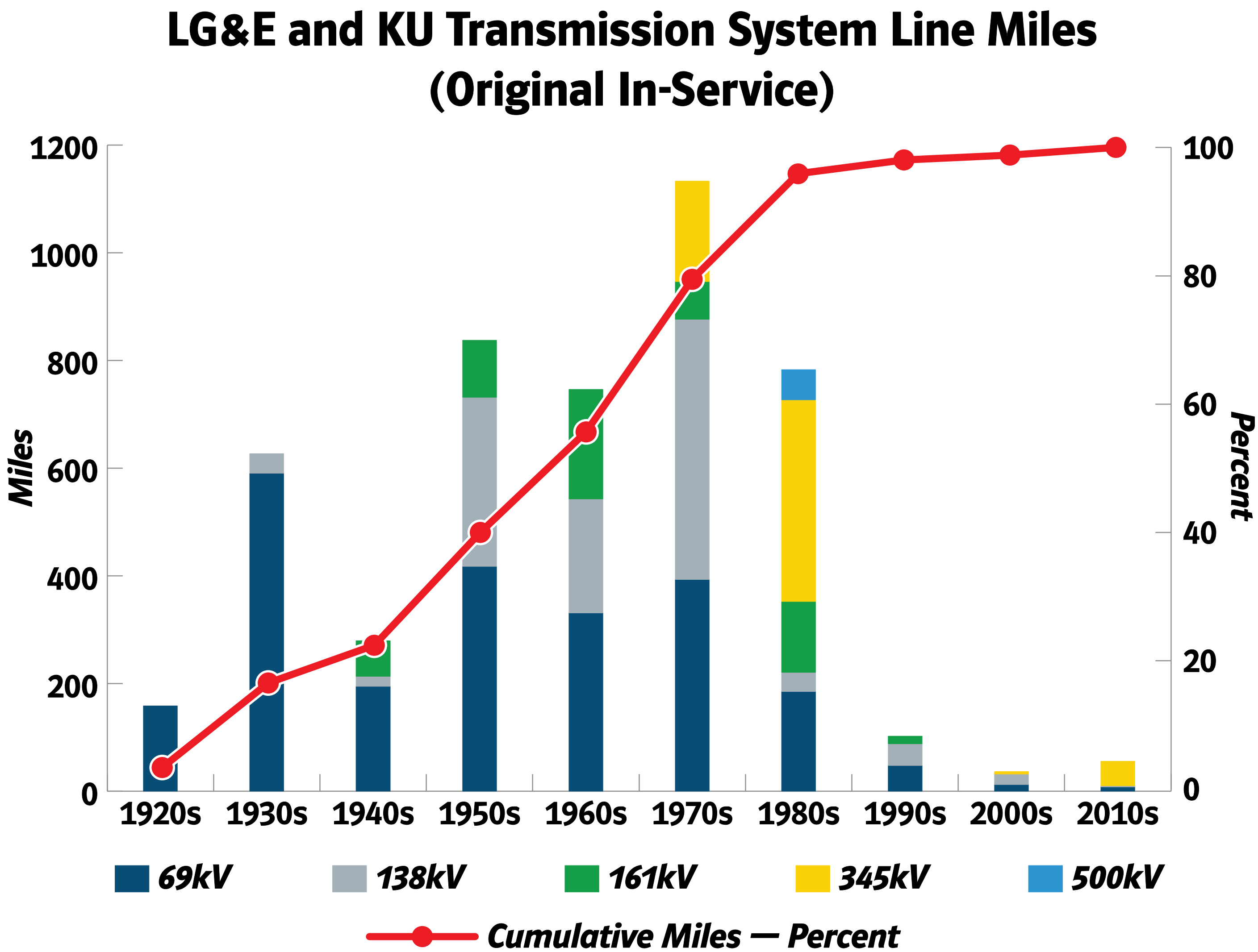


Figure 2: Transmission line miles added by voltage (1920 through 2010).

While the majority of the oldest (pre-1950) circuit breakers, transformers, protection systems and wood structures have since been replaced, a significant portion of the conductors, steel structures and insulators in the system are original. Most of the major equipment and protection systems in service today were installed between 1945 and 1990. As a result, many of these assets are reaching the end of their useful life, which would increase the number of failures and degrade system performance going forward unless they are replaced.

2.1.3. Transmission System Reliability

Catastrophic, in-service failures of key assets (e.g., transformers, switches, underground cable) present public and employee safety risks, and negatively impact customer reliability. Beyond direct customer impacts, such failures can increase system risk by reducing available system capacity, which in turn increases the probability for customer outages. Lastly, assets that fail while in-service are often more expensive to replace (as compared to proactive replacement) and can damage other assets and equipment in the immediate proximity.

Historically, both LG&E and KU transmission systems provided reliable service at a reasonable cost with total spending (capital and O&M) per line mile among the lowest of FERC regulated utilities in the country. Figure 3 provides a comparison of LG&E and KU transmission total spending (capital and O&M) costs per mile against other utilities based on FERC Form 1 data from 2011 through 2015. Similar analysis of total transmission spending (capital and O&M) per MWh (see Figure 4) indicates that LG&E and KU had the lowest cost among regulated utilities in the same period of time.

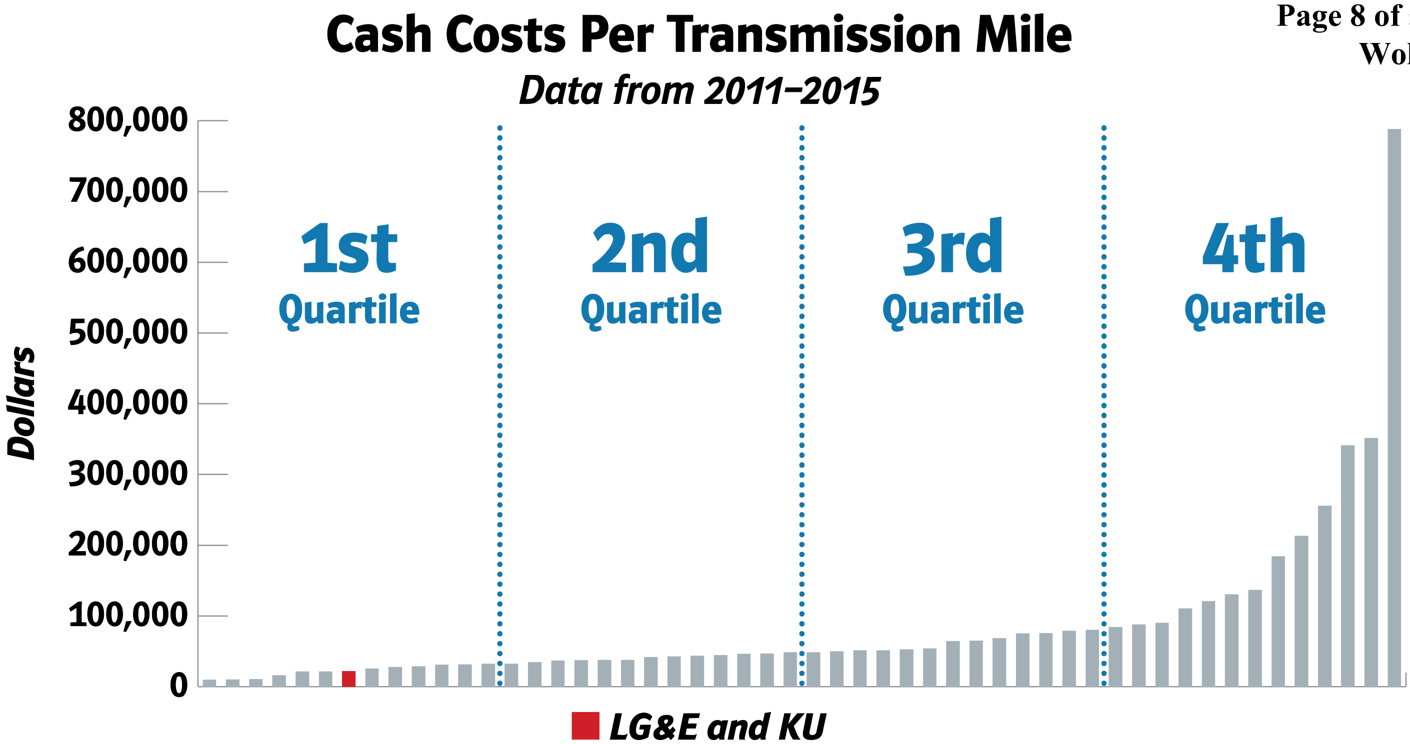


Figure 3: Industry comparison of LG&E and KU transmission total spending per mile (2011–2015).

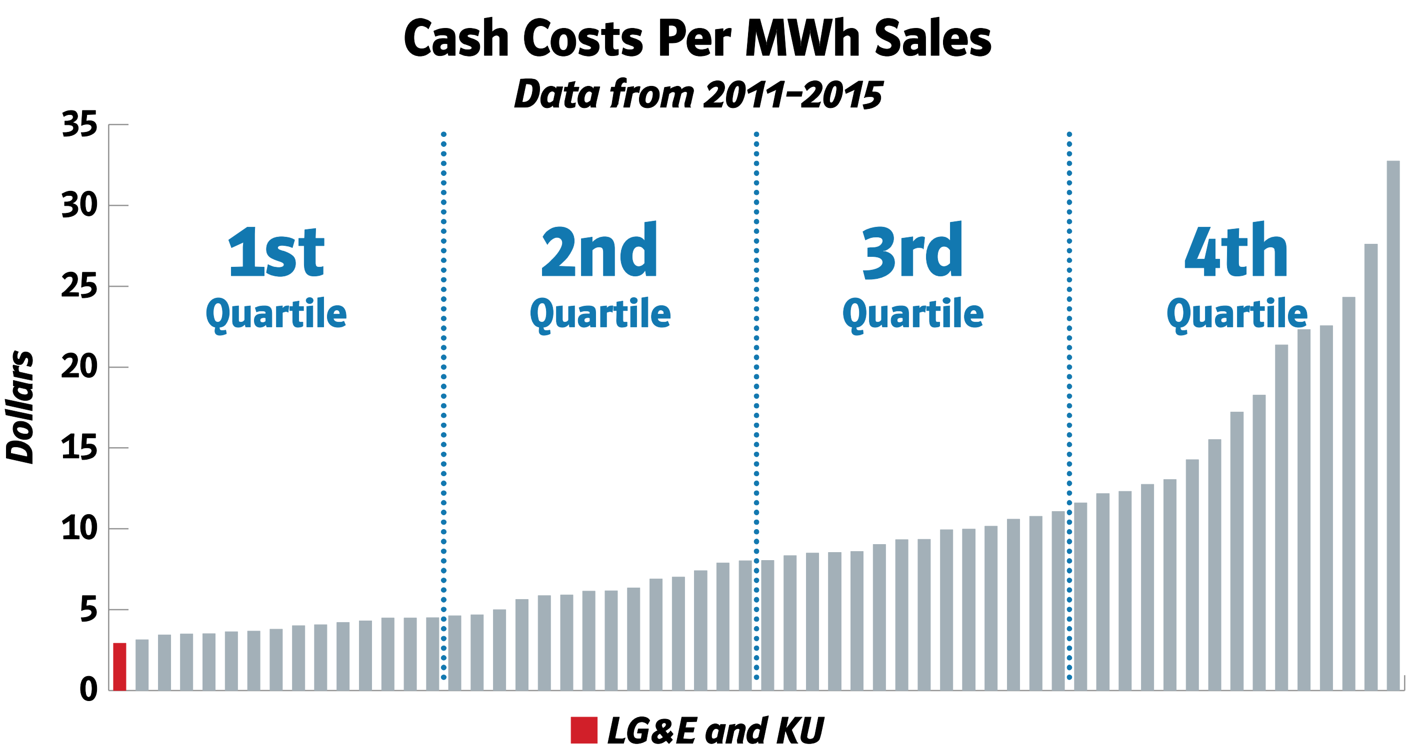


Figure 4: Industry comparison of LG&E and KU transmission total spending per MWh (2011–2015).

Over a six-month period, from September 2008 through January 2009, LG&E and KU's transmission and distribution systems were impacted by two significant weather systems and experienced the two largest outage events in the company's history. The September 2008 outage was caused by the remnants of Hurricane Ike that generated high-speed winds, which toppled trees into lines and knocked down transmission poles and structures. The Ice Storm of 2009 produced excessive ice loading on trees, structures and conductors and was particularly damaging to the transmission system. Both events required extensive efforts and support from neighboring utilities to restore service to customers. Subsequent to these events, the company began to notice increasing trends in transmission SAIDI (System Average Interruption Duration Index) performance as can be seen in Figure 5.

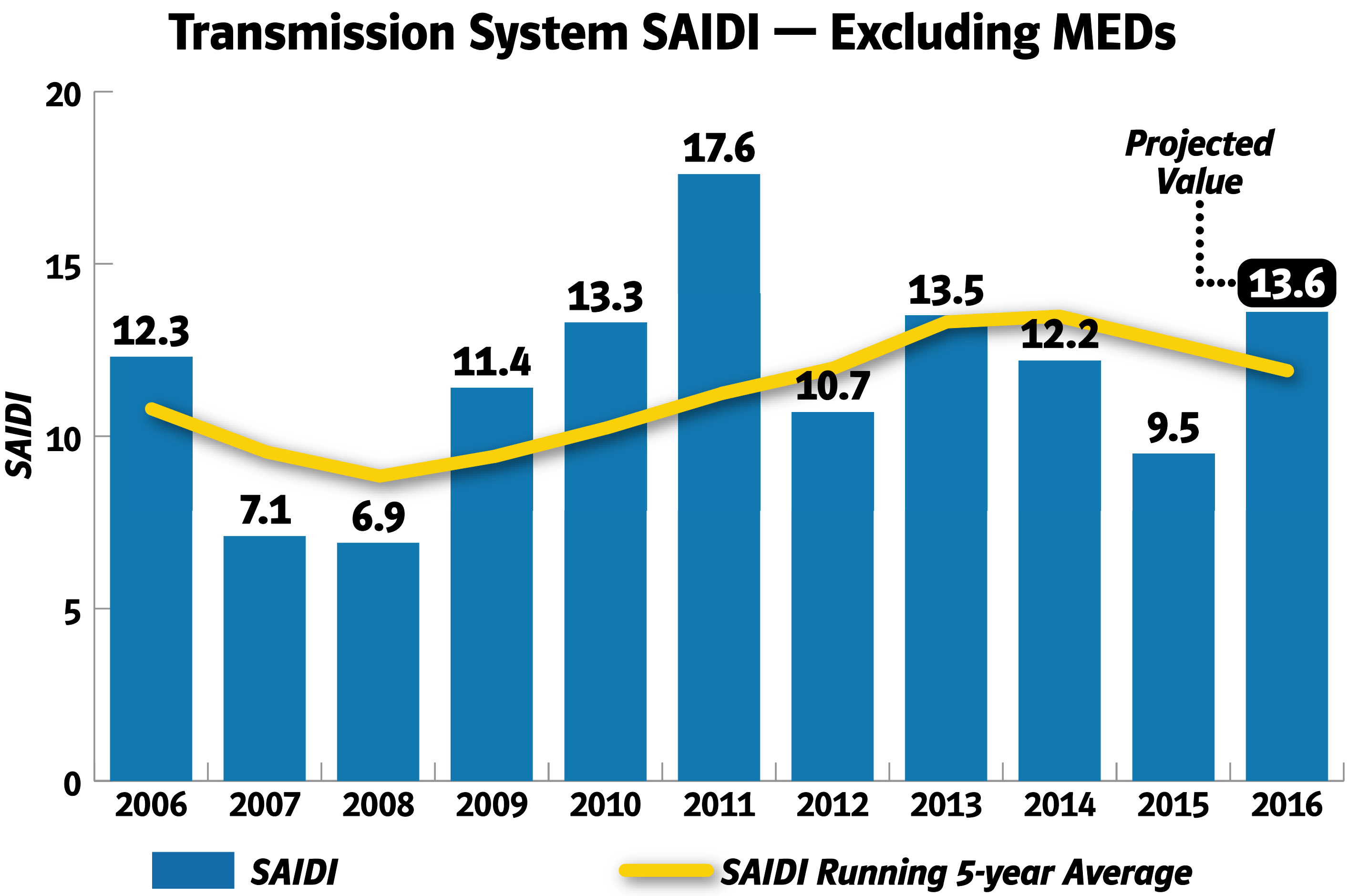


Figure 5: LG&E and KU transmission SAIDI performance (2006–2016).

SAIDI is a standard industry measure that indicates how long, expressed in number of minutes, an average customer has been out of service during a predefined period of time (most often in a year). This index is used to compare reliability performance across different utilities. In order to normalize reliability performance and account for differences across utilities (e.g., size and geography), the industry developed a standard methodology (IEEE 1366 2.5 β) which uses log standard deviation to establish a major event threshold for each utility in terms of SAIDI minutes. The threshold is unique to each utility, based on its SAIDI performance from the prior five years, but serves to normalize the data consistently across varying geographies, and major event frequencies and intensities experienced by each utility. Major Event Days (MEDs) that meet this data-driven threshold are removed to normalize the reliability performance so that "normal" performance is less skewed by unusual events.

In evaluating the annual SAIDI value excluding MEDs for the past 10 years, LG&E and KU has identified a slight upward trend, especially since 2008, when SAIDI has risen to the highest historical levels. The recent leveling in reliability performance (2012–2015) is mostly attributable to the lower number of moderate weather events below the IEEE 1366 normalization threshold and the decrease in the number of planned outages. The company believes that the general trend of increased SAIDI (deteriorated reliability) on the transmission system will not provide the level of service that customers require.

In April 2010, LG&E and KU joined the newly formed North American Transmission Forum (NATF). The NATF is a group of transmission owners and operators that had been operating as part of the North American Electric Reliability Corporation (NERC) since 2006 before becoming independent. NATF's purpose is to promote transmission reliability excellence through efforts by its members to help one another identify and correct problems in the areas of operating experience, physical and cyber security, and human performance through continuous improvement techniques.

Through discussions with peer utilities at NATF and other industry forums, LG&E and KU identified the need to improve its data reporting quality and accuracy of reliability information for transmission-related outages. To achieve this goal, the company created a department to formalize the reliability monitoring function, responsible for investigating each outage and gathering, analyzing and reporting transmission reliability performance data including root causes.

The data gathered through this process allows LG&E and KU to identify and analyze the underlying causes of outages in order to better understand reliability performance. For example, the company has been able to positively identify the cause of a greater percentage of sustained and momentary outages, decreasing the number of outages with unknown cause codes. As Figure 6 depicts, unknown outages have decreased from 58% of all outages in 2010 to 22% in 2015. Having an accurate cause code provides the necessary information to understand the underlying conditions that need to be addressed in order to reduce the frequency and duration of outages.

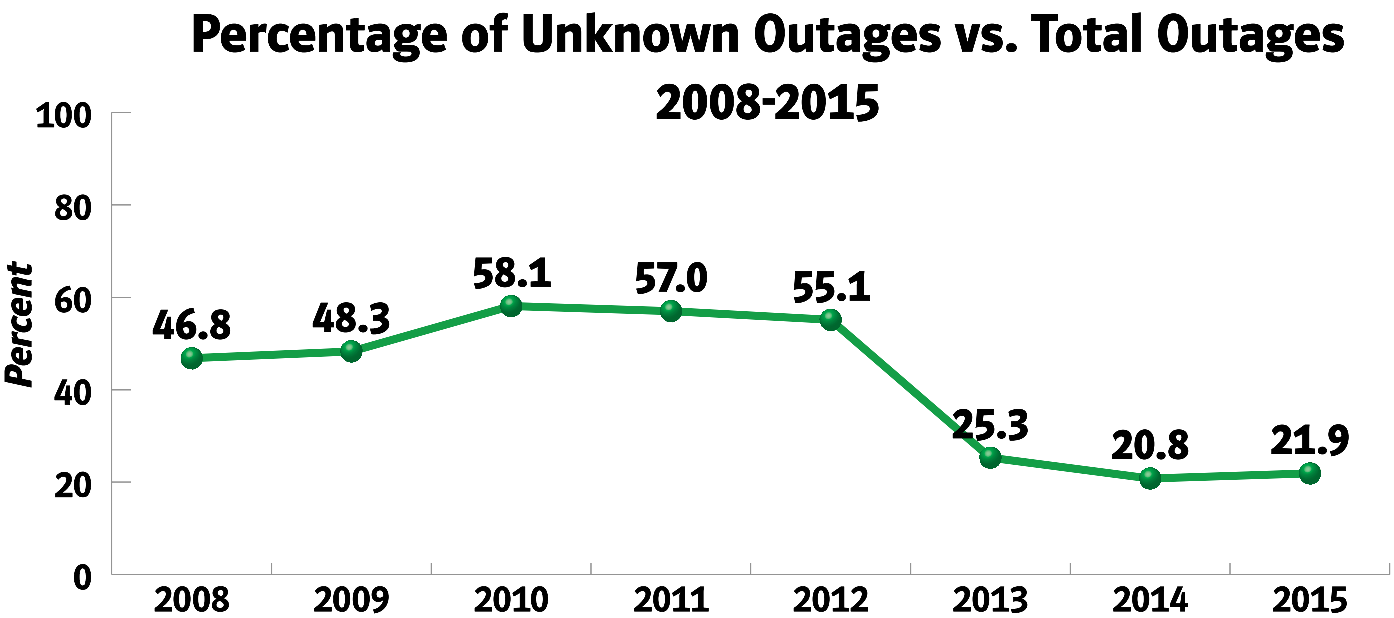


Figure 6: Percentage of unknown outages vs. total outages (2008-2015)

Customers cannot distinguish between outages on the transmission or distribution system. Transmission outages generally result in far fewer interruptions of service to customers than those that occur on the lower voltage distribution lines. However, the impact of transmission outages can be significant as they generally involve larger numbers of customers over a significant area.

2.1.4. Reliability Performance Industry Benchmarks

Joining the NATF provided the platform to compare transmission system reliability to peers at a detailed level on a more normalized basis. Specifically, in the NATF benchmark study comparing the number of sustained and momentary outages in 2011 and 2012, LG&E and KU[1] was in the fourth quartile for total system performance when compared to other transmission utilities across North America. This meant that the LG&E and KU transmission system experienced relatively more outages per mile of transmission line compared to most other utilities. REDACTED Pursuant to Third-Party Nondisclosure Agreement [redacted]

Figures 7–9 show that transmission SAIDI performance for the combined utilities is higher than average in benchmarking studies primarily driven by the number and duration of sustained outages on the KU transmission system. By contrast, the LG&E transmission system performs very well on this metric with first or second quartile performance in these years.

1. NATF Benchmarking study is conducted at the combined LG&E and KU level and it is not broken up by individual companies (LG&E vs. KU).

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2.1.5. LG&E and KU Transmission System Design

In order to better understand the differences between the KU and LG&E systems, it is helpful to compare outages per hundred miles (OHMY) on the KU and LG&E transmission systems. OHMY is calculated by dividing the total number of transmission outages, of any duration not normalized for weather, by the total transmission line miles, and then multiplying the result by 100. It provides a measure of the outage incident rate for every 100 miles of transmission line. OHMY is used by the NATF to help utilities compare outages across different transmission utilities to measure relative differences in performance. Based on this measure, as presented in Table 2, KU has averaged 10.21 outages per hundred miles compared to 12.01 for LG&E. Therefore, KU's per mile outage rate is slightly lower than LG&E's for the period 2008 thru June 30, 2016.

Table 2: LG&E and KU Outages by Hundred Miles of Lines (2008–2016)

Company	2008	2009	2010	2011	2012	2013	2014	2015	2016*	Average
KU	10.16	12.29	8.56	11.38	10.58	9.45	9.54	10.49	4.36	10.21
LG&E	9.70	14.33	14.11	11.96	13.03	8.62	14.43	11.31	4.63	12.01

*2016 thru June 30, 2016

Table 2: LG&E and KU Outages by Hundred Miles of Lines (2008-2016)

The OHMY metric demonstrates that KU and LG&E systems perform similarly based on the number of outages that they experience. However, when outage duration (SAIDI) is considered, KU's transmission SAIDI from 2009 through 2015 is about six times higher than LG&E's performance. This means that on an annual basis, KU customers experience longer transmission-related outages than LG&E's customers. While operations and maintenance programs are practically identical for the two transmission systems, the reason for the difference is in the legacy system design that was constructed to serve rural KU customers versus the LG&E design serving a more concentrated urban transmission load. Since LG&E serves the city of Louisville and surrounding counties, its service territory is more compact, allowing for a design that uses more redundancy through circuit ties to provide backup in case of an outage. Figure 10 demonstrates the typical design of the LG&E transmission system at the point of serving customers (Load A and Load B represent transmission customer connections). In the LG&E system, when a sustained outage occurs on a line between two substations, circuit

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8. 2016 value is projected based on year-to-date SAIDI performance as of 6/30/2016.

breakers isolate the fault and customers continue to receive power from redundant sources. In some cases, where circuit breakers are not practical, remotely controlled switches are sometimes used to isolate faults and/or quickly restore service from alternate sources.

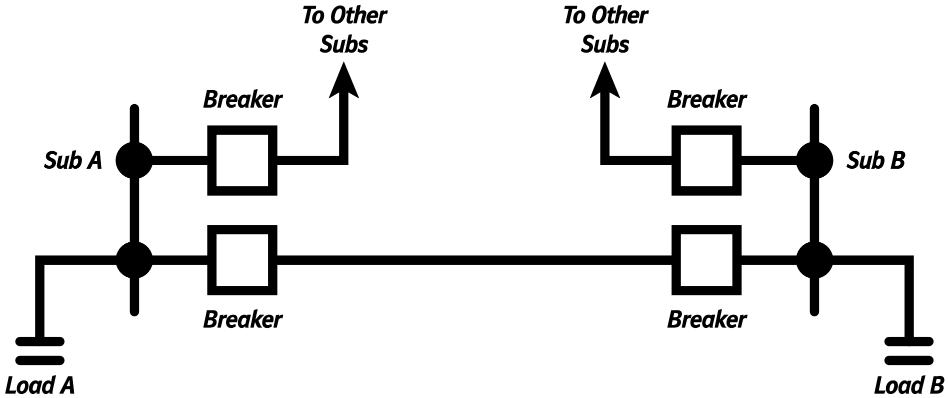

Figure 10: Typical LG&E transmission system circuit design.

The KU service territory is primarily rural, with low customer density and diverse geography, including mountainous areas, requiring longer circuits and more infrastructure per customer than in the LG&E territory. In many of the remote areas, the communications needed to allow for remote control of switches and circuit breakers at the time the system was constructed, was expensive and therefore very limited, or non-existent. Instead of a relatively few, large substations to serve customers, KU has built a large number of relatively small substations which are connected to the electric grid primarily through the 69kV transmission system.

As a result, most of the KU circuits to customer-serving substations are radial construction, meaning that equipment used to serve customers is directly connected to the transmission lines. An outage that occurs on the line between two circuit breakers interrupts service to all of the customers on that line until the service personnel can locate the problem, isolate or repair it and return service to customers. Figure 11 highlights this example of the typical design of the KU transmission system.

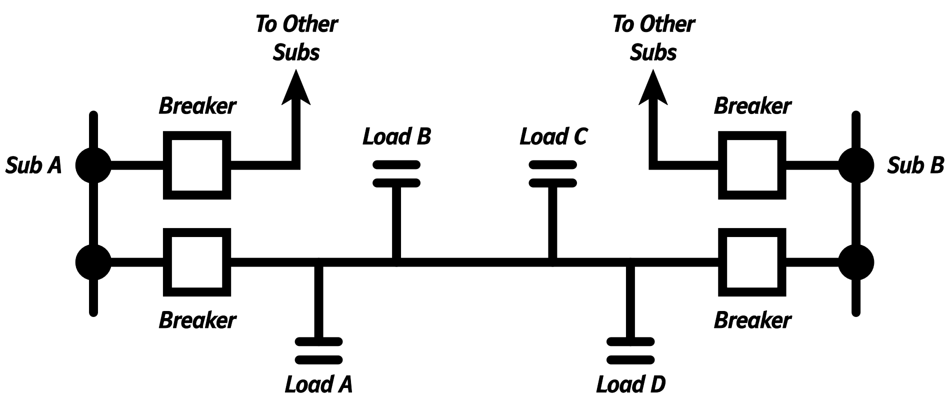

Figure 11: Typical KU transmission system circuit design.

Given these inherent differences in system design, the two systems perform differently from a customer reliability perspective, especially considering outage duration. The level of investment required to rebuild the KU system to resemble the LG&E system design is cost prohibitive (estimated to be in excess of $1 billion). Nevertheless, targeted investment and better availability and reliability of communications technology would allow noticeable improvement of KU system performance at a reasonable cost without a total system redesign. For example, installing remote switching equipment would improve restoration times, and where possible, deploying circuit breakers to shorten the length of long lines serving a large number of customers would decrease exposure to outages. LG&E and KU believe that through a targeted investment program, the company can, in a cost effective manner, significantly improve the SAIDI performance of the KU transmission system, and bring it to the second or third quartile among benchmarked utilities, while maintaining the first-quartile performance of the LG&E system. This investment program is presented in this paper and provides a reasonable approach to improve reliability to the company's customers.

While reducing restoration times will significantly improve SAIDI performance over time, it is also important to address the causes of outages and to minimize outages across both LG&E and KU. Large industrial customers directly served from the transmission system can be significantly impacted by both sustained and momentary interruptions. In order to eliminate outages, it is important to understand their root causes. This provides the basis for developing investment and maintenance programs to address the primary drivers of sustained and momentary outages which can be observed in Figures 12 and 13.

LG&E and KU Transmission SAIDI Causes

2012 through 6/30/2016 — Excluding MEDs

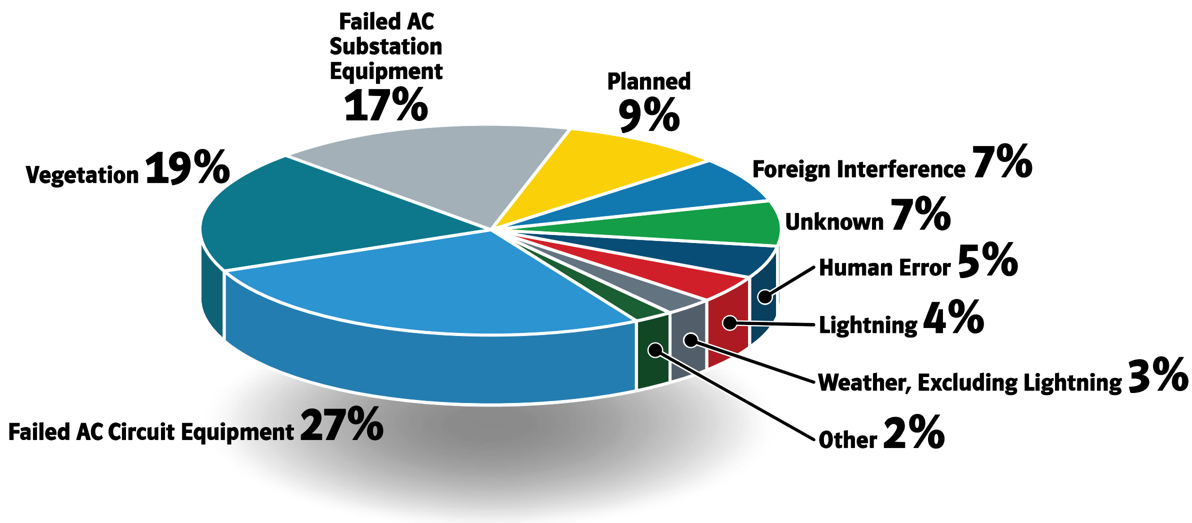

Figure 12: LG&E and KU transmission causes of outages by contribution to SAIDI excluding MEDs (2012-mid-2016).

LG&E and KU Transmission Outage Causes

2012 through 6/30/2016

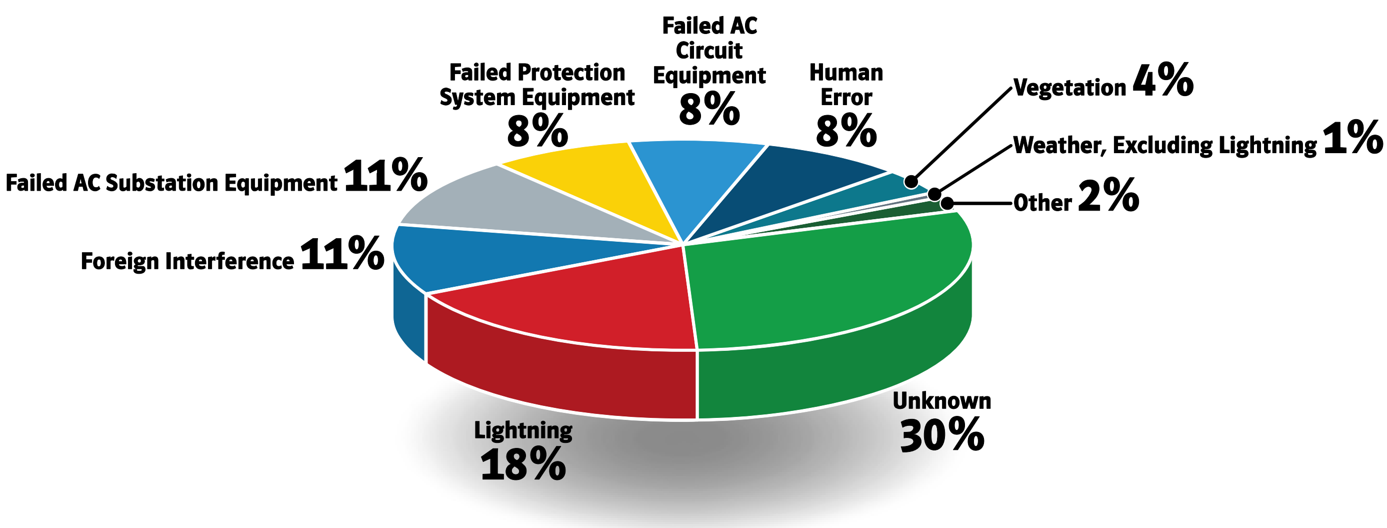

Figure 13: LG&E and KU transmission causes of outages (2012-mid 2016).

The charts in Figures 12 and 13 demonstrate that failed substation and line equipment and vegetation are the primary drivers of both outages and outage duration (SAIDI). It is important to note that often times, the cause of momentary outages cannot be determined, because they are typically caused by transient faults and the evidence is not easily determined after the fact. Based on company experience and field observations, the majority of "unknown" outages on the lower voltage lines (i.e., 69kV) appear to be caused by blowing trees and limbs that make contact with the energized conductors long enough to cause an outage. To address these outage causes and ultimately reduce the total number of momentary and sustained interruptions, the company seeks to enhance its existing vegetation clearing programs and to invest in proactive replacement of aging assets that are nearing the end of serviceable life and show deteriorated condition through inspections and analysis.

2.2. Initial Reliability Improvement Objectives and Steps

LG&E and KU's long-term goal (15–20 years) is to be in the first quartile of transmission reliability performance among its peers. As indicated above, the investment required to rebuild the KU transmission system similar to LG&E's is estimated at more than $1 billion.

Accordingly, in order to balance improvement with the cost of providing power to customers, LG&E and KU initially set a medium-term (5–10 years) objective to move the combined companies into the second quartile based on SAIDI performance among peer utilities.

Using the results of the benchmark studies and the initial reliability analysis (see example of the cause code based breakdown of reliability in Figures 12 and 13), the company identified a set of the improvement initiatives, which included the following:

- join and actively participate in the North American Transmission Forum and provide data necessary to allow comparison of system performance with other utilities;
- design and implement an outage investigation process to ensure accuracy of the data;
- focus on researching and identifying root cause of outages, thus reducing the number of outages with unknown cause code;
- develop supporting tools and reporting for reliability analysis and outage investigations;
- reduce planned outages by performing more maintenance work while the circuits are energized, while ensuring that safety is not compromised; and
- improve reliability performance of an initial set of transmission circuits with significant contribution to past SAIDI performance.

In addition to the reliability improvement programs, LG&E and KU has increased spending on the inspection and replacement program targeting wood poles and structures, cross arms, insulators and other transmission assets.

2.3. Case for Change

Customers increasingly expect safe and reliable service due to their increasing dependency on an economy and society supported by electrical power. Increased reliance on mobile devices, participation in online commerce, and more people telecommuting or working from home all require uninterrupted electricity supply. LG&E and KU's leadership believes that the reliability performance must improve to meet increasing customer expectations, continue to serve and attract businesses and support the growth of the economy within its service territory. The most important driver of overall LG&E and KU customer satisfaction according to the Bellomy Research survey[10] is power quality and reliability (approximately 32% of the weight).

Specifically, the company's leadership has set a goal of maintaining first quartile performance on the LG&E transmission system, while moving the KU transmission system performance into second quartile over the next 5-10 years with the long term objective of becoming a first quartile performer. As other peer utilities also improve their performance, the SAIDI values for the second and first quartile performance will likely continue to decrease (get better) requiring LG&E and KU to further improve reliability performance. LG&E and KU leadership has established expectations for reliability improvement that are discussed in section 2.5.

In addition to improving reliability performance, LG&E and KU must address the risks associated with equipment failures due to aging assets. Over the past several years, the company has experienced several major equipment failures that have resulted in extended customer outages, expensive repairs, and environmental clean-up costs. In one instance, an older vintage coupling capacitor (a device needed to facilitate communications between substations for control purposes) catastrophically failed, resulting in extended customer outages, repair and clean up. In 2013, a 50-year-old breaker (installed in 1963) failed in service, resulting in an oil spill that cost $1.2 million to clean up. The picture in Figure 14 was taken following that outage.

10. Since January 2010, Bellomy Research, Inc. has conducted and analyzed customer satisfaction research for residential customers of LG&E and KU and a peer group of 6 competitive investor-owned utilities in surrounding areas from Iowa to Georgia.

Figure 14: Example of a failed circuit breaker with oil release.

Despite the company's comprehensive inspection and maintenance programs, these types of failures occur, often without warning, as transmission equipment ages and experiences wear and tear. With the aging of infrastructure and key assets, the company believes that it has to develop, fund and implement asset renewal programs in order to minimize the number of asset failures in the future, improve reliability and reduce the risk to public and employee safety.

2.4. Recent Investments into System Improvement

In 2015 and 2016, LG&E and KU increased investment for several existing programs to improve reliability and replace underperforming, obsolete, and aging assets, including:

- wood structure and related equipment replacement programs investment doubled from 2014 levels;
- breaker replacement program increased significantly over 2014;
- protective relays, remote terminal units (RTU) and control house replacement programs significantly increased.

In addition to these asset replacements, LG&E and KU increased its capital investment in-line breaker installations on its worst performing lines to reduce the load exposure to line failures, and in remotely controlled switches to improve restoration times when an outage occurs, both of which are designed to improve system reliability.

Table 3 provides a summary of the incremental spending on the programs described above in 2015 and 2016.

Table 3: LG&E and KU Transmission Recent Capital Investments (MM USD)

		2014	2015	2016 (Projected)
Asset Replacement:	Wood Structures/Insulators/Cross Arms/Shield Wire	$18.0	$33.9	$44.2
	Circuit Breakers	$1.5	$5.0	$4.5
	Control Houses/Relays/RTUs	$2.5	$5.8	$7.0
Reliability:	Circuit Breakers	—	$3.2	$0.3
	Switches	—	$0.1	$1.7
	Protection and controls	—	—	$0.6

Table 3: LG&E and KU Transmission Recent Capital Investments (in millions of USD)

Since 2014,[11] LG&E and KU have replaced more than 1,400 wood poles, 250 defective cross arms, 450 insulators, 30 miles of shield wire, 75 circuit breakers, 60 relay panels, 35 remote terminal units, and 4 control houses.

Additionally, over this same time period, LG&E and KU improved reliability of 9 line segments by adding 3 breakers and 7 switches, reducing customer exposure to outages.

11. Based on projections for end of year 2016.

2.5. Performance Objectives

LG&E and KU leadership has set the goal to improve the overall transmission SAIDI performance excluding major outages by approximately 20-45% (3-6 minutes of SAIDI reduction) over the next 5-10 years. In order to achieve this goal, the number of outages must decline over this time period. The target level performance would most likely move the combined company into the second quartile SAIDI performance among its peers. The graph in Figure 15 depicts the overall projected improvement trend over that period of time.

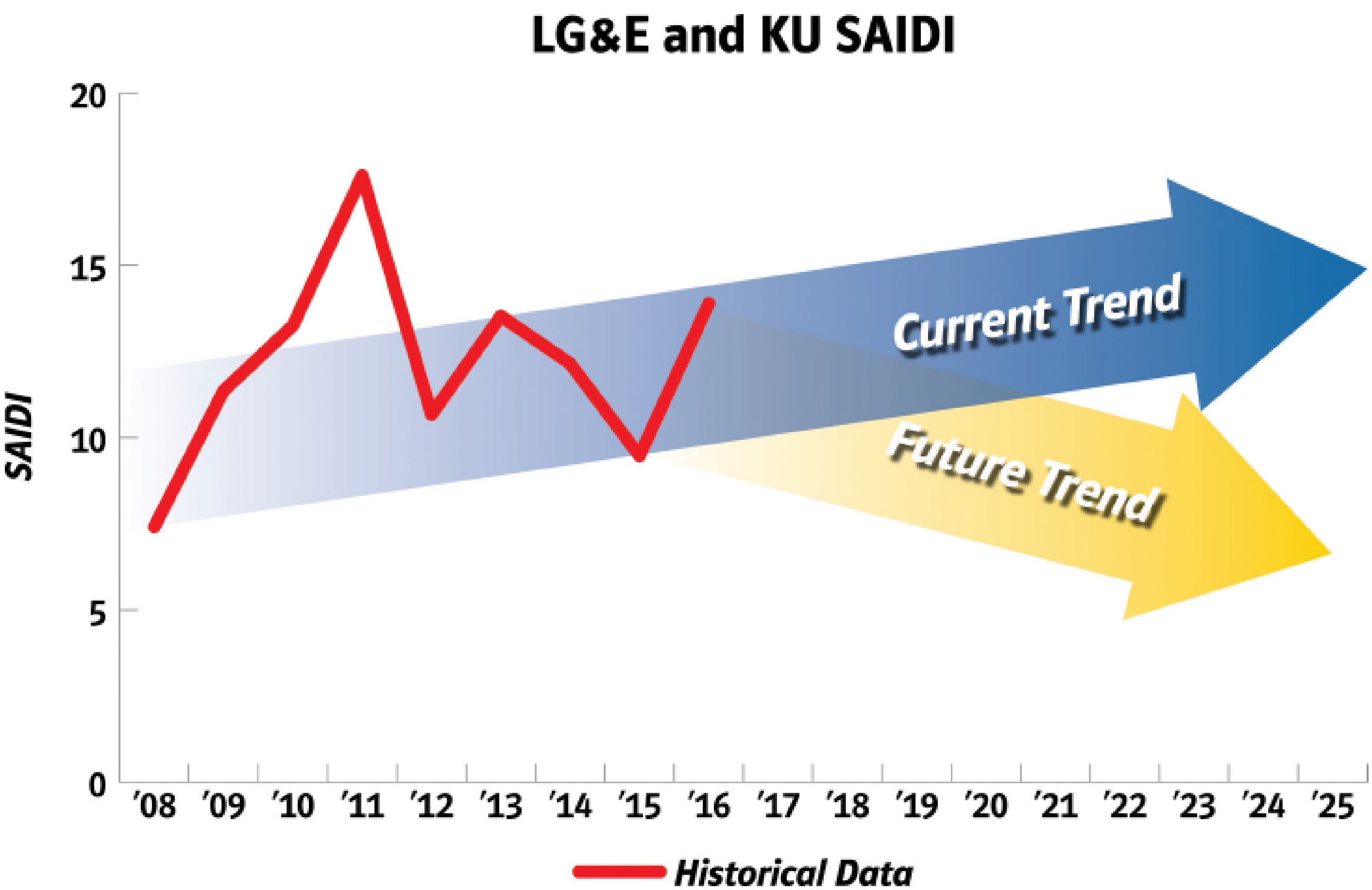

Figure 15: Projected 10-year LG&E and KU transmission SAIDI improvement trend.

In addition to the reliability targets, LG&E and KU plans to accelerate asset renewal programs so that the oldest assets within the asset class are younger than the expected useful age for that specific asset class. For example, if the expected life of a circuit breaker is 60 years, the company wants to minimize the population of circuit breakers on its system that are older than 60 years. However, age is not the only criteria as replacements will be prioritized on other factors such as condition, technical obsolescence, performance and consequence of failure. The company is targeting the following asset classes for replacement:

- wood structures and cross arms;
- insulators;
- overhead conductor and underground cable;
- shield wire;
- circuit breakers;
- control houses and related components: batteries, remote terminal units (RTU), digital fault recorders and protective relay panels; and
- coupling capacitors and instrument transformers.

3. Investment Selection Methodology

The focus of the increased investment is to improve and maintain high customer satisfaction by reducing the number of outages (sustained and momentary) over time and to significantly improve restoration time for sustained outages through a combination of O&M and capital programs. Without a focused investment in infrastructure replacement, the transmission system performance and reliability will deteriorate over time as the assets continue to age. In order to ensure system integrity and reliability in the future, a proactive approach to assessing the condition of and replacing critical transmission assets is needed.

The selection of the specific programs was based on the historical reliability performance and available asset failure data, as well as industry experience in managing specific asset classes.

3.1.Reliability Program Selection

LG&E and KU identified reliability enhancement programs based on historic reliability performance. The reliability performance team tracks the worst performing transmission circuits and analyzes the specific causes of failures on those circuits. Based on this research, the LG&E and KU transmission team identified specific reliability programs, such as enhanced vegetation clearing, switch maintenance, line sectionalizing and backbone protection, to best address these performance issues. LG&E and KU estimated the costs associated with each program based on experience or direct estimates from the vendors who would perform the maintenance or construction work.

In order to better understand the cost-benefit of alternatives and develop the most cost-effective approach to vegetation management challenges, the company retained Environmental Consultants Inc. (ECI).[12] ECI conducted a comprehensive assessment of the company's existing vegetation management program and costs, and made recommendations to enhance program management, reliability and cost effectiveness, to bring it in line with industry best practices.

3.2. System Integrity Program Selection

LG&E and KU selected system integrity programs based on the condition, technical obsolescence, age, and consequence of failure of the various assets within the transmission system. The company inspects and maintains assets (such as transformers) on a regular basis, and uses available diagnostics to determine the condition and replace or repair them before they deteriorate to the point of failure. However, condition data for other assets is not as readily available, so LG&E and KU uses asset age as well as historical performance and experience to estimate the condition of that asset. The company has developed a proactive targeted replacement program to reduce the average age of all assets and to replace poorly performing assets. As with the rest of the proposed programs, the costs associated with asset replacement were estimated based on historical experience.

Table 4 indicates which outage causes are addressed by the selected reliability and asset renewal programs.

12. ECI is a leading utility vegetation management consulting company and has been providing services to the industry for over 40 years.

Table 4: Programs for Targeted Causes of Outages (2012 thru mid-2016)

Cause Code	SAIDI including MEDs	SAIDI excluding MEDs	Number of Outages*	Targeted Programs
Vegetation	15.92	10.44	102	Enhanced vegetation management, line sectionalization
Failed Pole/Structure/Tower	7.74	3.44	27	Pole replacement program, line sectionalization
Failed Breaker	5.81	4.34	105	Breaker replacement program
Unknown	5.78	3.37	555	Enhanced vegetation management, line sectionalization
Failed Insulator	5.10	4.13	76	Insulator replacement, pole replacement, line sectionalization
Planned	5.08	4.92	88	Revised work practices
Lightning	4.94	2.06	424	Overhead line replacement, line arrestor replacement, line sectionalization
Wind	4.04	1.24	14	Enhanced vegetation management, line sectionalization
Foreign Interference	3.85	3.10	246	Line sectionalization
Failed Conductor	3.51	2.17	34	Detailed line inspections, overhead line replacements, enhanced vegetation management, line sectionalization
Failed Shield Wire	3.09	1.90	34	Detailed line inspections, overhead line replacements, line sectionalization
Failed Cross Arm	2.64	2.64	29	Detailed line inspections, defective equipment replacement, line sectionalization
Failed CCVT/ Coupling Capacitor	1.41	1.41	13	Coupling capacitor replacements, line sectionalization
Failed Arrester	1.02	1.02	18	Replace line arresters, line sectionalization
Failed Substation Equipment (other)	0.54	0.54	31	Substation asset replacement (e.g., switches, insulators, coupling capacitors)

*Includes both momentary and sustained outages.

Table 4: Proposed programs for targeted causes of outages (2012-mid 2016).

4. Overview of Proposed Projects

4.1. Reliability Projects/Programs

4.1.1. Overview

Transmission reliability improvement is focused on enhancing customer experience by minimizing outages and the duration of those outages when they occur. The key program areas that LG&E and KU will focus on are reduction of vegetation as a cause of outages and minimizing the impact of outages through sectionalizing. Vegetation line clearance will be transitioned to a five-year cycle, and will include removal of hazard trees (those that are dead, dying, or diseased and at risk of falling into a line) and problem species, as well as applying maintenance spraying where feasible. Switches will be maintained for operational readiness to ensure they are a part of the solution and not a contributor to outages. Additional breakers, motor operated switches, and tap switches will be installed to break up the transmission circuits into smaller segments to minimize the impact of future outages and aid in faster restoration of service to customers when a sustained outage occurs.

4.1.2. Operations and Maintenance Reliability Projects/Programs

Vegetation Management

From 2012 to mid-2016, tree related outages caused 19% of all LG&E and KU transmission system SAIDI. These outages were caused by trees falling into the lines. In the same period, the cause for approximately 30% of all sustained and momentary outages could not be determined. As discussed earlier, the company believes that a majority of these "unknown" outages are in fact caused by vegetation, in particular by limbs and trees swaying or blowing into and making temporary contact with transmission lines. Narrow corridors are especially vulnerable to these types of outages.

Over the past several years, the company's vegetation clearing practices have effectively prevented grow-in outages through just-in-time vegetation management practices. LG&E and KU currently inspects transmission lines at least three times per year to identify locations where vegetation is approaching the conductors. These locations are then prioritized and maintained to reduce the risk of an outage caused by vegetation. However, the current approach of clearing based on frequent inspections is no longer sufficient to address the risk of grow-ins or danger trees falling on lines from outside the maintained boundaries of the easement. Danger trees include those that are dead, dying or diseased, including those trees impacted by the emerald ash borer. The proposed comprehensive vegetation improvements will enable LG&E and KU to restore established right-of-ways through tree trimming, herbicide application, hazard tree patrol and removal, and an emerald ash borer program. Starting in mid-2017, the company will establish an average five-year line clearance cycle, with the first cycle completion targeted by 2022.

The proposed investment will enable sustainable and ultimately less costly right-of-way maintenance in the future. In subsequent cycles, the focus can shift to herbicide application for maintaining the majority of the right-of-ways and reduce the on-going clearance costs.

The proposed program has been developed with input from Environmental Consultants, Inc. (ECI). ECI observed routine vegetation patrols and developed an estimate of the total work load necessary to carry out the additional work.

The program will address 4,800 circuit miles below 200 kV and 700 circuit miles above 200 kV.

Total five-year cost of the program will be $64.0 million.

Line Switch Maintenance

From 2013 to mid-2016, there were 14 outages related to failed switches. Additionally, switches have, at times, created delays in restoration due to operating malfunctions. With the addition of motor operated remote controlled switches to improve restoration times, it will be crucial to maintain these switches to ensure effective operation. Line switches today are routinely inspected visually, and are operated and adjusted only on an as-needed basis. Through the line switch maintenance program, LG&E and KU will systematically inspect air break line switches and motor operators to ensure consistent functionality when needed to sectionalize the circuit and reduce the impact of an outage to customers. This program entails a thorough inspection including any necessary repairs. Every switch in the system will be visually inspected every two years. Motor operated switches will be inspected every year to ensure proper operation including integrity of batteries. In addition, each switch will be operated, adjusted, and — if needed — repaired over a six-year cycle.

This program will align LG&E and KU with industry best practice and enhance operational integrity of the transmission system.

The total five-year cost of the line switch maintenance program is $3.8 million starting in 2017.

4.1.3. Capital Improvement Reliability Projects/Programs

More than 80% of customers are served from substations connected to the company's 69kV transmission system. As described previously for KU, many of the line segments on the 69kV system have multiple distribution substations directly connected to the lines with a radial

13. Emerald ash borer (EAB), or Agrilus planipennis, is a green jewel beetle native to eastern Asia that feeds on ash species. Outside its native range, it is invasive and highly destructive to ash trees. EAB has caused a number of ash trees to deteriorate and ultimately fall on transmission lines causing outages.

(one-way) feed to the substation. When an outage occurs on one of these sections interrupting service to customers, company personnel are typically dispatched to the area to locate the problem section, isolate through switching and then restore service to customers. This process is time consuming and can be significantly improved by reducing the average line segment length with circuit breakers and/or strategically installing remotely controlled, motor operated switches to allow for the impacted section to be isolated and many customers restored within minutes. This will also improve the time to find the damaged section and restore service to the remaining customers.

Line Sectionalization

The purpose of this program will be to install in-line breakers or switches on long lines with multiple load taps to decrease customer exposure to outages and reduce SAIDI associated with these lines. Installation of these breakers and switches will allow LG&E and KU to perform sectionalizing when there is an outage.

Priority of lines will be based on the amount of exposure (length of transmission line) and the number of customers or amount of energy demand served from each circuit, while focusing on lines with historically poor SAIDI or SAIFI performance.

Installation of automated switches, motor operated switches, and tap switches will be considered when installation of breakers is cost prohibitive. Switches will not reduce the number of outages but will reduce the overall duration (SAIDI) of those outages. Today's analysis shows that if the proposed projects and other completed improvements had been in place between 2012 and 2016, customers would likely have experienced approximately five (5) fewer minutes of SAIDI (interruption of service) annually during that period.

The total five-year line sectionalizing program cost is estimated at $40.5 million, starting in 2017.

4.1.4. Benefits and Costs

Reliability improvement projects will support both reduction in the number of customer outages (momentary and sustained) and reduction in outage duration (SAIDI), emphasizing those circuits known to cause problems and those with the highest combinations of line exposure and customer density. The reliability team at LG&E and KU has estimated that the implementation of the proposed reliability programs will improve the company's annual SAIDI performance by 3–6 minutes over the next five to ten years.

4.1.5. Costs

The five-year capital and O&M spend (2017–2021) in proposed reliability programs is expected to be $108.3 million. The breakdown in annual investment by program is provided in Table 5.

Table 5: LG&E and KU Proposed Reliability Investment (MM USD)

Reliability	2017	2018	2019	2020	2021	Total
Vegetation Management*	$9.4	$12.9	$13.7	$13.9	$14.1	$64.0
Switch Maintenance	$0.3	$0.8	$0.9	$0.9	$0.9	$3.8
Total O&M	**$9.7**	**$13.7**	**$14.6**	**$14.8**	**$15.0**	**$67.8**
Line Sectionalizing	$9.6	$9.3	$8.9	$7.0	$5.7	$40.5
Total Capital	**$9.6**	**$9.3**	**$8.9**	**$7.0**	**$5.7**	**$40.5**
Total Reliability						**$108.3**

* Vegetation Management spending includes the $21 million of incremental spending over five years for the enhanced programs, as compared to planned historical spend according to the 2015 business plan.

Table 5: LG&E and KU proposed reliability investment (in millions of USD).

4.2. System Integrity and Modernization Projects/Programs

4.2.1. Overview

Equipment failure was the cause of about 27% of all transmission system outages from 2012-mid 2016. The outages associated with these failures made up 44% of the SAIDI during that same period. In addition to causing customer outages, in-service equipment failures present public and employee safety, environmental and financial risks. System integrity and modernization projects and programs are designed to replace a comprehensive slate of poor performing, obsolete, and end-of-life assets. These programs will reduce the aggregate age of the inventory and ensure that critical assets remain serviceable to support the system. Programs are designed to remove and replace problem assets prior to failure through systematic replacement. Detailed inspections will serve as the central driver for logical and timely asset replacements. Replacement priorities will be determined through assessment of a number of conditional factors in addition to age and, when possible, replacement priorities will be determined by testing and inspections.

4.2.2. System Integrity and Modernization Projects/Programs

System integrity and modernization projects are designed to replace a wide range of poor performing, defective, and obsolete aging assets. These projects will renew the transmission system systematically over time, eliminating weak links that are beyond or close to the end of their useful lives and either known to be failure prone, difficult to maintain, adjust or operate, or discovered to be damaged or close to failure. Detail regarding each program or group of projects follow in section 5. This set of programs and projects will ensure the long-term operability of the transmission system. Near term priorities will be based on inspections, testing, asset experience and knowledge as well as potential for outages to customers.

The specific asset programs focused on system integrity and modernization will target the following asset classes.

- Defective line equipment
- Overhead lines
- Protection and Control Systems
  - Control houses
  - Relay panels
  - Remote terminal units
  - Power line carriers
  - Digital fault recorders (DFRs)
  - Battery sets
- Circuit breakers
- Underground lines
- Line switches
- Substation insulators
- Substation line arresters
- Coupling capacitors

4.2.3. Benefits and Costs

Overall, the system integrity and modernization programs and projects are vital to maintaining a reliable and a fully functional transmission system. Good stewardship of the transmission system requires that its many critical assets are maintained properly throughout their life span, inspected for proper operation and periodic adjustment, and replaced as they approach end of life or show signs for impending problems. As a group, this comprehensive set of projects and programs targets assets in a systematic and logical fashion. Individual asset replacement priorities may change over time, but will be based on the ability of the equipment to provide reliable customer service and effective system operations. Increased replacement should reduce the number of in service failures that affect public and employee safety risk and customer reliability over the long term. Inspection and replacement priorities will consider the recent reliability performance of the equipment. Properly maintained, physical assets can be employed for many years; however, mechanical and electronic equipment have a finite life. This set of programs prudently addresses the need to renew such assets in a proactive and coordinated manner.

4.2.4. Cost

The five-year capital and O&M spend (2017–2021) in proposed system integrity and modernization programs is expected to be $429.5 million. The breakdown in annual investment by program is provided Table 6.

Table 6: LG&E and KU Proposed System Integrity & Modernization Investment (MM USD)

System Integrity and Modernization	2017	2018	2019	2020	2021	Total
Replace Defective Line Equipment	$38.5	$40.8	$39.4	$36.6	$36.6	$191.9
Replace Line Switches	$1.2	$1.7	$1.8	$3.6	$3.9	$12.2
Replace Overhead Lines	$8.9	$2.9	$12.3	$18.8	$42.2	$85.1
Improve P&C Systems	$9.5	$11.8	$13.4	$14.8	$14.6	$64.1
Replace Circuit Breakers	$7.5	$8.4	$8.4	$5.3	$5.3	$34.9
Replace Underground Lines	$3.2	$10.2	$10.0	$0	$0	$23.4
Replace Subs Insulators	$2.7	$2.1	$2.1	$0.7	$0.8	$8.4
Corrosion Protection*	$0.5	$0.7	$0.9	$1.1	$1.1	$4.3
Replace Substation Line Arresters	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0
Replace Coupling Capacitors	$0.6	$0.6	$0.6	$0.2	$0.2	$2.2
Total System Integrity and Modernization	**$73.2**	**$79.8**	**$89.5**	**$81.7**	**$105.3**	**$429.5**

* Corrosion protection program is an O&M expenditure.

Table 6: LG&E and KU proposed system integrity and modernization investment (in millions of USD).

The cost estimates for each program and project are based on previous similar projects and the ability to obtain outages to complete the work when scheduled. The actual costs may differ from the projections depending on the specific circumstances of each installation or replacement project.

5. Analysis of Proposed Projects

5.1. Reliability Improvement Projects

Below are details of the specific reliability programs and how they will be deployed to achieve improved reliability results.

5.1.1. Operations and Maintenance Reliability Projects/Programs

Program Title: Enhance Vegetation Management

Description: The transmission vegetation management program will transition from an inspection-driven maintenance approach to an average five-year cycle. The initial cycle will involve significant tree removal which will allow integration of herbicide applications on the majority of line segments in subsequent years. This approach will reduce costs significantly after the first cycle and over the long term. The company has already started to transition to the regular cycle for the 345kV and 500kV power lines to ensure cost effective compliance with NERC mandatory standards. The proposed plan begins the conversion for the rest of the transmission system. Figure 16 shows a transmission line easement before and after the enhanced trimming program application.

Figure 16: Before and after — example of the cleared transmission right-of-way.

The vegetation management program also includes a hazard tree patrol to assess and remove diseased or dying trees, and especially identify trees impacted by the Emerald Ash Borer (EAB) across the system. The EAB is an invasive species (see Figure 17) that has killed hundreds of millions of ash trees in North America that is now established in Kentucky and affecting ash trees throughout the Commonwealth.

Figure 17: Emerald ash borer. (Picture by David Cappaert, Michigan State University, Bugwood.org.)

Clearing efforts will be prioritized based on aerial inspection, hazard tree patrols, customer impact, and system impact. Higher voltages which can affect larger numbers of customers and radial lines will be emphasized.

Figure 18: Example of a hazard tree adjacent to a 69kV transmission line.

The five-year estimated cost of the program is $64.0 million.

Vegetation Management Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Base VM Spend	$7.2	$7.8	$8.2	$9.7	$9.9	$42.8
Incremental VM Spend	$2.2	$5.1	$5.5	$4.2	$4.2	$21.2
Total VM Spend	**$9.4**	**$12.9**	**$13.7**	**$13.9**	**$14.1**	**$64.0**

Benefits

This program will provide significant system benefits and long term assistance with managing our rights-of-way through:

- reduction in unknown momentary outages;
- reduced risk of wire damage and failure, associated outages, and public safety hazard;
- reduced SAIDI;
- improved management of vegetation growth and work;
- long-term lower cost to maintain easements and reliability;
- reduction of impacts to customers after initial cycle (more herbicide application and less clearing/removal); and
- improved system performance during weather outages.

Supporting Data

The enhanced Vegetation Management Program will reduce sustained and momentary outages. Historical data for the relevant cause codes is in the chart below. Based on company experience and field observations, the majority of "unknown" outages on the lower voltage lines (i.e., 69kV) appear to be caused by blowing trees and limbs that make contact with the energized conductors long enough to cause an outage. Enhanced tree removal programs as proposed will improve clearances, remove dead, dying and diseased trees that threaten the lines and reduce the likelihood of tree contacts. After the completion of the first full cycle, the company anticipates a 25-50% reduction in the number of vegetation-related outages.

Reliability Cause Code: Vegetation Management	2012	2013	2014	2015	2016*
Outage Counts	29	16	29	21	16
SAIDI incl. MEDs	2.57	3.12	6.56	0.88	2.85
SAIDI excl. MEDs	2.57	1.92	2.29	0.88	2.85

*2016 thru June 30, 2016.

Reliability Cause Code: Unknown	2012	2013	2014	2015	2016*
Outage Counts	329	128	117	127	51
SAIDI incl. MEDs	3.38	1.66	0.70	0.16	0.09
SAIDI excl. MEDs	1.61	1.03	0.70	0.16	0.09

*2016 thru June 30, 2016.

Program Title: Maintain Line Switches

Description

All air-break line switches (500 locations) and motor operators (40 locations) are currently visually inspected as part of routine line patrols. The proposed enhancement is to conduct detailed annual inspections of all automated and motor operated switches. This will include a voltage check on the batteries and verification of remote operation of the switch from the control center. All remaining manual switches will be subject to bi-annual comprehensive visual inspections. Additionally, all switches will be operated and aligned on a six-year cycle or as indicated through visual inspections. Crews will make minor repairs and adjustments as part of the inspection program as indicated.

All inspection cycles are within typical industry frequencies.

The five-year estimated cost of the program is $3.8 million.

Switch Maintenance Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Switch Maintenance	$0.3	$0.8	$0.9	$0.9	$0.9	$3.8

Benefits

Transmission line switches are used to isolate sections of lines in order to perform maintenance or, after an outage, to isolate the damaged section, restore service to customers and then make needed repairs. Therefore, proper line switch operation and functionality is critical for both routine operation of the system and to ensure timely restoration efforts during system outages. The proposed increase in the number of installed automated and motor operated switches necessitates a program to ensure these switches will operate properly when needed. This program will reduce the risk of equipment failure and associated system outages. In addition, the program will:

- ensure operational capability;
- reduce unplanned corrective maintenance; and
- reduce SAIDI and outages.

Supporting Data

The Switch Maintenance Program will improve restoration time and reduce outages related to switch failures. As can be seen below, SAIDI associated with switch failures has historically been low. However, there have been outages, while not frequent, in which an inoperable switch delayed service restoration. Switch maintenance, especially for motor operated switches, is important to ensure operability when needed, especially given the proposed installation of new switches throughout the service territory (discussed below).

Reliability Cause Code: Switch — Failed AC Circuit Equip.

	2012	2013	2014	2015	2016*
Outage Counts	4	0	1	4	2
SAIDI incl. MEDs	0.14	0.00	0.18	0.00	0.04
SAIDI excl. MEDs	0.14	0.00	0.18	0.00	0.04

*2016 thru June 30, 2016.

Environmental factors (e.g., weather) and frequency of switch operation can impact the alignment and functionality of line switches. Motor operated switches have batteries to ensure communications and switch operability when the power is out. These batteries must be routinely replaced so that they will operate reliably when needed. The photo in Figure 19, produced from a visual inspection, shows that the switch blade is not properly latched. While not obvious to the untrained eye, the switch contacts are not fully inserted into the jaws as compared to the same assembly on the left.

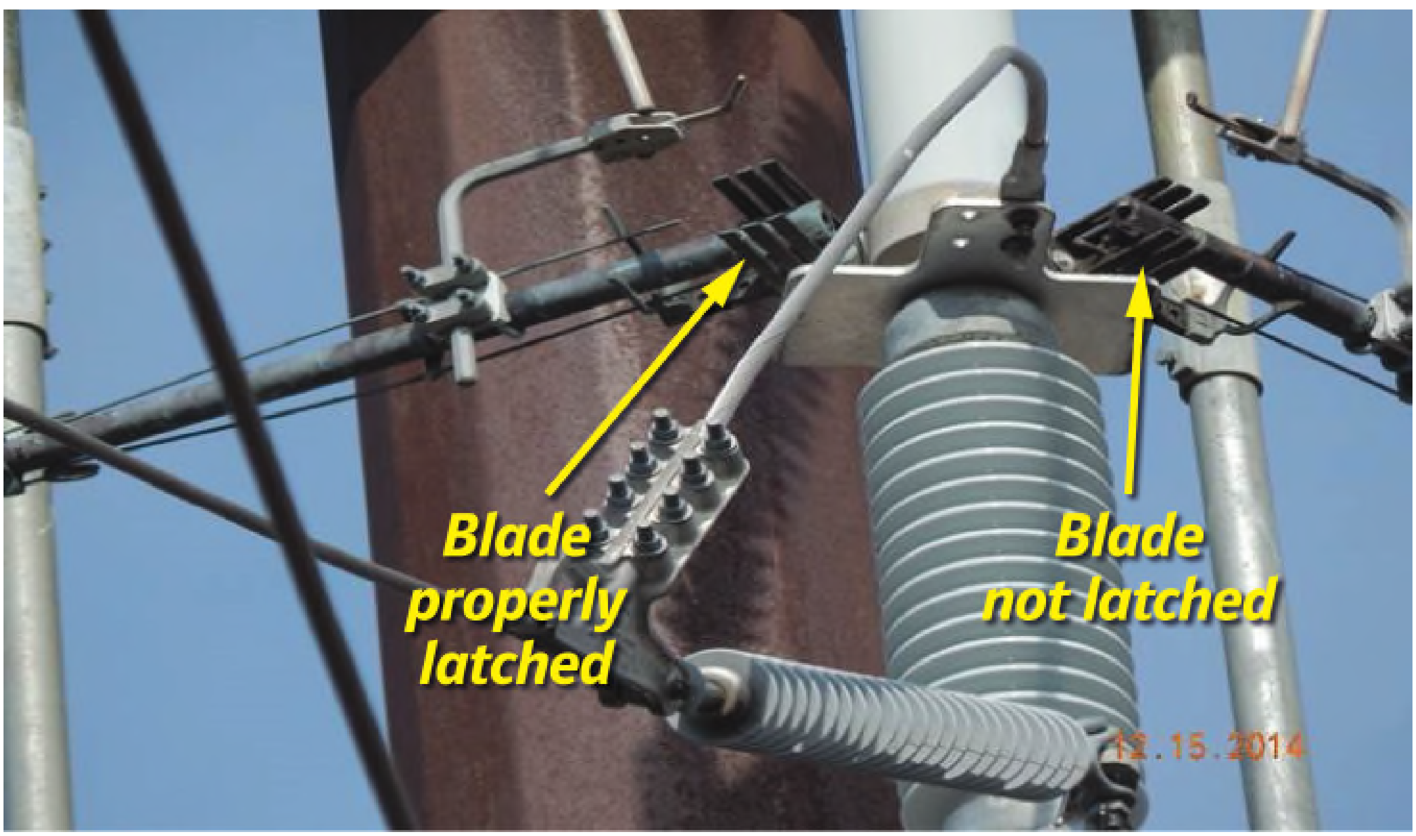

Figure 19: Example of the switch maintenance issue.

5.1.2. Capital Reliability Projects/Programs

As described in Section 2.1, the LG&E and KU transmission systems experience outages at a similar rate, with LG&E historically having slightly more outages per mile than KU. However, since the KU system has more than four times the length of transmission lines, it also has about four times as many outages in total. Built largely as a rural system, the KU transmission system connects relatively small distribution substations to the power grid through radial (one-way power feed) connections, with multiple distribution substations between circuit breakers. As a result, when an outage occurs on a transmission line, all of the distribution substations are affected. Service restoration requires service personnel to drive to switches along the line and manually isolate the damaged sections to restore service to customers. For the largely urban and customer dense LG&E transmission system, this functionality is for the most part automated with either circuit breakers or remotely controlled switches used to restore service without requiring manual operation. As a result, transmission outage durations on the LG&E system are much shorter. The work needed to upgrade the KU transmission system to provide the same level of restoration capability as LG&E's would include installation of two-way transmission feeds and associated circuit breakers and protection, control and metering devices to more than 600 distribution transformers. The cost of such an upgrade is estimated to be more than $1 billion. When originally designed and constructed, rural areas in KU's service territory did not have the telecommunication capacity and coverage found in the urban areas, so remote control was expensive or not available at all. Today, most areas are covered by some means of communications. The company proposes three programs to cost effectively improve the switching capability on the KU transmission system: (1) Install Automated Line Sectionalizing, (2) Install Motor Operated Switches, and (3) Install Tap Switches. These programs are designed to shorten the time to restore service on selected lines by installing the capability to automatically or remotely restore service to undamaged portions of transmission lines when an outage occurs. Once remote switching is complete, service personnel can be more precisely directed to the specific location of the damage to, if possible, restore additional customers through manual switching, isolate the damaged lines and make repairs.

Program Title: Install Line Sectionalizing

Program Description

The line sectionalization program will focus on installing in-line circuit breakers, automated switches, motor-operated switches (MOS) or tap switches on long lines with multiple distribution substations in order to decrease customer exposure to transmission outages. These installations will be prioritized based on historical SAIDI impacts and the number of outages that have occurred on each line. All lines with historical SAIDI of greater than 0.5 minutes between 2012 and first-quarter 2016 were candidates for sectionalization.

Constructing a circuit breaker in a transmission line effectively reduces the circuit length by creating two transmission lines segments out of one. If installed approximately in the middle of the circuit, half of the customers will avoid a service interruption during future outages (those on the undamaged side of the new breaker installation). However, depending on feasibility and cost (e.g., land acquisition or incremental transmission line and/or substation work required), circuit breaker installations can be quite expensive when compared to other options. For this reason, circuit breakers will be installed on longer lines with significant SAIDI history and significant exposure and customer count totals.

A cost-effective alternative to construction of circuit breakers is installation of an automated sectionalizing MOS. The MOS automatically opens when an outage occurs and isolates the line segment that was not directly impacted by the outage, restoring those customers served on the undamaged section of line. Customers who are restored this way will still experience a brief service interruption, but it many cases, the interruption will last a minute or less.

In locations where there is already an automated sectionalizing MOS or one is not feasible, the company will install motor operated switches, which provide a quick method for Transmission Control Center staff to remotely operate the switch and sectionalize the line to restore customers. While not providing for an automated operation, the remotely operated MOS can be deployed much faster than sending a service technician to the pole to operate a switch manually. This benefit is realized not only in rural areas, but also in urban locations where traffic light interruptions during power outages make it difficult to drive to switch locations. MOS will typically be utilized at points where distribution substations with more than 1,000 customers are directly connected to the transmission line. These installations will be prioritized based on historical reliability performance and exposure to outages.

Tap switches will be installed at locations without sectionalizing devices. They enable the company to isolate load connections from faulted sections of line and provide the ability to isolate loads during planned outages. Tap switches are installed at connection points on a single pole structure. Typically, the installation is a two-way switch that allows the load to be isolated from either side. These switches can be used during a situation where one side of the line has a fault or simply when a section of line needs isolation for maintenance work.

The five-year cost of the program is $40.5 million.

Line Sectionalization Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Install Auto Line Sectionalizing	$9.6	$9.3	$8.9	$7.0	$5.7	$40.5

Benefits

Installing additional sectionalizing devices on targeted transmission lines will:

- reduce the number of customers experiencing a sustained service interruption when an outage occurs on a transmission line; and
- significantly reduce the restoration time for those customers who are affected by the outage.

Supporting Data

Line sectionalizing minimizes the duration of customer interruptions for all outage causes that occur on a transmission line. The lines selected for the addition of circuit breakers and auto-switches have had a total SAIDI (excluding major outages) of 34 minutes from 2012 to June 30, 2016. The proposed improvements are estimated to reduce that SAIDI amount to just under 16 minutes for the same time period.

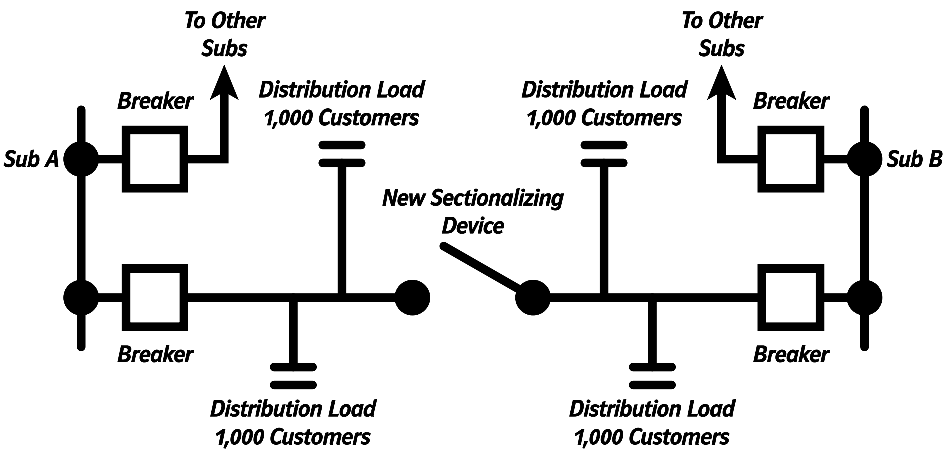

Figure 20: Example of the circuit with a new switch.

Figure 20 illustrates an example where a new sectionalizing device (a switch or a circuit breaker) is installed to reduce exposure to an outage. Prior to the device installation, a fault on this line would have interrupted 4,000 customers until service can be restored manually. With the new sectionalizing device installed, after an outage occurs this device will operate and the undamaged portion of line will be automatically restored so that only 2,000 customers experience an extended outage.

Figure 21: New circuit breaker installation inside the substation.

Figure 22 shows a recent MOS installation in the Lexington area.

Figure 22: Example of a recent MOS intallation in Lexington.

Figure 23 shows an example of a 2-way tap switch installation.

Figure 23: Example of a 2-way tap switch installed on a single phase.

5.2. System Integrity and Modernization Projects/Programs

Below are details of the many individual system integrity and modernization projects and programs that will be deployed.

5.2.1. Replace Defective Line Equipment

Description

Replace wood poles, cross-arms, and insulators identified as defective from system inspection programs. The company conducts climbing inspections to thoroughly assess the condition of its poles. The purpose of these inspections is to identify shell rot, wood checks, and woodpecker holes affecting the pole's strength. The results of the inspection are used to determine the pole's integrity and need for replacement. The initial scope of this program was developed based on historical inspection results and costs from 2013–2015. The company will complete the initial inspection cycle in 2018, and future inspections are expected to identify a lower number of assets for replacement. Development of this program will continue to be reviewed and adjusted with additional inspection results and historical costs.

The five-year cost of the program is $192 million.

Defective Line Replacement Program Cost (MM USD)

	2017	2018	2019	2020	2021	Total
Replace Defective Line Equipment	$38.5	$40.8	$39.4	$36.6	$36.6	$191.9

Benefits

Proactive replacement of these assets will reduce the risk of failure and number of system outages. Additional program benefits include:

- reduction of associated outages and public safety hazards;
- reduction of emergency replacements which are costlier than planned replacements;
- reduction of outages and SAIDI with associated improvement to customer satisfaction; and
- improved durability and resiliency to better withstand severe weather.

Supporting Data

Defective equipment targeted in this program has historically had a significant impact on reliability. The following tables demonstrate this impact.

Reliability Cause Code: Cross Arm

	2012	2013	2014	2015	2016*
Outage Counts	2	3	10	9	5
SAIDI incl. MEDs	0.12	0.50	0.32	1.33	0.37
SAIDI excl. MEDs	0.12	0.50	0.32	1.33	0.37

*2016 thru June 30, 2016.

Reliability Cause Code: Pole/Structure/Tower

	2012	2013	2014	2015	2016*
Outage Counts	7	3	4	7	6
SAIDI incl. MEDs	4.40	0.67	1.10	1.29	0.27
SAIDI excl. MEDs	0.62	0.67	0.58	1.29	0.27

*2016 thru June 30, 2016.

Reliability Cause Code: Insulator — Failed AC Circuit Equip.

	2012	2013	2014	2015	2016*
Outage Counts	4	4	12	5	10
SAIDI incl. MEDs	0.00	1.36	0.97	0.37	1.07
SAIDI excl. MEDs	0.00	1.36	0.00	0.37	1.07

*2016 thru June 30, 2016.

Figure 24: Examples of defective line equiment (deteriorated wood cross arm, damaged string of porcelain bell insulators and woodpecker damage on the pole).

Figure 25: Example of standard steel H-frame structure used to replace wood structure.

Supporting Data

Anticipated replacements for the five-year period are shown in Table 7.

Table 7: Transmission Defective Pole and Pole Equipment Replacement Schedule					
Replacements (in units)	2017	2018	2019	2020	2021
Cross Arms	200	200	150	50	50
Insulators	125	200	200	200	200
Poles	650	700	700	700	700

Table 7: Transmission defective pole and pole equipment replacement schedule.

Priorities for replacement will be based on customer impact, system impact (voltage and radial), and inspection age. Replacements are also coordinated with projects associated with the same asset or line.

5.2.2. Replace Overhead Lines

Description

Replace wires that are experiencing failure or have been identified as at risk on inspection. Many conductors are at or beyond their expected useful life, which is estimated to be 75 years, and are starting to perform poorly. Focus will be on single layer wires (copper, copper-weld, single layer ACSR) which are more prone to corrosion of the core (and subsequent failures) than multi-layer wires. There are 375 miles of such wire and 75 miles of shield wire beyond useful service life. Age, wire type, historical performance, and customer impact will determine replacement priorities. A total of 84 miles of conductor and shield wire will be replaced through this program over the next five years.

Development of this program will continue to be reviewed and adjusted with additional inspection results and historical costs. The five-year cost of this program is $85.1 million.

Overhead Line Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Overhead Lines	$8.9	$2.9	$12.3	$18.8	$42.2	$85.1

Supporting Data

Replacing overhead lines will improve outages for the following cause codes.

Reliability Cause Code: Conductor	2012	2013	2014	2015	2016*
Outage Counts	5	10	8	10	1
SAIDI incl. MEDs	0.08	1.08	0.61	1.72	0.03
SAIDI excl. MEDs	0.08	1.08	0.61	0.37	0.03

*2016 thru June 30, 2016.

Reliability Cause Code: Shield Wire	2012	2013	2014	2015	2016*
Outage Counts	9	8	8	7	2
SAIDI incl. MEDs	0.80	0.49	1.65	0.04	0.11
SAIDI excl. MEDs	0.20	0.49	1.06	0.04	0.11

*2016 thru June 30, 2016.

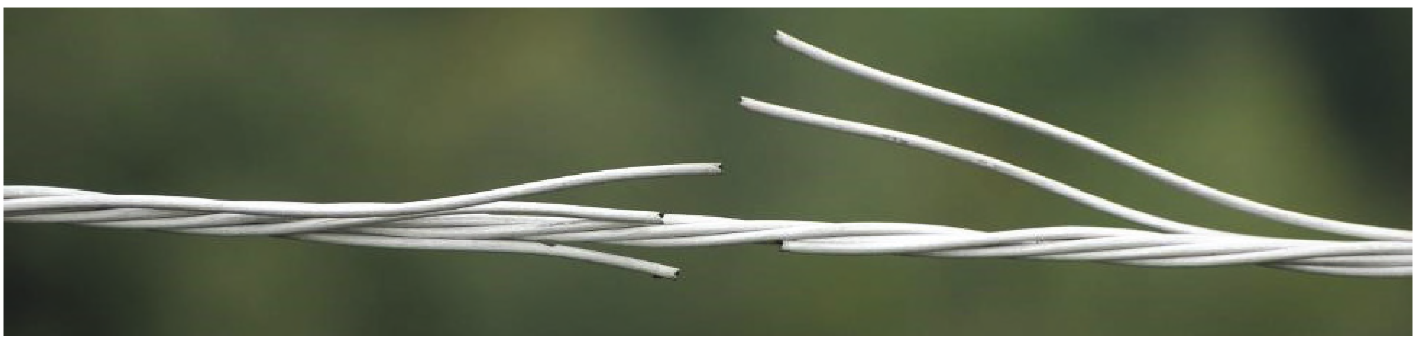

Figure 26: Example of a shield wire with broken strands.

5.2.3. Upgrade Protection and Control Systems

Protection and control (P&C) systems are used to identify power system disturbances, stop power system degradation, restore the system to a normal state, and minimize the impact of the disturbance. The P&C systems typically include relay panels, remote terminal units (RTUs), power line carriers (PLCs), digital fault recorders (DFRs) and batteries. All of these components are housed within the control house which is an enclosure inside a substation that protects these assets from external elements. The total proposed investment in P&C systems is $64.1 million over five years. The costs of each program are provided in Table 8. Each specific P&C program is described in further detail in this section.

Table 8: Total Protection & Controls Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Control Houses	$3.1	$3.6	$3.5	$3.3	$4.9	$18.4
Replace Relay Panels	$1.8	$3.4	$5.1	$6.6	$5.0	$21.9
Replace RTUs	$2.9	$3.1	$3.2	$3.3	$3.2	$15.7
Replace PLCs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0
Install DFRs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0
Replace Battery Sets	$0.5	$0.5	$0.4	$0.4	$0.3	$2.1
Total P&C	$9.5	$11.8	$13.4	$14.8	$14.6	$64.1

Table 8: Proposed P&C investment (2017–2021).

Replace Control Houses

Description

The goal for this project is to replace two to four obsolete control houses each year that do not support upgraded technology and upgrade the full slate of equipment across the spectrum of protection and control projects accordingly.

Control House projects fall into two categories: blanket (e.g., control house upgrades) and uniquely identified (e.g., Finchville Control House). The blanket projects include the following items: environmental controls, batteries, AC/DC systems, control building shell, foundation, control cable and control cable trench system. This cost is estimated at $1.2 M per house. In addition to the items associated with the blanket projects, the uniquely identified projects also include relay panels, RTU, power line carriers (PLCs), and DFR (if necessary). The cost for these incremental items are included in the budget. Each individual component is to be funded through its associated program (these programs are detailed below). Many existing buildings need to be replaced based on condition, size, and outdated contents.

Figure 27: Modular control house being delivered.

Priorities for comprehensive replacement are based on the following factors.

- Age and health of the relays within the existing control house (CH)
- Age and priority of the remote terminal unit (RTU) located in the CH
- Physical condition of the control house, which is determined through inspections (ranked each CH based on overall condition)
- Age of the existing battery system

Those CHs with the most need based on these factors will receive the highest priority for replacement.

Figure 28: Example of an old control house that needs to be replaced.

Cost for the control house upgrades (CH only) is estimated to be $18.4 million, ramping up from two control houses per year in 2017 and 2018 to four per year by year five.

Control House Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Control Houses	$3.1	$3.6	$3.5	$3.3	$4.9	$18.4

In addition to the general cost estimating assumptions described in section 4.2.4 above, the projected costs for control house replacement are based on the following assumptions:

- new control house can fit within the existing footprint of the station;
- the average size of a control house is on the smaller end of the specifications;
- control house design will be outsourced;
- Transmission Engineering, Construction and Maintenance will be able to support the below-grade design and construction; and
- contract design and commissioning staff will be available.

Benefits

Replacing the control house affords a great opportunity to upgrade to modern standards all of the integrated equipment within the control house. Thus, the control house replacement project drives priorities for most of the other protection and control programs. The following benefits are expected to be achieved:

- reduced future building maintenance costs — new buildings with insulation and climate controls to ensure asset health and proper operation of the equipment contained within;
- reduced potential for mis-operations due to mechanical failure of the relays;
- improved communications to the energy management system;
- reduced O&M costs for relay testing because the test cycle can be extended from five to ten years;
- enhanced worker safety due to environmental controls and panic bars on the doors;
- improved working clearance for personnel; and
- enhanced data gathering due to new functionality of microprocessor relays and digital fault recorders.

Supporting Data

Since 2012, protection and control components have caused 200 outages, both sustained and momentary, on the transmission system. Replacement of control houses has the potential to reduce outages across all areas of impact in one project.

Outage Counts for P&C Reliablity Cause Codes		
Control House Asset	Cause Code	Number of Outages
Relay Panels	Relay/Malfunction	102
RTU, PLC	Communication Failure	66
Control House Building	AC System	17
DFR	Unknown	11
Batteries	DC System	4
	Grand Total	200

Replace Relay Panels

Description

Relays are devices that are designed to respond to abnormal system conditions. These devices use current and/or voltage measurements from the system to determine if the electrical system they are monitoring is in a normal or abnormal state. If the system is in an abnormal state, the relay issues a signal to a circuit interrupting device to open its contacts and interrupt the current flow on the system it oversees. A relay panel consists of multiple relays that oversee a specific transmission line, bus, or transformer. Many different types of relays are used on the transmission system for different functions.

The objective of this program is to replace obsolete and end of life relay panels to maintain integrity of the system protection. There are approximately 5,700 relays across the system in 1,500 panels.

Relay overreaches and mis-operations cause unneeded outages. The older units are electro-mechanical and, while still functional, are approaching end of life and are becoming obsolete compared to modern microprocessor relays. These older units have slower response times, are difficult to keep properly adjusted, do not have replacement parts available, and lack telemetry for diagnostics and real-time operation. The immediate goal of the program is to replace all the remaining electromechanical relays and eventually establish a 25-year replacement cycle once the entire fleet is composed of microprocessor relays. Microprocessor relays generally have a 20- to 30-year expected life. Initially, the pace of replacement will be 20 panels per year, but climb to 40 by 2020 and eventually reach the 50-60 per year pace needed to maintain a 25 to 30-year replacement cycle. Replacement priorities will be based on a health index indicating the worst performing relays. This will also factor prominently in determining control house replacement priorities.

Five-year program cost is estimated to be $21.9 million.

Relay Panel Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace Relay Panels	$1.8	$3.4	$5.1	$6.6	$5.0	$21.9

Figure 29: Electro-mechanical relay panels.

Figure 30: Microprocessor relay panels.

Benefits

Relay panels have a significant effect on the operation of the transmission system and protect the system from abnormal conditions. Replacements of the relay panels will provide the following benefits:

- reduced risk of relay failure (i.e., relay does not operate);
- reduced customer SAIDI and SAIFI (frequency) by preventing overreach to backup relay zones; and
- reduced mis-operations (i.e., relay fails to operate properly).

Supporting Data

While relay malfunctions are not a large contributor to overall transmission SAIDI, they account for 137 outages over the period from 2007 to June 30, 2016. Relay malfunctions reached a peak in 2014, which was the first year that the Protection and Control group started a targeted approach to relay replacements. The relays deemed as the worst performing in LG&E and KU were targeted for replacement. Relay failures have contributed to 102 outages over the past five years.

Replace Remote Terminal Units (RTUs)

Description

RTUs are the critical link between the control center and the transmission substations enabling real-time monitoring of the power grid and control of the circuit breakers, switches and other devices to ensure proper flow of power across the system. They generally reside in the control houses located at each substation. RTUs reduce SAIDI by allowing transmission operators to issue commands to open and close breakers thus restoring outages more quickly. RTUs bring back data to the state estimator and operator screens that provide for the reliable operation of the transmission system. Because of the criticality of the RTU to the reliable operation of the transmission system and based on the fact that many of these units are old, obsolete (no longer supported by the manufacturer) and do not have the necessary parts for repairs, these units are being targeted for replacement as part of the overall transmission reliability program.

The objective of this program will be to replace obsolete or end-of-life (20-year expected useful life) RTUs to support control, automation and telemetry. Beyond those units associated with control house upgrades, the RTUs targeted for replacement will be the 1970s vintage Leeds & Northrup (L&N) units that are obsolete and prone to failure as well as a few similar vintage Valmet units. Aside from manufacturer (and indirectly age), priorities for replacement follow these criteria in order.

1. RTUs associated with bulk electric system (BES)
2. RTUs associated with radial feeds from the BES
3. RTUs associated with the 69 kV system
4. RTUs associated with telemetry of transmission service customers
5. Telecommunication projects driven by telephone carriers moving to digital circuits from analog

It is expected that the new RTUs will have a similar expected useful life (20 years) and similar failure rates, as the current ones, and that the future changes in the operating system will not force early replacements. The ultimate goal of the RTU program is to establish a 20-year replacement cycle.

Figure 31: GE D20 remote terminal unit.

Five-year program cost is estimated to be $15.7 million replacing approximately 15 units annually.

RTU Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace RTUs	$2.9	$3.1	$3.2	$3.3	$3.2	$15.7

Benefits

The proposed replacements will have the following benefits:

- reduced risk of RTU failure;
- increased situational awareness of the BES and Non-BES lines to ensure that they will remain reliable; and
- improved SAIDI performance through remote control of the protective system.

Supporting Data

The data below shows the increasing number of false indications reported by the RTUs in the substations. False indications are erroneously reported breaker operations that are sent to the Energy Management System. Since 2012 there has been a large increase in the number of false indications. False indications occur when the RTU is not working properly and an incorrect signal is sent to the control center. This indicates that the health of many of these assets are in decline.

Reliability Cause Code: False Indication					
False Indication	2012	2013	2014	2015	2016*
Number of Outages	10	54	165	49	56

*2016 thru June 30, 2016.

Replace Power Line Carriers (PLCs)

Description

This program will replace PLCs across the system that are beyond or approaching end of service life, which is estimated to be 20 years. PLCs are used to provide high-speed communications path for certain system protection schemes. A PLC uses one of the phase conductors as a medium for transmitting the high-speed communications channel with power flowing on the conductor at 60 Hertz. These communications schemes are used to eliminate system stability issues and minimize the damage to expensive assets. In addition to the high speed communication path provided by PLCs integral to protection schemes, the new units include a check-back function that will greatly reduce maintenance from quarterly checks to once every 12-year maintenance intervals. The plan is to replace twelve (12) units annually for 22 years. Sixty (60) units (out of the total of 266 PLCs on the system) will be replaced over the next five years at a total cost of $3.2 million. Priorities for replacement are based on failed units and then sorted by age.

Figure 32: Power line carrier set.

Five-year program cost is estimated to be $3.0 million replacing approximately twelve (12) units annually.

Power Line Carrier Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace PLCs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0

Benefits

Replacement of the Power Line Carriers (PLCs) will:

- reduce the risk of relay mis-operation due to communication failure;
- facilitate NERC reporting requirements; and
- reduce maintenance costs by extending required maintenance intervals due to additional functionality of the units.

Supporting Data

Power Line Carrier systems can experience communications failures called carrier holes. Carrier holes are intermittent losses of signal.

Certain high-speed communications schemes are vulnerable to these carrier holes. This program will address 66 communications related outages that took place over the past five years.

Install or Replace Digital Fault Recorders (DFRs)

Description

DFRs are a subset of equipment called Disturbance Monitoring Equipment (DME). These devices actively monitor the transmission system at each substation control house in which they are installed. Pre-defined thresholds are set in the device and when the system conditions meet those thresholds the device takes samples of the voltages and currents and stores them internally for future retrieval. This data is used by the engineering staff to analyze the outages for proper operation of the relays.

The expected useful life for the DFR units is 20 years. This program will install four digital fault recorders annually, for a total of 20 units in the period 2017–2021. Priorities include replacement of the problematic Metatech units, expansion for NERC standards, installation of new units associated with control house upgrades, and upgrades of end-of-life units.

Benefits

The benefits associated with DFR upgrades include:

- increased ability to recreate outages; and
- compliance with NERC standards that require disturbance monitoring equipment to be installed according to certain standards.

Supporting Data

Since 2012, LG&E and KU has had to address 66 maintenance issues on Metatech DFRs. LG&E and KU operates a total of 18 Metatech units which were installed in the period from 1994-2013. Another 18 DFRs, manufactured by Tesla were installed since 2014.

Five-year budget for the DFR installation project is $3.0 million.

Digital Fault Recorder Installation Program Cost (MM USD)

	2017	2018	2019	2020	2021	Total
Replace and Add New DFRs	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0

Figure 33: Tesla digital fault recorder.

Replace Battery Sets

Description

The protective relays and their associated control circuits on the transmission system rely on DC currents and voltages supplied through a battery system or DC charger to perform their functions. The batteries in use are lead acid and similar to an automotive battery. The strings of 12 volt batteries are placed in series to provide 48 or 125 volt strings.

After accounting for the battery sets associated with a control house replacement program, this program will replace battery sets at or approaching end of useful life (estimated at 20 years). It is important to note that the pro-active battery replacement is currently in place and that this program will simply accelerate the existing replacement cycle. Ultimately, the intent of this program is to replace all battery sets on a 20-year cycle.

The scope of this project is to replace approximately ten battery sets including the charger annually in perpetuity. Priorities will be set beyond the 20-year mark and those set demonstrating need for replacement.

Benefits

Benefits related to the battery set replacement program include:

- reducing the risk of DC failure;
- reducing the risk of breaker mis-operation or failure to operate that can increase SAIDI; and
- reducing the safety risk associated with the failure of the breaker to isolate the fault because the batteries are dead.

Supporting Data

Batteries are routinely tested for condition on a quarterly and annual basis. They are replaced at the end of their 20-year warranty period due to their criticality in system protection, unless the testing indicates the need to replace sooner. The cost projection assumes no change in the battery disposal procedures in the future. Cost of the program is estimated to be $2.1 million over five years.

Battery Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace Battery Sets	$0.5	$0.5	$0.4	$0.4	$0.3	$2.1

Figure 34: Battery set.

5.2.4. Replace Circuit Breakers

Description

Circuit breakers are mechanical switching devices which connect and break current circuits (operating current and fault currents) and carry the nominal current in the closed position. A breaker that fails to operate properly when required can lead to unnecessary outages and delayed restoration times. A catastrophic failure of an oil-filled circuit breaker can have an environmental impact through an oil release.

Two circuit breaker replacement programs are planned.

1. 345kV Circuit Breakers — Replace a total of 12 effectively obsolete breakers that were manufactured before 1990 and have limited replacement parts, high SF6 leak rates, outdated operating specifications, and difficulties keeping in proper adjustment. The design and construction of these specific breakers prevent them from reaching an average 60 years of useful life that is expected from the remaining in-service breakers.
2. Oil Circuit Breakers — Proactively replace 69kV, 138kV and 161kV breakers based on inspection/test results. Replacement drivers

include insufficient continuous current capacity, insufficient interrupting current capability, repair vs. replace economics, and management of the age of the breaker fleet.

The expected replacements by voltage class are as follows.

- (125) 69kV circuit breakers
- (40) 138kV or 161kV circuit breakers
- (12) 345kV circuit breakers

The five-year cost of this program is $34.9 million.

Breaker Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Circuit Breakers	$7.5	$8.4	$8.4	$5.3	$5.3	$34.9

The photo in Figure 35, taken in 2014 at an LG&E and KU station, shows a fire that started when a 69kV breaker failed to interrupt a fault.

Figure 35: 69kV circuit breaker failure.

Benefits

The benefits of this program are:

- reliability improvement by reducing the likelihood of breaker mis-operations and catastrophic failures;
- reduced environmental risks by replacing oil circuit breakers with gas (i.e., SF6) breakers thereby eliminating the possibility of a release of oil;
- reduced future maintenance costs; and
- more effective utilization of resources.

Supporting Data

Replacing breakers will lower the number of in-service failures and minimize customer outages.

Reliability Cause Code: Breaker	2012	2013	2014	2015	2016*
Outage Counts	21	27	37	18	2
SAIDI incl. MEDs	1.00	0.93	2.37	0.28	1.22
SAIDI excl. MEDs	1.00	0.93	0.90	0.28	1.22

*2016 thru June 30, 2016.

The following graphs reflect the age of the circuit breaker fleet. The bars indicates the number of breaker in service that were manufatured in a given year while the line shows the cumulative percentage of breakers that were installed prior to a specific year.

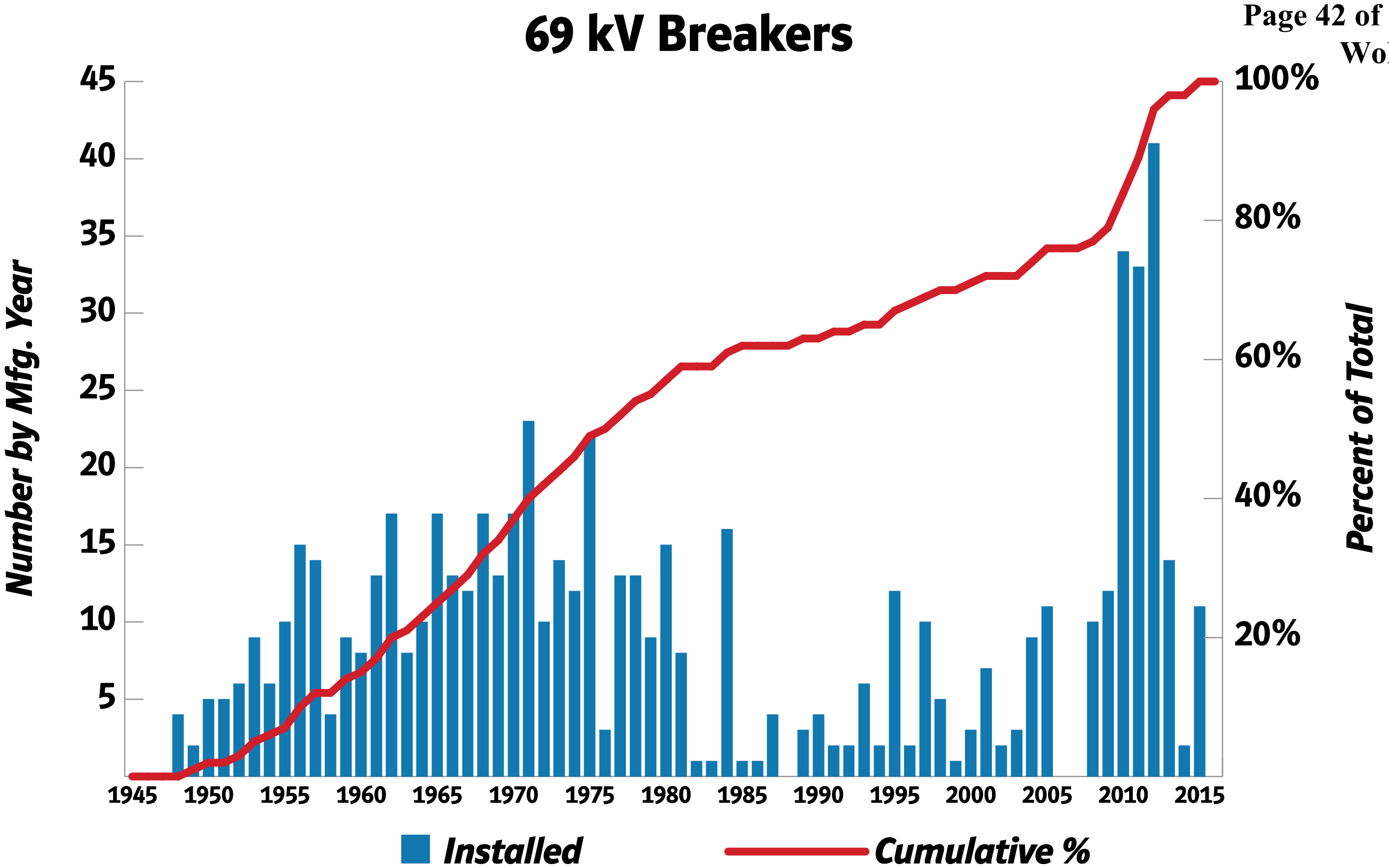

Figure 36a: Age profile of 69 kV breakers in service.

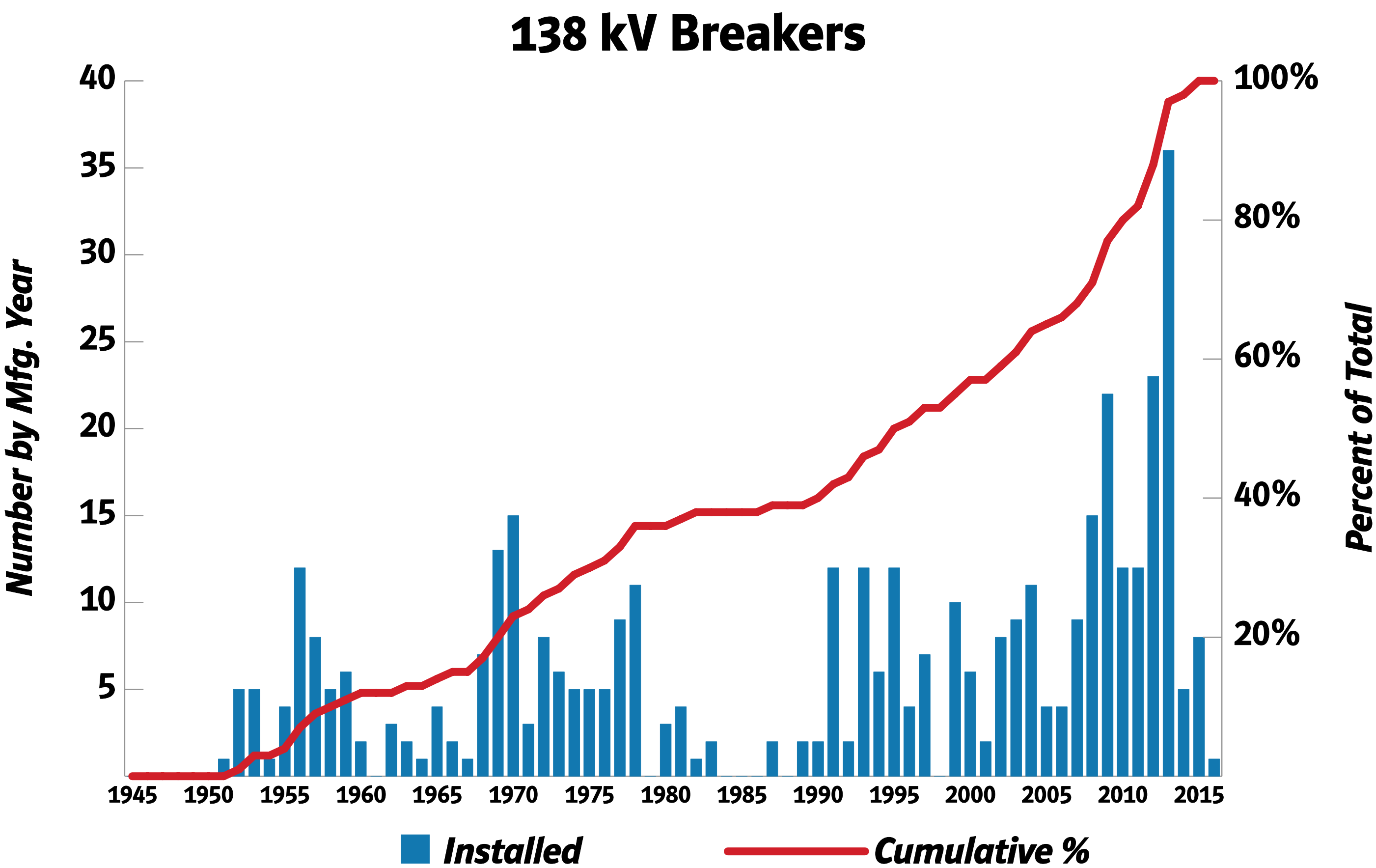

Figure 36b: Age profile of 138 kV breakers in service.

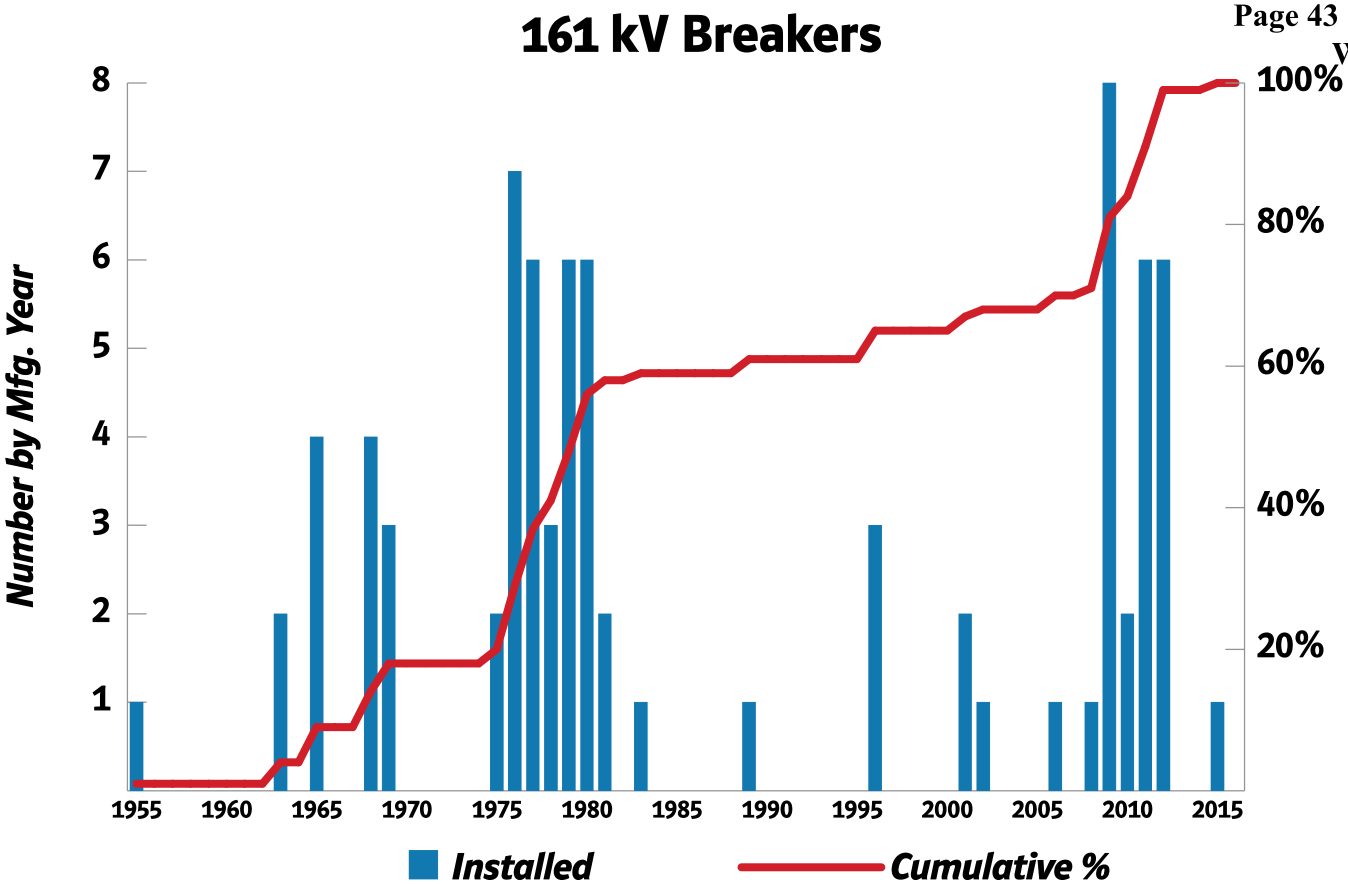

Figure 36c: Age profile of 161 kV breakers in service.

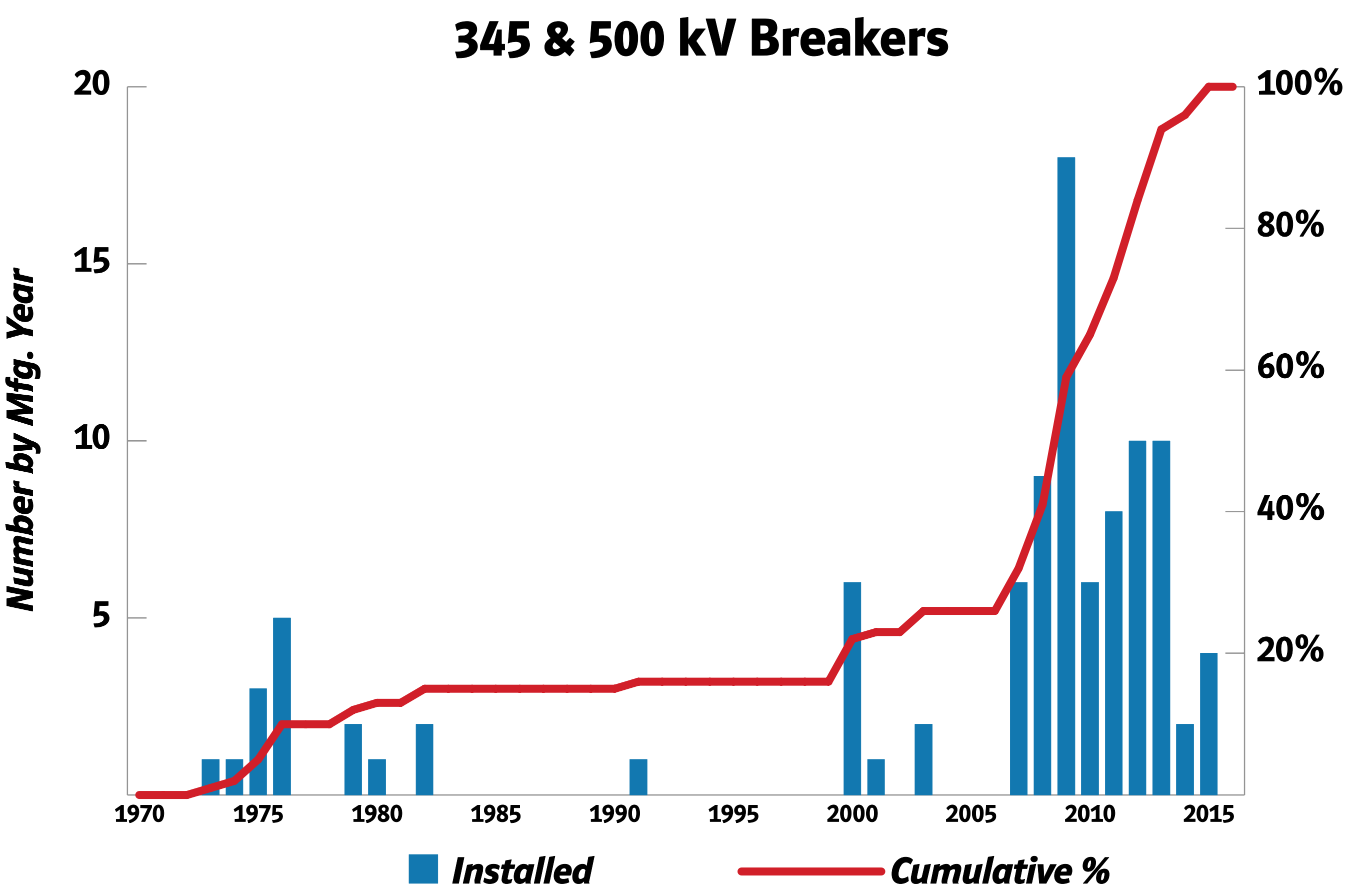

Figure 36d: Age profile of 345 and 500 kV breakers in service.

5.2.5. Replace Underground Lines

Description

Underground transmission can be utilized in locations where there is limited space to accommodate overhead transmission lines. It is often installed near airports and bridge crossings. The underground cables typically have a useful life of 35-40 years (the industry commonly considers underground cables to be half the life expectancy of an overhead transmission conductor). Many cables and fixtures in the company's transmission system are at or beyond their expected useful life and are starting to perform poorly. In order to sustain the reliability of the company's underground transmission system, it is necessary to monitor cable performance and plan for replacement of these facilities.

The five-year cost of this program is $23.4 million.

Underground Line Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace Underground Lines	$3.2	$10.2	$10.0	$0	$0	$23.4

Benefits

Replacement of underground components nearing the end of their useful life will lead to:

- reduction in risk of failure, associated outage, and public safety hazard;
- reduction in costly emergency repairs; and,
- reduction in risk of extended sustained outage.

Supporting Data

In the late 1960s, a 69 kV underground transmission circuit, approximately 3,200 feet in length, was installed in downtown Lexington feeding the Vine Street Substation. The cable in this line is composed of 1500 kcmil aluminum with XLPE insulation. The duct bank was built using Orangeburg pipe (fiber conduit). In 2012, this circuit experienced a splice failure where the three sections of underground cable are joined together. Another 69kV underground transmission circuit, approximately 3,600 feet in length, feeding the Vine Street Substation was installed in the early 1970s. The cable in this circuit is composed of 1500 kcmil aluminum with EPR insulation.

The Lexington Underground project will replace both underground transmission circuits serving the Vine Street substation, which serves approximately 5,200 customers, with a peak load of almost 27 MW. A majority of the businesses, government operations, and public transportation in the downtown area are served from the Vine Street substation. One underground line serving Vine Street substation has experienced a failure at a splice where two sections of underground cable are joined together.

Similarly, in the early 1970s, the company installed three 69kV underground dips into the Oxmoor Substation. The Oxmoor project will replace two of the underground dips (approximately 600 feet in length) into the Oxmoor substation in Louisville. These circuits are composed of 1250 kcmil copper with XLPE insulation. The termination for the underground feed on the Oxmoor-Aiken 69kV line at the Oxmoor Substation failed in 2015 and damaged a portion of the cable. The Oxmoor Substation serves approximately 6,300 customers in the Louisville area, including several businesses and a shopping mall along Shelbyville Road. The Oxmoor-Breckenridge underground segment will be replaced concurrently with the Oxmoor to Aiken underground segment due to the age of existing cable, and its inclusion in the existing duct bank that will be replaced as part of the proposed project. Over the past five years, the UG system has experienced four outages, but has not yet had a notable SAIDI impact because of the redundancy in the system.

Figure 37: Example of a failed underground transmission splice.

5.2.6. Replace Line Switches

Description

Line switches allow circuits to be sectionalized for isolating a fault and to facilitate line equipment maintenance, replacements, and upgrades. Proper operation and functionality of line switches is key to supporting restoration efforts during a system outage and supporting the capital replacement programs. This program will replace line switches identified as defective or obsolete from the switch maintenance programs that cannot be cost effectively repaired.

The projected spending on this program is based on historical costs. Development of this program will continue to be reviewed and adjusted with additional inspection results and historical costs. Replacements are prioritized based on known operational issues, availability of replacement components, and switch inspection results.

The five-year estimated cost of the program is $12.2 million.

Switch Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Line Switches	$1.2	$1.7	$1.8	$3.6	$3.9	$12.2

Planned Switch Replacements	2017	2018	2019	2020	2021
Number of Switches	3	5	5	10	10

Benefits

Replacement of defective line switches will reduce the risk of failure and impacts from system outages. Additional program benefits include:

- reduction of associated outages and public safety hazards; and
- reduction of SAIDI.

Supporting Data

The Switch Replacement Program will improve outages for the following cause code.

Reliability Cause Code: Switch — Failed AC Circuit Equip.	2012	2013	2014	2015	2016*
Outage Counts	4	0	1	4	2
SAIDI incl. MEDs	0.14	0.00	0.18	0.00	0.04
SAIDI excl. MEDs	0.14	0.00	0.18	0.00	0.04

*2016 thru June 30, 2016.

5.2.7. Replace Substation Insulators

Description

Insulators are used to isolate from ground and support energized conductors and substation equipment such as disconnect switches. Bus insulator failures can lead to an outage on multiple radial lines, and to a loss of an autotransformer leaving the system at risk for the next contingency.

There are two specific types of insulators targeted for replacement based on failure history: cap and pin type, and hollow post type.

- Cap and Pin — The failure mode for this design is at the joint where the cement used to connect the metallic cap to the porcelain deteriorates. The insulators at the highest risk are those that are part cantilevered or underhung from the steel as well as those that are part of a disconnect switch.
- Hollow Post — Multiple past failures have been attributed to water ingress into the hollow portion of the insulator. A flashover occurs as a result of tracking internal to the insulator.

In cases where either of these insulator types are used for a disconnect switch, the entire switch will be replaced instead of only replacing the insulators.

Stations for replacement are prioritized based upon both criticality as well as past failures.

The five-year cost of this program will be $8.4 million.

Substation Insulator Replacement Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Subs Insulators	$2.7	$2.1	$2.1	$0.7	$0.8	$8.4

Benefits

The key benefits related to the replacement of substation insulators include:

- reduced number of outages initiated by insulator failures, thereby improving SAIDI and reducing risk to system from failures; and
- reduced cost by replacing multiple insulators as part of a planned outage is more cost effective than continually replacing failed insulators as part of a forced outage.

Supporting Data

Proactively replacing both hollow post along with cap and pin insulators will reduce outages with the following cause code.

Reliability Cause Code: Insulator — Failed AC Substation Equip.	2012	2013	2014	2015	2016*
Outage Counts	4	9	8	12	8
SAIDI incl. MEDs	0.00	0.37	0.15	0.73	0.08
SAIDI	0.00	0.37	0.15	0.73	0.08

*2016 thru June 30, 2016.

Figure 38 shows a hollow post insulator as part of a disconnect switch assembly that violently failed, resulting in an outage.

Figure 38: Hollow post insulator after failure.

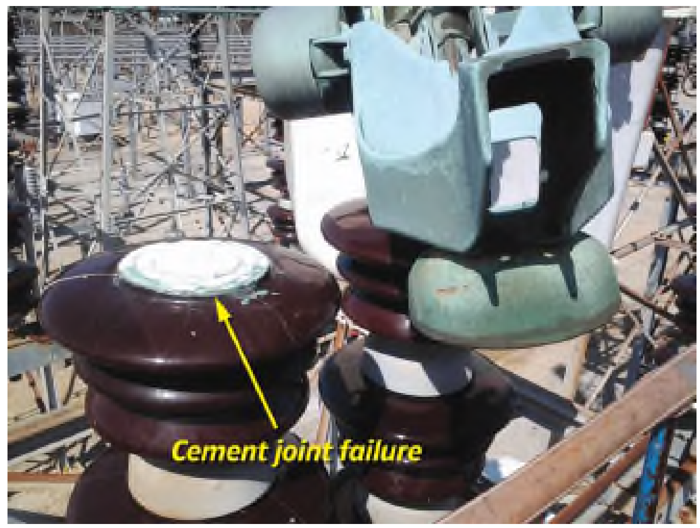

Figure 39: Failed cap and pin insulator.

5.2.8. Structure Corrosion Prevention and Coating

Description

Coating assessment will be performed on applicable assets, including lattice and tubular steel structures to assess corrosion activity and required actions, if any. Protective coatings will then be applied as required to prevent corrosion damage and extend the useful service life of these assets. When rust is discovered upon structure inspection, it is vital that protective coatings be applied in order to avoid loss of material thickness and subsequent structural failure.

Work will be prioritized based on observations from detailed inspections. The intent of the program is to establish and maintain a consistent coating cycle, which will be developed as part of the assessment program.

The five-year estimated cost of the corrosion protection program is $4.3 million.

Corrosion Prevention Program Cost (MM USD)	2017	2018	2019	2020	2021	Total
Corrosion Protections	$0.5	$0.7	$0.9	$1.1	$1.1	$4.3

Benefits

Corrosion prevention is imperative to extend the useful service life of steel assets. Coating these assets will maintain their integrity and functionality. This program will:

- reduce risk of structure damage and failure, associated outages, and public safety hazards;
- avoid costly replacement of structures (the higher the line voltage, the higher the costs); and
- improve system aesthetics, improving customer image.

Supporting Data

These are the types of structure and corrosion that this program is addressing.

Figure 40: Examples of poles and structures exepriencing corrosion activity.

5.2.9. Replace Substation Line Arresters

Description

Arresters are typically located where the incoming transmission line attaches to the substation steel as well as near the bushing terminals of power transformers. Their purpose is to clamp transient overvoltage caused by lightning, switching of electrical equipment and other causes to prevent transmission equipment dielectric failures. Older, obsolete arrestors are prone to failure, which will cause an outage on the line to which it is connected. In some cases, arrestors are made with porcelain and can fail violently, causing damage to surrounding equipment. Replacing them with modern arrestors without porcelain reduces the likelihood of failure and minimizes the possibility of collateral damage if they do fail.

Arrester types that will be targeted include spark gaps along with those utilizing silicon carbide technology which are obsolete and prone to premature failure. Arrester replacements will be prioritized based on age of terminal equipment at each substation. When possible, arresters will be replaced during other scheduled work to reduce installation costs.

The five-year cost of substation line arrester replacement program is $3.0 million.

Substation Arrester Replacement Program Cost (MM USD)						
	2017	2018	2019	2020	2021	Total
Replace Subs Line Arresters	$0.6	$0.6	$0.6	$0.6	$0.6	$3.0

Benefits

The benefits associated with the replacement of the substation line arresters include:

- reduced number of outages due to arrester failure, since the Metal Oxide Varistor (MOV) type arresters provide superior dielectric protection for station equipment and have lower failure rates, and thereby improving reliability and reducing SAIDI; and
- reduced cost of arrester replacement, since replacing line arresters as part of a planned outage is more cost-effective than continually replacing failed units due to forced outages.

Supporting Data

Proactively replacing both spark gap and silicon carbide type arresters will reduce outages with the following cause code.

Reliability Cause Code: Arrester — Failed AC Substation Equip.	2012	2013	2014	2015	2016*
Outage Counts	9	1	3	4	1
SAIDI incl. MEDs	0.00	0.00	0.26	0.00	0.76
SAIDI	0.00	0.00	0.26	0.00	0.76

*2016 thru June 30, 2016.

5.2.10. Replace Coupling Capacitors

Description

Coupling capacitors are utilized as part of a power line carrier protection scheme. They couple the signal from the carrier communication equipment to the transmission line.

It is difficult to detect a coupling capacitors that are trending to failure. Based on past experience, the failure of a coupling capacitor used to support associated equipment can result in significant collateral damage. The replacement program will be prioritized based on the criticality of the line, along with the age and type of coupling capacitor.

The five-year cost of the program is $2.2 million.

Coupling Capacitor Replacement Cost (MM USD)	2017	2018	2019	2020	2021	Total
Replace Coupling Capacitors	$0.6	$0.6	$0.6	$0.2	$0.2	$2.2

Benefits

Replacing coupling capacitors provides the following benefits:

- reduced risk of line outages due to violent failures of coupling capacitors that often lead to collateral damage to equipment located in the proximity; and
- reduced cost by replacing coupling capacitors as part of a planned outage instead of continually replacing failed units due to forced outages.

Supporting Data

Proactively replacing coupling capacitors will reduce outages with the following cause code.

Reliability Cause Code: CCVT Coupling Capacitor	2012	2013	2014	2015	2016*
Outage Counts	0	0	5	8	0
SAIDI incl. MEDs	0.00	0.00	1.08	0.33	0.00
SAIDI excl. MEDs	0.00	0.00	1.08	0.33	0.00

*2016 thru June 30, 2016.

6. Appendix A: Glossary of Terms

Batteries

A battery is a group of electrochemical cells that are used to store electricity and release it when needed. The cells can be recharged by passing a current through them in the direction opposite to the discharging flow of current. Batteries are used to supply power to the P&C systems if their primary power feed fails.

Breaker

A circuit breaker is a mechanical switching device which connects and breaks current circuits (operating current and fault currents) and carry the nominal current in the closed position.

Capacitor Bank

Capacitor banks are used to reduce system power losses, loading on substation transformers and raise voltage levels on the transmission system.

Circuit

A continuous flow of electricity from a source to a load or loads. In utility transmission, a circuit is the main line and all radial taps served by a single substation circuit breaker.

Circuit sectionalization

The practice used by utilities to break an electric circuit into sections that can be isolated from the rest of the circuit in case of an outage to protect all of the customers from getting an outage as a result. This also allows the utility to switch the source of power to the circuit from one feeder or substation to another during an outage, if another source is available.

Control House

A control house is an enclosure inside a substation that protects these P&C system assets (e.g., relay panels, remote terminal units (RTU), power line carriers (PLC) digital fault recorders (DFRs) and batteries) from external elements

Conductor

Conductor refers to a wire or cable that carry electricity across the transmission system.

Coupling Capacitors

Coupling capacitors are utilized as part of a power line carrier protection scheme. They couple the signal from the carrier communication equipment to the transmission line.

Cross Arm

Cross arms are used to support wires or equipment on top of a pole, providing clear area for linemen to climb around or past the electric equipment and to keep the phases separated

DC Current

One directional flow of electric charge.

Digital Fault Recorder

Devices that actively monitor the transmission system at each substation control house in which they are installed. Pre-defined thresholds are set in the device and when the system conditions meet those thresholds the device takes samples of the voltages and currents and stores them internally for future retrieval. This information is used by the engineering staff to analyze the outages for proper operation of the relays.

Easement

Easement is the right to cross or otherwise use someone else's land for a specified purpose.

Hazard Tree

A hazard tree is a tree with structural defects (disease or otherwise compromised structurally) likely to cause failure of all or part of the tree, which could strike a power line.

Insulator

Insulators provide an insulated point of attachment for wires that are under tension or not (such as jumper wires).

Lightning Arresters

Provide a path to the ground if lightning should strike the equipment. It diverts the current to the ground protecting the equipment from potential damage.

Major Event Day (MED)

Major Event Days (MEDs) are the days during which total SAIDI value exceeds a predetermined threshold indicating that the amount of outages is more than 2.5 standard deviations from the five-year mean. The outages that started on MED days are removed from the reliability index calculations in order to normalize the reliability performance and make it less skewed by unusual events.

Outage

Outage is a fault on the transmission line that may result in customer service interruption or take a circuit or a portion of circuit out of service.

Overhead Lines

Electric circuits that are placed above ground on poles, structures or to towers.

Pole

Utility pole is a column or post used to support overhead power lines and various other public utilities, such as cable, fiber optic cable, and related equipment.

Power Line Carrier (PLC)

PLC is a communication technology that enables sending data over existing power cables at high-speeds.

Radial (tap)

A section of the circuit constructed to extend to loads that are not directly in the path of the main line. Radials are typically connected to the main line through sectionalizing devices.

Recloser (circuit recloser)

Reclosers are designed to detect and clear momentary faults and to isolate line sections on which persistent failures have developed.

Relay

Relays are devices that are designed to respond to abnormal system conditions. These devices use current and/or voltage measurements from the system to determine if the electrical system they are monitoring is in a normal or abnormal state. If the system is in an abnormal state, the relay issues a signal to a circuit interrupting device to open its contacts and interrupt the current flow on the system it oversees.

Relay Panel

A relay panel consists of multiple relays that oversee a specific transmission line, bus, or transformer.

Reliability

Reliability can be defined as the ability of the transmission system to deliver electricity to all points of consumption, in the quantity and with the quality demanded by the customer. Reliability is often measured by outage indices defined by the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366. These indices relate to customer satisfaction, and are based on both the total length of each service interruption and the frequency of interruptions.

Remote Terminal Unit

A remote terminal unit (RTU) is a microprocessor-controlled electronic device that interfaces objects in the physical world to a distributed control system or SCADA (supervisory control and data acquisition) system by transmitting telemetry data to a master system, and by using messages from the master supervisory system to control connected objects.

Right-of-Way

Right-of-way (ROW) is the legal right, established by usage or grant, to pass along a specific route through grounds or property belonging to another

SAIDI

SAIDI is a standard industry measure that indicates how long, expressed in number of minutes, an average customer has been out of service during a predefined period of time (most often in a year). This index is used to compare reliability performance across different utilities.

SCADA

The SCADA system allows for remote operation of overhead and underground switches, reclosers and capacitors via coded communications (telephone or radio) system by the system operator. SCADA features an alarm system to alert the operator to the problems and their approximate location, and data acquisition capability that provides detailed information on the phase, secondary voltage, type and magnitude of the fault.

Structure

*See definition of **Pole**.*

Shield Wire

Shield wire is a ground conductor usually at the top of the supporting structure designed to shield or protect the transmission line from lightning strikes.

Substation

Transmission substation connects two or more transmission lines. The substations can be simple with same voltage or include transformers to reduce voltage of the transmission line.

Switch

Switches are mechanisms to open up or close a section of a circuit. The switch also serves as an opening point to separate two different substation feeds.

Tap

*See **Lateral**.*

Tower

Transmission towers are metal pylons that support overhead transmission lines.

Transformer

Transformer converts electrical energy in an electric utility system to change the voltage.

Transmission Operations Center

A facility that houses system operators and data management system, providing real-time status and the ability to remotely operate the transmission system.

Underground Lines

Transmission lines that are buried underground, typically in conduit.

Vegetation Management (VM)

Refers to the cyclical and reactive program for maintaining trees and tree limbs at a safe distance from the transmission power lines. A VM program is guided by a set of industry standards, NERC requirements and transmission company guidelines.

Voltage

Voltage is the difference in electric potential energy between two points per unit electric charge. Transmission system operates the line with voltages over 69kV.

PPL companies

KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated October 1, 2018

Case No. 2018-00304

Question No. 12

Responding Witness: Christopher M. Garrett

Q-12. Reference the Application, page 5. Confirm that if the Commission grants the Companies their requested 15-year amortization period for unprotected excess ADIT, the Commission can later amend that period in Case Nos. 2018-00294 & 2018-00295.

A-12. In the Commission's Order on September 28, 2018 in Case No. 2018-00034, the Commission stated: "The Commission does note the Attorney General's suggestion regarding the amortization period for the unprotected excess ADIT, and will reexamine the 15-year amortization period during KU/LG&E's next base rate cases."[4]

The Companies further note that should their proposal be accepted, the Companies would not begin amortization of the unprotected state excess ADIT until new base rates took effect as part of Case Nos. 2018-00294 and 2018-00295.

[4] *In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company and Louisville Gas and Electric Company*, Case No. 2018-00034, Order at 16 (Ky. PSC Sept. 28, 2018).