COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2014 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	**))))**	**CASE NO. 2014-00131**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY
TO WALLACE MCMULLEN AND SIERRA CLUB'S
INITIAL DATA REQUESTS
DATED NOVEMBER 7, 2014

FILED: NOVEMBER 21, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **David E. Huff**, being duly sworn, deposes and says that he is Director of Customer Energy Efficiency & Smart Grid Strategy for 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 that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David E. Huff

David E. Huff

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of November 2014.

Judy Schooler (SEAL)
Notary Public

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

My Commission Expires:

July 11, 2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for 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.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of November 2014.

Judy Schooler (SEAL)
Notary Public

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

My Commission Expires:

July 11, 2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for 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.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of November 2014.

Judy Schooler (SEAL)
Notary Public

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

My Commission Expires:

July 11, 2018

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Edwin R. Staton**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities 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.

E. R. Staton
Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of November 2014.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

July 11, 2018

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is the Vice President, Transmission and Generation Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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.

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of September 2014.

Judy Schooler (SEAL)
Notary Public

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

My Commission Expires:

July 11, 2018

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.1

Witness: Edwin R. Staton

Q1.1. Please provide all LG&E/KU responses to data requests from all other parties in this proceeding.

A1.1. The Companies will follow all applicable Commission regulations concerning the filing and distribution of documents in this proceeding. The Companies will separately provide to any intervenor who has entered into a valid confidentiality agreement with the Companies, as has Sierra Club, copies of any confidential information the Companies file in this proceeding.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.2

Witness: Edwin R. Staton

Q1.2. Please provide any redacted documents included in this filing in non-redacted, electronic versions (machine readable, unprotected, with formulas intact), if they have not already been provided to the Environmental Intervenors.

A1.2. Please see the Companies' response to Question No. 1.1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.3

Witness: Charles R. Schram

Q1.3. Produce any workpapers (in machine readable and unprotected format, with formulas intact) used to produce the load forecast, reserve margin study, and/or resource assessment.

A1.3. All electronic files are being provided on an external hard drive. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.4

Witness: Charles R. Schram

Q1.4. Produce the input and output files (in machine readable and unprotected format with formulas intact) for all Strategist modeling carried out as part of this IRP.

A1.4. Please see the Companies' response to Question No. 1.3.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.5

Witness: Charles R. Schram

Q1.5. For the Companies' fleet, please provide the following historical annual data by unit, from 2005 to present:

a. Fixed O&M cost
b. Variable O&M cost (without fuel)
c. Fuel costs
d. Capital costs
e. Heat rate
f. Generation
g. Capacity rating

A1.5. Please see attached.

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

TYRONE - Steam

	YEAR TO DATE			
	UNIT 1	UNIT 2	UNIT 3	TOTAL
KWH Output				
Net KWH - Coal..	-	-	355,762,000	355,762,000
Net KWH - Oil..	(1,404,000)	(1,408,000)	-	(2,812,000)
Total KWH Output......................................	(1,404,000)	(1,408,000)	355,762,000	352,950,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight...	-	-	10,932,472.90	10,932,472.90
Coal, Inc. Frt, Hand'l, Etc (2)................................	45,725.29	49,881.96	11,353,278.53	11,448,885.78
Total Fuel (2)..	45,725.29	49,881.96	11,353,278.53	11,448,885.78
Other Operation Expenses	195,377.43	213,138.72	1,310,125.73	1,718,641.88
Maintenance	111,132.75	122,433.26	1,484,056.46	1,717,622.47
Rents	-	-	-	-
Total Production Expenses	352,235.47	385,453.94	14,147,460.72	14,885,150.13
Fuel Costs - Cents				
Coal, Incl. Freight (1)	-	-	3.073	3.073
Coal and Other (1) (2)...	-	-	3.191	3.218
Total all Fuel Costs (2)..	(3.257)	(3.543)	3.191	3.244
Other Operation Expenses...	(13.916)	(15.138)	0.368	0.487
Maintenance..	(7.915)	(8.696)	0.417	0.487
Rents..	-	-	-	-
Total Production Expenses......................................	(25.088)	(27.376)	3.977	4.217
Quantities of Fuel Burned:				
Coal - Tons..	-	-	183,916.00	183,916.00
Oil - Gal - Start-up/Stab...................................	-	-	153,163	153,163
Million BTU Burned:				
Coal..	-	-	4,585,419.48	4,585,419.48
Oil - Start-up/Stab..	-	-	21,442.00	21,442.00
Total MMBTU Burned	-	-	4,606,861.48	4,606,861.48
Average BTU per Net KWH Output..........................	-	-	12,949	13,052

(1) Based on KWH generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

GREEN RIVER - Steam

	YEAR TO DATE				
	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal..	-	-	336,573,000	338,730,000	675,303,000
Total KWH Output......................................	-	-	336,573,000	338,730,000	675,303,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight...	-	-	6,376,990.80	5,773,633.78	12,150,624.58
Coal, Inc. Frt, Hand'l, Etc (1)................................	-	-	6,767,148.87	6,306,741.65	13,073,890.52
Total Fuel (1)...	-	-	6,767,148.87	6,306,741.65	13,073,890.52
Other Operation Expenses	-	-	1,961,873.83	1,511,047.98	3,472,921.81
Maintenance	2,635.01	2,548.17	1,325,526.72	3,393,996.88	4,724,706.78
Rents	-	-	-	-	-
Total Production Expenses	2,635.01	2,548.17	10,054,549.42	11,211,786.51	21,271,519.11
Fuel Costs - Cents					
Coal, Incl. Freight	-	-	1.895	1.704	1.799
Coal and Other (1)...	-	-	2.011	1.862	1.936
Total all Fuel Costs (1)...	-	-	2.011	1.862	1.936
Other Operation Expenses...	-	-	0.583	0.446	0.514
Maintenance..	-	-	0.394	1.002	0.700
Rents..	-	-	-	-	-
Total Production Expenses......................................	-	-	2.987	3.310	3.150
Quantities of Fuel Burned:					
Coal - Tons...	-	-	176,672.00	160,089.00	336,761.00
Oil - Gal - Start-up/Stab....................................	-	-	96,837	112,313	209,150
Million BTU Burned:					
Coal..	-	-	4,322,681.98	3,893,586.48	8,216,268.46
Oil - Start-up/Stab..	-	-	13,557.00	15,724.00	29,281.00
Total MMBTU Burned	-	-	4,336,238.98	3,909,310.48	8,245,549.46
Average BTU per Net KWH Output..........................	-	-	12,884	11,541	12,210

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

EW Brown - Steam

	YEAR TO DATE			
	UNIT 1	UNIT 2	UNIT 3	TOTAL
KWH Output				
Net KWH - Coal..	563,532,000	1,075,007,000	1,584,997,000	3,223,536,000
Total KWH Output.....................................	563,532,000	1,075,007,000	1,584,997,000	3,223,536,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight...	11,671,502.96	20,222,044.67	30,971,527.19	62,865,074.82
Coal, Inc. Frt, Hand'l, Etc (1)................................	12,074,686.50	20,607,669.78	32,053,776.73	64,736,133.01
Total Fuel (1)..	12,074,686.50	20,607,669.78	32,053,776.73	64,736,133.01
Other Operation Expenses	593,552.07	946,240.08	4,981,496.98	6,521,289.13
Maintenance	1,461,003.44	2,077,471.02	9,131,533.90	12,670,008.36
Rents	-	-	-	-
Total Production Expenses	14,129,242.01	23,631,380.88	46,166,807.61	83,927,430.50
Fuel Costs - Cents				
Coal, Incl. Freight	2.071	1.881	1.954	1.950
Coal and Other (1)	2.143	1.917	2.022	2.008
Total all Fuel Costs (1)..	2.143	1.917	2.022	2.008
Other Operation Expenses...	0.105	0.088	0.314	0.202
Maintenance..	0.259	0.193	0.576	0.393
Rents..	-	-	-	-
Total Production Expenses......................................	2.507	2.198	2.913	2.604
Quantities of Fuel Burned:				
Coal - Tons..	250,826.00	434,723.00	667,213.00	1,352,762.00
Oil - Gal - Start-up/Stab....................................	139,258	45,186	180,773	365,217
Million BTU Burned:				
Coal..	6,251,337.55	10,832,617.97	16,615,108.94	33,699,064.46
Oil - Start-up/Stab..	19,497.00	6,326.00	25,307.00	51,130.00
Total MMBTU Burned	6,270,834.55	10,838,943.97	16,640,415.94	33,750,194.46
Average BTU per Net KWH Output..........................	11,128	10,083	10,499	10,470

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

GHENT - Steam

	YEAR TO DATE				
	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal...	3,488,619,000	2,762,178,000	3,086,506,000	3,249,370,000	12,586,673,000
Total KWH Output......................................	3,488,619,000	2,762,178,000	3,086,506,000	3,249,370,000	12,586,673,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight..	49,428,890.87	51,888,110.19	66,930,111.49	62,212,204.88	230,459,317.43
Coal, Inc. Frt, Hand'l, Etc (1)................................	49,983,929.71	52,666,338.54	67,989,543.98	63,951,030.45	234,590,842.68
Total Fuel (1)...	49,983,929.71	52,666,338.54	67,989,543.98	63,951,030.45	234,590,842.68
Other Operation Expenses	3,318,668.21	2,531,401.79	2,776,142.44	3,949,286.14	12,575,498.58
Maintenance	6,663,927.24	7,105,463.15	3,495,988.81	3,774,041.46	21,039,420.66
Rents	-	-	-	-	-
Total Production Expenses	59,966,525.16	62,303,203.48	74,261,675.23	71,674,358.05	268,205,761.92
Fuel Costs - Cents					
Coal, Incl. Freight	1.417	1.879	2.168	1.915	1.831
Coal and Other (1)..	1.433	1.907	2.203	1.968	1.864
Total all Fuel Costs (1)..	1.433	1.907	2.203	1.968	1.864
Other Operation Expenses...	0.095	0.092	0.090	0.122	0.100
Maintenance...	0.191	0.257	0.113	0.116	0.167
Rents...	-	-	-	-	-
Total Production Expenses......................................	1.719	2.256	2.406	2.206	2.131
Quantities of Fuel Burned:					
Coal - Tons...	1,494,626.00	1,166,409.00	1,515,661.00	1,406,119.00	5,582,815.00
Oil - Gal - Start-up/Stab....................................	108,292	239,124	416,881	392,047	1,156,344
Million BTU Burned:					
Coal..	35,750,245.77	27,149,962.92	35,254,320.16	32,697,874.24	130,852,403.11
Oil - Start-up/Stab..	15,161.00	33,475.00	58,365.00	54,888.00	161,889.00
Total MMBTU Burned	35,765,407.77	27,183,437.92	35,312,685.16	32,752,762.26	131,014,292.11
Average BTU per Net KWH Output..........................	10,252	9,841	11,441	10,080	10,409

Attachment to Response to Sierra Club Question No. 1.5 (a)(b)(c)

Schram

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

	YEAR TO DATE					
Cane Run - Steam	UNITS 1 & 2	UNIT 3	UNIT 4	UNIT 5	UNIT 6	TOTAL
KWH Output						
Net KWH - Coal...	-	-	1,052,063,000	1,091,048,000	1,542,731,000	3,685,842,000
Production Costs ($)						
Fuel Costs						
Coal, Inc. Freight...	-	-	14,337,827.16	14,378,189.62	19,794,690.50	48,510,707.28
Coal, Inc. Frt, Hand'l, Etc (2)................................	-	-	15,190,036.69	15,476,021.94	21,007,862.67	51,673,921.30
Total Fuel (2)...	-	-	15,190,036.69	15,476,021.94	21,007,862.67	51,673,921.30
Other Operation Expenses	-	-	5,670,001.82	5,929,846.36	9,251,777.59	20,851,625.77
Maintenance	861.83	28,837.83	2,889,144.59	2,791,490.41	5,247,876.15	10,958,210.81
Rents	-	-	13,838.04	15,375.60	22,038.36	51,252.00
Total Production Expenses	861.83	28,837.83	23,763,021.14	24,212,734.31	35,529,554.77	83,535,009.88
Fuel Costs - Cents						
Coal, Incl. Freight (1)	-	-	1.363	1.318	1.283	1.316
Coal and Other (1) (2)...	-	-	1.444	1.418	1.362	1.402
Total all Fuel Costs (2)..	-	-	1.444	1.418	1.362	1.402
Other Operation Expenses...	-	-	0.539	0.544	0.600	0.566
Maintenance...	-	-	0.275	0.256	0.340	0.297
Rents..	-	-	0.001	0.001	0.001	0.001
Total Production Expenses......................................	-	-	2.259	2.219	2.303	2.266
Quantities of Fuel Burned:						
Coal - Tons...	-	-	506,195.10	505,524.65	695,762.95	1,707,482.70
Gas - MCF - Start-up/Stab....................................	-	-	50,573	78,973	75,952	205,498
Oil - Gallons...	-	-	-	-	-	-
Million BTU Burned:						
Coal..	-	-	11,402,407.53	11,382,279.89	15,678,004.21	38,462,691.63
Gas - Start-up/Stab...	-	-	51,837.00	80,946.00	77,852.00	210,635.00
Oil..	-	-	-	-	-	-
Total MMBTU Burned	-	-	11,454,244.53	11,463,225.89	15,755,856.21	38,673,326.63
Average BTU per Net KWH Output (Heat Rate)	-	-	10,887	10,507	10,213	10,492

(1) Based on KWH generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

	YEAR TO DATE				
Mill Creek - Steam	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal..	2,223,638,000	1,828,966,000	2,969,840,000	3,092,783,000	10,115,227,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight...	29,866,953.99	25,735,947.75	39,584,702.17	41,953,817.20	137,141,421.11
Coal, Inc. Frt, Hand'l, Etc (2)................................	31,046,386.82	26,859,292.59	42,148,451.18	45,400,619.67	145,454,750.26
Total Fuel (2)..	31,046,386.82	26,859,292.59	42,148,451.18	45,400,619.67	145,454,750.26
Other Operation Expenses	5,382,780.60	4,758,851.13	4,550,634.15	6,213,763.13	20,906,029.01
Maintenance	2,975,210.06	5,673,185.15	3,856,700.24	5,659,689.17	18,164,784.62
Rents	-	-	-	-	-
Total Production Expenses	39,404,377.48	37,291,328.87	50,555,785.57	57,274,071.97	184,525,563.89
Fuel Costs - Cents					
Coal, Incl. Freight (1)	1.343	1.407	1.333	1.357	1.356
Coal and Other (1) (2)...	1.396	1.469	1.419	1.468	1.438
Total all Fuel Costs (2)..	1.396	1.469	1.419	1.468	1.438
Other Operation Expenses...	0.242	0.260	0.153	0.201	0.207
Maintenance..	0.134	0.310	0.130	0.183	0.180
Rents..	-	-	-	-	-
Total Production Expenses......................................	1.772	2.039	1.702	1.852	1.824
Quantities of Fuel Burned:					
Coal - Tons...	1,010,247.05	870,685.05	1,340,470.90	1,416,215.70	4,637,618.70
Gas - MCF - Start-up/Stab...................................	25,830	22,264	139,593	203,209	390,896
Oil - Gallons...	-	-	-	-	-
Million BTU Burned:					
Coal...	23,037,474.62	19,850,321.47	30,567,047.41	32,275,974.87	105,730,818.37
Gas - Start-up/Stab..	26,477.00	22,822.00	143,084.00	208,287.00	400,670.00
Oil...	-	-	-	-	-
Total MMBTU Burned	23,063,951.62	19,873,143.47	30,710,131.47	32,484,261.87	106,131,488.37
Average BTU per Net KWH Output (Heat Rate)	10,372	10,866	10,341	10,503	10,492

(1) Based on KWH generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2005

	CURRENT MONTH		YEAR TO DATE		YEAR ENDED CURRENT MONTH	
Trimble County - Steam (3)	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR
Net KWH - LGE..	284,428,600	233,677,000	2,886,772,400	3,114,522,000	2,886,772,400	3,114,522,000
IMEA...	46,160,000	38,464,000	475,819,700	532,440,000	475,819,700	532,440,000
IMPA...	49,056,400	43,060,000	505,962,900	568,134,000	505,962,900	568,134,000
Total KWH Output......................................	379,645,000	315,201,000	3,868,555,000	4,215,096,000	3,868,555,000	4,215,096,000
Fuel Costs $:						
Coal, Inc. Freight..	5,229,091.70	4,082,145.60	53,150,454.22	48,705,512.27	53,150,454.22	48,705,512.27
Coal, Inc. Frt, Hand'l, Etc (2)..............................	5,332,189.83	4,202,011.85	54,505,773.25	49,710,027.01	54,505,773.25	49,710,027.01
Total Fuel (2)..	5,332,189.83	4,202,011.85	54,505,773.25	49,710,027.01	54,505,773.25	49,710,027.01
Other Operation Expenses $.............................	712,381.78	603,713.96	7,071,964.72	6,503,737.85	7,071,964.72	6,503,737.85
Maintenance $..	377,884.44	1,118,842.32	8,224,434.34	6,528,286.12	8,224,434.34	6,528,286.12
Rents $...	-	-	-	-	-	-
Total Production Expenses $................................	6,422,456.05	5,924,568.13	69,802,172.31	62,742,050.98	69,802,172.31	62,742,050.98
Cost per Net KWH Output-Cents:						
Coal Inc. Freight (1)................................	1.377	1.295	1.374	1.156	1.374	1.156
Coal Inc. Frt, Hand'l, Etc (1) (2)..........................	1.405	1.333	1.409	1.179	1.409	1.179
Total all Fuel Costs (2).....................................	1.405	1.333	1.409	1.179	1.409	1.179
Other Operation Expenses....................................	0.188	0.192	0.183	0.154	0.183	0.154
Maintenance..	0.100	0.355	0.213	0.155	0.213	0.155
Rents..	-	-	-	-	-	-
Total Production Expenses..................................	1.692	1.880	1.804	1.489	1.804	1.489
Quantities of Fuel Burned:						
Coal - Tons..	163,692.50	138,268.00	1,645,163.00	1,846,564.00	1,645,163.00	1,846,564.00
Oil - Gallons..	6,063	33,747	318,606	105,914	318,606	105,914
Million BTU Burned:						
Coal...	3,848,679.95	3,247,086.00	38,848,075.73	43,006,316.00	38,848,075.73	43,006,316.00
Oil...	849.00	4,724.00	44,606.00	14,826.00	44,606.00	14,826.00
Total...	3,849,528.95	3,251,810.00	38,892,681.73	43,021,142.00	38,892,681.73	43,021,142.00
Average BTU Per Net KWH Output.......................	10,140	10,317	10,054	10,206	10,054	10,206
Average BTU Per pound of Coal........................	11,756	11,742	11,807	11,645	11,807	11,645
Per Cu. Ft. of Gas.................................	-	-	-	-	-	-
Per Gallon of Oil...................................	140,030	139,983	140,004	139,981	140,004	139,981
Cost Coal & Freight per MBTU (Cents).................	135.867	125.717	136.816	113.252	136.816	113.252
Total All Fuel Cost per MBTU (2).....................	138.515	129.221	140.144	115.548	140.144	115.548
Cost of Coal & Freight Per Ton ($)....................	31.945	29.523	32.307	26.376	32.307	26.376

(1) Based on KWH generated by coal or gas as applicable.
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).
(3) Information on this report represents 100% generation, quantities used, and costs.

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

TYRONE - Steam

	YEAR TO DATE			
	UNIT 1	UNIT 2	UNIT 3	TOTAL
KWH Output				
Net KWH - Coal..	-	-	253,848,000	253,848,000
Net KWH - Oil..	(1,203,000)	(1,208,000)	-	(2,411,000)
Total KWH Output......................................	(1,203,000)	(1,208,000)	253,848,000	251,437,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight...	-	-	8,878,472.27	8,878,472.27
Coal, Inc. Frt, Hand'l, Etc (2)................................	51,633.14	56,327.00	9,417,107.82	9,525,067.96
Total Fuel (2)..	51,633.14	56,327.00	9,417,107.82	9,525,067.96
Other Operation Expenses	222,117.31	242,309.07	1,464,934.59	1,929,360.97
Maintenance	107,324.56	111,536.23	1,399,697.68	1,618,558.47
Rents	-	-	-	-
Total Production Expenses	381,075.01	410,172.30	12,281,740.09	13,072,987.40
Fuel Costs - Cents				
Coal, Incl. Freight (1)	-	-	3.498	3.498
Coal and Other (1) (2)...	-	-	3.710	3.752
Total All Fuel Costs (2)..	(4.292)	(4.663)	3.710	3.788
Other Operation Expenses..	(18.464)	(20.059)	0.577	0.767
Maintenance..	(8.921)	(9.233)	0.551	0.644
Rents..	-	-	-	-
Total Production Expenses......................................	(31.677)	(33.955)	4.838	5.199
Quantities of Fuel Burned:				
Coal - Tons..	-	-	131,112.00	131,112.00
Oil - Gal - Start-up/Stab....................................	-	-	175,379	175,379
Million BTU Burned:				
Coal..	-	-	3,265,220.53	3,265,220.53
Oil - Start-up/Stab..	-	-	24,554.00	24,554.00
Total MMBTU Burned	-	-	3,289,774.53	3,289,774.53
Average BTU per Net KWH Output..........................	-	-	12,960	13,084

(1) Based on KWH generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

GREEN RIVER - Steam

	YEAR TO DATE				
	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal..	-	-	206,046,000	433,665,000	639,711,000
Total KWH Output......................................	-	-	206,046,000	433,665,000	639,711,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight...	-	-	4,770,843.47	8,811,954.99	13,582,798.46
Coal, Inc. Frt, Hand'l, Etc (1)................................	-	-	5,158,433.52	9,398,666.78	14,557,100.30
Total Fuel (1)..	-	-	5,158,433.52	9,398,666.78	14,557,100.30
Other Operation Expenses	-	-	1,311,462.16	2,579,803.84	3,891,266.00
Maintenance	-	-	1,621,485.26	2,129,437.02	3,750,922.28
Rents	-	-	-	-	-
Total Production Expenses	-	-	8,091,380.94	14,107,907.64	22,199,288.58
Fuel Costs - Cents					
Coal, Incl. Freight	-	-	2.315	2.032	2.123
Coal and Other (1)...	-	-	2.504	2.167	2.276
Total All Fuel Costs (1)..	-	-	2.504	2.167	2.276
Other Operation Expenses..	-	-	0.636	0.595	0.608
Maintenance..	-	-	0.787	0.491	0.586
Rents..	-	-	-	-	-
Total Production Expenses......................................	-	-	3.927	3.253	3.470
Quantities of Fuel Burned:					
Coal - Tons..	-	-	113,648.00	212,919.00	326,567.00
Oil - Gal - Start-up/Stab...................................	-	-	56,821	89,248	146,069
Million BTU Burned:					
Coal..	-	-	2,629,509.04	4,921,536.88	7,551,045.92
Oil - Start-up/Stab..	-	-	7,955.00	12,496.00	20,451.00
Total MMBTU Burned	-	-	2,637,464.04	4,934,032.88	7,571,496.92
Average BTU per Net KWH Output..........................	-	-	12,800	11,378	11,836

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

EW Brown - Steam

	YEAR TO DATE			
	UNIT 1	UNIT 2	UNIT 3	TOTAL
KWH Output				
Net KWH - Coal	480,534,000	956,008,000	2,031,288,000	3,467,830,000
Total KWH Output	480,534,000	956,008,000	2,031,288,000	3,467,830,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight	11,934,970.62	21,373,263.70	46,213,311.03	79,521,545.35
Coal, Inc. Frt, Hand'l, Etc (1)	12,572,599.06	21,768,976.02	47,435,832.43	81,777,407.51
Total Fuel (1)	12,572,599.06	21,768,976.02	47,435,832.43	81,777,407.51
Other Operation Expenses	685,554.25	1,109,623.37	5,904,472.42	7,699,650.04
Maintenance	2,228,747.12	2,274,841.53	5,623,903.15	10,127,491.80
Rents	-	-	-	-
Total Production Expenses	15,486,900.43	25,153,440.92	58,964,208.00	99,604,549.35
Fuel Costs - Cents				
Coal, Incl. Freight	2.484	2.236	2.275	2.293
Coal and Other (1)	2.616	2.277	2.335	2.358
Total All Fuel Costs (1)	2.616	2.277	2.335	2.358
Other Operation Expenses	0.143	0.116	0.291	0.222
Maintenance	0.464	0.238	0.277	0.292
Rents	-	-	-	-
Total Production Expenses	3.223	2.631	2.903	2.872
Quantities of Fuel Burned:				
Coal - Tons	220,177.00	397,613.00	857,446.00	1,475,236.00
Oil - Gal - Start-up/Stab	221,600	35,298	179,363	436,261
Million BTU Burned:				
Coal	5,459,868.27	9,868,251.86	21,239,582.87	36,567,703.00
Oil - Start-up/Stab	31,023.00	4,941.00	25,109.00	61,073.00
Total MMBTU Burned	5,490,891.27	9,873,192.86	21,264,691.87	36,628,776.00
Average BTU per Net KWH Output	11,427	10,328	10,469	10,562

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

GHENT - Steam

	YEAR TO DATE				
	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal..	3,374,404,000	3,013,392,000	2,967,905,000	2,852,022,000	12,207,723,000
Total KWH Output......................................	3,374,404,000	3,013,392,000	2,967,905,000	2,852,022,000	12,207,723,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight..	51,369,577.17	66,608,790.01	76,898,606.60	71,777,921.35	266,654,895.13
Coal, Inc. Frt, Hand'l, Etc (1)................................	52,198,303.58	67,534,233.85	78,223,135.79	73,857,907.66	271,813,580.88
Total Fuel (1)...	52,198,303.58	67,534,233.85	78,223,135.79	73,857,907.66	271,813,580.88
Other Operation Expenses	4,104,944.39	3,187,189.20	3,524,407.43	4,107,477.09	14,924,018.11
Maintenance	7,590,097.26	4,553,437.89	3,892,077.25	4,534,728.77	20,570,341.17
Rents	-	-	-	-	-
Total Production Expenses	63,893,345.23	75,274,860.94	85,639,620.47	82,500,113.52	307,307,940.16
Fuel Costs - Cents					
Coal, Incl. Freight	1.522	2.210	2.591	2.517	2.184
Coal and Other (1)..	1.547	2.241	2.636	2.590	2.227
Total All Fuel Costs (1)..	1.547	2.241	2.636	2.590	2.227
Other Operation Expenses...	0.122	0.106	0.119	0.144	0.122
Maintenance...	0.225	0.151	0.131	0.159	0.169
Rents..	-	-	-	-	-
Total Production Expenses......................................	1.893	2.498	2.886	2.893	2.517
Quantities of Fuel Burned:					
Coal - Tons...	1,495,766.00	1,278,327.00	1,483,378.00	1,382,820.00	5,640,291.00
Oil - Gal - Start-up/Stab....................................	216,430	251,346	436,391	484,747	1,388,914
Million BTU Burned:					
Coal..	35,660,930.77	29,421,479.45	33,934,849.25	31,733,751.24	130,751,010.71
Oil - Start-up/Stab..	30,302.00	35,190.00	61,096.00	67,864.00	194,452.00
Total MMBTU Burned	35,691,232.77	29,456,669.45	33,995,945.25	31,801,615.24	130,945,462.71
Average BTU per Net KWH Output..........................	10,577	9,775	11,455	11,151	10,726

Attachment to Response to Sierra Club Question No. 1.5 (a)(b)(c)

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

	YEAR TO DATE					
Cane Run - Steam	UNITS 1 & 2	UNIT 3	UNIT 4	UNIT 5	UNIT 6	TOTAL
KWH Output						
Net KWH - Coal..	-	-	961,053,000	1,087,296,000	1,530,907,000	3,579,256,000
Production Costs ($)						
Fuel Costs						
Coal, Inc. Freight..	-	-	15,254,683.74	18,057,707.37	24,258,404.32	57,570,795.43
Coal, Inc. Frt, Hand'l, Etc (2).................................	-	-	16,133,180.57	18,830,549.09	25,114,692.51	60,078,422.17
Total Fuel (2)..	-	-	16,133,180.57	18,830,549.09	25,114,692.51	60,078,422.17
Other Operation Expenses	-	-	5,475,463.04	6,593,756.71	9,786,927.75	21,856,147.50
Maintenance	-	-	4,017,006.19	3,294,914.65	5,992,982.91	13,304,903.75
Rents	-	-	13,838.04	15,375.60	22,038.36	51,252.00
Total Production Expenses	-	-	25,639,487.84	28,734,596.05	40,916,641.53	95,290,725.42
Fuel Costs - Cents						
Coal, Incl. Freight (1)	-	-	1.587	1.661	1.585	1.608
Coal and Other (1) (2)..	-	-	1.679	1.732	1.641	1.679
Total All Fuel Costs (2)...	-	-	1.679	1.732	1.641	1.679
Other Operation Expenses...	-	-	0.570	0.606	0.639	0.611
Maintenance...	-	-	0.418	0.303	0.391	0.372
Rents...	-	-	0.001	0.001	0.001	0.001
Total Production Expenses.......................................	-	-	2.668	2.643	2.673	2.662
Quantities of Fuel Burned:						
Coal - Tons...	-	-	444,050.50	525,182.50	707,462.50	1,676,695.50
Gas - MCF - Start-up/Stab....................................	-	-	58,237	42,284	30,908	131,429
Oil - Gallons..	-	-	-	-	-	-
Million BTU Burned:						
Coal...	-	-	10,036,737.05	11,866,560.79	15,984,446.14	37,887,743.98
Gas - Start-up/Stab..	-	-	59,693.00	43,340.50	31,679.50	134,713.00
Oil..	-	-	-	-	-	-
Total MMBTU Burned	-	-	10,096,430.05	11,909,901.29	16,016,125.64	38,022,456.98
Average BTU per Net KWH Output (Heat Rate)	-	-	10,506	10,954	10,462	10,623

(1) Based on KWH generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

Mill Creek - Steam	YEAR TO DATE UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal...	1,975,638,000	2,032,265,000	2,842,591,000	2,954,368,000	9,804,862,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight...	30,777,412.11	32,567,103.27	44,287,775.00	46,070,612.73	153,702,903.11
Coal, Inc. Frt, Hand'l, Etc (2)................................	32,081,562.76	33,551,706.89	46,876,405.33	48,764,594.93	161,274,269.91
Total Fuel (2)...	32,081,562.76	33,551,706.89	46,876,405.33	48,764,594.93	161,274,269.91
Other Operation Expenses	5,099,182.11	4,972,810.09	4,467,589.34	6,326,878.80	20,866,460.34
Maintenance	6,394,163.45	4,278,315.86	5,579,210.36	7,857,245.84	24,108,935.51
Rents	-	-	-	-	-
Total Production Expenses	43,574,908.32	42,802,832.84	56,923,205.03	62,948,719.57	206,249,665.76
Fuel Costs - Cents					
Coal, Incl. Freight (1)	1.558	1.603	1.558	1.559	1.568
Coal and Other (1) (2)...	1.624	1.651	1.649	1.651	1.645
Total All Fuel Costs (2)..	1.624	1.651	1.649	1.651	1.645
Other Operation Expenses...	0.258	0.245	0.157	0.214	0.213
Maintenance...	0.324	0.211	0.196	0.266	0.246
Rents..	-	-	-	-	-
Total Production Expenses.......................................	2.206	2.106	2.003	2.131	2.104
Quantities of Fuel Burned:					
Coal - Tons...	897,848.05	948,347.30	1,288,058.80	1,335,232.40	4,469,486.55
Gas - MCF - Start-up/Stab....................................	52,861	13,491	167,457	156,545	390,354
Oil - Gallons...	-	-	-	-	-
Million BTU Burned:					
Coal..	20,697,482.94	21,866,910.45	29,707,520.23	30,811,465.69	103,083,379.31
Gas - Start-up/Stab..	54,185.00	13,829.00	171,646.00	160,460.00	400,120.00
Oil...	-	-	-	-	-
Total MMBTU Burned	20,751,667.94	21,880,739.45	29,879,166.23	30,971,925.69	103,483,499.31
Average BTU per Net KWH Output (Heat Rate)	10,504	10,767	10,511	10,483	10,554

(1) Based on KWH generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2006

	CURRENT MONTH		YEAR TO DATE		YEAR ENDED CURRENT MONTH	
Trimble County - Steam (3)	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR
Net KWH - LGE..	277,027,000	284,428,600	3,160,653,100	2,886,772,400	3,160,653,100	2,886,772,400
IMEA...	46,225,000	46,160,000	519,678,100	475,819,700	519,678,100	475,819,700
IMPA...	49,121,000	49,056,400	552,253,800	505,962,900	552,253,800	505,962,900
Total KWH Output......................................	372,373,000	379,645,000	4,232,585,000	3,868,555,000	4,232,585,000	3,868,555,000
Production Costs ($)						
Fuel Costs $:						
Coal, Inc. Freight..	5,438,666.89	5,229,091.70	60,256,799.02	53,150,454.22	60,256,799.02	53,150,454.22
Coal, Inc. Frt, Hand'l, Etc (2)..............................	5,556,563.32	5,332,189.83	61,627,384.94	54,505,773.25	61,627,384.94	54,505,773.25
Total Fuel (2)..	5,556,563.32	5,332,189.83	61,627,384.94	54,505,773.25	61,627,384.94	54,505,773.25
Other Operation Expenses $.............................	1,022,771.21	712,381.78	7,895,094.97	7,071,964.72	7,895,094.97	7,071,964.72
Maintenance $..	809,952.88	377,884.44	7,615,910.36	8,224,434.34	7,615,910.36	8,224,434.34
Rents $...	-	-	-	-	-	-
Total Production Expenses $................................	7,389,287.41	6,422,456.05	77,138,390.27	69,802,172.31	77,138,390.27	69,802,172.31
Cost per Net KWH Output-Cents:						
Coal Inc. Freight (1)................................	1.461	1.377	1.424	1.374	1.424	1.374
Coal Inc. Frt, Hand'l, Etc (1) (2)..........................	1.492	1.405	1.456	1.409	1.456	1.409
Total All Fuel Costs (2).....................................	1.492	1.405	1.456	1.409	1.456	1.409
Other Operation Expenses....................................	0.275	0.188	0.187	0.183	0.187	0.183
Maintenance..	0.218	0.100	0.180	0.213	0.180	0.213
Rents..	-	-	-	-	-	-
Total Production Expenses..................................	1.984	1.692	1.822	1.804	1.822	1.804
Quantities of Fuel Burned:						
Coal - Tons..	158,777.00	163,692.50	1,787,705.50	1,645,163.00	1,787,705.50	1,645,163.00
Oil - Gallons..	1,000	6,063	221,998	318,606	221,998	318,606
Million BTU Burned:						
Coal...	3,776,666.66	3,848,679.95	42,456,098.55	38,848,075.73	42,456,098.55	38,848,075.73
Oil...	140.00	849.00	31,080.00	44,606.00	31,080.00	44,606.00
Total...	3,776,806.66	3,849,528.95	42,487,178.55	38,892,681.73	42,487,178.55	38,892,681.73
Average BTU Per Net KWH Output.......................	10,143	10,140	10,038	10,054	10,038	10,054
Average BTU Per pound of Coal.........................	11,893	11,756	11,874	11,807	11,874	11,807
Per Gallon of Oil...................................	140,000	140,030	140,001	140,004	140,001	140,004
Cost Coal & Freight per MBTU (Cents).................	144.007	135.867	141.927	136.816	141.927	136.816
Total All Fuel Cost per MBTU (2).....................	147.123	138.515	145.049	140.144	145.049	140.144
Cost of Coal & Freight Per Ton ($)....................	34.253	31.945	33.706	32.307	33.706	32.307

(1) Based on KWH generated by coal or gas as applicable.
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).
(3) Information on this report represents 100% generation, quantities used, and costs.

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

TYRONE - Steam

	YEAR TO DATE			
	UNIT 1	UNIT 2	UNIT 3	TOTAL
KWH Output				
Net KWH - Coal	-	-	390,188,000	390,188,000
Net KWH - Oil	(192,000)	(193,000)	-	(385,000)
Total KWH Output	(192,000)	(193,000)	390,188,000	389,803,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight	-	-	13,790,037.67	13,790,037.67
Coal, Inc. Frt, Hand'l, Etc (2)	63,840.76	69,644.56	14,864,979.39	14,998,464.71
Total Fuel (2)	63,840.76	69,644.56	14,864,979.39	14,998,464.71
Other Operation Expenses	209,923.17	229,105.64	1,417,482.76	1,856,511.57
Maintenance	110,754.62	121,716.97	1,502,624.81	1,735,096.40
Total Production Expenses	384,518.55	420,467.17	17,785,086.96	18,590,072.68
Fuel Costs - Cents				
Coal, Incl. Freight (1)	-	-	3.534	3.534
Coal and Other (1) (2)	-	-	3.810	3.844
Total All Fuel Costs (2)	(33.250)	(36.085)	3.810	3.848
Other Operation Expenses	(109.335)	(118.708)	0.363	0.476
Maintenance	(57.685)	(63.066)	0.385	0.445
Total Production Expenses	(200.270)	(217.859)	4.558	4.769
Quantities of Fuel Burned:				
Coal - Tons	-	-	199,025.85	199,025.85
Oil - Gal - Start-up/Stab	-	-	135,388	135,388
Million BTU Burned:				
Coal	-	-	5,038,538.73	5,038,538.73
Oil - Start-up/Stab	-	-	18,954.32	18,954.32
Total MMBTU Burned	-	-	5,057,493.05	5,057,493.05
Average BTU per Net KWH Output	-	-	12,962	12,974

Attachment to Response to Sierra Club Question No. 1.5 (a)(b)(c)

Schram

(1) Based on KWH generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

GREEN RIVER - Steam

	YEAR TO DATE		
	UNIT 3	UNIT 4	TOTAL
KWH Output			
Net KWH - Coal..	420,678,000	576,042,000	996,720,000
Total KWH Output.......................................	420,678,000	576,042,000	996,720,000
Production Costs ($)			
Fuel Costs			
Coal, Inc. Freight..	9,501,562.12	11,661,885.09	21,163,447.21
Coal, Inc. Frt, Hand'l, Etc (1).................................	9,837,599.26	12,131,651.41	21,969,250.67
Total Fuel (1)...	9,837,599.26	12,131,651.41	21,969,250.67
Other Operation Expenses	1,697,002.70	2,211,679.83	3,908,682.53
Maintenance	1,671,935.41	3,062,604.38	4,734,539.79
Total Production Expenses	13,206,537.37	17,405,935.62	30,612,472.99
Fuel Costs - Cents			
Coal, Incl. Freight	2.259	2.024	2.123
Coal and Other (1)...	2.339	2.106	2.204
Total All Fuel Costs (1)..	2.339	2.106	2.204
Other Operation Expenses...	0.403	0.384	0.392
Maintenance..	0.397	0.532	0.475
Total Production Expenses.......................................	3.139	3.022	3.071
Quantities of Fuel Burned:			
Coal - Tons..	218,165.00	266,289.00	484,454.00
Oil - Gal - Start-up/Stab....................................	62,416	78,776	141,192
Million BTU Burned:			
Coal..	5,241,798.29	6,380,919.56	11,622,717.85
Oil - Start-up/Stab...	8,738.24	11,028.64	19,766.88
Total MMBTU Burned	5,250,536.53	6,391,948.20	11,642,484.73
Average BTU per Net KWH Output..........................	12,481	11,096	11,681

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

EW Brown - Steam

	YEAR TO DATE			
	UNIT 1	UNIT 2	UNIT 3	TOTAL
KWH Output				
Net KWH - Coal..	493,483,000	1,013,933,000	2,396,909,000	3,904,325,000
Total KWH Output......................................	493,483,000	1,013,933,000	2,396,909,000	3,904,325,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight...	12,809,959.73	24,316,349.02	57,051,160.69	94,177,469.44
Coal, Inc. Frt, Hand'l, Etc (1)................................	13,399,655.08	24,792,881.97	58,358,986.36	96,551,523.41
Total Fuel (1)..	13,399,655.08	24,792,881.97	58,358,986.36	96,551,523.41
Other Operation Expenses	614,156.70	1,043,683.56	6,077,536.39	7,735,376.65
Maintenance	5,148,693.19	2,159,281.59	5,810,625.67	13,118,600.45
Total Production Expenses	19,162,504.97	27,995,847.12	70,247,148.42	117,405,500.51
Fuel Costs - Cents				
Coal, Incl. Freight	2.596	2.398	2.380	2.412
Coal and Other (1)	2.715	2.445	2.435	2.473
Total All Fuel Costs (1)..	2.715	2.445	2.435	2.473
Other Operation Expenses..	0.124	0.103	0.254	0.198
Maintenance..	1.043	0.213	0.242	0.336
Total Production Expenses......................................	3.883	2.761	2.931	3.007
Quantities of Fuel Burned:				
Coal - Tons..	224,065.00	428,237.00	1,005,580.00	1,657,882.00
Oil - Gal - Start-up/Stab...................................	156,586	48,979	174,780	380,345
Million BTU Burned:				
Coal...	5,492,004.69	10,498,526.02	24,638,305.01	40,628,835.72
Oil - Start-up/Stab...	21,922.04	6,857.06	24,469.20	53,248.30
Total MMBTU Burned	5,513,926.73	10,505,383.08	24,662,774.21	40,682,084.02
Average BTU per Net KWH Output..........................	11,173	10,361	10,289	10,420

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

KENTUCKY UTILITIES COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

GHENT - Steam

	YEAR TO DATE				
	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal...	2,915,043,000	3,454,216,000	2,358,308,000	3,232,661,000	11,960,228,000
Total KWH Output.......................................	2,915,043,000	3,454,216,000	2,358,308,000	3,232,661,000	11,960,228,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight..	47,321,308.53	85,089,854.45	46,128,546.84	84,047,848.21	262,587,558.03
Coal, Inc. Frt, Hand'l, Etc (1).................................	48,475,316.80	86,313,019.08	48,149,108.94	86,070,631.21	269,008,076.03
Total Fuel (1)...	48,475,316.80	86,313,019.08	48,149,108.94	86,070,631.21	269,008,076.03
Other Operation Expenses	4,277,978.12	3,599,055.59	3,687,607.76	4,296,339.09	15,860,980.56
Maintenance	12,751,666.25	4,748,583.37	7,342,430.36	4,580,933.63	29,423,613.61
Total Production Expenses	65,504,961.17	94,660,658.04	59,179,147.06	94,947,903.93	314,292,670.20
Fuel Costs - Cents					
Coal, Incl. Freight	1.623	2.463	1.956	2.600	2.196
Coal and Other (1)..	1.663	2.499	2.042	2.663	2.249
Total All Fuel Costs (1)..	1.663	2.499	2.042	2.663	2.249
Other Operation Expenses...	0.147	0.104	0.156	0.133	0.133
Maintenance...	0.437	0.137	0.311	0.142	0.246
Total Production Expenses......................................	2.247	2.740	2.509	2.937	2.628
Quantities of Fuel Burned:					
Coal - Tons...	1,316,642.00	1,448,552.00	1,108,471.00	1,431,096.00	5,304,761.00
Oil - Gal - Start-up/Stab....................................	298,637	329,928	711,004	408,296	1,747,865
Million BTU Burned:					
Coal..	31,118,913.48	34,960,432.85	26,006,225.88	34,572,753.84	126,658,326.05
Oil - Start-up/Stab..	41,809.18	46,189.92	99,540.56	57,161.44	244,701.10
Total MMBTU Burned	31,160,722.66	35,006,622.77	26,105,766.44	34,629,915.28	126,903,027.15
Average BTU per Net KWH Output..........................	10,690	10,134	11,070	10,713	10,610

(1) Also includes oil used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

	YEAR TO DATE			
Cane Run - Steam	UNIT 4	UNIT 5	UNIT 6	TOTAL
KWH Output				
Net KWH - Coal..	1,105,274,000	1,043,893,000	1,395,319,000	3,544,486,000
Production Costs ($)				
Fuel Costs				
Coal, Inc. Freight..	18,183,020.14	17,715,100.58	22,453,024.43	58,351,145.15
Coal, Inc. Frt, Hand'l, Etc (2)................................	19,028,166.24	18,489,572.84	23,472,491.61	60,990,230.69
Total Fuel (2)...	19,028,166.24	18,489,572.84	23,472,491.61	60,990,230.69
Other Operation Expenses	5,918,298.20	5,959,356.85	9,376,682.61	21,254,337.66
Maintenance	2,978,076.13	3,540,096.07	6,390,793.01	12,908,965.21
Rents	13,838.04	15,375.60	22,038.36	51,252.00
Total Production Expenses	27,938,378.61	28,004,401.36	39,262,005.59	95,204,785.56
Fuel Costs - Cents				
Coal, Incl. Freight (1)	1.645	1.697	1.609	1.646
Coal and Other (1) (2)...	1.722	1.771	1.682	1.721
Total All Fuel Costs (2)..	1.722	1.771	1.682	1.721
Other Operation Expenses...	0.535	0.571	0.672	0.600
Maintenance...	0.269	0.339	0.458	0.364
Rents...	0.001	0.001	0.002	0.001
Total Production Expenses......................................	2.528	2.683	2.814	2.686
Quantities of Fuel Burned:				
Coal - Tons...	520,726.00	507,214.70	642,267.90	1,670,208.60
Gas - MCF - Start-up/Stab...................................	59,449	46,805	56,446	162,700
Oil - Gallons...	-	-	-	-
Million BTU Burned:				
Coal..	11,666,199.15	11,363,888.80	14,387,745.39	37,417,833.34
Gas - Start-up/Stab..	60,934.00	47,975.00	57,857.00	166,766.00
Oil...	-	-	-	-
Total MMBTU Burned	11,727,133.15	11,411,863.80	14,445,602.39	37,584,599.34
Average BTU per Net KWH Output (Heat Rate)	10,610	10,932	10,353	10,604

(1) Based on KWH generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

	YEAR TO DATE				
Mill Creek - Steam	UNIT 1	UNIT 2	UNIT 3	UNIT 4	TOTAL
KWH Output					
Net KWH - Coal...	2,163,431,000	1,944,646,000	2,805,103,000	3,584,949,000	10,498,129,000
Production Costs ($)					
Fuel Costs					
Coal, Inc. Freight..	35,309,144.72	32,383,914.26	46,325,747.38	59,850,870.59	173,869,676.95
Coal, Inc. Frt, Hand'l, Etc (2).................................	36,618,254.10	33,545,522.34	48,531,019.51	62,681,254.42	181,376,050.37
Total Fuel (2)...	36,618,254.10	33,545,522.34	48,531,019.51	62,681,254.42	181,376,050.37
Other Operation Expenses	4,767,229.16	4,316,394.81	3,452,950.89	5,737,552.33	18,274,127.19
Maintenance	4,596,866.02	5,879,180.38	6,869,390.20	6,386,633.26	23,732,069.86
Total Production Expenses	45,982,349.28	43,741,097.53	58,853,360.60	74,805,440.01	223,382,247.42
Fuel Costs - Cents					
Coal, Incl. Freight (1)	1.632	1.665	1.651	1.670	1.656
Coal and Other (1) (2)...	1.693	1.725	1.730	1.748	1.728
Total All Fuel Costs (2)..	1.693	1.725	1.730	1.748	1.728
Other Operation Expenses...	0.220	0.222	0.123	0.160	0.174
Maintenance...	0.212	0.302	0.245	0.178	0.226
Total Production Expenses.......................................	2.125	2.249	2.098	2.087	2.128
Quantities of Fuel Burned:					
Coal - Tons...	978,943.60	897,662.25	1,283,412.00	1,658,997.85	4,819,015.70
Gas - MCF - Start-up/Stab....................................	30,832	10,971	101,080	144,216	287,099
Oil - Gallons..	-	-	-	-	-
Million BTU Burned:					
Coal..	22,564,556.17	20,692,578.70	29,584,917.26	38,249,835.06	111,091,887.19
Gas - Start-up/Stab...	31,602.00	11,247.00	103,606.00	147,822.00	294,277.00
Oil..	-	-	-	-	-
Total MMBTU Burned	22,596,158.17	20,703,825.70	29,688,523.26	38,397,657.06	111,386,164.19
Average BTU per Net KWH Output (Heat Rate)	10,445	10,647	10,584	10,711	10,610

(1) Based on KWH generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC GENERATING COSTS AND FUEL PERFORMANCE
DECEMBER 31, 2007

	CURRENT MONTH		YEAR TO DATE		YEAR ENDED CURRENT MONTH	
Trimble County - Steam (3)	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR	THIS YEAR	LAST YEAR
Net KWH - LGE..	267,657,000	277,027,000	2,708,402,000	3,160,653,100	2,708,402,000	3,160,653,100
IMEA..	44,164,000	46,225,000	449,962,000	519,678,100	449,962,000	519,678,100
IMPA..	47,128,000	49,121,000	477,581,000	552,253,800	477,581,000	552,253,800
Total KWH Output.....................................	358,949,000	372,373,000	3,635,945,000	4,232,585,000	3,635,945,000	4,232,585,000
Production Costs ($)						
Fuel Costs $:						
Coal, Inc. Freight..	5,696,978.91	5,438,666.89	55,626,485.33	60,256,799.02	55,626,485.33	60,256,799.02
Coal, Inc. Frt, Hand'l, Etc (2)..............................	5,886,599.67	5,556,563.32	57,421,989.26	61,627,384.94	57,421,989.26	61,627,384.94
Total Fuel (2)..	5,886,599.67	5,556,563.32	57,421,989.26	61,627,384.94	57,421,989.26	61,627,384.94
Other Operation Expenses $.............................	739,181.15	1,022,771.21	8,160,819.79	7,895,094.97	8,160,819.79	7,895,094.97
Maintenance $..	1,209,104.76	809,952.88	11,066,335.82	7,615,910.36	11,066,335.82	7,615,910.36
Total Production Expenses $................................	7,834,885.58	7,389,287.41	76,649,144.87	77,138,390.27	76,649,144.87	77,138,390.27
Cost per Net KWH Output-Cents:						
Coal Inc. Freight (1)................................	1.587	1.461	1.530	1.424	1.530	1.424
Coal Inc. Frt, Hand'l, Etc (1) (2)..........................	1.640	1.492	1.579	1.456	1.579	1.456
Total All Fuel Costs (2)....................................	1.640	1.492	1.579	1.456	1.579	1.456
Other Operation Expenses....................................	0.206	0.275	0.224	0.187	0.224	0.187
Maintenance..	0.337	0.218	0.304	0.180	0.304	0.180
Total Production Expenses.................................	2.183	1.984	2.108	1.822	2.108	1.822
Quantities of Fuel Burned:						
Coal - Tons..	157,436.64	158,777.00	1,553,094.19	1,787,705.50	1,553,094.19	1,787,705.50
Oil - Gallons..	34,054	1,000	366,367	221,998	366,367	221,998
Million BTU Burned:						
Coal..	3,714,534.91	3,776,666.66	37,034,130.12	42,456,098.55	37,034,130.12	42,456,098.55
Oil..	4,767.56	140.00	51,291.38	31,080.00	51,291.38	31,080.00
Total..	3,719,302.47	3,776,806.66	37,085,421.50	42,487,178.55	37,085,421.50	42,487,178.55
Average BTU Per Net KWH Output.......................	10,362	10,143	10,200	10,038	10,200	10,038
Average BTU Per pound of Coal........................	11,797	11,893	11,923	11,874	11,923	11,874
Per Gallon of Oil....................................	140,000	140,000	140,000	140,001	140,000	140,001
Cost Coal & Freight per MBTU (Cents).................	153.370	144.007	150.203	141.927	150.203	141.927
Total All Fuel Cost per MBTU (2)......................	158.272	147.123	154.837	145.049	154.837	145.049
Cost of Coal & Freight Per Ton ($)...................	36.186	34.253	35.817	33.706	35.817	33.706

(1) Based on KWH generated by coal or gas as applicable.
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net).
(3) Information on this report represents 100% generation, quantities used, and costs.

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2008

Tyrone - Steam

	Year to Date			
	Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal..	-	-	355,632,000	355,632,000
Net Kwh - Oil..	-	-	-	-
Total Kwh Output...	-	-	355,632,000	355,632,000
Production Costs ($)				
Fuel Costs				
Coal, Including Freight...	-	-	12,788,947.49	12,788,947.49
Coal, Including Freight, Handling, Etc (2)...........................	-	-	14,287,470.49	14,287,470.49
Total Fuel (2)..	-	-	14,287,470.49	14,287,470.49
Other Operation Expenses	-	-	1,955,523.61	1,955,523.61
Maintenance	1,886.77	2,738.85	1,674,853.00	1,679,478.62
Total Production Expenses	1,886.77	2,738.85	17,917,847.10	17,922,472.72
Cost per Net Kwh Output-Cents:				
Coal, Including Freight (1)	-	-	3.596	3.596
Coal Including Freight, Handling, Etc (1) (2).......................	-	-	4.017	4.017
Total All Fuel Costs (2)..	-	-	4.017	4.017
Other Operation Expenses..	-	-	0.550	0.550
Maintenance..	-	-	0.472	0.472
Total Production Expenses......................................	-	-	5.039	5.039
Quantities of Fuel Burned:				
Coal - Tons..	-	-	176,178.39	176,178.39
Oil - Gallons - Start-up/Stabilization..................................	-	-	184,970.00	184,970.00
MMBtu Burned:				
Coal...	-	-	4,479,233.87	4,479,233.87
Oil - Start-up/Stabilization..	-	-	25,895.80	25,895.80
Total MMBtu Burned	-	-	4,505,129.67	4,505,129.67
Average Btu per Net Kwh Output...	-	-	12,668	12,668

(1) Based on Kwh generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of ashes and fly ash (net)

January 22, 2009

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2008

Green River - Steam

	Year to Date		
	Unit 3	Unit 4	Total
Kwh Output			
Net Kwh - Coal...	379,545,000	582,590,000	962,135,000
Total Kwh Output.......................................	379,545,000	582,590,000	962,135,000
Production Costs ($)			
Fuel Costs			
Coal, Including Freight..	10,042,635.69	14,266,042.69	24,308,678.38
Coal, Including Freight, Handling, Etc (1)............................	10,705,324.64	15,215,312.41	25,920,637.05
Total Fuel (1)...	10,705,324.64	15,215,312.41	25,920,637.05
Other Operation Expenses	1,472,139.97	2,269,590.45	3,741,730.42
Maintenance	2,095,419.06	2,312,233.38	4,407,652.44
Total Production Expenses	14,272,883.67	19,797,136.24	34,070,019.91
Cost per Net Kwh Output-Cents:			
Coal, Including Freight	2.646	2.449	2.527
Coal Including Freight, Handling, Etc (1)..............................	2.821	2.612	2.694
Total All Fuel Costs (1)..	2.821	2.612	2.694
Other Operation Expenses...	0.388	0.390	0.389
Maintenance...	0.552	0.397	0.458
Total Production Expenses.......................................	3.761	3.399	3.541
Quantities of Fuel Burned:			
Coal - Tons...	193,206.00	274,949.00	468,155.00
Oil - Gallons - Start-up/Stabilization...................................	69,753.50	90,719.50	160,473.00
MMBtu Burned:			
Coal..	4,534,743.81	6,453,083.57	10,987,827.38
Oil - Start-up/Stabilization..	9,765.49	12,700.73	22,466.22
Total MMBtu Burned	4,544,509.30	6,465,784.30	11,010,293.60
Average Btu per Net Kwh Output...	11,974	11,098	11,444

(1) Also includes oil used for firing, disposal of ashes and fly ash (net)

January 22, 2009

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2008

EW Brown - Steam

	Year to Date Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal...	513,921,000	1,074,881,000	2,534,659,000	4,123,461,000
Total Kwh Output..	513,921,000	1,074,881,000	2,534,659,000	4,123,461,000
Production Costs ($)				
Fuel Costs				
Coal, Including Freight...	14,892,563.87	28,929,864.37	68,776,133.70	112,598,561.94
Coal, Including Freight, Handling, Etc (1)............................	15,611,072.83	29,723,818.32	70,132,892.00	115,467,783.15
Total Fuel (1)..	15,611,072.83	29,723,818.32	70,132,892.00	115,467,783.15
Other Operation Expenses	978,237.58	1,794,614.64	4,383,855.16	7,156,707.38
Maintenance	2,874,450.20	2,853,362.49	6,364,793.62	12,092,606.31
Total Production Expenses	19,463,760.61	34,371,795.45	80,881,540.78	134,717,096.84
Cost per Net Kwh Output-Cents:				
Coal, Including Freight	2.898	2.691	2.713	2.731
Coal Including Freight, Handling, Etc (1)..............................	3.038	2.765	2.767	2.800
Total All Fuel Costs (1)..	3.038	2.765	2.767	2.800
Other Operation Expenses...	0.190	0.167	0.173	0.174
Maintenance..	0.559	0.265	0.251	0.293
Total Production Expenses.......................................	3.787	3.197	3.191	3.267
Quantities of Fuel Burned:				
Coal - Tons..	237,034.00	460,588.00	1,090,176.00	1,787,798.00
Oil - Gallons - Start-up/Stabilization..................................	159,840.00	135,279.00	119,412.00	414,531.00
MMBtu Burned:				
Coal..	5,737,708.79	11,149,847.29	26,382,669.08	43,270,225.16
Oil - Start-up/Stabilization..	22,377.60	18,939.06	16,717.68	58,034.34
Total MMBtu Burned	5,760,086.39	11,168,786.35	26,399,386.76	43,328,259.50
Average Btu per Net Kwh Output...	11,208	10,391	10,415	10,508

(1) Also includes oil used for firing, disposal of ashes and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2008

Ghent - Steam

	Year to Date				
	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal...	3,598,899,000	2,804,097,000	3,262,152,000	2,840,532,000	12,505,680,000
Total Kwh Output..	3,598,899,000	2,804,097,000	3,262,152,000	2,840,532,000	12,505,680,000
Production Costs ($)					
Fuel Costs					
Coal, Including Freight...	72,698,475.31	90,378,388.75	68,705,438.35	72,048,015.41	303,830,317.82
Coal, Including Freight, Handling, Etc (1)............................	74,045,372.25	92,323,278.03	71,190,434.66	75,083,522.10	312,642,607.04
Total Fuel (1)..	74,045,372.25	92,323,278.03	71,190,434.66	75,083,522.10	312,642,607.04
Other Operation Expenses	5,483,438.95	2,974,160.94	6,471,556.67	5,420,352.51	20,349,509.07
Maintenance	6,199,458.50	7,088,861.06	6,157,132.79	9,940,734.89	29,386,187.24
Total Production Expenses	85,728,269.70	102,386,300.03	83,819,124.12	90,444,609.50	362,378,303.35
Cost per Net Kwh Output-Cents:					
Coal, Including Freight	2.020	3.223	2.106	2.536	2.430
Coal Including Freight, Handling, Etc (1)..............................	2.057	3.292	2.182	2.643	2.500
Total All Fuel Costs (1)..	2.057	3.292	2.182	2.643	2.500
Other Operation Expenses...	0.152	0.106	0.198	0.191	0.163
Maintenance...	0.172	0.253	0.189	0.350	0.235
Total Production Expenses......................................	2.381	3.651	2.569	3.184	2.898
Quantities of Fuel Burned:					
Coal - Tons...	1,638,782.00	1,202,574.00	1,547,730.00	1,316,066.00	5,705,152.00
Oil - Gallons - Start-up/Stabilization...................................	269,898.00	436,861.00	611,246.00	545,170.00	1,863,175.00
MMBtu Burned:					
Coal..	38,270,583.12	29,115,821.10	36,146,218.69	31,060,626.11	134,593,249.02
Oil - Start-up/Stabilization..	37,785.72	61,160.54	85,574.44	76,323.80	260,844.50
Total MMBtu Burned	38,308,368.84	29,176,981.64	36,231,793.13	31,136,949.91	134,854,093.52
Average Btu per Net Kwh Output...	10,644	10,405	11,107	10,962	10,783

(1) Also includes oil used for firing, disposal of ashes and fly ash (net)

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2008

Cane Run - Steam	Year to Date			
	Unit 4	Unit 5	Unit 6	Total
Kwh Output				
Net Kwh - Coal..	1,044,031,000	886,232,000	1,482,371,000	3,412,634,000
Production Costs ($)				
Fuel Costs				
Coal, Including Freight...	19,759,867.14	16,108,840.91	27,484,594.75	63,353,302.80
Coal, Including Freight, Handling, Etc (2)............................	21,154,036.12	17,183,233.75	29,081,915.56	67,419,185.43
Total Fuel (2)...	21,154,036.12	17,183,233.75	29,081,915.56	67,419,185.43
Other Operation Expenses	7,224,508.07	6,668,424.44	12,762,871.19	26,655,803.70
Maintenance	4,173,053.16	6,954,246.17	5,718,941.53	16,846,240.86
Rents	4,612.68	5,125.20	7,346.12	17,084.00
Total Production Expenses	32,556,210.03	30,811,029.56	47,571,074.40	110,938,313.99
Fuel Costs - Cents				
Coal, Including Freight (1)	1.893	1.818	1.854	1.856
Coal and Other (1) (2)...	2.026	1.939	1.962	1.976
Total All Fuel Costs (2)..	2.026	1.939	1.962	1.976
Other Operation Expenses...	0.692	0.752	0.861	0.781
Maintenance...	0.400	0.785	0.386	0.494
Rents...	-	0.001	-	0.001
Total Production Expenses......................................	3.118	3.477	3.209	3.252
Quantities of Fuel Burned:				
Coal - Tons...	501,955.45	416,929.37	700,608.58	1,619,493.40
Gas - Mcf - Start-up/Stabilization................................	51,223.00	36,516.00	64,995.00	152,734.00
Oil - Gallons - Start-up/Stabilization..................................	-	-	-	-
MMBtu Burned:				
Coal..	11,181,616.20	9,273,219.07	15,602,539.10	36,057,374.37
Gas - Start-up/Stabilization..	52,504.00	37,429.00	66,622.00	156,555.00
Oil - Start-up/Stabilization..	-	-	-	-
Total MMBtu Burned	11,234,120.20	9,310,648.07	15,669,161.10	36,213,929.37
Average Btu per Net Kwh Output (Heat Rate)	10,760	10,506	10,570	10,612

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net)

January 22, 2009

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2008

Mill Creek - Steam	Year to Date				
	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	1,994,139,000	2,083,269,000	3,002,860,000	3,335,864,000	10,416,132,000
Production Costs ($)					
Fuel Costs					
Coal, Including Freight..	35,383,612.06	37,372,206.25	52,883,771.43	57,822,956.79	183,462,546.53
Coal, Including Freight, Handling, Etc (2).............................	37,730,819.41	39,153,226.19	56,418,415.05	62,938,622.31	196,241,082.96
Total Fuel (2)..	37,730,819.41	39,153,226.19	56,418,415.05	62,938,622.31	196,241,082.96
Other Operation Expenses	5,312,620.67	5,024,114.65	4,684,588.91	7,398,166.10	22,419,490.33
Maintenance	6,915,053.94	3,678,889.74	5,828,763.62	9,575,443.96	25,998,151.26
Total Production Expenses	49,958,494.02	47,856,230.58	66,931,767.58	79,912,232.37	244,658,724.55
Fuel Costs - Cents					
Coal, Including Freight (1)	1.774	1.794	1.761	1.733	1.761
Coal and Other (1) (2)...	1.892	1.879	1.879	1.887	1.884
Total All Fuel Costs (2)..	1.892	1.879	1.879	1.887	1.884
Other Operation Expenses...	0.266	0.241	0.156	0.222	0.215
Maintenance...	0.347	0.177	0.194	0.287	0.250
Total Production Expenses......................................	2.505	2.297	2.229	2.396	2.349
Quantities of Fuel Burned:					
Coal - Tons...	926,296.85	985,386.30	1,389,177.95	1,518,150.70	4,819,011.80
Gas - Mcf - Start-up/Stabilization................................	59,349.00	19,119.00	109,601.00	191,198.00	379,267.00
Oil - Gallons - Start-up/Stabilization....................................	-	-	-	-	-
MMBtu Burned:					
Coal..	21,108,342.48	22,462,932.31	31,662,153.13	34,632,640.39	109,866,068.31
Gas - Start-up/Stabilization..	60,833.00	19,599.00	112,341.00	195,979.00	388,752.00
Oil - Start-up/Stabilization..	-	-	-	-	-
Total MMBtu Burned	21,169,175.48	22,482,531.31	31,774,494.13	34,828,619.39	110,254,820.31
Average Btu per Net Kwh Output (Heat Rate)	10,616	10,792	10,581	10,441	10,585

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net)

January 22, 2009

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2008

Trimble County - Steam (3)	Current Month		Year to Date		Year Ended Current Month	
	This Year	Last Year	This Year	Last Year	This Year	Last Year
Net Kwh - LGE	245,994,000	267,657,000	3,058,244,000	2,708,402,000	3,058,244,000	2,708,402,000
IMEA	38,793,000	44,164,000	515,584,000	449,962,000	515,584,000	449,962,000
IMPA	41,161,000	47,128,000	547,951,000	477,581,000	547,951,000	477,581,000
Total Kwh Output	325,948,000	358,949,000	4,121,779,000	3,635,945,000	4,121,779,000	3,635,945,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight	7,116,583.81	5,696,978.91	76,969,574.84	55,626,485.33	76,969,574.84	55,626,485.33
Coal, Including Freight, Handling, Etc (2)	7,430,261.46	5,886,599.67	78,852,262.31	57,421,989.26	78,852,262.31	57,421,989.26
Total Fuel (2)	7,430,261.46	5,886,599.67	78,852,262.31	57,421,989.26	78,852,262.31	57,421,989.26
Other Operation Expenses	974,707.40	739,181.15	10,107,060.57	8,160,819.79	10,107,060.57	8,160,819.79
Maintenance	1,408,787.04	1,209,104.76	10,151,818.88	11,066,335.82	10,151,818.88	11,066,335.82
Total Production Expenses	9,813,755.90	7,834,885.58	99,111,141.76	76,649,144.87	99,111,141.76	76,649,144.87
Cost per Net Kwh Output-Cents:						
Coal Including. Freight (1)	2.183	1.587	1.867	1.530	1.867	1.530
Coal Including Freight, Handling, Etc (1) (2)	2.280	1.640	1.913	1.579	1.913	1.579
Total All Fuel Costs (2)	2.280	1.640	1.913	1.579	1.913	1.579
Other Operation Expenses	0.299	0.206	0.245	0.224	0.245	0.224
Maintenance	0.432	0.337	0.246	0.304	0.246	0.304
Total Production Expenses	3.011	2.183	2.404	2.107	2.404	2.107
Quantities of Fuel Burned:						
Coal - Tons	146,210.00	157,436.64	1,813,014.85	1,553,094.19	1,813,014.85	1,553,094.19
Oil - Gallons - Start-up/Stabilization	66,095.00	34,054.00	241,086.00	366,367.00	241,086.00	366,367.00
MMBtu Burned:						
Coal	3,345,981.30	3,714,534.91	42,196,914.98	37,034,130.12	42,196,914.98	37,034,130.12
Oil - Start-up/Stabilization	9,253.30	4,767.56	33,752.04	51,291.38	33,752.04	51,291.38
Total MMBtu Burned	3,355,234.60	3,719,302.47	42,230,667.02	37,085,421.50	42,230,667.02	37,085,421.50
Average Btu per Net Kwh Output	10,294	10,362	10,246	10,200	10,246	10,200
Average Btu per Pound of Coal	11,442	11,797	11,637	11,923	11,637	11,923
Average Btu per Gallon of Oil	140,000	140,000	140,000	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)	212.690	153.370	182.406	150.203	182.406	150.203
Total All Fuel Cost per MMBtu (2)	221.453	158.272	186.718	154.837	186.718	154.837
Cost of Coal & Freight per Ton ($)	48.674	36.186	42.454	35.817	42.454	35.817

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net)
(3) Information on this report represents 100% generation, quantities used, and costs

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2009

Tyrone - Steam	Year to Date Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal..	-	-	23,524,000	23,524,000
Net Kwh - Oil...	-	-	-	-
Total Kwh Output..	-	-	23,524,000	23,524,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight...	-	-	940,115.51	940,115.51
Coal, Including Freight, Handling, Etc (2)..............................	-	-	1,131,201.90	1,131,201.90
Total Fuel (2)..	-	-	1,131,201.90	1,131,201.90
Other Operation Expenses	-	-	876,873.64	876,873.64
Maintenance	-	323.47	349,820.93	350,144.40
Total Production Expenses	-	323.47	2,357,896.47	2,358,219.94
Cost per Net Kwh Output-Cents:				
Coal, Including Freight (1)	-	-	3.996	3.996
Coal Including Freight, Handling, Etc (1) (2).......................	-	-	4.809	4.809
Total All Fuel Costs (2)..	-	-	4.809	4.809
Other Operation Expenses..	-	-	3.728	3.728
Maintenance..	-	-	1.487	1.488
Total Production Expenses......................................	-	-	10.024	10.025
Quantities of Fuel Burned:				
Coal - Tons...	-	-	12,091.58	12,091.58
Oil - Gallons - Start-up/Stabilization....................................	-	-	22,296.00	22,296.00
MMBtu Burned:				
Coal..	-	-	309,478.50	309,478.50
Oil - Start-up/Stabilization..	-	-	3,121.44	3,121.44
Total MMBtu Burned	-	-	312,599.94	312,599.94
Average Btu per Net Kwh Output (Heat Rate).........................	-	-	13,289	13,289

(1) Based on Kwh generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of ashes and fly ash (net)

January 25, 2010

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2009

Green River - Steam	Year to Date Unit 3	Unit 4	Total
Kwh Output			
Net Kwh - Coal..	216,614,000	408,847,000	625,461,000
Total Kwh Output......................................	216,614,000	408,847,000	625,461,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight...	6,682,764.91	11,856,086.11	18,538,851.02
Coal, Including Freight, Handling, Etc (1)...........................	7,240,291.89	12,708,857.52	19,949,149.41
Total Fuel (1)..	7,240,291.89	12,708,857.52	19,949,149.41
Other Operation Expenses	1,462,179.63	2,486,068.87	3,948,248.50
Maintenance	2,000,821.33	3,714,277.35	5,715,098.68
Total Production Expenses	10,703,292.85	18,909,203.74	29,612,496.59
Cost per Net Kwh Output-Cents:			
Coal, Including Freight	3.085	2.900	2.964
Coal Including Freight, Handling, Etc (1)..............................	3.342	3.108	3.190
Total All Fuel Costs (1)..	3.342	3.108	3.190
Other Operation Expenses..	0.675	0.608	0.631
Maintenance...	0.924	0.908	0.914
Total Production Expenses......................................	4.941	4.624	4.735
Quantities of Fuel Burned:			
Coal - Tons...	108,979.00	194,126.00	303,105.00
Oil - Gallons - Start-up/Stabilization..................................	82,215.00	129,961.00	212,176.00
MMBtu Burned:			
Coal..	2,553,385.22	4,546,751.94	7,100,137.16
Oil - Start-up/Stabilization..	11,510.10	18,194.54	29,704.64
Total MMBtu Burned	2,564,895.32	4,564,946.48	7,129,841.80
Average Btu per Net Kwh Output...	11,841	11,165	11,399

(1) Also includes oil used for firing, disposal of ashes and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2009

EW Brown - Steam	Year to Date Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal...	217,008,000	547,458,000	1,740,829,000	2,505,295,000
Total Kwh Output..	217,008,000	547,458,000	1,740,829,000	2,505,295,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight...	7,967,225.02	18,098,625.23	58,457,231.99	84,523,082.24
Coal, Including Freight, Handling, Etc (1)............................	8,552,903.80	18,947,664.47	59,958,770.20	87,459,338.47
Total Fuel (1)...	8,552,903.80	18,947,664.47	59,958,770.20	87,459,338.47
Other Operation Expenses	888,857.93	1,746,377.38	4,866,017.06	7,501,252.37
Maintenance	2,312,405.47	6,023,566.07	7,300,240.79	15,636,212.33
Total Production Expenses	11,754,167.20	26,717,607.92	72,125,028.05	110,596,803.17
Cost per Net Kwh Output-Cents:				
Coal, Including Freight	3.671	3.306	3.358	3.374
Coal Including Freight, Handling, Etc (1)..............................	3.941	3.461	3.444	3.491
Total All Fuel Costs (1)..	3.941	3.461	3.444	3.491
Other Operation Expenses..	0.410	0.319	0.280	0.299
Maintenance..	1.066	1.100	0.419	0.624
Total Production Expenses......................................	5.417	4.880	4.143	4.414
Quantities of Fuel Burned:				
Coal - Tons..	103,543.00	234,006.00	755,102.00	1,092,651.00
Oil - Gallons - Start-up/Stabilization..................................	130,637.00	170,311.00	176,350.00	477,298.00
MMBtu Burned:				
Coal..	2,516,670.71	5,709,694.01	18,403,751.66	26,630,116.38
Oil - Start-up/Stabilization..	18,289.18	23,843.54	24,689.00	66,821.72
Total MMBtu Burned	2,534,959.89	5,733,537.55	18,428,440.66	26,696,938.10
Average Btu per Net Kwh Output..	11,681	10,473	10,586	10,656

(1) Also includes oil used for firing, disposal of ashes and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2009

	Year to Date				
Ghent - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal...	2,867,588,000	2,413,738,000	3,182,388,000	2,881,867,000	11,345,581,000
Total Kwh Output..	2,867,588,000	2,413,738,000	3,182,388,000	2,881,867,000	11,345,581,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight...	72,472,831.27	65,904,570.47	86,213,479.80	76,770,979.05	301,361,860.59
Coal, Including Freight, Handling, Etc (1)............................	73,356,378.97	67,048,885.97	87,500,919.90	79,011,121.18	306,917,306.02
Total Fuel (1)..	73,356,378.97	67,048,885.97	87,500,919.90	79,011,121.18	306,917,306.02
Other Operation Expenses	6,492,917.15	6,167,616.27	7,069,818.76	8,152,029.46	27,882,381.64
Maintenance	11,606,518.80	8,067,327.72	7,095,221.09	6,330,377.06	33,099,444.67
Total Production Expenses	91,455,814.92	81,283,829.96	101,665,959.75	93,493,527.70	367,899,132.33
Cost per Net Kwh Output-Cents:					
Coal, Including Freight	2.527	2.730	2.709	2.664	2.656
Coal Including Freight, Handling, Etc (1)..............................	2.558	2.778	2.750	2.742	2.705
Total All Fuel Costs (1)...	2.558	2.778	2.750	2.742	2.705
Other Operation Expenses...	0.226	0.256	0.222	0.283	0.246
Maintenance..	0.405	0.334	0.223	0.220	0.292
Total Production Expenses.......................................	3.189	3.368	3.195	3.245	3.243
Quantities of Fuel Burned:					
Coal - Tons...	1,304,851.00	1,089,304.00	1,552,115.00	1,385,617.00	5,331,887.00
Oil - Gallons - Start-up/Stabilization...................................	248,919.00	397,708.00	467,049.00	489,107.00	1,602,783.00
MMBtu Burned:					
Coal..	30,142,970.24	25,389,808.75	35,890,668.93	32,039,410.58	123,462,858.50
Oil - Start-up/Stabilization...	34,848.66	55,679.12	65,386.86	68,474.98	224,389.62
Total MMBtu Burned	30,177,818.90	25,445,487.87	35,956,055.79	32,107,885.56	123,687,248.12
Average Btu per Net Kwh Output...	10,524	10,542	11,298	11,141	10,902

(1) Also includes oil used for firing, disposal of ashes and fly ash (net)

Attachment to Response to Sierra Club Question No. 1.5 (a)(b)(c)

January 25, 2010

Schram

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2009

	Year to Date			
Cane Run - Steam	Unit 4	Unit 5	Unit 6	Total
Kwh Output				
Net Kwh - Coal..	950,924,000	956,126,000	1,340,828,000	3,247,878,000
Production Costs ($)				
Fuel Costs				
Coal, Including Freight..	17,809,761.15	17,864,023.03	25,508,514.77	61,182,298.95
Coal, Including Freight, Handling, Etc (2)..............................	19,301,755.70	18,937,137.37	26,751,641.11	64,990,534.18
Total Fuel (2)...	19,301,755.70	18,937,137.37	26,751,641.11	64,990,534.18
Other Operation Expenses	6,609,388.35	6,916,996.33	11,730,652.89	25,257,037.57
Maintenance	3,774,419.10	4,128,256.21	5,681,632.28	13,584,307.59
Total Production Expenses	29,685,563.15	29,982,389.91	44,163,926.28	103,831,879.34
Fuel Costs - Cents				
Coal, Including Freight (1)	1.873	1.868	1.902	1.884
Coal and Other (1) (2)..	2.030	1.981	1.995	2.001
Total All Fuel Costs (2)...	2.030	1.981	1.995	2.001
Other Operation Expenses...	0.695	0.723	0.875	0.778
Maintenance...	0.397	0.432	0.424	0.418
Total Production Expenses	3.122	3.136	3.294	3.197
Quantities of Fuel Burned:				
Coal - Tons...	460,928.00	459,815.00	655,227.90	1,575,970.90
Gas - Mcf - Start-up/Stabilization................................	71,426.00	41,169.00	36,997.00	149,592.00
Oil - Gallons - Start-up/Stabilization.....................................	-	-	-	-
MMBtu Burned:				
Coal..	10,140,259.20	10,120,728.93	14,420,251.43	34,681,239.56
Gas - Start-up/Stabilization..	73,211.00	42,197.00	37,921.00	153,329.00
Oil - Start-up/Stabilization...	-	-	-	-
Total MMBtu Burned	10,213,470.20	10,162,925.93	14,458,172.43	34,834,568.56
Average Btu per Net Kwh Output (Heat Rate)	10,741	10,629	10,783	10,725

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net)

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2009

Mill Creek - Steam	Year to Date				
	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	2,121,020,000	1,860,292,000	2,805,833,000	3,587,250,000	10,374,395,000
Production Costs ($)					
Fuel Costs					
Coal, Including Freight..	39,709,657.35	35,867,516.03	52,047,789.14	65,456,844.18	193,081,806.70
Coal, Including Freight, Handling, Etc (2)..............................	41,363,177.60	37,494,573.09	54,866,428.02	69,170,415.38	202,894,594.09
Total Fuel (2)...	41,363,177.60	37,494,573.09	54,866,428.02	69,170,415.38	202,894,594.09
Other Operation Expenses	5,910,909.77	5,242,034.02	5,138,220.97	8,339,509.19	24,630,673.95
Maintenance	4,981,216.48	7,400,615.75	7,715,608.95	6,985,222.86	27,082,664.04
Total Production Expenses	52,255,303.85	50,137,222.86	67,720,257.94	84,495,147.43	254,607,932.08
Fuel Costs - Cents					
Coal, Including Freight (1)	1.872	1.928	1.855	1.825	1.861
Coal and Other (1) (2)...	1.950	2.016	1.955	1.928	1.956
Total All Fuel Costs (2)..	1.950	2.016	1.955	1.928	1.956
Other Operation Expenses...	0.279	0.282	0.183	0.232	0.237
Maintenance...	0.235	0.398	0.275	0.195	0.261
Total Production Expenses......................................	2.464	2.696	2.413	2.355	2.454
Quantities of Fuel Burned:					
Coal - Tons...	975,528.55	878,969.30	1,283,228.50	1,610,066.20	4,747,792.55
Gas - Mcf - Start-up/Stabilization................................	27,867.00	26,461.00	90,624.00	134,547.00	279,499.00
Oil - Gallons - Start-up/Stabilization....................................	-	-	-	-	-
MMBtu Burned:					
Coal..	22,387,042.74	20,166,056.23	29,451,658.99	36,956,256.52	108,961,014.48
Gas - Start-up/Stabilization..	28,564.00	27,123.00	92,891.00	137,910.00	286,488.00
Oil - Start-up/Stabilization..	-	-	-	-	-
Total MMBtu Burned	22,415,606.74	20,193,179.23	29,544,549.99	37,094,166.52	109,247,502.48
Average Btu per Net Kwh Output (Heat Rate)	10,568	10,855	10,530	10,341	10,530

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net)

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2009

	Current Month		Year to Date		Year Ended Current Month	
Trimble County - Steam (3)	This Year	Last Year	This Year	Last Year	This Year	Last Year
Kwh Output						
Net Kwh - LGE...	176,725,000	245,994,000	2,346,678,000	3,058,244,000	2,346,678,000	3,058,244,000
IMEA..	26,304,000	38,793,000	387,195,000	515,584,000	387,195,000	515,584,000
IMPA...	27,914,000	41,161,000	399,974,000	547,951,000	399,974,000	547,951,000
Total Kwh Output......................................	230,943,000	325,948,000	3,133,847,000	4,121,779,000	3,133,847,000	4,121,779,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight..	4,449,835.10	7,116,583.81	65,458,757.72	76,969,574.84	65,458,757.72	76,969,574.84
Coal, Including Freight, Handling, Etc (2)......................	5,059,444.09	7,430,261.46	68,048,823.15	78,852,262.31	68,048,823.15	78,852,262.31
Total Fuel (2)..	5,059,444.09	7,430,261.46	68,048,823.15	78,852,262.31	68,048,823.15	78,852,262.31
Other Operation Expenses......................................	876,709.76	974,707.40	10,522,941.74	10,107,060.57	10,522,941.74	10,107,060.57
Maintenance...	1,147,409.47	1,408,787.04	17,025,319.35	10,151,818.88	17,025,319.35	10,151,818.88
Total Production Expenses..	7,083,563.32	9,813,755.90	95,597,084.24	99,111,141.76	95,597,084.24	99,111,141.76
Cost per Net Kwh Output-Cents:						
Coal Including. Freight (1)................................	1.927	2.183	2.089	1.867	2.089	1.867
Coal Including Freight, Handling, Etc (1) (2)..................	2.191	2.280	2.171	1.913	2.171	1.913
Total All Fuel Costs (2).....................................	2.191	2.280	2.171	1.913	2.171	1.913
Other Operation Expenses....................................	0.380	0.299	0.336	0.245	0.336	0.245
Maintenance...	0.497	0.432	0.543	0.246	0.543	0.246
Total Production Expenses..................................	3.068	3.011	3.050	2.404	3.050	2.404
Quantities of Fuel Burned:						
Coal - Tons..	101,870.81	146,210.00	1,409,665.16	1,813,014.85	1,409,665.16	1,813,014.85
Oil - Gallons - Start-up/Stabilization..............................	161,506.00	66,095.00	717,202.00	241,086.00	717,202.00	241,086.00
MMBtu Burned:						
Coal...	2,316,655.07	3,345,981.30	32,308,420.94	42,196,914.98	32,308,420.94	42,196,914.98
Oil - Start-up/Stabilization..	22,610.84	9,253.30	100,408.28	33,752.04	100,408.28	33,752.04
Total MMBtu Burned...	2,339,265.91	3,355,234.60	32,408,829.22	42,230,667.02	32,408,829.22	42,230,667.02
Average Btu per Net Kwh Output.......................	10,129	10,294	10,342	10,246	10,342	10,246
Average Btu per Pound of Coal.................................	11,371	11,442	11,460	11,637	11,460	11,637
Average Btu per Gallon of Oil...	140,000	140,000	140,000	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)...........................	192.080	212.690	202.606	182.406	202.606	182.406
Total All Fuel Cost per MMBtu (2)...................................	216.283	221.453	209.970	186.718	209.970	186.718
Cost of Coal & Freight per Ton ($)....................................	43.681	48.674	46.436	42.454	46.436	42.454

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of ashes and fly ash (net)
(3) Information on this report represents 100% generation, quantities used, and costs

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2010

Tyrone - Steam	Year to Date Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal	-	-	137,167,000	137,167,000
Net Kwh - Oil	-	-	-	-
Total Kwh Output	-	-	137,167,000	137,167,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight	$ -	$ -	$ 6,447,718.39	$ 6,447,718.39
Coal, Including Freight, Handling, Etc (2)	-	-	6,952,081.25	6,952,081.25
Total Fuel (2)	-	-	6,952,081.25	6,952,081.25
Other Operation Expenses	-	-	1,178,048.25	1,178,048.25
Maintenance	842.37	2,064.30	1,051,005.15	1,053,911.82
Rents	-	-	-	-
Total Production Expenses	$ 842.37	$ 2,064.30	$ 9,181,134.65	$ 9,184,041.32
Cost per Net Kwh Output - Cents:				
Coal, Including Freight (1)	-	-	4.701	4.701
Coal Including Freight, Handling, Etc (1) (2)	-	-	5.068	5.068
Total All Fuel Costs (2)	-	-	5.068	5.068
Other Operation Expenses	-	-	0.859	0.859
Maintenance	-	-	0.766	0.768
Rents	-	-	-	-
Total Production Expenses	-	-	6.693	6.695
Quantities of Fuel Burned:				
Coal - Tons	-	-	72,111.00	72,111.00
Oil - Gallons - Start-up/Stabilization	-	-	73,398.00	73,398.00
MMBtu Burned:				
Coal	-	-	1,838,303.72	1,838,303.72
Oil - Start-up/Stabilization	-	-	10,275.72	10,275.72
Total MMBtu Burned	-	-	1,848,579.44	1,848,579.44
Average Btu per Net Kwh Output (Heat Rate)	-	-	13,477	13,477

(1) Based on Kwh generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2010

Green River - Steam	Year to Date Unit 3	Year to Date Unit 4	Year to Date Total
Kwh Output			
Net Kwh - Coal	345,262,000	544,049,000	889,311,000
Total Kwh Output	345,262,000	544,049,000	889,311,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 10,698,608.57	$ 15,688,056.70	$ 26,386,665.27
Coal, Including Freight, Handling, Etc (1)	11,116,546.36	16,347,727.49	27,464,273.85
Total Fuel (1)	11,116,546.36	16,347,727.49	27,464,273.85
Other Operation Expenses	1,488,230.96	2,481,630.16	3,969,861.12
Maintenance	4,146,772.25	3,389,705.16	7,536,477.41
Rents	-	-	-
Total Production Expenses	$ 16,751,549.57	$ 22,219,062.81	$ 38,970,612.38
Cost per Net Kwh Output - Cents:			
Coal, Including Freight	3.099	2.884	2.967
Coal Including Freight, Handling, Etc (1)	3.220	3.005	3.088
Total All Fuel Costs (1)	3.220	3.005	3.088
Other Operation Expenses	0.431	0.456	0.446
Maintenance	1.201	0.623	0.847
Rents	-	-	-
Total Production Expenses	4.852	4.084	4.381
Quantities of Fuel Burned:			
Coal - Tons	174,073.00	254,351.00	428,424.00
Oil - Gallons - Start-up/Stabilization	53,900.00	94,386.00	148,286.00
MMBtu Burned:			
Coal	4,118,275.38	6,019,962.35	10,138,237.73
Oil - Start-up/Stabilization	7,546.00	13,214.04	20,760.04
Total MMBtu Burned	4,125,821.38	6,033,176.39	10,158,997.77
Average Btu per Net Kwh Output	11,950	11,089	11,423

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2010

EW Brown - Steam	Year to Date Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal...	411,311,000	763,280,000	1,828,361,000	3,002,952,000
Total Kwh Output...	411,311,000	763,280,000	1,828,361,000	3,002,952,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight...	$ 15,171,727.17	$ 26,108,687.67	$ 67,424,689.33	$ 108,705,104.17
Coal, Including Freight, Handling, Etc (1)..................	15,780,544.69	26,850,948.38	68,698,589.93	111,330,083.00
Total Fuel (1)..	15,780,544.69	26,850,948.38	68,698,589.93	111,330,083.00
Other Operation Expenses...	1,302,900.54	2,241,160.63	5,460,506.89	9,004,568.06
Maintenance..	2,846,036.14	3,285,757.43	6,673,182.49	12,804,976.06
Rents..	2,232.87	3,572.57	9,080.26	14,885.70
Total Production Expenses..	$ 19,931,714.24	$ 32,381,439.01	$ 80,841,359.57	$ 133,154,512.82
Cost per Net Kwh Output - Cents:				
Coal, Including Freight...	3.689	3.421	3.688	3.620
Coal Including Freight, Handling, Etc (1)....................	3.837	3.518	3.757	3.707
Total All Fuel Costs (1)...	3.837	3.518	3.757	3.707
Other Operation Expenses...	0.317	0.294	0.299	0.300
Maintenance..	0.692	0.430	0.365	0.426
Rents..	0.001	0.000	0.000	0.002
Total Production Expenses..	4.847	4.242	4.421	4.435
Quantities of Fuel Burned:				
Coal - Tons..	185,326.00	319,944.00	829,367.00	1,334,637.00
Oil - Gallons - Start-up/Stabilization...........................	153,258.00	140,584.00	80,285.00	374,127.00
MMBtu Burned:				
Coal..	4,532,440.79	7,828,089.25	20,266,133.13	32,626,663.17
Oil - Start-up/Stabilization..	21,456.12	19,681.76	11,239.90	52,377.78
Total MMBtu Burned	4,553,896.91	7,847,771.01	20,277,373.03	32,679,040.95
Average Btu per Net Kwh Output...................................	11,072	10,282	11,090	10,882

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Attachment to Response to Sierra Club Question No. 1.5 (a)(b)(c)

January 31, 2011

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2010

	Year to Date				
Ghent - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal	3,295,876,000	3,201,480,000	3,431,840,000	2,667,176,000	12,596,372,000
Total Kwh Output	3,295,876,000	3,201,480,000	3,431,840,000	2,667,176,000	12,596,372,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight	$ 75,625,304.04	$ 73,767,242.17	$ 82,719,727.65	$ 65,577,565.05	$ 297,689,838.91
Coal, Including Freight, Handling, Etc (1)	76,419,104.62	74,535,767.67	84,000,184.52	67,617,184.78	302,572,241.59
Total Fuel (1)	76,419,104.62	74,535,767.67	84,000,184.52	67,617,184.78	302,572,241.59
Other Operation Expenses	7,979,878.25	4,810,856.22	8,676,565.21	9,271,950.63	30,739,250.31
Maintenance	10,054,633.53	7,542,210.43	6,995,664.47	10,245,476.64	34,837,985.07
Rents	-	-	-	-	-
Total Production Expenses	$ 94,453,616.40	$ 86,888,834.32	$ 99,672,414.20	$ 87,134,612.05	$ 368,149,476.97
Cost per Net Kwh Output - Cents:					
Coal, Including Freight	2.295	2.304	2.410	2.459	2.363
Coal Including Freight, Handling, Etc (1)	2.319	2.328	2.448	2.535	2.402
Total All Fuel Costs (1)	2.319	2.328	2.448	2.535	2.402
Other Operation Expenses	0.242	0.150	0.253	0.348	0.244
Maintenance	0.305	0.236	0.204	0.384	0.277
Rents	-	-	-	-	-
Total Production Expenses	2.866	2.714	2.905	3.267	2.923
Quantities of Fuel Burned:					
Coal - Tons	1,498,423.00	1,461,441.00	1,629,927.00	1,275,474.00	5,865,265.00
Oil - Gallons - Start-up/Stabilization	143,952.00	122,025.00	350,041.00	299,667.00	915,685.00
MMBtu Burned:					
Coal	34,450,154.94	33,604,139.84	37,479,455.95	29,333,000.41	134,866,751.14
Oil - Start-up/Stabilization	20,153.28	17,083.50	49,005.74	41,953.38	128,195.90
Total MMBtu Burned	34,470,308.22	33,621,223.34	37,528,461.69	29,374,953.79	134,994,947.04
Average Btu per Net Kwh Output	10,459	10,502	10,935	11,014	10,717

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2010

	Current Month		Year to Date		Year Ended Current Month	
Trimble County - Steam (3)	This Year	Last Year	This Year	Last Year	This Year	Last Year
Kwh Output						
Net Kwh - Coal..	120,425,000	-	273,933,000	-	273,933,000	-
IMEA...	19,453,000	-	44,892,000	-	44,892,000	-
IMPA...	20,678,000	-	47,694,000	-	47,694,000	-
Total Kwh Output..	160,556,000	-	366,519,000	-	366,519,000	-
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight....................................	$ 3,358,977.86	$ -	$ 7,230,413.20	$ -	$ 7,230,413.20	$ -
Coal, Including Freight, Handling, Etc (2)........	3,619,076.74	-	10,305,542.47	-	10,305,542.47	-
Total Fuel (2)...	3,619,076.74	-	10,305,542.47	-	10,305,542.47	-
Other Operation Expenses....................................	-	-	672,440.02	-	672,440.02	-
Maintenance..	-	-	861,524.14	-	861,524.14	-
Rents..	-	-	-	-	-	-
Total Production Expenses...................................	$ 3,619,076.74	$ -	$ 11,839,506.63	$ -	$ 11,839,506.63	$ -
Cost per Net Kwh Output - Cents:	-	-	-	-	-	-
Coal, Including Freight (1)...............................	2.092	-	1.973	-	1.973	-
Coal Including Freight, Handling, Etc (1) (2)....	2.254	-	2.812	-	2.812	-
Total All Fuel Costs (2)...................................	2.254	-	2.812	-	2.812	-
	-	-	-	-	-	-
Other Operation Expenses....................................	-	-	0.183	-	0.183	-
Maintenance..	-	-	0.235	-	0.235	-
Rents..	-	-	-	-	-	-
Total Production Expenses...................................	2.254	-	3.230	-	3.230	-
Quantities of Fuel Burned:						
Coal - Tons..	71,977.16	-	149,700.16	-	149,700.16	-
Oil - Gallons - Start-up/Stabilization................	107,922.00	-	1,380,217.00	-	1,380,217.00	-
MMBtu Burned:						
Coal...	1,532,476.15	-	3,276,483.54	-	3,276,483.54	-
Oil - Start-up/Stabilization...............................	15,109.09	-	193,230.28	-	193,230.28	-
Total MMBtu Burned...	1,547,585.24	-	3,469,713.82	-	3,469,713.82	-
Average Btu per Net Kwh Output...............................	9,639	-	9,467	-	9,467	-
Average Btu per Pound of Coal............................	10,646	-	10,943	-	10,943	-
Average Btu per Gallon of Oil.............................	140,000	-	140,000	-	140,000	-
Cost Coal and Freight per MMBtu (Cents)...........	219.186	-	220.676	-	220.676	-
Total All Fuel Cost per MMBtu (2)......................	233.853	-	297.014	-	297.014	-
Cost of Coal and Freight Per Ton ($)....................	46.667	-	48.299	-	48.299	-

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% of KU's portion of Trimble County Unit #2 generation, quantities used, and costs of Trimble County Unit #2

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2010

Cane Run - Steam	Year to Date Unit 3	Unit 4	Unit 5	Unit 6	Total
Kwh Output					
Net Kwh - Coal.................……………………………	-	927,129,000	1,110,383,000	1,222,086,000	3,259,598,000
Production Costs ($)					
Fuel Costs					
Coal, Including Freight...	$ -	$ 20,831,765.50	$ 23,638,328.56	$ 26,040,900.15	$ 70,510,994.21
Coal, Including Freight, Handling, Etc (2)..............................	-	22,017,671.16	24,625,180.71	27,241,604.26	73,884,456.13
Total Fuel (2)...	-	22,017,671.16	24,625,180.71	27,241,604.26	73,884,456.13
Other Operation Expenses	-	6,484,671.39	7,862,116.20	10,191,054.67	24,537,842.26
Maintenance	(114.66)	5,145,458.92	3,498,654.12	12,401,934.20	21,045,932.58
Rents ....……………………………	-	2,754.00	3,060.00	4,386.00	10,200.00
Total Production Expenses	$ (114.66)	$ 33,650,555.47	$ 35,989,011.03	$ 49,838,979.13	$ 119,478,430.97
Fuel Costs - Cents					
Coal, Including Freight (1)	-	2.247	2.129	2.131	2.163
Coal and Other (1) (2)..	-	2.375	2.218	2.229	2.267
Total All Fuel Costs (2)..	-	2.375	2.218	2.229	2.267
Other Operation Expenses...	-	0.699	0.708	0.834	0.753
Maintenance...	-	0.555	0.315	1.015	0.646
Rents ....……………………………	-	-	-	-	-
Total Production Expenses.......................................	-	3.629	3.241	4.078	3.666
Quantities of Fuel Burned:					
Coal - Tons...	-	473,917.00	536,117.01	593,528.00	1,603,562.01
Gas - Mcf - Start-up/Stabilization................................	-	49,363.00	35,957.00	39,464.00	124,784.00
Oil - Gallons - Start-up/Stabilization....................................	-	-	-	-	-
MMBtu Burned:					
Coal..	-	10,414,517.03	11,777,066.70	13,040,374.81	35,231,958.54
Gas - Start-up/Stabilization..	-	50,598.00	36,854.00	40,452.00	127,904.00
Oil - Start-up/Stabilization..	-	-	-	-	-
Total MMBtu Burned	-	10,465,115.03	11,813,920.70	13,080,826.81	35,359,862.54
Average Btu per Net Kwh Output (Heat Rate)	-	11,288	10,640	10,704	10,848

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

January 31, 2011

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2010

Mill Creek - Steam	Year to Date Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	2,009,037,000	2,101,040,000	2,914,876,000	3,348,610,000	10,373,563,000
Production Costs ($)					
Fuel Costs					
Coal, Including Freight..	$ 38,600,936.67	$ 40,960,587.08	$ 56,250,643.28	$ 63,108,707.29	$ 198,920,874.32
Coal, Including Freight, Handling, Etc (2)............................	40,205,901.61	42,530,167.18	58,646,783.46	66,464,377.51	207,847,229.76
Total Fuel (2)..	40,205,901.61	42,530,167.18	58,646,783.46	66,464,377.51	207,847,229.76
Other Operation Expenses	5,794,577.26	5,539,310.02	5,796,067.26	7,666,272.88	24,796,227.42
Maintenance	8,435,601.95	5,173,858.47	6,996,647.28	10,360,350.63	30,966,458.33
Rents...	14,852.25	14,852.25	18,388.50	22,632.00	70,725.00
Total Production Expenses	$ 54,450,933.07	$ 53,258,187.92	$ 71,457,886.50	$ 84,513,633.02	$ 263,680,640.51
Fuel Costs - Cents					
Coal, Including Freight (1)	1.921	1.950	1.930	1.885	1.918
Coal and Other (1) (2)...	2.001	2.024	2.012	1.985	2.004
Total All Fuel Costs (2)..	2.001	2.024	2.012	1.985	2.004
Other Operation Expenses...	0.288	0.264	0.199	0.229	0.239
Maintenance..	0.420	0.246	0.240	0.309	0.299
Rents...	0.001	0.001	0.001	0.001	0.001
Total Production Expenses.......................................	2.710	2.535	2.452	2.524	2.543
Quantities of Fuel Burned:					
Coal - Tons..	934,149.65	992,301.25	1,361,933.45	1,530,988.05	4,819,372.40
Gas - Mcf - Start-up/Stabilization................................	45,335.00	44,726.00	93,184.00	157,246.00	340,491.00
Oil - Gallons - Start-up/Stabilization..................................	-	-	-	-	-
MMBtu Burned:					
Coal..	21,416,794.55	22,740,636.04	31,203,400.56	35,065,853.54	110,426,684.69
Gas - Start-up/Stabilization..	46,467.00	45,844.00	95,513.00	161,177.00	349,001.00
Oil - Start-up/Stabilization..	-	-	-	-	-
Total MMBtu Burned	21,463,261.55	22,786,480.04	31,298,913.56	35,227,030.54	110,775,685.69
Average Btu per Net Kwh Output (Heat Rate)	10,683	10,845	10,738	10,520	10,679

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

January 31, 2011

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2010

Trimble County - Steam (3)	Year to Date Unit 1	Unit 2	Total
Kwh Output			
Net Kwh - LGE	2,672,799,000	64,257,000	2,737,056,000
IMEA	455,790,000	10,530,000	466,320,000
IMPA	486,774,000	11,187,000	497,961,000
Total Kwh Output	3,615,363,000	85,974,000	3,701,337,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 80,776,283.92	$ 1,696,871.06	$ 82,473,154.98
Coal, Including Freight, Handling, Etc (2)	85,240,588.41	2,421,739.66	87,662,328.07
Total Fuel (2)	85,240,588.41	2,421,739.66	87,662,328.07
Other Operation Expenses	8,875,777.61	157,732.83	9,033,510.44
Maintenance	14,240,238.24	229,097.35	14,469,335.59
Rents	10,849.15	-	10,849.15
Total Production Expenses	$ 108,367,453.41	$ 2,808,569.84	$ 111,176,023.25
Cost per Net Kwh Output - Cents:			
Coal Including. Freight (1)	2.234	1.974	2.228
Coal Including Freight, Handling, Etc (1) (2)	2.358	2.817	2.368
Total All Fuel Costs (2)	2.358	2.817	2.368
Other Operation Expenses	0.246	0.183	0.244
Maintenance	0.394	0.266	0.391
Rents	-	-	-
Total Production Expenses	2.998	3.266	3.003
Quantities of Fuel Burned:			
Coal - Tons	1,654,066.50	35,130.56	1,689,197.06
Oil - Gallons - Start-up/Stabilization	1,365,638.00	325,327.00	1,690,965.00
MMBtu Burned:			
Coal	38,172,214.24	768,924.97	38,941,139.21
Oil - Start-up/Stabilization	191,189.24	45,545.82	236,735.06
Total MMBtu Burned	38,363,403.48	814,470.79	39,177,874.27
Average Btu per Net Kwh Output	10,611	9,473	10,585
Average Btu per Pound of Coal	11,539	10,944	11,527
Average Btu per Gallon of Oil	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)	211.610	220.681	211.789
Total All Fuel Cost per MMBtu (2)	222.192	297.339	223.755
Cost of Coal & Freight per Ton ($)	48.835	48.302	48.824

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% generation, quantities used, and costs of Trimble County Unit #1 and 100% of LG&E's portion of Trimble County Unit #2

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2011

Tyrone - Steam	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year	Year Ended Current Month This Year	Year Ended Current Month Last Year
Kwh Output						
Net Kwh - Coal	(97,000)	26,218,000	22,022,000	137,167,000	22,022,000	137,167,000
Net Kwh - Oil	-	-	-	-	-	-
Total Kwh Output	(97,000)	26,218,000	22,022,000	137,167,000	22,022,000	137,167,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight	$ -	$ 1,264,196.36	$ 1,219,816.51	$ 6,447,718.39	$ 1,219,816.51	$ 6,447,718.39
Coal, Including Freight, Handling, Etc (2)	1,715.98	1,326,072.09	1,395,692.86	6,952,081.25	1,395,692.86	6,952,081.25
Total Fuel (2)	1,715.98	1,326,072.09	1,395,692.86	6,952,081.25	1,395,692.86	6,952,081.25
Other Operation Expenses	30,816.18	145,631.61	888,868.58	1,178,048.25	888,868.58	1,178,048.25
Maintenance	17,677.36	43,883.06	299,923.49	1,053,911.82	299,923.49	1,053,911.82
Rents	-	-	-	-	-	-
Total Production Expenses	$ 50,209.52	$ 1,515,586.76	$ 2,584,484.93	$ 9,184,041.32	$ 2,584,484.93	$ 9,184,041.32
Cost per Net Kwh Output - Cents:						
Coal, Including Freight (1)	-	4.822	5.539	4.701	5.539	4.701
Coal Including Freight, Handling, Etc (1) (2)	(1.769)	5.058	6.338	5.068	6.338	5.068
Total All Fuel Costs (2)	(1.769)	5.058	6.338	5.068	6.338	5.068
Other Operation Expenses	(31.769)	0.555	4.036	0.859	4.036	0.859
Maintenance	(18.224)	0.167	1.362	0.768	1.362	0.768
Rents	-	-	-	-	-	-
Total Production Expenses	(51.762)	5.780	11.736	6.695	11.736	6.695
Quantities of Fuel Burned:						
Coal - Tons	-	13,349.20	12,671.40	72,111.00	12,671.40	72,111.00
Oil - Gallons - Start-up/Stabilization	-	14,600.00	37,050.00	73,398.00	37,050.00	73,398.00
MMBtu Burned:						
Coal	-	338,849.23	323,742.10	1,838,303.72	323,742.10	1,838,303.72
Oil - Start-up/Stabilization	-	2,044.00	5,187.00	10,275.72	5,187.00	10,275.72
Total MMBtu Burned	-	340,893.23	328,929.10	1,848,579.44	328,929.10	1,848,579.44
Average Btu per Net Kwh Output	-	13,002	14,936	13,477	14,936	13,477
Average Btu per Pound of Coal	-	12,692	12,775	12,746	12,775	12,746
Average Btu per Gallon of Oil	-	140,000	140,000	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)	-	373.085	376.786	350.743	376.786	350.743
Total All Fuel Cost per MMBtu (2)	-	388.999	424.314	376.077	424.314	376.077
Cost of Coal & Freight Per Ton ($)	-	94.702	96.265	89.414	96.265	89.414

(1) Based on Kwh generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2011

Green River - Steam	Year to Date Unit 3	Year to Date Unit 4	Year to Date Total
Kwh Output			
Net Kwh - Coal	329,516,000	458,964,000	788,480,000
Total Kwh Output	329,516,000	458,964,000	788,480,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 10,635,897.94	$ 13,541,513.51	$ 24,177,411.45
Coal, Including Freight, Handling, Etc (1)	11,174,382.05	14,311,701.45	25,486,083.50
Total Fuel (1)	11,174,382.05	14,311,701.45	25,486,083.50
Other Operation Expenses	1,722,402.05	2,347,406.41	4,069,808.46
Maintenance	1,639,530.33	4,668,286.76	6,307,817.09
Rents	-	-	-
Total Production Expenses	$ 14,536,314.43	$ 21,327,394.62	$ 35,863,709.05
Cost per Net Kwh Output - Cents:			
Coal, Including Freight	3.228	2.950	3.066
Coal, Including Freight, Handling, Etc (1)	3.391	3.118	3.232
Total All Fuel Costs (1)	3.391	3.118	3.232
Other Operation Expenses	0.523	0.511	0.516
Maintenance	0.498	1.017	0.800
Rents	-	-	-
Total Production Expenses	4.412	4.646	4.548
Quantities of Fuel Burned:			
Coal - Tons	169,473.00	214,312.00	383,785.00
Oil - Gallons - Start-up/Stabilization	82,171.00	110,738.00	192,909.00
MMBtu Burned:			
Coal	4,090,207.67	5,178,266.14	9,268,473.81
Oil - Start-up/Stabilization	11,503.94	15,503.32	27,007.26
Total MMBtu Burned	4,101,711.61	5,193,769.46	9,295,481.07
Average Btu per Net Kwh Output	12,448	11,316	11,789

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2011

	Year to Date			
EW Brown - Steam	Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal...	317,251,000	616,832,000	1,563,842,000	2,497,925,000
Total Kwh Output...	317,251,000	616,832,000	1,563,842,000	2,497,925,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight...	$ 11,952,310.09	$ 22,126,923.81	$ 58,026,884.01	$ 92,106,117.91
Coal, Including Freight, Handling, Etc (1)..................	12,685,803.46	23,163,727.49	59,789,850.25	95,639,381.20
Total Fuel (1)..	12,685,803.46	23,163,727.49	59,789,850.25	95,639,381.20
Other Operation Expenses...	1,361,331.45	2,241,272.55	5,717,969.65	9,320,573.65
Maintenance...	2,373,077.55	4,177,149.42	7,109,295.20	13,659,522.17
Rents..	2,238.44	3,581.48	9,102.84	14,922.76
Total Production Expenses..	$ 16,422,450.90	$ 29,585,730.94	$ 72,626,217.94	$ 118,634,399.78
Cost per Net Kwh Output - Cents:				
Coal, Including Freight...	3.767	3.587	3.711	3.687
Coal, Including Freight, Handling, Etc (1)..................	3.999	3.755	3.823	3.829
Total All Fuel Costs (1)...	3.999	3.755	3.823	3.829
Other Operation Expenses...	0.429	0.363	0.366	0.373
Maintenance...	0.748	0.677	0.455	0.547
Rents..	0.001	0.001	0.001	0.002
Total Production Expenses..	5.177	4.796	4.645	4.751
Quantities of Fuel Burned:				
Coal - Tons..	163,976.00	286,081.00	744,530.00	1,194,587.00
Oil - Gallons - Start-up/Stabilization...........................	163,321.00	193,404.00	199,556.00	556,281.00
MMBtu Burned:				
Coal..	3,847,487.17	6,804,619.29	17,742,432.60	28,394,539.06
Oil - Start-up/Stabilization..	22,864.94	27,076.56	27,937.84	77,879.34
Total MMBtu Burned	3,870,352.11	6,831,695.85	17,770,370.44	28,472,418.40
Average Btu per Net Kwh Output...................................	12,200	11,075	11,363	11,398

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2011

	Year to Date				
Ghent - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal	3,394,813,000	3,345,081,000	2,866,840,000	2,899,005,000	12,505,739,000
Total Kwh Output	3,394,813,000	3,345,081,000	2,866,840,000	2,899,005,000	12,505,739,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight	$ 79,272,884.66	$ 81,190,125.54	$ 68,938,843.71	$ 70,463,486.67	$ 299,865,340.58
Coal, Including Freight, Handling, Etc (1)	80,141,908.28	82,179,336.66	70,201,579.87	72,923,589.55	305,446,414.36
Total Fuel (1)	80,141,908.28	82,179,336.66	70,201,579.87	72,923,589.55	305,446,414.36
Other Operation Expenses	9,040,343.82	5,942,023.45	8,780,036.62	11,537,869.92	35,300,273.81
Maintenance	9,497,921.46	6,761,335.69	18,188,486.93	6,901,577.36	41,349,321.44
Rents	-	-	-	-	-
Total Production Expenses	$ 98,680,173.56	$ 94,882,695.80	$ 97,170,103.42	$ 91,363,036.83	$ 382,096,009.61
Cost per Net Kwh Output - Cents:					
Coal, Including Freight	2.335	2.427	2.405	2.431	2.398
Coal, Including Freight, Handling, Etc (1)	2.361	2.457	2.449	2.515	2.442
Total All Fuel Costs (1)	2.361	2.457	2.449	2.515	2.442
Other Operation Expenses	0.266	0.178	0.306	0.398	0.282
Maintenance	0.280	0.202	0.634	0.238	0.331
Rents	-	-	-	-	-
Total Production Expenses	2.907	2.837	3.389	3.151	3.055
Quantities of Fuel Burned:					
Coal - Tons	1,560,490.00	1,601,231.00	1,354,863.00	1,388,355.00	5,904,939.00
Oil - Gallons - Start-up/Stabilization	143,561.00	177,623.00	265,867.00	375,509.00	962,560.00
MMBtu Burned:					
Coal	35,957,258.13	36,893,931.77	31,210,727.04	31,994,949.26	136,056,866.20
Oil - Start-up/Stabilization	20,098.54	24,867.22	37,221.38	52,571.26	134,758.40
Total MMBtu Burned	35,977,356.67	36,918,798.99	31,247,948.42	32,047,520.52	136,191,624.60
Average Btu per Net Kwh Output	10,598	11,037	10,900	11,055	10,890

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

January 26, 2012

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2011

	Current Month		Year to Date		Year Ended Current Month	
Trimble County - Steam (3)	This Year	Last Year	This Year	Last Year	This Year	Last Year
Kwh Output						
Net Kwh - Coal	256,770,000	120,425,000	2,791,871,000	273,933,000	2,791,871,000	273,933,000
IMEA	42,238,000	19,453,000	459,156,000	44,892,000	459,156,000	44,892,000
IMPA	44,940,000	20,678,000	488,140,000	47,694,000	488,140,000	47,694,000
Total Kwh Output	343,948,000	160,556,000	3,739,167,000	366,519,000	3,739,167,000	366,519,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight	$ 7,234,927.40	$ 3,358,977.86	$ 77,472,242.75	$ 7,230,413.20	$ 77,472,242.75	$ 7,230,413.20
Coal, Including Freight, Handling, Etc (2)	7,574,927.58	3,619,076.74	83,209,442.34	10,305,542.47	83,209,442.34	10,305,542.47
Total Fuel (2)	7,574,927.58	3,619,076.74	83,209,442.34	10,305,542.47	83,209,442.34	10,305,542.47
Other Operation Expenses	711,988.32	-	7,803,039.69	672,440.02	7,803,039.69	672,440.02
Maintenance	612,517.19	-	6,308,824.75	861,524.14	6,308,824.75	861,524.14
Rents	-	-	-	-	-	-
Total Production Expenses	$ 8,899,433.09	$ 3,619,076.74	$ 97,321,306.78	$ 11,839,506.63	$ 97,321,306.78	$ 11,839,506.63
Cost per Net Kwh Output - Cents:						
Coal, Including Freight (1)	2.103	2.092	2.072	1.973	2.072	1.973
Coal Including Freight, Handling, Etc (1) (2)	2.202	2.254	2.225	2.812	2.225	2.812
Total All Fuel Costs (2)	2.202	2.254	2.225	2.812	2.225	2.812
Other Operation Expenses	0.207	-	0.209	0.183	0.209	0.183
Maintenance	0.178	-	0.169	0.235	0.169	0.235
Rents	-	-	-	-	-	-
Total Production Expenses	2.587	2.254	2.603	3.230	2.603	3.230
Quantities of Fuel Burned:						
Coal - Tons	152,026.09	71,977.16	1,637,009.09	149,700.16	1,637,009.09	149,700.16
Oil - Gallons - Start-up/Stabilization	84,703.00	107,922.00	1,472,612.00	1,380,217.00	1,472,612.00	1,380,217.00
MMBtu Burned:						
Coal	3,240,794.84	1,532,476.15	35,041,100.14	3,276,483.54	35,041,100.14	3,276,483.54
Oil - Start-up/Stabilization	11,858.47	15,109.09	206,165.72	193,230.28	206,165.72	193,230.28
Total MMBtu Burned	3,252,653.31	1,547,585.24	35,247,265.86	3,469,713.82	35,247,265.86	3,469,713.82
Average Btu per Net Kwh Output	9,457	9,639	9,427	9,467	9,427	9,467
Average Btu per Pound of Coal	10,659	10,646	10,703	10,943	10,703	10,943
Average Btu per Gallon of Oil	140,000	140,000	140,000	140,000	140,000	140,000
Cost Coal and Freight per MMBtu (Cents)	223.245	219.186	221.090	220.676	221.090	220.676
Total All Fuel Cost per MMBtu (2)	232.885	233.853	236.073	297.014	236.073	297.014
Cost of Coal and Freight Per Ton ($)	47.590	46.667	47.325	48.299	47.325	48.299

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% of KU's portion of Trimble County Unit #2 generation, quantities used, and costs of Trimble County Unit #2

January 26, 2012

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2011

Cane Run - Steam	Year to Date Unit 4	Unit 5	Unit 6	Total
Kwh Output				
Net Kwh - Coal..	974,308,000	958,713,000	1,289,138,000	3,222,159,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight..	$ 22,007,659.86	$ 20,154,458.60	$ 26,798,723.55	$ 68,960,842.01
Coal, Including Freight, Handling, Etc (2)...........................	23,146,047.97	21,196,585.24	28,596,016.96	72,938,650.17
Total Fuel (2)...	23,146,047.97	21,196,585.24	28,596,016.96	72,938,650.17
Other Operation Expenses	7,371,386.63	7,211,994.17	11,855,942.17	26,439,322.97
Maintenance	3,396,607.20	6,075,763.31	4,281,481.84	13,753,852.35
Rents	2,524.50	2,805.00	4,020.50	9,350.00
Total Production Expenses	$ 33,916,566.30	$ 34,487,147.72	$ 44,737,461.47	$ 113,141,175.49
Fuel Costs - Cents				
Coal, Including Freight (1)	2.259	2.102	2.079	2.140
Coal and Other (1) (2)...	2.376	2.211	2.218	2.264
Total All Fuel Costs (2)..	2.376	2.211	2.218	2.264
Other Operation Expenses...	0.757	0.752	0.920	0.821
Maintenance...	0.349	0.634	0.332	0.427
Rents	0.000	0.000	0.000	0.000
Total Production Expenses......................................	3.482	3.597	3.470	3.512
Quantities of Fuel Burned:				
Coal - Tons...	498,546.00	456,960.01	608,316.99	1,563,823.00
Gas - Mcf - Start-up/Stabilization................................	46,287.00	43,552.00	94,594.00	184,433.00
Oil - Gallons - Start-up/Stabilization..................................	-	-	-	-
MMBtu Burned:				
Coal...	11,066,458.23	10,137,987.65	13,503,631.90	34,708,077.78
Gas - Start-up/Stabilization...	47,444.26	44,641.18	96,958.04	189,043.48
Oil - Start-up/Stabilization..	-	-	-	-
Total MMBtu Burned	11,113,902.49	10,182,628.83	13,600,589.94	34,897,121.26
Average Btu per Net Kwh Output (Heat Rate)	11,407	10,621	10,550	10,830

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

January 26, 2012

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2011

	Year to Date				
Mill Creek - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	2,044,330,000	1,980,508,000	1,878,796,000	3,160,051,000	9,063,685,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight..	$ 42,525,040.40	$ 43,033,925.73	$ 39,271,501.75	$ 65,649,563.30	$ 190,480,031.18
Coal, Including Freight, Handling, Etc (2)..............................	43,865,485.75	44,559,707.29	41,712,257.31	68,815,619.91	198,953,070.26
Total Fuel (2)...	43,865,485.75	44,559,707.29	41,712,257.31	68,815,619.91	198,953,070.26
Other Operation Expenses	5,744,959.63	5,189,820.96	4,614,136.65	7,694,879.45	23,243,796.69
Maintenance	6,572,462.03	4,603,072.44	12,560,202.72	8,146,286.35	31,882,023.54
Rents..	15,183.00	15,183.00	18,798.00	23,136.00	72,300.00
Total Production Expenses	$ 56,198,090.41	$ 54,367,783.69	$ 58,905,394.68	$ 84,679,921.71	$ 254,151,190.49
Fuel Costs - Cents					
Coal, Including Freight (1)	2.080	2.173	2.090	2.077	2.102
Coal and Other (1) (2)..	2.146	2.250	2.220	2.178	2.195
Total All Fuel Costs (2)..	2.146	2.250	2.220	2.178	2.195
Other Operation Expenses..	0.281	0.262	0.246	0.244	0.256
Maintenance...	0.321	0.232	0.669	0.258	0.352
Rents..	0.001	0.001	0.001	0.001	0.001
Total Production Expenses.......................................	2.749	2.745	3.136	2.681	2.804
Quantities of Fuel Burned:					
Coal - Tons...	946,228.85	954,569.90	861,596.10	1,458,716.25	4,221,111.10
Gas - Mcf - Start-up/Stabilization................................	54,165.00	72,013.00	147,217.00	192,235.00	465,630.00
Oil - Gallons - Start-up/Stabilization....................................	-	-	-	-	-
MMBtu Burned:					
Coal...	21,665,806.25	21,861,836.39	19,720,103.11	33,401,351.69	96,649,097.44
Gas - Start-up/Stabilization...	55,518.21	73,814.93	150,898.74	197,040.38	477,272.26
Oil - Start-up/Stabilization..	-	-	-	-	-
Total MMBtu Burned	21,721,324.46	21,935,651.32	19,871,001.85	33,598,392.07	97,126,369.70
Average Btu per Net Kwh Output (Heat Rate)	10,625	11,076	10,576	10,632	10,716

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

January 26, 2012

Schram

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2011

Trimble County - Steam (3)	Year to Date Unit 1	Year to Date Unit 2	Year to Date Total
Kwh Output			
Net Kwh - LGE	2,350,170,000	654,882,000	3,005,052,000
IMEA	419,989,000	107,700,000	527,689,000
IMPA	441,880,000	114,503,000	556,383,000
Total Kwh Output	3,212,039,000	877,085,000	4,089,124,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 74,409,865.26	$ 18,178,941.36	$ 92,588,806.62
Coal, Including Freight, Handling, Etc (2)	77,292,361.11	19,511,991.24	96,804,352.35
Total Fuel (2)	77,292,361.11	19,511,991.24	96,804,352.35
Other Operation Expenses	6,884,566.13	1,844,725.46	8,729,291.59
Maintenance	14,811,454.18	1,483,314.56	16,294,768.74
Rents	9,931.15	-	9,931.15
Total Production Expenses	$ 98,998,312.57	$ 22,840,031.26	$ 121,838,343.83
Cost per Net Kwh Output - Cents:			
Coal Including. Freight (1)	2.317	2.073	2.264
Coal Including Freight, Handling, Etc (1) (2)	2.406	2.225	2.367
Total All Fuel Costs (2)	2.406	2.225	2.367
Other Operation Expenses	0.214	0.210	0.213
Maintenance	0.461	0.169	0.398
Rents	0.000	-	0.000
Total Production Expenses	3.081	2.604	2.978
Quantities of Fuel Burned:			
Coal - Tons	1,493,805.55	384,124.74	1,877,930.29
Oil - Gallons - Start-up/Stabilization	623,566.00	345,432.00	968,998.00
MMBtu Burned:			
Coal	34,263,825.70	8,222,613.54	42,486,439.24
Oil - Start-up/Stabilization	87,299.24	48,360.51	135,659.75
Total MMBtu Burned	34,351,124.94	8,270,974.05	42,622,098.99
Average Btu per Net Kwh Output	10,694	9,430	10,423
Average Btu per Pound of Coal	11,469	10,703	11,312
Average Btu per Gallon of Oil	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)	217.167	221.085	217.926
Total All Fuel Cost per MMBtu (2)	225.007	235.909	227.122
Cost of Coal & Freight per Ton ($)	49.812	47.326	49.304

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% generation, quantities used, and costs of Trimble County Unit #1 and 100% of LG&E's portion of Trimble County Unit #2

January 26, 2012

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2012

Tyrone - Steam	Current Month - This Year	Current Month - Last Year	Year to Date - This Year	Year to Date - Last Year	Year Ended Current Month - This Year	Year Ended Current Month - Last Year
Kwh Output						
Net Kwh - Coal	(89,000)	(97,000)	(1,407,000)	22,022,000	(1,407,000)	22,022,000
Net Kwh - Oil	-	-	-	-	-	-
Total Kwh Output	(89,000)	(97,000)	(1,407,000)	22,022,000	(1,407,000)	22,022,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight	$ -	$ -	$ -	$ 1,219,816.51	$ -	$ 1,219,816.51
Coal, Including Freight, Handling, Etc (2)	1,891.82	1,715.98	35,824.23	1,395,692.86	35,824.23	1,395,692.86
Total Fuel (2)	1,891.82	1,715.98	35,824.23	1,395,692.86	35,824.23	1,395,692.86
Other Operation Expenses	45,846.12	30,816.18	371,632.65	888,868.58	371,632.65	888,868.58
Maintenance	1,085.80	17,677.36	158,968.19	299,923.49	158,968.19	299,923.49
Rents	-	-	-	-	-	-
Total Production Expenses	$ 48,823.74	$ 50,209.52	$ 566,425.07	$ 2,584,484.93	$ 566,425.07	$ 2,584,484.93
Cost per Net Kwh Output - Cents:						
Coal, Including Freight (1)	-	-	-	5.539	-	5.539
Coal Including Freight, Handling, Etc (1) (2)	(2.126)	(1.769)	(2.546)	6.338	(2.546)	6.338
Total All Fuel Costs (2)	(2.126)	(1.769)	(2.546)	6.338	(2.546)	6.338
Other Operation Expenses	(51.512)	(31.769)	(26.413)	4.036	(26.413)	4.036
Maintenance	(1.220)	(18.224)	(11.298)	1.362	(11.298)	1.362
Rents	-	-	-	-	-	-
Total Production Expenses	(54.858)	(51.762)	(40.257)	11.736	(40.257)	11.736
Quantities of Fuel Burned:						
Coal - Tons	-	-	-	12,671.40	-	12,671.40
Oil - Gallons - Start-up/Stabilization	-	-	-	37,050.00	-	37,050.00
MMBtu Burned:						
Coal	-	-	-	323,742.10	-	323,742.10
Oil - Start-up/Stabilization	-	-	-	5,187.00	-	5,187.00
Total MMBtu Burned	-	-	-	328,929.10	-	328,929.10
Average Btu per Net Kwh Output	-	-	-	14,936	-	14,936
Average Btu per Pound of Coal	-	-	-	12,775	-	12,775
Average Btu per Gallon of Oil	-	-	-	140,000	-	140,000
Cost Coal & Freight per MMBtu (Cents)	-	-	-	376.786	-	376.786
Total All Fuel Cost per MMBtu (2)	-	-	-	424.314	-	424.314
Cost of Coal & Freight Per Ton ($)	-	-	-	96.265	-	96.265

(1) Based on Kwh generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2012

	Year to Date		
Green River - Steam	Unit 3	Unit 4	Total
Kwh Output			
Net Kwh - Coal	270,773,000	635,500,000	906,273,000
Total Kwh Output	270,773,000	635,500,000	906,273,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 9,485,399.09	$ 18,102,424.28	$ 27,587,823.37
Coal, Including Freight, Handling, Etc (1)	10,073,746.88	19,046,397.25	29,120,144.13
Total Fuel (1)	10,073,746.88	19,046,397.25	29,120,144.13
Other Operation Expenses	1,266,780.17	2,769,323.68	4,036,103.85
Maintenance	2,877,694.50	2,967,959.42	5,845,653.92
Rents	-	-	-
Total Production Expenses	$ 14,218,221.55	$ 24,783,680.35	$ 39,001,901.90
Cost per Net Kwh Output - Cents:			
Coal, Including Freight	3.503	2.849	3.044
Coal, Including Freight, Handling, Etc (1)	3.720	2.997	3.213
Total All Fuel Costs (1)	3.720	2.997	3.213
Other Operation Expenses	0.468	0.436	0.445
Maintenance	1.063	0.467	0.645
Rents	-	-	-
Total Production Expenses	5.251	3.900	4.303
Quantities of Fuel Burned:			
Coal - Tons	159,343.00	310,510.00	469,853.00
Oil - Gallons - Start-up/Stabilization	54,561.00	100,238.00	154,799.00
MMBtu Burned:			
Coal	3,795,674.98	7,396,704.26	11,192,379.24
Oil - Start-up/Stabilization	7,638.54	14,033.32	21,671.86
Total MMBtu Burned	3,803,313.52	7,410,737.58	11,214,051.10
Average Btu per Net Kwh Output	14,046	11,661	12,374

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

January 25, 2013

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2012

	Year to Date			
EW Brown - Steam	Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal...	324,035,000	721,085,000	1,323,503,000	2,368,623,000
Total Kwh Output...	324,035,000	721,085,000	1,323,503,000	2,368,623,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight..	$ 11,748,921.54	$ 23,855,858.46	$ 45,499,367.56	$ 81,104,147.56
Coal, Including Freight, Handling, Etc (1).................	12,529,145.32	24,909,929.03	47,373,280.38	84,812,354.73
Total Fuel (1)...	12,529,145.32	24,909,929.03	47,373,280.38	84,812,354.73
Other Operation Expenses...	1,449,153.78	3,039,111.93	5,317,225.84	9,805,491.55
Maintenance..	3,971,953.18	3,732,698.06	14,411,908.06	22,116,559.30
Rents...	2,428.92	3,886.27	9,877.59	16,192.78
Total Production Expenses..	$ 17,952,681.20	$ 31,685,625.29	$ 67,112,291.87	$ 116,750,598.36
Cost per Net Kwh Output - Cents:				
Coal, Including Freight..	3.626	3.308	3.438	3.424
Coal, Including Freight, Handling, Etc (1).................	3.867	3.455	3.579	3.581
Total All Fuel Costs (1)...	3.867	3.455	3.579	3.581
Other Operation Expenses...	0.447	0.421	0.402	0.414
Maintenance..	1.226	0.518	1.089	0.934
Rents...	0.001	0.001	0.001	0.002
Total Production Expenses..	5.541	4.395	5.071	4.931
Quantities of Fuel Burned:				
Coal - Tons..	169,481.00	339,217.00	646,088.00	1,154,786.00
Oil - Gallons - Start-up/Stabilization..........................	147,661.00	176,369.00	199,941.00	523,971.00
MMBtu Burned:				
Coal..	3,898,580.52	7,824,139.09	14,885,581.37	26,608,300.98
Oil - Start-up/Stabilization..	20,672.54	24,691.66	27,991.74	73,355.94
Total MMBtu Burned	3,919,253.06	7,848,830.75	14,913,573.11	26,681,656.92
Average Btu per Net Kwh Output.................................	12,095	10,885	11,268	11,265

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2012

	Year to Date				
Ghent - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	3,166,600,000	3,052,544,000	3,302,452,000	2,653,566,000	12,175,162,000
Total Kwh Output..	3,166,600,000	3,052,544,000	3,302,452,000	2,653,566,000	12,175,162,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight..	$ 76,117,596.36	$ 72,431,241.36	$ 80,720,976.26	$ 66,940,962.40	$ 296,210,776.38
Coal, Including Freight, Handling, Etc (1)................	77,415,101.60	73,544,662.19	82,055,649.64	69,205,003.14	302,220,416.57
Total Fuel (1)...	77,415,101.60	73,544,662.19	82,055,649.64	69,205,003.14	302,220,416.57
Other Operation Expenses..	8,934,740.13	5,456,024.91	9,951,105.65	10,906,006.82	35,247,877.51
Maintenance...	12,401,482.62	16,159,649.78	9,850,162.15	8,629,268.79	47,040,563.34
Rents..	-	-	-	-	-
Total Production Expenses...	$ 98,751,324.35	$ 95,160,336.88	$ 101,856,917.44	$ 88,740,278.75	$ 384,508,857.42
Cost per Net Kwh Output - Cents:					
Coal, Including Freight..	2.404	2.373	2.444	2.523	2.433
Coal, Including Freight, Handling, Etc (1)................	2.445	2.409	2.485	2.608	2.482
Total All Fuel Costs (1)...	2.445	2.409	2.485	2.608	2.482
Other Operation Expenses..	0.282	0.179	0.301	0.411	0.290
Maintenance...	0.392	0.529	0.298	0.325	0.386
Rents..	-	-	-	-	-
Total Production Expenses...	3.119	3.117	3.084	3.344	3.158
Quantities of Fuel Burned:					
Coal - Tons...	1,497,671.00	1,428,925.00	1,590,198.00	1,307,491.00	5,824,285.00
Oil - Gallons - Start-up/Stabilization.........................	251,102.00	186,848.00	250,413.00	245,542.00	933,905.00
MMBtu Burned:					
Coal..	33,863,883.02	32,355,067.66	35,976,953.24	29,567,721.26	131,763,625.18
Oil - Start-up/Stabilization..	35,154.28	26,158.72	35,057.82	34,375.88	130,746.70
Total MMBtu Burned..	33,899,037.30	32,381,226.38	36,012,011.06	29,602,097.14	131,894,371.88
Average Btu per Net Kwh Output.................................	10,705	10,608	10,905	11,156	10,833

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2012

Trimble County - Steam (3)	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year	Year Ended Current Month This Year	Year Ended Current Month Last Year
Kwh Output						
Net Kwh - Coal	(5,749,000)	256,770,000	2,015,516,000	2,791,871,000	2,015,516,000	2,791,871,000
IMEA	8,000	42,238,000	333,787,000	459,156,000	333,787,000	459,156,000
IMPA	8,000	44,940,000	354,748,000	488,140,000	354,748,000	488,140,000
Total Kwh Output	(5,733,000)	343,948,000	2,704,051,000	3,739,167,000	2,704,051,000	3,739,167,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight	$ 24,169.40	$ 7,234,927.40	$ 59,594,544.95	$ 77,472,242.75	$ 59,594,544.95	$ 77,472,242.75
Coal, Including Freight, Handling, Etc (2)	573,103.33	7,574,927.58	65,140,300.11	83,209,442.34	65,140,300.11	83,209,442.34
Total Fuel (2)	573,103.33	7,574,927.58	65,140,300.11	83,209,442.34	65,140,300.11	83,209,442.34
Other Operation Expenses	500,422.42	711,988.32	8,662,361.63	7,803,039.69	8,662,361.63	7,803,039.69
Maintenance	1,504,213.91	612,517.19	10,860,900.04	6,308,824.75	10,860,900.04	6,308,824.75
Rents	-	-	-	-	-	-
Total Production Expenses	$ 2,577,739.66	$ 8,899,433.09	$ 84,663,561.78	$ 97,321,306.78	$ 84,663,561.78	$ 97,321,306.78
Cost per Net Kwh Output - Cents:						
Coal, Including Freight (1)	(0.422)	2.103	2.204	2.072	2.204	2.072
Coal Including Freight, Handling, Etc (1) (2)	(9.997)	2.202	2.409	2.225	2.409	2.225
Total All Fuel Costs (2)	(9.997)	2.202	2.409	2.225	2.409	2.225
Other Operation Expenses	(8.729)	0.207	0.320	0.209	0.320	0.209
Maintenance	(26.238)	0.178	0.402	0.169	0.402	0.169
Rents	-	-	-	-	-	-
Total Production Expenses	(44.964)	2.587	3.131	2.603	3.131	2.603
Quantities of Fuel Burned:						
Coal - Tons	480.62	152,026.09	1,186,532.05	1,637,009.09	1,186,532.05	1,637,009.09
Oil - Gallons - Start-up/Stabilization	129,275.00	84,703.00	1,426,397.00	1,472,612.00	1,426,397.00	1,472,612.00
MMBtu Burned:						
Coal	10,270.38	3,240,794.84	25,352,319.82	35,041,100.14	25,352,319.82	35,041,100.14
Oil - Start-up/Stabilization	18,098.52	11,858.47	199,695.59	206,165.72	199,695.59	206,165.72
Total MMBtu Burned	28,368.90	3,252,653.31	25,552,015.41	35,247,265.86	25,552,015.41	35,247,265.86
Average Btu per Net Kwh Output	(4,948)	9,457	9,450	9,427	9,450	9,427
Average Btu per Pound of Coal	10,685	10,659	10,683	10,703	10,683	10,703
Average Btu per Gallon of Oil	140,000	140,000	140,000	140,000	140,000	140,000
Cost Coal and Freight per MMBtu (Cents)	235.331	223.245	235.065	221.090	235.065	221.090
Total All Fuel Cost per MMBtu (2)	2,020.182	232.885	254.932	236.073	254.932	236.073
Cost of Coal and Freight Per Ton ($)	50.288	47.590	50.226	47.325	50.226	47.325

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% of KU's portion of Trimble County Unit #2 generation, quantities used, and costs of Trimble County Unit #2

January 25, 2013

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2012

	Year to Date			
Cane Run - Steam	Unit 4	Unit 5	Unit 6	Total
Kwh Output				
Net Kwh - Coal	653,072,000	928,589,000	1,084,657,000	2,666,318,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight	$ 17,179,507.85	$ 22,312,529.33	$ 25,840,587.99	$ 65,332,625.17
Coal, Including Freight, Handling, Etc (2)	18,391,960.94	23,288,813.95	26,978,376.57	68,659,151.46
Total Fuel (2)	18,391,960.94	23,288,813.95	26,978,376.57	68,659,151.46
Other Operation Expenses	5,750,645.93	7,512,618.37	12,669,578.32	25,932,842.62
Maintenance	8,014,612.27	3,794,602.04	6,357,990.30	18,167,204.61
Rents	3,213.00	3,570.00	5,117.00	11,900.00
Total Production Expenses	$ 32,160,432.14	$ 34,599,604.36	$ 46,011,062.19	$ 112,771,098.69
Fuel Costs - Cents				
Coal, Including Freight (1)	2.631	2.403	2.382	2.450
Coal and Other (1) (2)	2.816	2.508	2.487	2.575
Total All Fuel Costs (2)	2.816	2.508	2.487	2.575
Other Operation Expenses	0.881	0.809	1.168	0.973
Maintenance	1.227	0.409	0.586	0.681
Rents	0.000	0.000	0.000	0.000
Total Production Expenses	4.924	3.726	4.241	4.229
Quantities of Fuel Burned:				
Coal - Tons	345,700.43	449,436.32	519,907.55	1,315,044.30
Gas - Mcf - Start-up/Stabilization	60,106.00	36,760.00	39,517.00	136,383.00
Oil - Gallons - Start-up/Stabilization	-	-	-	-
MMBtu Burned:				
Coal	7,621,880.32	9,910,389.34	11,462,941.19	28,995,210.85
Gas - Start-up/Stabilization	61,608.69	37,679.06	40,504.98	139,792.73
Oil - Start-up/Stabilization	-	-	-	-
Total MMBtu Burned	7,683,489.01	9,948,068.40	11,503,446.17	29,135,003.58
Average Btu per Net Kwh Output (Heat Rate)	11,765	10,713	10,606	10,927

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2012

	Year to Date				
Mill Creek - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal...	2,016,171,000	1,452,212,000	2,611,560,000	2,281,218,000	8,361,161,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight..	$ 49,450,175.97	$ 36,504,578.79	$ 62,834,530.92	$ 55,922,805.47	$ 204,712,091.15
Coal, Including Freight, Handling, Etc (2)..................	50,530,804.98	37,633,465.21	65,098,797.22	59,245,749.53	212,508,816.94
Total Fuel (2)..	50,530,804.98	37,633,465.21	65,098,797.22	59,245,749.53	212,508,816.94
Other Operation Expenses	6,166,640.61	5,370,549.19	6,038,195.39	7,110,647.10	24,686,032.29
Maintenance	5,438,510.28	11,573,207.68	6,125,976.03	10,266,924.77	33,404,618.76
Rents..	9,702.00	9,702.00	12,012.00	14,784.00	46,200.00
Total Production Expenses	$ 62,145,657.87	$ 54,586,924.08	$ 77,274,980.64	$ 76,638,105.40	$ 270,645,667.99
Fuel Costs - Cents					
Coal, Including Freight (1)	2.453	2.514	2.406	2.451	2.448
Coal and Other (1) (2).......................................	2.506	2.591	2.493	2.597	2.542
Total All Fuel Costs (2).....................................	2.506	2.591	2.493	2.597	2.542
Other Operation Expenses.....................................	0.306	0.370	0.231	0.312	0.295
Maintenance..	0.270	0.797	0.235	0.450	0.400
Rents..	0.000	0.001	0.000	0.001	0.001
Total Production Expenses....................................	3.082	3.759	2.959	3.360	3.238
Quantities of Fuel Burned:					
Coal - Tons..	936,736.20	688,687.55	1,189,467.15	1,064,326.05	3,879,216.95
Gas - Mcf - Start-up/Stabilization...........................	17,821.00	24,847.00	115,246.00	204,934.00	362,848.00
Oil - Gallons - Start-up/Stabilization.......................	-	-	-	-	-
MMBtu Burned:					
Coal...	21,373,706.74	15,733,119.13	27,136,378.83	24,278,360.98	88,521,565.68
Gas - Start-up/Stabilization.................................	18,266.59	25,468.23	118,127.20	210,057.40	371,919.42
Oil - Start-up/Stabilization.................................	-	-	-	-	-
Total MMBtu Burned	21,391,973.33	15,758,587.36	27,254,506.03	24,488,418.38	88,893,485.10
Average Btu per Net Kwh Output (Heat Rate)	10,610	10,851	10,436	10,735	10,632

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

Attachment to Response to Sierra Club Question No. 1.5 (a)(b)(c)

January 25, 2013
Schram

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2012

Trimble County - Steam (3)	Year to Date Unit 1	Year to Date Unit 2	Year to Date Total
Kwh Output			
Net Kwh - Coal	2,865,938,000	472,775,000	3,338,713,000
IMEA	493,160,000	78,296,000	571,456,000
IMPA	507,548,000	83,213,000	590,761,000
Total Kwh Output	3,866,646,000	634,284,000	4,500,930,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 93,863,807.60	$ 13,978,958.21	$ 107,842,765.81
Coal, Including Freight, Handling, Etc (2)	96,198,904.89	15,522,667.12	111,721,572.01
Total Fuel (2)	96,198,904.89	15,522,667.12	111,721,572.01
Other Operation Expenses	8,327,802.65	2,031,910.89	10,359,713.54
Maintenance	9,519,780.36	1,929,269.56	11,449,049.92
Rents	11,269.74	-	11,269.74
Total Production Expenses	$ 114,057,757.64	$ 19,483,847.57	$ 133,541,605.21
Cost per Net Kwh Output - Cents:			
Coal Including. Freight (1)	2.428	2.204	2.396
Coal Including Freight, Handling, Etc (1) (2)	2.488	2.447	2.482
Total All Fuel Costs (2)	2.488	2.447	2.482
Other Operation Expenses	0.215	0.320	0.230
Maintenance	0.246	0.304	0.254
Rents	0.000	-	0.000
Total Production Expenses	2.949	3.071	2.966
Quantities of Fuel Burned:			
Coal - Tons	1,808,397.98	278,322.36	2,086,720.34
Oil - Gallons - Start-up/Stabilization	421,549.00	334,587.00	756,136.00
MMBtu Burned:			
Coal	41,347,558.15	5,946,843.16	47,294,401.31
Oil - Start-up/Stabilization	59,016.86	46,842.18	105,859.04
Total MMBtu Burned	41,406,575.01	5,993,685.34	47,400,260.35
Average Btu per Net Kwh Output	10,709	9,450	10,531
Average Btu per Pound of Coal	11,432	10,683	11,332
Average Btu per Gallon of Oil	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)	227.012	235.065	228.024
Total All Fuel Cost per MMBtu (2)	232.328	258.984	235.698
Cost of Coal & Freight per Ton ($)	51.904	50.226	51.681

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% generation, quantities used, and costs of Trimble County Unit #1 and 100% of LG&E's portion of Trimble County Unit #2

January 25, 2013

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2013

Tyrone - Steam	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year	Year Ended Current Month This Year	Year Ended Current Month Last Year
Kwh Output						
Net Kwh - Coal..	-	(89,000)	(114,000)	(1,407,000)	(114,000)	(1,407,000)
Net Kwh - Oil...	-	-	-	-	-	-
Total Kwh Output...	-	(89,000)	(114,000)	(1,407,000)	(114,000)	(1,407,000)
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight..	$ -	$ -	$ -	$ -	$ -	$ -
Coal, Including Freight, Handling, Etc (2)................	-	1,891.82	79,556.50	35,824.23	79,556.50	35,824.23
Total Fuel (2)...	-	1,891.82	79,556.50	35,824.23	79,556.50	35,824.23
Other Operation Expenses	14,423.80	45,846.12	400,041.93	371,632.65	400,041.93	371,632.65
Maintenance	-	1,085.80	6,519.06	158,968.19	6,519.06	158,968.19
Rents...	-	-	-	-	-	-
Total Production Expenses..	$ 14,423.80	$ 48,823.74	$ 486,117.49	$ 566,425.07	$ 486,117.49	$ 566,425.07
Cost per Net Kwh Output - Cents:						
Coal, Including Freight (1).......................................	-	-	-	-	-	-
Coal Including Freight, Handling, Etc (1) (2)...........	-	(2.126)	(69.786)	(2.546)	(69.786)	(2.546)
Total All Fuel Costs (2)...	-	(2.126)	(69.786)	(2.546)	(69.786)	(2.546)
Other Operation Expenses...	-	(51.512)	(350.914)	(26.413)	(350.914)	(26.413)
Maintenance..	-	(1.220)	(5.718)	(11.298)	(5.718)	(11.298)
Rents...	-	-	-	-	-	-
Total Production Expenses..	-	(54.858)	(426.419)	(40.258)	(426.419)	(40.258)
Quantities of Fuel Burned:						
Coal - Tons..	-	-	-	-	-	-
Oil - Gallons - Start-up/Stabilization........................	-	-	-	-	-	-
MMBtu Burned:						
Coal...	-	-	-	-	-	-
Oil - Start-up/Stabilization.......................................	-	-	-	-	-	-
Total MMBtu Burned..	-	-	-	-	-	-
Average Btu per Net Kwh Output................................	-	-	-	-	-	-
Average Btu per Pound of Coal...................................	-	-	-	-	-	-
Average Btu per Gallon of Oil.....................................	-	-	-	-	-	-
Cost Coal & Freight per MMBtu (Cents).....................	-	-	-	-	-	-
Total All Fuel Cost per MMBtu (2).............................	-	-	-	-	-	-
Cost of Coal & Freight Per Ton ($).............................	-	-	-	-	-	-

(1) Based on Kwh generated by coal or oil as applicable
(2) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2013

Green River - Steam	Year to Date Unit 3	Unit 4	Total
Kwh Output			
Net Kwh - Coal	310,970,000	652,894,000	963,864,000
Total Kwh Output	310,970,000	652,894,000	963,864,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 9,848,005.71	$ 17,761,912.35	$ 27,609,918.06
Coal, Including Freight, Handling, Etc (1)	10,340,877.35	18,572,022.11	28,912,899.46
Total Fuel (1)	10,340,877.35	18,572,022.11	28,912,899.46
Other Operation Expenses	1,495,993.67	2,809,000.31	4,304,993.98
Maintenance	2,022,457.24	4,189,093.45	6,211,550.69
Rents	-	-	-
Total Production Expenses	$ 13,859,328.26	$ 25,570,115.87	$ 39,429,444.13
Cost per Net Kwh Output - Cents:			
Coal, Including Freight	3.167	2.720	2.865
Coal, Including Freight, Handling, Etc (1)	3.325	2.845	3.000
Total All Fuel Costs (1)	3.325	2.845	3.000
Other Operation Expenses	0.481	0.430	0.447
Maintenance	0.650	0.642	0.644
Rents	-	-	-
Total Production Expenses	4.457	3.916	4.091
Quantities of Fuel Burned:			
Coal - Tons	171,867.00	309,791.00	481,658.00
Oil - Gallons - Start-up/Stabilization	42,877.00	86,836.00	129,713.00
MMBtu Burned:			
Coal	4,034,104.39	7,270,713.73	11,304,818.12
Oil - Start-up/Stabilization	6,002.78	12,157.04	18,159.82
Total MMBtu Burned	4,040,107.17	7,282,870.77	11,322,977.94
Average Btu per Net Kwh Output	12,992	11,155	11,747

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

January 27, 2014

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2013

	Year to Date			
EW Brown - Steam	Unit 1	Unit 2	Unit 3	Total
Kwh Output				
Net Kwh - Coal...	378,905,000	875,868,000	1,599,752,000	2,854,525,000
Total Kwh Output...	378,905,000	875,868,000	1,599,752,000	2,854,525,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight..	$ 13,706,374.56	$ 28,392,146.19	$ 54,427,800.52	$ 96,526,321.27
Coal, Including Freight, Handling, Etc (1)................	14,403,930.11	29,195,232.60	56,256,697.75	99,855,860.46
Total Fuel (1)...	14,403,930.11	29,195,232.60	56,256,697.75	99,855,860.46
Other Operation Expenses...	1,627,893.21	3,191,828.61	7,670,937.59	12,490,659.41
Maintenance..	2,629,202.28	4,073,442.15	7,366,516.63	14,069,161.06
Rents..	1,786.90	2,859.03	7,266.72	11,912.65
Total Production Expenses..	$ 18,662,812.50	$ 36,463,362.39	$ 71,301,418.69	$ 126,427,593.58
Cost per Net Kwh Output - Cents:				
Coal, Including Freight..	3.617	3.242	3.402	3.382
Coal, Including Freight, Handling, Etc (1)................	3.801	3.333	3.517	3.498
Total All Fuel Costs (1)...	3.801	3.333	3.517	3.498
Other Operation Expenses...	0.430	0.364	0.480	0.438
Maintenance..	0.694	0.465	0.460	0.493
Rents..	0.000	0.000	0.000	0.000
Total Production Expenses..	4.925	4.163	4.457	4.429
Quantities of Fuel Burned:				
Coal - Tons..	199,731.00	411,928.00	794,623.00	1,406,282.00
Oil - Gallons - Start-up/Stabilization..........................	123,877.00	99,487.00	185,390.00	408,754.00
MMBtu Burned:				
Coal..	4,541,881.80	9,382,989.23	18,068,111.74	31,992,982.77
Oil - Start-up/Stabilization..	17,342.78	13,928.18	25,954.60	57,225.56
Total MMBtu Burned	4,559,224.58	9,396,917.41	18,094,066.34	32,050,208.33
Average Btu per Net Kwh Output.................................	12,033	10,729	11,311	11,228

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2013

Ghent - Steam	Year to Date Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	3,334,601,000	3,513,063,000	3,294,839,000	3,011,140,000	13,153,643,000
Total Kwh Output..	3,334,601,000	3,513,063,000	3,294,839,000	3,011,140,000	13,153,643,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight..	$ 77,777,785.76	$ 81,386,705.06	$ 79,532,631.63	$ 72,302,670.40	$ 310,999,792.85
Coal, Including Freight, Handling, Etc (1)................	78,874,602.60	82,411,055.54	80,923,698.38	74,804,746.92	317,014,103.44
Total Fuel (1)...	78,874,602.60	82,411,055.54	80,923,698.38	74,804,746.92	317,014,103.44
Other Operation Expenses..	9,252,868.20	6,267,770.53	9,613,630.75	12,893,948.23	38,028,217.71
Maintenance...	10,380,952.50	6,741,666.14	6,500,320.24	9,327,737.79	32,950,676.67
Rents..	-	-	-	-	-
Total Production Expenses...	$ 98,508,423.30	$ 95,420,492.21	$ 97,037,649.37	$ 97,026,432.94	$ 387,992,997.82
Cost per Net Kwh Output - Cents:					
Coal, Including Freight..	2.332	2.317	2.414	2.401	2.364
Coal, Including Freight, Handling, Etc (1)................	2.365	2.346	2.456	2.484	2.410
Total All Fuel Costs (1)...	2.365	2.346	2.456	2.484	2.410
Other Operation Expenses..	0.277	0.178	0.292	0.428	0.289
Maintenance...	0.311	0.192	0.197	0.310	0.251
Rents..	-	-	-	-	-
Total Production Expenses...	2.954	2.716	2.945	3.222	2.950
Quantities of Fuel Burned:					
Coal - Tons...	1,594,244.00	1,666,171.00	1,617,865.00	1,474,696.00	6,352,976.00
Oil - Gallons - Start-up/Stabilization..........................	181,896.00	152,633.00	259,539.00	299,847.00	893,915.00
MMBtu Burned:					
Coal..	35,935,318.77	37,555,823.76	36,469,488.91	33,233,322.67	143,193,954.11
Oil - Start-up/Stabilization..	25,465.44	21,368.62	36,335.46	41,978.58	125,148.10
Total MMBtu Burned..	35,960,784.21	37,577,192.38	36,505,824.37	33,275,301.25	143,319,102.21
Average Btu per Net Kwh Output.................................	10,784	10,696	11,080	11,051	10,896

(1) Also includes oil used for firing, disposal of bottom ash and fly ash (net)

Kentucky Utilities Company
Electric Generating Costs and Fuel Performance
December 31, 2013

Trimble County - Steam (3)	Current Month This Year	Current Month Last Year	Year to Date This Year	Year to Date Last Year	Year Ended Current Month This Year	Year Ended Current Month Last Year
Kwh Output						
Net Kwh - Coal	265,414,000	(5,749,000)	2,533,399,000	2,015,516,000	2,533,399,000	2,015,516,000
IMEA	41,894,000	8,000	415,990,000	333,787,000	415,990,000	333,787,000
IMPA	44,601,000	8,000	442,368,000	354,748,000	442,368,000	354,748,000
Total Kwh Output	351,909,000	(5,733,000)	3,391,757,000	2,704,051,000	3,391,757,000	2,704,051,000
Production Costs ($)						
Fuel Costs:						
Coal, Including Freight	$ 7,445,978.29	$ 24,169.40	$ 75,544,052.21	59,594,544.95	$ 75,544,052.21	$ 59,594,544.95
Coal, Including Freight, Handling, Etc (2)	8,159,035.50	573,103.33	80,468,330.55	65,140,300.11	80,468,330.55	65,140,300.11
Total Fuel (2)	8,159,035.50	573,103.33	80,468,330.55	65,140,300.11	80,468,330.55	65,140,300.11
Other Operation Expenses	1,195,340.13	500,422.42	9,383,355.55	8,662,361.63	9,383,355.55	8,662,361.63
Maintenance	531,934.94	1,504,213.91	9,476,099.85	10,860,900.04	9,476,099.85	10,860,900.04
Rents	-	-	-	-	-	-
Total Production Expenses	$ 9,886,310.57	$ 2,577,739.66	$ 99,327,785.95	$ 84,663,561.78	$ 99,327,785.95	$ 84,663,561.78
Cost per Net Kwh Output - Cents:						
Coal, Including Freight (1)	2.116	(0.422)	2.227	2.204	2.227	2.204
Coal Including Freight, Handling, Etc (1) (2)	2.319	(9.997)	2.372	2.409	2.372	2.409
Total All Fuel Costs (2)	2.319	(9.997)	2.372	2.409	2.372	2.409
Other Operation Expenses	0.340	(8.729)	0.277	0.320	0.277	0.320
Maintenance	0.151	(26.238)	0.279	0.402	0.279	0.402
Rents	-	-	-	-	-	-
Total Production Expenses	2.809	(44.963)	2.929	3.131	2.929	3.131
Quantities of Fuel Burned:						
Coal - Tons	149,194.21	480.62	1,481,791.82	1,186,532.05	1,481,791.82	1,186,532.05
Oil - Gallons - Start-up/Stabilization	198,731.88	129,275.19	1,149,446.70	1,426,397.04	1,149,446.70	1,426,397.04
MMBtu Burned:						
Coal	3,188,151.37	10,270.38	31,611,456.58	25,352,319.82	31,611,456.58	25,352,319.82
Oil - Start-up/Stabilization	27,822.47	18,098.52	160,922.57	199,695.59	160,922.57	199,695.59
Total MMBtu Burned	3,215,973.84	28,368.90	31,772,379.15	25,552,015.41	31,772,379.15	25,552,015.41
Average Btu per Net Kwh Output	9,139	(4,948)	9,368	9,450	9,368	9,450
Average Btu per Pound of Coal	10,685	10,685	10,667	10,683	10,667	10,683
Average Btu per Gallon of Oil	140,000	140,000	140,000	140,000	140,000	140,000
Cost Coal and Freight per MMBtu (Cents)	233.552	235.331	238.977	235.065	238.977	235.065
Total All Fuel Cost per MMBtu (2)	253.703	2,020.182	253.265	254.932	253.265	254.932
Cost of Coal and Freight Per Ton ($)	49.908	50.288	50.982	50.226	50.982	50.226

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% of KU's portion of Trimble County Unit #2 generation, quantities used, and costs of Trimble County Unit #2

January 27, 2014

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2013

Cane Run - Steam	Year to Date Unit 4	Unit 5	Unit 6	Total
Kwh Output				
Net Kwh - Coal.................……………………………	696,703,000	864,302,000	995,291,000	2,556,296,000
Production Costs ($)				
Fuel Costs:				
Coal, Including Freight...	$ 17,363,230.82	$ 20,426,142.22	$ 23,423,937.64	$ 61,213,310.68
Coal, Including Freight, Handling, Etc (2)............................	18,715,875.72	21,400,877.74	24,661,496.62	64,778,250.08
Total Fuel (2)...	18,715,875.72	21,400,877.74	24,661,496.62	64,778,250.08
Other Operation Expenses	6,270,348.96	7,365,482.69	10,989,291.05	24,625,122.70
Maintenance ....……………	3,175,020.46	4,357,975.87	4,882,337.94	12,415,334.27
Rents ....…………………..………	2,295.00	2,550.00	3,655.00	8,500.00
Total Production Expenses	$ 28,163,540.14	$ 33,126,886.30	$ 40,536,780.61	$ 101,827,207.05
Fuel Costs - Cents				
Coal, Including Freight (1)	2.492	2.363	2.353	2.395
Coal and Other (1) (2)...	2.686	2.476	2.478	2.534
Total All Fuel Costs (2)..	2.686	2.476	2.478	2.534
Other Operation Expenses...	0.900	0.852	1.104	0.963
Maintenance...	0.456	0.504	0.491	0.486
Rents ....…………………………	0.000	0.000	0.000	0.000
Total Production Expenses......................................	4.042	3.833	4.073	3.983
Quantities of Fuel Burned:				
Coal - Tons...	360,686.07	422,154.96	486,422.18	1,269,263.21
Gas - Mcf - Start-up/Stabilization................................	51,390.00	30,798.00	35,026.00	117,214.00
Oil - Gallons - Start-up/Stabilization..................................	-	-	-	-
MMBtu Burned:				
Coal...	7,999,400.44	9,353,146.30	10,780,444.32	28,132,991.06
Gas - Start-up/Stabilization..	52,674.80	31,568.01	35,901.71	120,144.52
Oil - Start-up/Stabilization..	-	-	-	-
Total MMBtu Burned	8,052,075.24	9,384,714.31	10,816,346.03	28,253,135.58
Average Btu per Net Kwh Output (Heat Rate)	11,557	10,858	10,868	11,052

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

January 27, 2014

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2013

	Year to Date				
Mill Creek - Steam	Unit 1	Unit 2	Unit 3	Unit 4	Total
Kwh Output					
Net Kwh - Coal..	1,466,563,000	1,898,669,000	2,212,407,000	2,709,274,000	8,286,913,000
Production Costs ($)					
Fuel Costs:					
Coal, Including Freight..	$ 36,665,281.60	$ 47,853,690.86	$ 55,086,533.90	$ 68,840,460.44	$ 208,445,966.80
Coal, Including Freight, Handling, Etc (2)............................	38,072,239.83	49,279,774.99	57,701,723.00	72,520,187.47	217,573,925.29
Total Fuel (2)..	38,072,239.83	49,279,774.99	57,701,723.00	72,520,187.47	217,573,925.29
Other Operation Expenses	5,787,185.49	5,777,151.80	5,402,306.65	7,458,956.49	24,425,600.43
Maintenance	12,414,517.14	4,658,317.62	11,644,864.55	8,305,130.68	37,022,829.99
Rents..	9,345.00	9,345.00	11,570.00	14,240.00	44,500.00
Total Production Expenses	$ 56,283,287.46	$ 59,724,589.41	$ 74,760,464.20	$ 88,298,514.64	$ 279,066,855.71
Fuel Costs - Cents					
Coal, Including Freight (1)	2.500	2.520	2.490	2.541	2.515
Coal and Other (1) (2)..	2.596	2.595	2.608	2.677	2.626
Total All Fuel Costs (2)..	2.596	2.595	2.608	2.677	2.626
Other Operation Expenses..	0.395	0.304	0.244	0.275	0.295
Maintenance..	0.847	0.245	0.526	0.307	0.447
Rents..	0.001	0.000	0.001	0.001	0.001
Total Production Expenses......................................	3.838	3.146	3.379	3.259	3.368
Quantities of Fuel Burned:					
Coal - Tons..	669,720.35	870,281.55	995,862.15	1,251,685.30	3,787,549.35
Gas - Mcf - Start-up/Stabilization................................	46,815.00	49,078.00	149,082.00	219,066.00	464,041.00
Oil - Gallons - Start-up/Stabilization..................................	-	-	-	-	-
MMBtu Burned:					
Coal..	15,582,516.04	20,210,141.90	23,076,867.98	29,108,955.11	87,978,481.03
Gas - Start-up/Stabilization..	47,985.43	50,304.98	152,809.10	224,542.72	475,642.23
Oil - Start-up/Stabilization..	-	-	-	-	-
Total MMBtu Burned	15,630,501.47	20,260,446.88	23,229,677.08	29,333,497.83	88,454,123.26
Average Btu per Net Kwh Output (Heat Rate)	10,658	10,671	10,500	10,827	10,674

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)

January 27, 2014

Louisville Gas and Electric Company
Electric Generating Costs and Fuel Performance
December 31, 2013

	Year to Date		
Trimble County - Steam (3)	Unit 1	Unit 2	Total
Kwh Output			
Net Kwh - Coal	2,539,649,000	594,254,000	3,133,903,000
IMEA	457,014,000	97,579,000	554,593,000
IMPA	476,175,000	103,765,000	579,940,000
Total Kwh Output	3,472,838,000	795,598,000	4,268,436,000
Production Costs ($)			
Fuel Costs:			
Coal, Including Freight	$ 87,886,473.14	$ 17,467,924.06	$ 105,354,397.20
Coal, Including Freight, Handling, Etc (2)	90,374,965.04	18,642,847.71	109,017,812.75
Total Fuel (2)	90,374,965.04	18,642,847.71	109,017,812.75
Other Operation Expenses	8,580,582.04	2,200,852.74	10,781,434.78
Maintenance	12,365,145.36	2,222,094.39	14,587,239.75
Rents	1,873.90	-	1,873.90
Total Production Expenses	$ 111,322,566.34	$ 23,065,794.84	$ 134,388,361.18
Cost per Net Kwh Output - Cents:			
Coal Including. Freight (1)	2.531	2.196	2.468
Coal Including Freight, Handling, Etc (1) (2)	2.602	2.343	2.554
Total All Fuel Costs (2)	2.602	2.343	2.554
Other Operation Expenses	0.247	0.277	0.253
Maintenance	0.356	0.279	0.342
Rents	0.000	-	0.000
Total Production Expenses	3.206	2.899	3.148
Quantities of Fuel Burned:			
Coal - Tons	1,635,232.49	347,868.17	1,983,100.66
Oil - Gallons - Start-up/Stabilization	478,098.00	269,623.30	747,721.30
MMBtu Burned:			
Coal	37,309,250.78	7,421,169.51	44,730,420.29
Oil - Start-up/Stabilization	66,933.72	37,747.26	104,680.98
Total MMBtu Burned	37,376,184.50	7,458,916.77	44,835,101.27
Average Btu per Net Kwh Output	10,762	9,375	10,504
Average Btu per Pound of Coal	11,408	10,667	11,278
Average Btu per Gallon of Oil	140,000	140,000	140,000
Cost Coal & Freight per MMBtu (Cents)	235.562	235.380	235.532
Total All Fuel Cost per MMBtu (2)	241.798	249.940	243.153
Cost of Coal & Freight per Ton ($)	53.746	50.214	53.126

(1) Based on Kwh generated by coal or gas as applicable
(2) Also includes oil and gas used for firing, disposal of bottom ash and fly ash (net)
(3) Information on this report represents 100% generation, quantities used, and costs of Trimble County Unit #1 and 100% of LG&E's portion of Trimble County Unit #2

January 27, 2014

Capital 2005-2013 ($000s)

	Capital								
	2005	2006	2007	2008	2009	2010	2011	2012	2013
STEAM									
Ghent	36,178	163,967	292,750	161,378	66,664	53,277	86,727	210,985	351,070
GH Common	3,198	34,673	90,527	13,014	16,464	13,840	61,816	131,364	95,657
GH1	1,838	9,037	13,281	1,609	2,631	10,841	3,031	13,310	50,302
GH1&2	52	26	9	52	1	-	287	16	59
GH2	3,711	10,562	47,018	89,388	42,850	743	10,900	27,451	22,777
GH3	25,682	66,528	56,530	10,983	1,190	6,539	7,118	25,384	99,850
GH3&4	87	28	82	4	21	20	15	-	977
GH4	1,610	43,112	85,304	46,328	3,507	21,293	3,560	13,460	81,447
Brown	12,781	20,885	128,113	148,759	141,246	107,738	67,293	62,778	38,580
BR Common	2,216	16,253	119,284	141,493	133,091	70,373	4,433	6,505	5,321
BR1	220	1,987	4,425	1,647	896	2,267	1,741	688	1,178
BR1&2	43	205	(0)	149	-	70	366	49	9
BR2	625	163	497	3,537	5,849	2,405	4,893	540	2,321
BR2&3	18	-	-	-	-	-	17	-	-
BR3	9,660	2,277	3,907	1,934	1,410	32,622	55,842	54,995	29,751
Green River	2,519	1,602	359	1,066	383	2,787	705	1,265	526
GR Common	1,688	357	(58)	338	172	696	311	938	60
GR1&2	-	-	-	18	-	(96)	-	-	-
GR3	42	505	129	224	114	1,292	26	162	(13)
GR4	789	740	287	485	97	896	367	165	479
Tyrone	1,269	1,348	623	1,263	163	77	8	-	4,001
Pineville	-	-	-	-	-	-	-	222	(0)
Mill Creek	14,496	19,750	12,243	16,667	14,945	28,243	33,337	89,948	282,333
MC Common	947	440	354	111	174	(218)	1,119	(1,043)	363
MC1	722	2,424	1,010	7,102	(200)	3,349	1,166	21,226	67,019
MC2	3,177	810	2,123	217	5,360	5,280	8,644	21,446	36,709
MC3	274	2,867	6,429	691	2,019	4,112	10,379	11,533	52,700
MC4	9,376	13,210	2,327	8,546	7,593	15,720	12,030	36,786	125,543
Cane Run	5,834	9,387	7,303	7,224	7,872	8,554	4,104	1,463	8,611
CR Common	606	2,064	3	409	1,369	921	301	294	62
CR3	(31)	-	-	-	-	-	-	-	-
CR4	833	967	124	499	962	495	535	603	1,351
CR5	1,808	512	2,049	4,267	1,218	400	489	369	400
CR6	2,619	5,844	5,138	2,048	4,322	6,738	2,778	197	6,798
CR1&2	-	-	(12)	-	-	-	-	-	-
Trimble County	16,693	121,190	308,236	276,054	177,841	39,060	28,916	39,850	22,733
TC common	(73)	830	343	1,316	558	853	(95)	13	38
TC1	12,517	8,211	19,610	1,583	7,490	6,140	9,225	5,250	15,074
TC2	4,248	112,150	288,283	273,155	169,793	32,067	19,786	34,587	7,620
Total Steam	89,769	338,130	749,626	612,412	409,115	239,735	221,089	406,510	707,852

Station	Unit	Average Net Heat Rate (Btu/Kwh) 2005	Average Net Heat Rate (Btu/Kwh) 2006	Average Net Heat Rate (Btu/Kwh) 2007	Average Net Heat Rate (Btu/Kwh) 2008	Average Net Heat Rate (Btu/Kwh) 2009	Average Net Heat Rate (Btu/Kwh) 2010	Average Net Heat Rate (Btu/Kwh) 2011	Average Net Heat Rate (Btu/Kwh) 2012	Average Net Heat Rate (Btu/Kwh) 2013
		(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)	(Q.1.6.e.)
Brown	1	11,115	11,318	11,167	11,063	11,682	11,064	12,021	12,092	12,026
Brown	2	10,082	10,256	10,354	10,282	10,414	10,293	10,825	10,710	10,457
Brown	3	10,538	10,453	10,291	10,321	10,534	10,815	11,154	11,267	11,308
Brown	5	12,265	13,389	15,582	21,983	23,867	17,401	24,738	18,529	24,324
Brown	6	10,832	11,177	11,519	13,439	12,583	13,095	14,822	11,507	9,689
Brown	7	11,222	10,986	11,744	12,075	11,546	13,698	12,977	11,560	12,117
Brown	8	18,923	13,775	14,816	17,485	17,357	17,650	20,569	21,175	20,979
Brown	9	24,969	15,031	15,524	19,714	28,521	19,671	22,337	17,585	17,924
Brown	10	24,433	15,257	21,431	27,104	20,463	20,873	31,003	23,499	38,448
Brown	11	19,121	15,615	15,911	44,845	18,038	16,941	38,470	18,458	31,950
Cane Run	4	10,897	10,469	9,907	10,776	10,830	10,418	10,602	11,764	11,556
Cane Run	5	10,532	11,030	11,227	10,495	10,648	10,748	10,720	10,713	10,858
Cane Run	6	10,234	10,491	10,556	10,602	10,823	10,718	10,593	11,286	10,841
Cane Run	11	21,437	9,511	42,849	84,423	20,943	144,188	21,328	28,638	38,642
Dix Dam	1	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Dix Dam	2	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Dix Dam	3	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ghent	1	10,303	10,628	10,647	10,653	10,437	10,329	10,413	10,705	10,784
Ghent	2	10,232	10,145	10,158	10,323	10,465	10,399	10,905	10,608	10,696
Ghent	3	10,671	10,957	10,896	10,998	11,131	10,801	10,768	10,905	11,080
Ghent	4	10,110	10,664	10,679	10,797	10,988	10,887	10,900	11,156	11,051
Green River	3	14,411	12,746	12,522	11,936	11,942	11,929	12,426	14,058	13,154
Green River	4	14,726	11,339	11,175	11,067	11,278	11,043	11,485	11,668	11,311
Haefling	1	0	0	0	0	0	--,---	--,---	--,---	--,---
Haefling	2	0	0	0	0	0	--,---	--,---	--,---	--,---
Mill Creek	1	10,446	10,567	10,493	10,646	10,639	10,684	10,622	10,607	10,658
Mill Creek	2	10,956	10,895	10,695	10,820	10,928	10,845	11,075	10,867	10,672
Mill Creek	3	10,424	10,570	10,625	10,619	10,619	10,738	10,602	10,436	10,504
Mill Creek	4	10,588	10,548	10,759	10,653	10,410	10,518	10,616	10,735	10,827
Ohio Falls	1	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	2	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	3	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	4	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	5	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	6	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	7	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Ohio Falls	8	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---	--,---
Paddys Run	11	23,443	21,836	38,035	0	151,188	42,947	74,663	43,968	0
Paddys Run	12	14,606	15,293	226,781	0	0	55,026	0	49,351	0
Paddys Run	13	9,140	10,850	10,704	11,118	11,886	10,956	11,100	11,571	11,355
Trimble County	1	10,222	10,191	10,358	10,368	10,554	10,695	10,665	10,705	10,763
Trimble County	2	--,---	--,---	--,---	--,---	--,---	--,---	9,560	9,435	9,359
Trimble County	5	11,194	11,597	11,577	11,085	11,833	11,529	10,925	11,178	13,196
Trimble County	6	11,586	11,547	11,356	11,693	12,592	11,766	11,576	11,188	12,975
Trimble County	7	11,705	11,437	11,491	11,796	10,809	14,835	10,560	11,819	13,033
Trimble County	8	11,619	11,332	11,380	11,215	12,222	11,755	10,861	11,352	12,653
Trimble County	9	11,626	11,241	11,313	11,119	12,346	11,678	11,057	10,589	13,659
Trimble County	10	11,080	11,125	11,261	11,074	13,512	11,570	10,720	11,533	10,680
Zorn	1	0	19,820	22,120	0	16,419	22,881	0	20,911	25,818

Station	Unit	Net Generation (MWh) 2005	Net Generation (MWh) 2006	Net Generation (MWh) 2007	Net Generation (MWh) 2008	Net Generation (MWh) 2009	Net Generation (MWh) 2010	Net Generation (MWh) 2011	Net Generation (MWh) 2012	Net Generation (MWh) 2013
		(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)	(Q.1.6.f.)
Brown	1	563,532	480,534	493,483	513,921	217,008	411,311	317,251	324,035	378,905
Brown	2	1,075,007	956,008	1,013,933	1,074,881	547,458	763,280	616,832	721,085	875,868
Brown	3	1,584,997	2,031,288	2,396,909	2,534,659	1,740,829	1,828,361	1,563,842	1,323,503	1,599,792
Brown	5	122,928	30,777	19,823	2,340	2,380	8,061	3,634	6,618	3,382
Brown	6	165,122	97,500	88,563	21,817	36,780	48,131	28,481	127,748	50,307
Brown	7	156,711	99,276	51,599	33,143	26,632	46,851	33,892	95,198	42,879
Brown	8	2,954	46,642	19,870	6,622	7,658	7,864	4,340	2,561	2,834
Brown	9	1,636	27,105	11,236	3,411	1,509	5,196	4,718	7,403	5,316
Brown	10	1,683	20,966	5,334	1,722	2,370	4,365	1,741	2,188	875
Brown	11	1,854	12,875	4,458	677	4,551	8,529	1,301	5,671	1,299
Cane Run	4	1,049,200	964,843	1,102,772	1,042,427	947,128	927,127	967,087	653,192	696,743
Cane Run	5	1,088,209	1,081,141	1,041,443	883,495	952,330	1,110,385	952,048	928,589	864,302
Cane Run	6	1,538,197	1,529,163	1,392,399	1,477,446	1,335,527	1,233,866	1,287,984	1,084,657	995,291
Cane Run	11	143	1,179	239	4	210	228	198	296	200
Dix Dam	1	(20)	(6)	2,385	25,148	28,950	15,173	33,650	13,582	26,593
Dix Dam	2	17,306	22,875	17,364	25,078	32,016	14,736	13,098	5,416	39,906
Dix Dam	3	19,304	24,157	15,319	201	7,905	6,012	34,236	18,728	40,124
Ghent	1	3,488,919	3,374,706	2,915,043	3,598,899	2,867,642	3,295,876	3,394,813	3,166,600	3,298,654
Ghent	2	2,762,380	3,013,652	3,454,216	2,804,097	2,413,738	3,201,480	3,346,081	3,053,242	3,513,063
Ghent	3	3,086,729	2,968,147	2,358,308	3,262,152	3,182,388	3,431,840	2,866,840	3,333,292	3,294,839
Ghent	4	3,249,587	2,852,269	3,232,661	2,840,532	2,881,867	2,667,176	2,899,005	2,653,566	3,011,140
Green River	3	336,573	206,046	420,678	379,545	216,618	345,263	329,516	270,552	310,970
Green River	4	338,730	433,395	576,042	582,590	408,851	544,049	458,964	635,128	652,894
Haefling	1	(200)	(130)	(118)	(122)	(136)	175	143	585	383
Haefling	2	(204)	109	(3)	(130)	(147)	193	167	326	37
Mill Creek	1	2,211,424	1,964,526	2,153,807	1,985,134	2,106,620	2,009,037	2,044,329	2,016,171	1,466,563
Mill Creek	2	1,818,869	2,008,722	1,936,303	2,073,872	1,847,309	2,101,040	1,980,508	1,452,211	1,898,669
Mill Creek	3	2,953,575	2,827,105	2,793,210	2,989,529	2,786,525	2,914,876	1,875,925	2,611,560	2,212,407
Mill Creek	4	3,077,144	2,938,797	3,569,587	3,263,083	3,562,608	3,348,610	3,163,052	2,281,218	2,709,274
Ohio Falls	1	25,611	28,749	15,124	9,054	14,442	16,315	14,285	4,852	0
Ohio Falls	2	24,523	26,106	14,100	7,036	18,324	22,157	18,257	12,466	1,258
Ohio Falls	3	20,774	34,100	11,599	11,578	27,760	21,876	15,804	3,906	26,932
Ohio Falls	4	31,924	41,959	11,217	26,414	29,682	36,320	33,599	25,974	30,840
Ohio Falls	5	37,200	31,261	22,348	5,340	0	0	0	40,352	35,715
Ohio Falls	6	28,768	31,684	0	28,106	47,707	53,248	46,812	48,320	28,041
Ohio Falls	7	769	2,097	37,819	47,125	50,786	56,181	48,324	46,337	49,328
Ohio Falls	8	26,024	43,706	31,439	29,642	44,297	34,505	33,726	30,662	23,872
Paddys Run	11	700	882	159	0	12	279	95	221	(38)
Paddys Run	12	473	376	8	0	0	76	(272)	340	(182)
Paddys Run	13	134,409	88,772	66,112	6,480	1,247	14,831	31,411	56,710	29,267
Trimble County	1	2,858,445	3,131,213	2,683,007	3,048,777	2,300,055	2,722,317	2,410,890	2,899,985	2,604,629
Trimble County	2	-,---	-,---	-,---	-,---	-,---	-,---	3,116,818	2,506,228	3,140,516
Trimble County	5	8,924	11,776	92,506	73,991	43,455	129,011	59,355	226,311	66,372
Trimble County	6	22,459	23,796	83,951	69,781	28,243	100,288	66,423	259,618	89,149
Trimble County	7	44,210	50,944	112,700	59,476	39,368	108,211	72,925	100,026	72,123
Trimble County	8	77,152	76,817	149,773	63,037	33,230	98,266	54,521	102,009	27,346
Trimble County	9	46,514	59,506	148,369	58,190	29,731	125,065	75,141	259,734	84,647
Trimble County	10	90,645	71,376	130,927	51,429	21,366	103,882	47,533	86,050	26,433
Zorn	1	0	392	272	0	216	198	(74)	649	212

Station	Unit	Net Summer Capacity (MW) 2005 (Q.1.6.g.)	Net Summer Capacity (MW) 2006 (Q.1.6.g.)	Net Summer Capacity (MW) 2007 (Q.1.6.g.)	Net Summer Capacity (MW) 2008 (Q.1.6.g.)	Net Summer Capacity (MW) 2009 (Q.1.6.g.)	Net Summer Capacity (MW) 2010 (Q.1.6.g.)	Net Summer Capacity (MW) 2011 (Q.1.6.g.)	Net Summer Capacity (MW) 2012 (Q.1.6.g.)	Net Summer Capacity (MW) 2013 (Q.1.6.g.)
Brown	1	101	101	101	101	101	101	106	106	106
Brown	2	167	167	167	167	167	167	166	166	166
Brown	3	429	429	429	429	429	416	412	412	410
Brown	IAC	98	98	98	98	98	98	98	98	98
Brown	5	117	117	117	117	117	117	112	112	112
Brown	6	154	154	154	154	154	154	146	146	146
Brown	7	154	154	154	154	154	154	146	14	146
Brown	8	106	106	106	106	106	106	102	102	102
Brown	9	106	106	106	106	106	106	102	102	102
Brown	10	106	106	106	106	106	106	102	102	102
Brown	11	106	106	106	106	106	106	102	102	102
Cane Run	4	155	155	155	155	155	155	155	155	155
Cane Run	5	168	168	168	168	168	168	168	168	168
Cane Run	6	240	240	240	240	240	240	240	240	240
Cane Run	11	14	14	14	14	14	14	14	14	14
Dix Dam	1	8	8	8	8	8	8	8	8	8
Dix Dam	2	8	8	8	8	8	8	8	8	8
Dix Dam	3	8	8	8	8	8	8	8	8	8
Ghent	1	475	475	475	475	475	475	479	479	479
Ghent	2	484	484	484	484	484	484	495	495	495
Ghent	3	493	493	480	480	480	480	489	489	489
Ghent	4	493	493	493	493	479	479	469	469	469
Green River	3	68	68	68	68	68	68	68	68	68
Green River	4	95	95	95	95	95	95	95	95	93
Haefling	1	12	12	12	12	12	12	12	12	12
Haefling	2	12	12	12	12	12	12	12	12	12
Mill Creek	1	303	303	303	303	303	303	303	303	303
Mill Creek	2	301	301	301	301	301	301	301	301	301
Mill Creek	3	391	391	391	391	391	391	391	391	391
Mill Creek	4	477	477	477	477	477	477	477	477	477
Ohio Falls	1	6	6	6	6	6	6	6	6	6
Ohio Falls	2	6	6	6	6	6	6	6	6	6
Ohio Falls	3	6	6	6	6	6	6	6	6	6
Ohio Falls	4	6	6	6	6	6	6	6	6	6
Ohio Falls	5	6	6	6	6	6	6	6	8	8
Ohio Falls	6	6	6	8	8	8	8	8	8	8
Ohio Falls	7	6	6	8	8	8	8	8	8	8
Ohio Falls	8	6	6	6	6	6	6	6	6	6
Paddys Run	11	12	12	12	12	12	12	12	12	12
Paddys Run	12	23	23	23	23	23	23	23	23	23
Paddys Run	13	158	158	158	158	158	158	147	147	147
Trimble County	1	383	383	383	383	383	383	383	383	383
Trimble County	2	---	---	---	---	---	---	549	549	549
Trimble County	5	160	160	160	160	160	160	157	157	157
Trimble County	6	160	160	160	160	160	160	157	157	157
Trimble County	7	160	160	160	160	160	160	157	157	157
Trimble County	8	160	160	160	160	160	160	157	157	157
Trimble County	9	160	160	160	160	160	160	157	157	157
Trimble County	10	160	160	160	160	160	160	157	157	157
Zorn	1	14	14	14	14	14	14	14	14	14

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.6

Witness: Charles R. Schram

Q1.6. For each existing generating unit, please provide the following projected annual data by unit, for the economic analysis period in this filing (i.e., 2014-2028):

a. Fixed O&M cost;
b. Variable O&M cost (without fuel)
c. Fuel costs;
d. Capital costs
e. Capacity factor; and
f. Generation.

A1.6. Please see attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a Joint Petition for Confidential Protection. Fixed O&M and capital costs for existing units were not inputs to the IRP analysis and are available only by station through 2023; fixed O&M and capital costs are taken from the Companies' 2014 Business Plan.

Fixed O&M ($000)
2014 Business Plan
100% of Trimble County (STEAM)

	Fixed Costs									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
STEAM										
Ghent	[redacted]									
Brown										
Green River										
Tyrone										
Pineville										
Mill Creek										
Cane Run										
Trimble County										
SCCT/NGCC										
Trimble County	[redacted]									
Cane Run										
Paddys Run										
Zorn										
Canal										
Brown										
Haefling										
HYDRO										
Ohio Falls	[redacted]									
Dix Dam										

CONFIDENTIAL INFORMATION REDACTED

Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
Brown 2															
Brown 3															
Brown 5															
Brown 6															
Brown 7															
Brown 8															
Brown 9															
Cane Run 11															
Cane Run 4															
Cane Run 5															
Cane Run 6															
Cane Run 7															
Dix Dam 1-3															
Ghent 1															
Ghent 2															
Ghent 3															
Ghent 4															
Green River 3															
Green River 4															
Haefling 1-2															
Mill Creek 1															
Mill Creek 2															
Mill Creek 3															
Mill Creek 4															
Ohio Falls 1-8															
Paddy's Run 11															
Paddy's Run 12															
Paddy's Run 13															
Trimble County 1															
Trimble County 10															
Trimble County 2															
Trimble County 5															
Trimble County 6															
Trimble County 7															
Trimble County 8															
Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
Brown 11															
Brown 2															
Brown 3															
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Cane Run 11															
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Dix Dam 1-3															
Ghent 1															
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Ghent 4															
Green River 3															
Green River 4															
Haefling 1-2															
Mill Creek 1															
Mill Creek 2															
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Mill Creek 4															
Ohio Falls 1-8															
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Trimble County 8															
Trimble County 9															
Zorn 1															

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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Cane Run 11															
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Zorn 1															

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Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-High Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Zorn 1															

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Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
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Zorn 1															

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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
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Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Mid Carbon															
Brown 1	[redacted]														
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Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Zero Carbon															
Brown 1	[redacted]														
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Variable O&M ($000)
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	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Carbon Cap															
Brown 1	[redacted]														
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Mid Carbon															
Brown 1	[redacted]														
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-High Load-Zero Carbon															
Brown 1	[redacted]														
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
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Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Mid Carbon															
Brown 1	[redacted]														
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Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
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Variable O&M ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10	[redacted]														
Brown 11	[redacted]														
Brown 2	[redacted]														
Brown 3	[redacted]														
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Brown 9	[redacted]														
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Ghent 4	[redacted]														
Green River 3	[redacted]														
Green River 4	[redacted]														
Haefling 1-2	[redacted]														
Mill Creek 1	[redacted]														
Mill Creek 2	[redacted]														
Mill Creek 3	[redacted]														
Mill Creek 4	[redacted]														
Ohio Falls 1-8	[redacted]														
Paddy's Run 11	[redacted]														
Paddy's Run 12	[redacted]														
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Trimble County 1	[redacted]														
Trimble County 10	[redacted]														
Trimble County 2	[redacted]														
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Trimble County 9	[redacted]														
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-High Load-Zero Carbon															
Brown 1	[redacted]														
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	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Zero Carbon															
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Variable O&M ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
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75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10	[redacted]														
Brown 11	[redacted]														
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Paddy's Run 11	[redacted]														
Paddy's Run 12	[redacted]														
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Trimble County 1	[redacted]														
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Trimble County 9	[redacted]														
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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Zero Carbon															
Brown 1	[redacted]														
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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
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Fuel Costs ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10	[redacted]														
Brown 11	[redacted]														
Brown 2	[redacted]														
Brown 3	[redacted]														
Brown 5	[redacted]														
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Brown 9	[redacted]														
Cane Run 11	[redacted]														
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Dix Dam 1-3	[redacted]														
Ghent 1	[redacted]														
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Mill Creek 1	[redacted]														
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Mill Creek 4	[redacted]														
Ohio Falls 1-8	[redacted]														
Paddy's Run 11	[redacted]														
Paddy's Run 12	[redacted]														
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Trimble County 1	[redacted]														
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Trimble County 9	[redacted]														
Zorn 1	[redacted]														

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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-High Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10	[redacted]														
Brown 11	[redacted]														
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Fuel Costs ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10															
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Trimble County 8															
Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-High Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Ghent 1															
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Green River 3															
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Haefling 1-2															
Mill Creek 1															
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Ohio Falls 1-8															
Paddy's Run 11															
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Trimble County 1															
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Trimble County 8															
Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Trimble County 8															
Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Trimble County 9															
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CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10															
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Trimble County 8															
Trimble County 9															
Zorn 1															

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Fuel Costs ($000)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-High Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
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Trimble County 9															
Zorn 1															

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Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Zero Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
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Paddy's Run 11															
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Trimble County 1															
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Trimble County 7															
Trimble County 8															
Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Carbon Cap															
Brown 1	[redacted]														
Brown 10															
Brown 11															
Brown 2															
Brown 3															
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Cane Run 11															
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Ghent 4															
Green River 3															
Green River 4															
Haefling 1-2															
Mill Creek 1															
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Mill Creek 4															
Ohio Falls 1-8															
Paddy's Run 11															
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Paddy's Run 13															
Trimble County 1															
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Trimble County 6															
Trimble County 7															
Trimble County 8															
Trimble County 9															
Zorn 1															

CONFIDENTIAL INFORMATION REDACTED

Fuel Costs ($000)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Mid Carbon															
Brown 1	[redacted]														
Brown 10															
Brown 11															
Brown 2															
Brown 3															
Brown 5															
Brown 6															
Brown 7															
Brown 8															
Brown 9															
Cane Run 11															
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Dix Dam 1-3															
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Ghent 4															
Green River 3															
Green River 4															
Haefling 1-2															
Mill Creek 1															
Mill Creek 2															
Mill Creek 3															
Mill Creek 4															
Ohio Falls 1-8															
Paddy's Run 11															
Paddy's Run 12															
Paddy's Run 13															
Trimble County 1															
Trimble County 10															
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Trimble County 5															
Trimble County 6															
Trimble County 7															
Trimble County 8															
Trimble County 9															
Zorn 1															

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Capital ($000)
2014 Business Plan
75% of Trimble County (STEAM)

	Capital									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
STEAM										
Ghent	[redacted]									
Brown										
Green River										
Tyrone										
Pineville										
Mill Creek										
Cane Run										
Trimble County										
SCCT/NGCC										
Trimble County	[redacted]									
Cane Run										
Paddys Run										
Zorn										
Canal										
Brown										
Haefling										
HYDRO										
Ohio Falls	[redacted]									
Dix Dam										

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Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Zero Carbon															
Brown 1	13.8%	10.0%	14.9%	20.8%	27.6%	29.7%	25.7%	33.8%	29.8%	34.5%	33.1%	40.1%	39.3%	39.0%	40.4%
Brown 10	0.7%	0.7%	0.9%	0.9%	1.1%	0.8%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%
Brown 11	0.5%	0.5%	0.6%	0.7%	0.8%	0.5%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%
Brown 2	22.1%	20.6%	27.2%	27.1%	42.8%	40.2%	37.2%	42.0%	44.7%	41.7%	38.8%	49.0%	50.2%	49.4%	50.5%
Brown 3	33.6%	30.7%	34.0%	35.6%	34.9%	32.0%	35.0%	37.2%	36.2%	38.4%	37.8%	41.9%	38.3%	45.1%	45.4%
Brown 5	0.9%	0.9%	1.0%	1.1%	1.3%	1.0%	0.5%	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.0%	1.2%
Brown 6	2.1%	2.0%	2.2%	2.3%	2.8%	2.2%	1.7%	2.0%	2.1%	2.3%	2.4%	2.8%	3.2%	3.1%	3.8%
Brown 7	2.7%	2.5%	2.7%	3.1%	3.0%	3.0%	2.2%	2.6%	2.8%	3.0%	3.0%	3.5%	4.0%	3.8%	4.7%
Brown 8	0.6%	0.7%	0.7%	0.8%	0.9%	0.6%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%
Brown 9	0.8%	0.9%	1.0%	1.1%	1.3%	1.0%	0.5%	0.5%	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	30.5%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	76.8%	20.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	47.2%	14.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	64.2%	45.1%	40.6%	40.2%	31.8%	27.9%	29.2%	31.2%	24.5%	29.0%	30.5%	34.2%	29.3%	29.8%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	76.8%	61.4%	74.9%	78.4%	74.9%	78.2%	74.5%	76.3%	68.7%	78.1%	76.4%	79.6%	78.3%	80.1%	78.6%
Ghent 2	87.2%	78.2%	84.0%	85.8%	85.8%	74.0%	85.8%	84.1%	85.7%	83.9%	85.4%	84.2%	75.3%	85.9%	83.9%
Ghent 3	54.9%	60.4%	73.4%	75.0%	68.1%	68.4%	69.1%	70.9%	70.9%	70.6%	71.5%	66.5%	74.1%	75.0%	73.4%
Ghent 4	63.0%	52.2%	68.6%	64.3%	68.6%	69.6%	61.2%	59.0%	67.3%	65.8%	64.5%	69.1%	72.1%	68.3%	64.6%
Green River 3	17.8%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.5%	37.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.3%	0.3%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Mill Creek 1	88.2%	72.6%	82.8%	79.0%	85.8%	81.9%	86.6%	75.0%	87.0%	81.7%	86.9%	82.5%	87.3%	81.4%	87.2%
Mill Creek 2	84.0%	76.2%	80.0%	87.8%	83.1%	89.0%	76.8%	89.1%	83.9%	89.1%	83.9%	89.2%	83.9%	89.1%	77.0%
Mill Creek 3	86.4%	87.8%	61.1%	71.3%	77.2%	69.5%	80.3%	76.5%	81.7%	76.5%	81.4%	77.0%	82.3%	70.9%	82.7%
Mill Creek 4	69.0%	67.9%	78.9%	85.6%	83.1%	88.9%	83.5%	89.0%	76.5%	89.1%	83.7%	89.3%	83.8%	89.3%	84.0%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	14.0%	12.3%	10.9%	9.4%	8.4%	10.2%	7.4%	8.4%	8.3%	9.3%	9.0%	9.9%	10.7%	9.5%	12.9%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 10	4.9%	4.1%	4.3%	4.8%	5.1%	3.8%	2.9%	3.5%	3.6%	4.0%	3.8%	4.5%	5.1%	4.7%	5.9%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	21.9%	17.5%	16.0%	11.6%	16.8%	16.8%	10.5%	11.8%	10.8%	13.6%	11.8%	13.6%	15.4%	13.6%	17.0%
Trimble County 6	17.0%	13.2%	12.0%	13.5%	13.3%	13.1%	8.2%	7.9%	10.0%	10.7%	9.4%	10.9%	12.5%	11.0%	14.0%
Trimble County 7	12.8%	9.9%	9.9%	10.5%	8.8%	10.1%	6.5%	7.8%	8.0%	8.6%	7.4%	8.7%	10.3%	9.0%	11.5%
Trimble County 8	9.3%	7.5%	7.4%	7.7%	8.7%	7.8%	5.0%	6.0%	6.1%	6.7%	5.9%	7.0%	8.3%	7.3%	9.4%
Trimble County 9	6.8%	5.6%	5.6%	6.3%	6.3%	5.8%	3.8%	4.6%	4.8%	5.2%	4.8%	5.7%	6.6%	5.8%	7.5%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Carbon Cap															
Brown 1	13.8%	10.0%	14.9%	20.8%	27.6%	29.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.7%	0.7%	0.9%	0.9%	1.1%	0.8%	0.4%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.6%	0.6%
Brown 11	0.5%	0.5%	0.6%	0.7%	0.8%	0.5%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%
Brown 2	22.1%	20.6%	27.2%	27.1%	42.8%	40.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.6%	30.7%	34.0%	35.6%	34.9%	32.0%	38.0%	34.8%	33.5%	42.5%	34.9%	40.3%	33.0%	42.5%	38.3%
Brown 5	0.9%	0.9%	1.0%	1.1%	1.3%	1.0%	0.7%	0.4%	0.4%	0.8%	0.5%	0.8%	0.7%	0.9%	0.7%
Brown 6	2.1%	2.0%	2.2%	2.3%	2.8%	2.2%	1.3%	0.9%	0.9%	1.3%	1.2%	1.5%	1.5%	1.6%	1.5%
Brown 7	2.7%	2.5%	2.7%	3.1%	3.0%	3.0%	1.6%	1.1%	1.2%	1.6%	1.5%	1.9%	1.8%	2.0%	1.9%
Brown 8	0.6%	0.7%	0.7%	0.8%	0.9%	0.6%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%
Brown 9	0.8%	0.9%	1.0%	1.1%	1.3%	1.0%	0.5%	0.4%	0.4%	0.5%	0.5%	0.6%	0.6%	0.6%	0.7%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	30.5%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	76.8%	20.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	47.2%	14.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	64.2%	45.1%	40.6%	40.2%	31.8%	97.3%	77.5%	81.2%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	76.8%	61.4%	74.9%	78.4%	74.9%	78.2%	42.7%	35.6%	32.0%	40.7%	35.7%	40.4%	42.0%	39.4%	39.5%
Ghent 2	87.2%	78.2%	84.0%	85.8%	85.8%	74.0%	70.1%	74.6%	74.9%	70.4%	69.0%	70.3%	61.0%	70.1%	70.5%
Ghent 3	54.9%	60.4%	73.4%	75.0%	68.1%	68.4%	20.9%	23.2%	25.0%	20.4%	21.7%	21.5%	27.5%	23.9%	23.9%
Ghent 4	63.0%	52.2%	68.6%	64.3%	68.6%	69.6%	16.7%	12.8%	14.5%	16.5%	17.2%	20.2%	22.6%	18.3%	17.8%
Green River 3	17.8%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.5%	37.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.3%	0.3%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
Mill Creek 1	88.2%	72.6%	82.8%	79.0%	85.8%	81.9%	73.9%	67.4%	78.1%	69.3%	74.4%	70.6%	74.2%	68.4%	74.5%
Mill Creek 2	84.0%	76.2%	80.0%	87.8%	83.1%	89.0%	66.1%	82.3%	77.2%	76.7%	73.4%	76.6%	72.8%	76.1%	67.7%
Mill Creek 3	86.4%	87.8%	61.1%	71.3%	77.2%	69.5%	61.4%	61.2%	63.5%	58.5%	58.0%	57.0%	60.4%	52.5%	60.2%
Mill Creek 4	69.0%	67.9%	78.9%	85.6%	83.1%	88.9%	61.3%	72.1%	61.8%	62.9%	57.3%	62.2%	60.6%	61.6%	58.8%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	14.0%	12.3%	10.9%	9.4%	8.4%	10.2%	31.7%	5.5%	5.6%	24.0%	7.3%	8.8%	8.9%	8.1%	9.2%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	86.5%	82.6%	87.7%	81.7%	86.3%	74.8%	86.5%	81.5%	86.7%
Trimble County 10	4.9%	4.1%	4.3%	4.8%	5.1%	3.8%	7.8%	1.7%	1.8%	2.6%	2.2%	2.6%	2.7%	2.7%	2.7%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.6%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	21.9%	17.5%	16.0%	11.6%	16.8%	16.8%	27.7%	6.5%	6.1%	12.1%	7.5%	9.8%	10.4%	9.4%	9.8%
Trimble County 6	17.0%	13.2%	12.0%	13.5%	13.3%	13.1%	22.5%	4.4%	5.3%	9.0%	5.9%	7.6%	8.0%	7.3%	7.6%
Trimble County 7	12.8%	9.9%	9.9%	10.5%	8.8%	10.1%	17.9%	3.9%	4.0%	6.7%	4.6%	5.8%	6.1%	5.7%	6.0%
Trimble County 8	9.3%	7.5%	7.4%	7.7%	8.7%	7.8%	13.9%	2.9%	3.0%	4.9%	3.5%	4.5%	4.6%	4.5%	4.5%
Trimble County 9	6.8%	5.6%	5.6%	6.3%	6.3%	5.8%	10.6%	2.2%	2.3%	3.5%	2.7%	3.4%	3.6%	3.5%	3.5%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Mid Carbon															
Brown 1	13.8%	10.0%	14.9%	20.8%	27.6%	29.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.7%	0.7%	0.9%	0.9%	1.1%	0.8%	0.3%	0.3%	0.3%	0.4%	0.5%	0.5%	0.6%	0.6%	0.2%
Brown 11	0.5%	0.5%	0.6%	0.7%	0.8%	0.5%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.4%	0.1%
Brown 2	22.1%	20.6%	27.2%	27.1%	42.8%	40.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.6%	30.7%	34.0%	35.6%	34.9%	32.0%	33.4%	34.8%	33.4%	34.8%	33.6%	35.1%	31.9%	36.5%	34.3%
Brown 5	0.9%	0.9%	1.0%	1.1%	1.3%	1.0%	0.4%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%	0.7%	0.2%
Brown 6	2.1%	2.0%	2.2%	2.3%	2.8%	2.2%	1.1%	0.9%	0.9%	1.0%	1.1%	1.3%	1.4%	1.4%	0.5%
Brown 7	2.7%	2.5%	2.7%	3.1%	3.0%	3.0%	1.3%	1.1%	1.2%	1.3%	1.4%	1.6%	1.8%	1.7%	0.7%
Brown 8	0.6%	0.7%	0.7%	0.8%	0.9%	0.6%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.2%
Brown 9	0.8%	0.9%	1.0%	1.1%	1.3%	1.0%	0.4%	0.4%	0.4%	0.4%	0.5%	0.6%	0.7%	0.7%	0.2%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
Cane Run 4	30.5%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	76.8%	20.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	47.2%	14.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	64.2%	45.1%	40.6%	40.2%	31.8%	91.3%	82.7%	89.7%	76.3%	97.0%	93.0%	97.2%	93.0%	81.5%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	76.8%	61.4%	74.9%	78.4%	74.9%	78.2%	44.5%	35.8%	32.0%	42.1%	35.4%	41.1%	42.4%	41.6%	29.6%
Ghent 2	87.2%	78.2%	84.0%	85.8%	85.8%	74.0%	73.0%	72.1%	71.0%	73.0%	70.2%	71.6%	62.1%	72.1%	62.6%
Ghent 3	54.9%	60.4%	73.4%	75.0%	68.1%	68.4%	35.9%	23.3%	25.0%	26.2%	24.5%	24.6%	31.6%	26.8%	17.6%
Ghent 4	63.0%	52.2%	68.6%	64.3%	68.6%	69.6%	23.2%	12.8%	14.5%	15.8%	14.4%	17.0%	20.0%	16.9%	13.3%
Green River 3	17.8%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.5%	37.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.3%	0.3%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.1%
Mill Creek 1	88.2%	72.6%	82.8%	79.0%	85.8%	81.9%	79.2%	66.5%	76.6%	72.9%	75.8%	72.4%	75.3%	71.0%	71.5%
Mill Creek 2	84.0%	76.2%	80.0%	87.8%	83.1%	89.0%	71.9%	81.5%	75.5%	81.3%	74.3%	80.4%	74.6%	79.8%	62.5%
Mill Creek 3	86.4%	87.8%	61.1%	71.3%	77.2%	69.5%	62.0%	59.0%	59.5%	58.6%	57.2%	58.8%	61.6%	54.5%	51.9%
Mill Creek 4	69.0%	67.9%	78.9%	85.6%	83.1%	88.9%	69.0%	68.9%	58.6%	67.1%	58.2%	64.8%	62.6%	65.5%	51.1%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
Paddy's Run 13	14.0%	12.3%	10.9%	9.4%	8.4%	10.2%	6.9%	5.6%	5.9%	6.5%	6.3%	7.2%	7.7%	6.8%	4.4%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	87.5%	82.2%	86.6%	81.9%	86.5%	74.9%	86.8%	81.7%	84.0%
Trimble County 10	4.9%	4.1%	4.3%	4.8%	5.1%	3.8%	2.3%	1.7%	1.8%	1.9%	2.0%	2.3%	2.6%	2.4%	1.0%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	21.9%	17.5%	16.0%	11.6%	16.8%	16.8%	11.6%	6.6%	6.3%	7.8%	7.0%	8.5%	9.8%	8.5%	5.1%
Trimble County 6	17.0%	13.2%	12.0%	13.5%	13.3%	13.1%	8.7%	4.5%	5.3%	5.9%	5.3%	6.5%	7.5%	6.6%	3.8%
Trimble County 7	12.8%	9.9%	9.9%	10.5%	8.8%	10.1%	6.3%	3.9%	4.1%	4.5%	4.2%	5.0%	5.7%	5.1%	2.7%
Trimble County 8	9.3%	7.5%	7.4%	7.7%	8.7%	7.8%	4.6%	2.9%	3.0%	3.4%	3.2%	3.8%	4.4%	4.0%	2.0%
Trimble County 9	6.8%	5.6%	5.6%	6.3%	6.3%	5.8%	3.2%	2.2%	2.3%	2.5%	2.5%	3.0%	3.3%	3.2%	1.5%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-High Load-Zero Carbon															
Brown 1	18.3%	13.5%	20.3%	27.3%	34.3%	38.7%	37.2%	47.4%	41.6%	48.5%	47.4%	55.5%	54.5%	55.3%	55.7%
Brown 10	1.3%	1.3%	1.6%	1.7%	2.0%	0.6%	0.4%	0.4%	0.5%	0.3%	0.4%	0.5%	0.5%	0.6%	0.7%
Brown 11	0.9%	1.0%	1.2%	1.3%	1.5%	0.4%	0.3%	0.3%	0.4%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%
Brown 2	27.7%	26.7%	33.8%	33.3%	50.4%	48.7%	48.2%	53.8%	57.3%	54.1%	50.4%	62.5%	62.9%	63.4%	63.7%
Brown 3	34.2%	31.1%	34.7%	36.6%	36.2%	31.0%	36.9%	44.7%	47.1%	50.0%	50.5%	58.3%	51.8%	60.3%	59.6%
Brown 5	1.6%	1.6%	1.8%	2.0%	2.4%	0.7%	0.5%	0.5%	0.6%	0.4%	0.5%	0.6%	0.7%	0.8%	0.9%
Brown 6	3.7%	3.5%	3.8%	4.0%	4.9%	1.9%	0.9%	1.1%	1.2%	1.4%	1.5%	1.8%	2.0%	2.1%	2.6%
Brown 7	4.5%	4.2%	4.5%	5.1%	5.0%	2.4%	1.2%	1.4%	1.6%	1.8%	1.9%	2.2%	2.6%	2.6%	3.2%
Brown 8	1.1%	1.2%	1.4%	1.5%	1.8%	0.4%	0.3%	0.4%	0.4%	0.2%	0.3%	0.3%	0.4%	0.4%	0.5%
Brown 9	1.6%	1.6%	1.8%	2.0%	2.4%	0.7%	0.5%	0.5%	0.6%	0.4%	0.5%	0.6%	0.7%	0.7%	0.9%
Cane Run 11	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	37.5%	10.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	79.5%	23.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	53.8%	18.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	64.6%	53.9%	49.6%	50.3%	38.5%	29.1%	25.1%	25.5%	18.0%	21.2%	22.3%	28.8%	24.4%	26.8%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	78.8%	64.3%	76.8%	80.2%	77.0%	80.3%	77.8%	79.5%	71.6%	81.5%	80.0%	82.8%	81.6%	83.1%	82.0%
Ghent 2	87.4%	78.6%	84.1%	86.0%	85.9%	74.6%	86.6%	84.8%	86.4%	84.7%	86.3%	85.0%	76.1%	86.7%	84.8%
Ghent 3	60.9%	65.6%	78.2%	78.9%	71.4%	72.6%	74.6%	76.5%	76.5%	76.5%	77.9%	71.3%	79.8%	81.0%	79.6%
Ghent 4	67.0%	60.3%	73.5%	70.7%	74.0%	76.1%	69.3%	65.6%	74.6%	74.2%	73.0%	76.9%	79.3%	76.5%	71.2%
Green River 3	22.5%	6.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.7%	37.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.4%	0.5%	0.6%	0.6%	0.7%	0.2%	0.1%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%
Mill Creek 1	88.7%	73.6%	83.6%	79.7%	86.6%	82.5%	87.3%	75.7%	87.7%	82.5%	87.8%	83.2%	88.1%	82.5%	88.2%
Mill Creek 2	84.1%	77.1%	80.6%	88.3%	83.5%	89.2%	77.0%	89.3%	84.1%	89.3%	84.1%	89.4%	84.1%	89.4%	77.2%
Mill Creek 3	87.3%	87.9%	62.8%	73.1%	79.3%	71.3%	82.6%	79.0%	84.4%	79.1%	84.3%	79.8%	85.4%	73.5%	85.6%
Mill Creek 4	69.4%	71.4%	79.8%	86.4%	83.7%	89.4%	84.1%	89.6%	77.1%	89.7%	84.3%	89.8%	84.4%	89.9%	84.6%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	17.8%	15.8%	14.2%	12.6%	11.0%	7.5%	4.5%	4.9%	5.4%	6.1%	5.7%	6.2%	7.2%	6.7%	8.9%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 10	8.1%	6.6%	7.0%	8.0%	8.5%	2.4%	1.6%	1.9%	2.1%	2.3%	2.4%	3.0%	3.2%	3.2%	4.0%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	29.2%	24.4%	22.3%	16.7%	23.7%	14.6%	5.5%	7.0%	6.6%	8.1%	7.7%	8.9%	10.0%	9.0%	11.7%
Trimble County 6	23.6%	19.2%	17.2%	19.5%	19.5%	11.4%	4.5%	4.4%	5.8%	6.3%	5.8%	6.9%	8.0%	7.3%	9.3%
Trimble County 7	18.6%	14.9%	14.8%	15.7%	13.3%	8.5%	3.4%	4.3%	4.3%	4.9%	4.9%	5.7%	6.4%	5.9%	7.6%
Trimble County 8	14.2%	11.6%	11.4%	11.9%	13.6%	6.5%	2.6%	3.0%	3.5%	3.8%	3.7%	4.7%	5.3%	5.1%	6.4%
Trimble County 9	10.8%	8.8%	8.9%	10.1%	10.0%	4.7%	2.0%	2.4%	2.6%	3.1%	3.1%	3.6%	4.1%	4.0%	5.0%
Zorn 1	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Zero Carbon															
Brown 1	9.9%	7.1%	10.3%	15.0%	21.3%	22.0%	18.0%	23.6%	20.9%	23.5%	22.6%	27.5%	27.4%	25.7%	27.1%
Brown 10	0.3%	0.4%	0.4%	0.5%	0.5%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.5%
Brown 11	0.2%	0.3%	0.3%	0.3%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%
Brown 2	17.0%	15.1%	20.9%	21.0%	34.9%	31.7%	27.8%	31.5%	33.4%	30.3%	28.5%	35.8%	37.8%	35.2%	36.7%
Brown 3	33.3%	30.5%	33.5%	35.0%	34.0%	30.8%	34.1%	35.8%	34.6%	36.3%	35.4%	38.2%	34.3%	39.9%	39.6%
Brown 5	0.4%	0.5%	0.6%	0.6%	0.7%	0.5%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%	0.6%	0.6%	0.7%
Brown 6	1.1%	1.1%	1.2%	1.2%	1.5%	1.1%	0.8%	0.9%	0.9%	1.0%	1.0%	1.2%	1.2%	1.2%	1.4%
Brown 7	1.5%	1.4%	1.6%	1.7%	1.7%	1.5%	1.1%	1.2%	1.3%	1.4%	1.4%	1.6%	1.7%	1.6%	1.9%
Brown 8	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%
Brown 9	0.4%	0.5%	0.5%	0.6%	0.6%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.6%	0.6%	0.7%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	23.7%	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	73.1%	16.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	40.2%	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	63.5%	36.1%	31.5%	30.2%	23.2%	19.1%	19.7%	20.9%	16.1%	19.0%	19.8%	23.2%	18.5%	19.5%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	74.3%	57.8%	72.6%	75.9%	72.3%	75.2%	70.8%	72.5%	65.2%	73.9%	72.1%	75.6%	74.1%	76.0%	74.2%
Ghent 2	86.9%	77.8%	83.7%	85.6%	85.4%	73.3%	84.9%	83.2%	84.6%	82.7%	84.2%	83.0%	74.3%	84.7%	82.6%
Ghent 3	48.0%	54.2%	67.4%	69.8%	63.6%	63.0%	61.9%	63.4%	63.6%	62.7%	63.0%	59.8%	66.6%	66.8%	64.8%
Ghent 4	57.9%	43.4%	62.4%	56.2%	61.4%	61.1%	51.2%	50.0%	57.2%	54.3%	53.0%	57.7%	61.5%	55.9%	54.2%
Green River 3	13.5%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.3%	37.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Mill Creek 1	87.7%	71.5%	82.0%	78.3%	84.8%	81.2%	85.8%	74.2%	86.0%	80.8%	85.9%	81.6%	86.3%	80.2%	86.0%
Mill Creek 2	83.9%	75.2%	79.3%	87.1%	82.4%	88.6%	76.5%	88.8%	83.5%	88.7%	83.5%	88.8%	83.4%	88.7%	76.6%
Mill Creek 3	85.4%	87.5%	59.2%	69.5%	75.0%	67.6%	77.8%	74.1%	79.1%	74.0%	78.5%	74.2%	79.3%	68.4%	79.4%
Mill Creek 4	68.5%	63.9%	77.7%	84.6%	82.3%	88.0%	82.5%	88.1%	75.7%	88.0%	82.6%	88.3%	82.7%	88.3%	82.9%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	10.6%	9.1%	8.0%	6.7%	6.1%	7.1%	4.9%	5.4%	5.2%	6.0%	5.7%	6.3%	6.7%	5.7%	8.0%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 10	2.8%	2.3%	2.5%	2.7%	2.8%	2.0%	1.5%	1.7%	1.7%	1.9%	1.8%	2.0%	2.2%	2.0%	2.5%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	15.4%	11.8%	10.8%	7.7%	11.0%	10.6%	6.2%	6.7%	6.2%	7.8%	6.5%	7.5%	8.4%	7.1%	9.1%
Trimble County 6	11.5%	8.5%	7.8%	8.7%	8.4%	7.9%	4.7%	4.4%	5.4%	5.8%	5.0%	5.7%	6.5%	5.5%	7.1%
Trimble County 7	8.2%	6.2%	6.2%	6.5%	5.5%	5.9%	3.6%	4.2%	4.2%	4.5%	3.8%	4.4%	5.1%	4.4%	5.6%
Trimble County 8	5.7%	4.6%	4.5%	4.7%	5.2%	4.3%	2.7%	3.1%	3.1%	3.4%	2.9%	3.4%	3.9%	3.4%	4.4%
Trimble County 9	4.0%	3.3%	3.3%	3.6%	3.6%	3.1%	2.0%	2.3%	2.3%	2.5%	2.3%	2.7%	3.0%	2.6%	3.3%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Carbon Cap															
Brown 1	9.9%	7.1%	10.3%	15.0%	21.3%	22.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.3%	0.4%	0.4%	0.5%	0.5%	0.3%	0.5%	0.5%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.6%
Brown 11	0.2%	0.3%	0.3%	0.3%	0.4%	0.2%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%
Brown 2	17.0%	15.1%	20.9%	21.0%	34.9%	31.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.3%	30.5%	33.5%	35.0%	34.0%	30.8%	38.2%	34.7%	33.7%	43.3%	33.8%	36.7%	32.2%	35.5%	36.2%
Brown 5	0.4%	0.5%	0.6%	0.6%	0.7%	0.5%	0.9%	0.6%	0.6%	1.0%	0.7%	0.7%	0.8%	0.7%	0.8%
Brown 6	1.1%	1.1%	1.2%	1.2%	1.5%	1.1%	1.5%	1.4%	1.4%	1.7%	1.3%	1.6%	1.6%	1.5%	1.8%
Brown 7	1.5%	1.4%	1.6%	1.7%	1.7%	1.5%	1.9%	1.9%	1.7%	2.1%	1.7%	1.9%	2.1%	1.9%	2.2%
Brown 8	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Brown 9	0.4%	0.5%	0.5%	0.6%	0.6%	0.4%	0.6%	0.6%	0.6%	0.6%	0.6%	0.7%	0.8%	0.7%	0.7%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	23.7%	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	73.1%	16.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	40.2%	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	63.5%	36.1%	31.5%	30.2%	23.2%	97.3%	93.0%	96.9%	77.9%	88.9%	93.0%	97.3%	86.9%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	74.3%	57.8%	72.6%	75.9%	72.3%	75.2%	49.6%	50.7%	44.6%	53.7%	45.7%	51.7%	51.3%	49.9%	51.5%
Ghent 2	86.9%	77.8%	83.7%	85.6%	85.4%	73.3%	74.7%	75.1%	76.3%	73.8%	77.2%	74.9%	66.1%	77.7%	74.4%
Ghent 3	48.0%	54.2%	67.4%	69.8%	63.6%	63.0%	31.4%	36.4%	37.3%	30.6%	32.4%	31.7%	39.6%	34.6%	32.0%
Ghent 4	57.9%	43.4%	62.4%	56.2%	61.4%	61.1%	24.8%	20.4%	23.2%	25.5%	19.4%	22.6%	26.1%	19.1%	24.9%
Green River 3	13.5%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.3%	37.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%
Mill Creek 1	87.7%	71.5%	82.0%	78.3%	84.8%	81.2%	76.4%	67.1%	79.0%	71.7%	79.4%	74.2%	77.7%	74.0%	77.2%
Mill Creek 2	83.9%	75.2%	79.3%	87.1%	82.4%	88.6%	69.5%	82.8%	79.0%	78.2%	78.8%	82.8%	77.5%	83.3%	70.5%
Mill Creek 3	85.4%	87.5%	59.2%	69.5%	75.0%	67.6%	67.2%	66.3%	67.0%	65.3%	70.5%	65.8%	68.3%	62.3%	69.8%
Mill Creek 4	68.5%	63.9%	77.7%	84.6%	82.3%	88.0%	66.2%	73.7%	65.0%	72.0%	71.9%	73.7%	69.4%	77.0%	69.7%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	10.6%	9.1%	8.0%	6.7%	6.1%	7.1%	17.3%	10.7%	8.7%	22.7%	7.7%	9.7%	9.6%	7.5%	11.4%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	87.9%	82.7%	87.8%	82.7%	88.1%	75.6%	87.9%	82.9%	88.0%
Trimble County 10	2.8%	2.3%	2.5%	2.7%	2.8%	2.0%	2.7%	2.8%	2.6%	3.0%	2.5%	2.9%	3.1%	2.7%	3.2%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	15.4%	11.8%	10.8%	7.7%	11.0%	10.6%	12.3%	12.5%	10.1%	13.5%	9.0%	11.5%	12.6%	9.6%	12.9%
Trimble County 6	11.5%	8.5%	7.8%	8.7%	8.4%	7.9%	9.1%	8.0%	8.7%	10.0%	7.0%	8.7%	9.5%	7.5%	10.0%
Trimble County 7	8.2%	6.2%	6.2%	6.5%	5.5%	5.9%	6.7%	7.3%	6.5%	7.4%	5.4%	6.8%	7.2%	5.8%	7.5%
Trimble County 8	5.7%	4.6%	4.5%	4.7%	5.2%	4.3%	4.9%	5.2%	4.8%	5.5%	4.1%	5.1%	5.4%	4.4%	5.7%
Trimble County 9	4.0%	3.3%	3.3%	3.6%	3.6%	3.1%	3.6%	3.9%	3.5%	4.0%	3.1%	3.9%	4.0%	3.4%	4.4%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Mid Carbon															
Brown 1	9.9%	7.1%	10.3%	15.0%	21.3%	22.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.3%	0.4%	0.4%	0.5%	0.5%	0.3%	0.5%	0.6%	0.6%	0.6%	0.7%	0.2%	0.2%	0.2%	0.2%
Brown 11	0.2%	0.3%	0.3%	0.3%	0.4%	0.2%	0.4%	0.4%	0.4%	0.4%	0.5%	0.1%	0.1%	0.1%	0.2%
Brown 2	17.0%	15.1%	20.9%	21.0%	34.9%	31.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.3%	30.5%	33.5%	35.0%	34.0%	30.8%	33.6%	35.1%	33.8%	35.2%	34.0%	34.6%	31.1%	35.8%	34.7%
Brown 5	0.4%	0.5%	0.6%	0.6%	0.7%	0.5%	0.6%	0.7%	0.7%	0.8%	0.8%	0.2%	0.2%	0.2%	0.3%
Brown 6	1.1%	1.1%	1.2%	1.2%	1.5%	1.1%	1.4%	1.6%	1.6%	1.8%	1.8%	0.6%	0.5%	0.6%	0.6%
Brown 7	1.5%	1.4%	1.6%	1.7%	1.7%	1.5%	1.8%	2.0%	2.1%	2.2%	2.2%	0.8%	0.7%	0.7%	0.8%
Brown 8	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.4%	0.5%	0.5%	0.5%	0.6%	0.2%	0.2%	0.2%	0.2%
Brown 9	0.4%	0.5%	0.5%	0.6%	0.6%	0.4%	0.6%	0.7%	0.7%	0.7%	0.8%	0.2%	0.2%	0.2%	0.3%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Cane Run 4	23.7%	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	73.1%	16.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	40.2%	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	63.5%	36.1%	31.5%	30.2%	23.2%	95.1%	91.2%	95.9%	77.7%	97.3%	93.0%	96.9%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	74.3%	57.8%	72.6%	75.9%	72.3%	75.2%	52.1%	56.1%	49.1%	61.6%	53.5%	43.1%	31.2%	29.4%	31.6%
Ghent 2	86.9%	77.8%	83.7%	85.6%	85.4%	73.3%	77.4%	76.6%	77.7%	77.0%	77.4%	70.3%	57.2%	67.2%	68.5%
Ghent 3	48.0%	54.2%	67.4%	69.8%	63.6%	63.0%	39.2%	41.8%	42.7%	44.9%	40.1%	28.7%	20.8%	16.9%	17.6%
Ghent 4	57.9%	43.4%	62.4%	56.2%	61.4%	61.1%	24.0%	24.8%	28.0%	29.8%	25.6%	17.4%	11.2%	9.5%	12.1%
Green River 3	13.5%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.3%	37.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	87.7%	71.5%	82.0%	78.3%	84.8%	81.2%	80.3%	69.3%	80.2%	76.0%	79.9%	71.8%	72.7%	68.7%	74.2%
Mill Creek 2	83.9%	75.2%	79.3%	87.1%	82.4%	88.6%	73.7%	85.2%	79.8%	85.2%	79.2%	80.0%	70.9%	76.6%	67.0%
Mill Creek 3	85.4%	87.5%	59.2%	69.5%	75.0%	67.6%	68.5%	66.4%	70.0%	68.2%	70.0%	59.5%	52.9%	47.0%	56.6%
Mill Creek 4	68.5%	63.9%	77.7%	84.6%	82.3%	88.0%	74.8%	80.0%	68.4%	80.7%	72.5%	65.7%	53.5%	54.6%	54.4%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 13	10.6%	9.1%	8.0%	6.7%	6.1%	7.1%	8.9%	10.1%	10.0%	11.1%	10.3%	5.2%	4.2%	3.8%	5.0%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.1%	88.1%	82.9%	88.1%	82.9%	88.1%	74.8%	85.4%	80.5%	86.1%
Trimble County 10	2.8%	2.3%	2.5%	2.7%	2.8%	2.0%	2.8%	3.3%	3.2%	3.5%	3.3%	1.3%	1.1%	1.0%	1.2%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	15.4%	11.8%	10.8%	7.7%	11.0%	10.6%	11.9%	14.0%	12.4%	15.8%	13.1%	7.8%	4.7%	4.3%	5.3%
Trimble County 6	11.5%	8.5%	7.8%	8.7%	8.4%	7.9%	9.0%	8.8%	10.8%	12.0%	9.9%	5.5%	3.5%	3.2%	3.9%
Trimble County 7	8.2%	6.2%	6.2%	6.5%	5.5%	5.9%	6.7%	8.2%	8.2%	8.9%	7.5%	3.9%	2.5%	2.4%	2.9%
Trimble County 8	5.7%	4.6%	4.5%	4.7%	5.2%	4.3%	4.9%	6.0%	5.9%	6.5%	5.7%	2.7%	1.9%	1.8%	2.2%
Trimble County 9	4.0%	3.3%	3.3%	3.6%	3.6%	3.1%	3.7%	4.3%	4.3%	4.8%	4.4%	1.9%	1.4%	1.4%	1.6%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Zero Carbon															
Brown 1	1.3%	1.3%	1.6%	1.7%	1.9%	1.5%	0.4%	0.4%	0.4%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%
Brown 10	0.9%	1.1%	1.1%	1.3%	1.5%	1.1%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%	0.6%
Brown 11	0.6%	0.7%	0.8%	0.9%	1.0%	0.7%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%
Brown 2	2.3%	2.2%	2.7%	2.5%	3.1%	2.3%	0.6%	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%
Brown 3	33.1%	30.4%	33.1%	34.5%	33.1%	29.7%	32.9%	34.3%	32.9%	34.3%	32.9%	34.3%	29.6%	34.3%	33.0%
Brown 5	1.5%	1.7%	1.8%	1.9%	2.3%	1.8%	0.4%	0.4%	0.5%	0.5%	0.6%	0.6%	0.7%	0.8%	0.9%
Brown 6	5.5%	14.1%	4.3%	4.6%	11.6%	12.5%	5.0%	2.3%	2.6%	2.0%	1.5%	1.5%	1.9%	1.7%	2.1%
Brown 7	6.9%	16.3%	5.2%	5.8%	10.4%	14.8%	6.0%	3.0%	3.3%	2.6%	1.9%	1.9%	2.4%	2.1%	2.7%
Brown 8	0.7%	0.8%	0.9%	1.0%	1.2%	0.8%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.4%
Brown 9	1.2%	1.4%	1.4%	1.5%	1.9%	1.5%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	5.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	53.4%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	15.9%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	63.0%	26.4%	40.3%	21.3%	23.0%	22.4%	8.2%	6.9%	7.0%	7.5%	7.7%	14.8%	14.3%	15.7%	20.1%
Ghent 2	85.8%	67.2%	79.4%	79.1%	78.0%	59.4%	57.6%	58.3%	54.9%	65.3%	61.8%	66.4%	57.3%	67.3%	69.8%
Ghent 3	27.1%	15.2%	21.8%	12.7%	13.1%	11.4%	4.5%	3.7%	4.0%	4.3%	4.6%	4.9%	6.0%	5.7%	6.3%
Ghent 4	49.9%	58.6%	59.9%	57.6%	52.6%	55.7%	50.5%	41.0%	50.7%	53.0%	52.1%	52.4%	54.0%	52.6%	44.2%
Green River 3	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.4%	29.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.2%	0.3%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	86.4%	45.1%	72.7%	61.9%	70.4%	68.9%	67.4%	59.8%	65.8%	68.3%	69.6%	69.4%	71.7%	68.7%	74.1%
Mill Creek 2	83.8%	57.5%	72.8%	74.8%	69.2%	78.3%	61.1%	69.3%	62.4%	76.4%	70.3%	78.3%	70.8%	78.0%	70.1%
Mill Creek 3	82.0%	78.8%	35.2%	30.3%	34.5%	32.5%	18.2%	16.9%	16.9%	32.0%	31.4%	38.7%	39.6%	37.3%	46.6%
Mill Creek 4	66.6%	27.6%	58.7%	57.7%	56.8%	56.8%	43.0%	37.9%	33.9%	50.6%	45.2%	58.2%	56.2%	58.1%	60.2%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.2%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	52.6%	54.2%	50.5%	51.8%	39.2%	51.8%	51.9%	53.5%	50.4%	51.5%	45.1%	41.4%	42.5%	44.7%	45.0%
Trimble County 1	88.4%	81.5%	88.4%	75.9%	88.3%	82.6%	86.9%	81.5%	86.4%	82.6%	87.6%	75.6%	87.8%	82.3%	88.0%
Trimble County 10	44.7%	93.9%	39.4%	73.8%	72.3%	65.0%	48.5%	34.2%	33.2%	19.6%	18.7%	13.5%	18.7%	14.8%	17.4%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	80.3%	100.7%	63.6%	80.5%	94.4%	97.9%	76.8%	63.1%	51.9%	50.5%	42.2%	33.0%	42.5%	35.8%	40.3%
Trimble County 6	74.1%	100.4%	52.1%	93.1%	91.1%	95.8%	71.4%	47.1%	55.1%	43.0%	36.7%	27.8%	36.9%	30.3%	34.7%
Trimble County 7	67.1%	100.1%	54.1%	89.2%	71.6%	93.1%	65.8%	51.8%	49.1%	36.1%	31.6%	23.3%	31.7%	25.4%	29.5%
Trimble County 8	59.7%	98.8%	49.0%	72.1%	82.5%	89.6%	59.9%	45.6%	43.5%	29.9%	26.9%	19.4%	26.9%	21.2%	24.9%
Trimble County 9	52.2%	96.5%	44.1%	80.1%	69.3%	84.9%	54.1%	39.7%	38.2%	24.3%	22.6%	16.2%	22.5%	17.7%	20.9%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Carbon Cap															
Brown 1	1.3%	1.3%	1.6%	1.7%	1.9%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.9%	1.1%	1.1%	1.3%	1.5%	0.3%	0.4%	0.4%	0.5%	0.5%	0.6%	0.6%	0.7%	0.2%	0.2%
Brown 11	0.6%	0.7%	0.8%	0.9%	1.0%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.1%	0.2%
Brown 2	2.3%	2.2%	2.7%	2.5%	3.1%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.1%	30.4%	33.1%	34.5%	33.1%	29.5%	32.9%	34.3%	33.0%	34.3%	33.0%	34.4%	29.7%	34.3%	32.9%
Brown 5	1.5%	1.7%	1.8%	1.9%	2.3%	0.6%	0.6%	0.7%	0.7%	0.8%	0.9%	1.0%	1.1%	0.3%	0.4%
Brown 6	5.5%	14.1%	4.3%	4.6%	11.6%	7.6%	2.3%	2.3%	2.6%	2.0%	1.5%	1.5%	1.9%	0.6%	0.6%
Brown 7	6.9%	16.3%	5.2%	5.8%	10.4%	8.6%	3.0%	3.0%	3.3%	2.6%	1.9%	1.9%	2.4%	0.7%	0.7%
Brown 8	0.7%	0.8%	0.9%	1.0%	1.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.6%	0.2%	0.2%
Brown 9	1.2%	1.4%	1.4%	1.5%	1.9%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%	0.8%	0.8%	0.2%	0.3%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Cane Run 4	5.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	53.4%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	15.9%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	63.0%	26.4%	40.3%	21.3%	23.0%	13.0%	5.9%	6.9%	7.0%	7.5%	7.8%	14.8%	14.4%	9.3%	6.3%
Ghent 2	85.8%	67.2%	79.4%	79.1%	78.0%	48.1%	49.7%	58.3%	54.9%	65.3%	61.8%	66.4%	57.3%	54.9%	48.2%
Ghent 3	27.1%	15.2%	21.8%	12.7%	13.1%	6.3%	3.5%	3.7%	3.9%	4.3%	4.6%	4.9%	6.0%	2.4%	2.3%
Ghent 4	49.9%	58.6%	59.9%	57.6%	52.6%	53.2%	49.2%	41.0%	50.7%	53.0%	52.1%	52.4%	54.0%	49.1%	39.3%
Green River 3	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.4%	29.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.2%	0.3%	0.3%	0.3%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%
Mill Creek 1	86.4%	45.1%	72.7%	61.9%	70.4%	65.6%	62.8%	59.8%	65.8%	68.3%	69.6%	69.4%	71.7%	61.1%	62.8%
Mill Creek 2	83.8%	57.5%	72.8%	74.8%	69.2%	74.4%	57.0%	69.3%	62.4%	76.4%	70.3%	78.3%	70.8%	67.9%	56.6%
Mill Creek 3	82.0%	78.8%	35.2%	30.3%	34.5%	23.7%	11.2%	16.9%	16.9%	32.0%	31.4%	38.7%	39.7%	28.5%	23.2%
Mill Creek 4	66.6%	27.6%	58.7%	57.7%	56.8%	42.8%	31.0%	37.9%	33.9%	50.6%	45.2%	58.2%	56.2%	44.7%	34.1%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.2%	0.2%	0.2%	0.2%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Paddy's Run 13	52.6%	54.2%	50.5%	51.8%	39.2%	51.5%	51.7%	53.5%	50.4%	51.5%	45.1%	41.4%	42.5%	35.2%	31.6%
Trimble County 1	88.4%	81.5%	88.4%	75.9%	88.3%	82.2%	85.4%	81.5%	86.4%	82.6%	87.6%	75.6%	87.8%	78.4%	82.9%
Trimble County 10	44.7%	93.9%	39.4%	73.8%	72.3%	48.8%	37.0%	34.2%	33.2%	19.6%	18.7%	13.5%	18.7%	7.6%	7.0%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.1%	83.1%
Trimble County 5	80.3%	100.7%	63.6%	80.5%	94.4%	88.5%	64.5%	63.1%	51.9%	50.5%	42.2%	33.0%	42.5%	23.2%	18.4%
Trimble County 6	74.1%	100.4%	52.1%	93.1%	91.1%	84.5%	58.3%	47.1%	55.1%	43.0%	36.7%	27.8%	36.9%	18.8%	15.4%
Trimble County 7	67.1%	100.1%	54.1%	89.2%	71.6%	80.0%	52.5%	51.8%	49.1%	36.1%	31.6%	23.3%	31.7%	15.1%	12.7%
Trimble County 8	59.7%	98.8%	49.0%	72.1%	82.5%	74.8%	47.0%	45.6%	43.5%	29.9%	26.9%	19.4%	26.9%	12.1%	10.5%
Trimble County 9	52.2%	96.5%	44.1%	80.1%	69.3%	69.2%	41.9%	39.7%	38.2%	24.3%	22.6%	16.2%	22.5%	9.6%	8.6%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Mid Carbon															
Brown 1	1.3%	1.3%	1.6%	1.7%	1.9%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.9%	1.1%	1.1%	1.3%	1.5%	1.1%	3.0%	1.4%	2.0%	3.0%	4.8%	5.5%	15.9%	31.0%	40.3%
Brown 11	0.6%	0.7%	0.8%	0.9%	1.0%	0.7%	1.4%	0.6%	1.1%	1.3%	2.9%	3.4%	8.2%	17.0%	27.0%
Brown 2	2.3%	2.2%	2.7%	2.5%	3.1%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.1%	30.4%	33.1%	34.5%	33.1%	29.7%	33.0%	34.2%	32.9%	34.3%	32.9%	34.3%	29.7%	34.4%	33.1%
Brown 5	1.5%	1.7%	1.8%	1.9%	2.3%	1.8%	9.4%	5.3%	14.1%	14.8%	17.3%	18.8%	27.4%	30.7%	39.7%
Brown 6	5.5%	14.1%	4.3%	4.6%	11.6%	12.5%	93.6%	85.1%	75.9%	81.5%	74.8%	77.9%	82.6%	85.3%	89.7%
Brown 7	6.9%	16.3%	5.2%	5.8%	10.4%	14.8%	94.5%	87.7%	78.3%	83.6%	76.6%	79.9%	84.8%	87.2%	90.5%
Brown 8	0.7%	0.8%	0.9%	1.0%	1.2%	0.8%	1.9%	0.9%	1.3%	1.7%	3.6%	4.2%	10.0%	20.2%	30.7%
Brown 9	1.2%	1.4%	1.4%	1.5%	1.9%	1.5%	3.9%	1.9%	2.4%	3.7%	5.8%	6.7%	19.1%	34.8%	44.9%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Cane Run 4	5.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	53.4%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	15.9%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	63.0%	26.4%	40.3%	21.3%	23.0%	22.4%	6.8%	2.4%	2.2%	2.0%	1.5%	1.6%	1.8%	1.9%	2.1%
Ghent 2	85.8%	67.2%	79.4%	79.1%	78.0%	59.4%	36.3%	21.6%	12.8%	14.6%	14.3%	15.5%	13.3%	12.6%	11.6%
Ghent 3	27.1%	15.2%	21.8%	12.7%	13.1%	11.4%	3.6%	1.2%	0.6%	0.6%	0.8%	0.8%	0.9%	0.9%	1.0%
Ghent 4	49.9%	58.6%	59.9%	57.6%	52.6%	55.7%	40.4%	27.4%	12.8%	14.5%	11.2%	10.1%	8.8%	6.5%	4.9%
Green River 3	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.4%	29.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.2%	0.3%	0.3%	0.3%	0.2%	0.2%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	86.4%	45.1%	72.7%	61.9%	70.4%	68.9%	48.7%	30.0%	26.3%	31.2%	30.1%	32.7%	32.8%	26.4%	28.7%
Mill Creek 2	83.8%	57.5%	72.8%	74.8%	69.2%	78.3%	40.4%	32.0%	19.9%	24.8%	23.4%	30.9%	28.6%	24.6%	22.4%
Mill Creek 3	82.0%	78.8%	35.2%	30.3%	34.5%	32.5%	17.9%	11.4%	7.4%	8.0%	8.0%	8.4%	9.2%	7.5%	6.6%
Mill Creek 4	66.6%	27.6%	58.7%	57.7%	56.8%	56.8%	22.3%	8.8%	5.3%	5.5%	5.7%	5.9%	5.9%	4.4%	4.0%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Paddy's Run 13	52.6%	54.2%	50.5%	51.8%	39.2%	51.8%	52.4%	52.8%	48.8%	51.6%	48.9%	49.7%	48.7%	49.3%	49.7%
Trimble County 1	88.4%	81.5%	88.4%	75.9%	88.3%	82.6%	71.6%	55.3%	44.2%	46.2%	46.1%	44.8%	49.7%	46.3%	49.9%
Trimble County 10	44.7%	93.9%	39.4%	73.8%	72.3%	65.0%	100.3%	97.3%	94.6%	96.5%	91.0%	92.2%	91.6%	92.6%	93.8%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	80.3%	73.0%	65.9%	69.7%	67.2%	68.4%	61.1%	66.2%	69.9%
Trimble County 5	80.3%	100.7%	63.6%	80.5%	94.4%	97.9%	100.7%	99.8%	79.6%	99.3%	94.8%	95.3%	95.0%	95.4%	95.8%
Trimble County 6	74.1%	100.4%	52.1%	93.1%	91.1%	95.8%	100.6%	80.4%	98.4%	99.2%	94.6%	95.1%	94.8%	95.1%	95.6%
Trimble County 7	67.1%	100.1%	54.1%	89.2%	71.6%	93.1%	100.6%	99.2%	98.0%	98.8%	94.2%	95.0%	94.5%	94.8%	95.3%
Trimble County 8	59.7%	98.8%	49.0%	72.1%	82.5%	89.6%	100.6%	98.8%	97.4%	98.1%	93.3%	94.2%	93.6%	94.3%	94.9%
Trimble County 9	52.2%	96.5%	44.1%	80.1%	69.3%	84.9%	100.5%	98.4%	96.1%	97.5%	92.6%	93.7%	92.8%	93.7%	94.5%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-High Load-Zero Carbon															
Brown 1	2.4%	2.2%	2.7%	3.0%	3.3%	1.1%	0.7%	0.8%	0.9%	0.3%	0.4%	0.5%	0.5%	0.6%	0.7%
Brown 10	1.8%	1.9%	2.0%	2.4%	2.8%	0.8%	0.5%	0.6%	0.7%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%
Brown 11	1.1%	1.3%	1.4%	1.7%	1.9%	0.5%	0.3%	0.4%	0.5%	0.1%	0.2%	0.2%	0.2%	0.3%	0.3%
Brown 2	4.0%	3.6%	4.6%	4.0%	5.3%	1.8%	1.0%	1.2%	1.3%	0.5%	0.6%	0.6%	0.7%	0.8%	1.0%
Brown 3	33.3%	30.6%	33.4%	34.7%	33.4%	29.6%	33.0%	34.3%	33.0%	34.2%	32.9%	34.3%	29.6%	34.3%	33.0%
Brown 5	2.7%	2.8%	2.9%	3.3%	4.0%	1.3%	0.8%	0.9%	1.0%	0.3%	0.4%	0.4%	0.5%	0.6%	0.7%
Brown 6	9.1%	19.2%	7.0%	7.7%	17.4%	12.3%	4.3%	4.3%	4.9%	1.5%	0.9%	1.0%	1.2%	1.3%	1.5%
Brown 7	10.7%	21.4%	8.2%	9.4%	14.8%	13.5%	5.3%	5.3%	6.0%	2.0%	1.2%	1.3%	1.5%	1.6%	1.9%
Brown 8	1.3%	1.5%	1.7%	1.9%	2.2%	0.6%	0.4%	0.5%	0.5%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%
Brown 9	2.2%	2.4%	2.4%	2.8%	3.5%	1.1%	0.7%	0.8%	0.8%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%
Cane Run 11	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Cane Run 4	8.3%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	59.3%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	20.5%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	66.9%	32.0%	46.0%	28.3%	29.9%	19.0%	8.8%	10.7%	10.8%	6.0%	5.1%	8.5%	8.8%	9.7%	12.2%
Ghent 2	86.2%	69.6%	80.3%	80.1%	79.2%	52.7%	56.5%	63.8%	61.4%	59.4%	46.4%	52.0%	46.0%	54.3%	58.4%
Ghent 3	32.7%	21.0%	28.2%	17.9%	18.4%	10.3%	5.5%	6.0%	6.5%	3.1%	3.1%	3.4%	4.0%	4.1%	4.5%
Ghent 4	52.5%	60.5%	62.1%	59.8%	54.9%	54.4%	50.7%	42.3%	52.1%	52.4%	48.0%	49.8%	50.5%	50.2%	42.4%
Green River 3	3.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.6%	32.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.4%	0.5%	0.5%	0.6%	0.7%	0.2%	0.1%	0.2%	0.2%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	87.0%	50.6%	74.3%	64.9%	72.6%	67.4%	66.2%	61.7%	68.9%	65.6%	60.4%	62.4%	63.8%	62.0%	68.5%
Mill Creek 2	84.0%	61.8%	74.4%	76.8%	71.6%	76.8%	61.0%	73.3%	66.9%	72.4%	57.8%	66.8%	60.5%	67.6%	63.6%
Mill Creek 3	82.7%	80.6%	40.3%	37.4%	42.0%	30.3%	15.9%	23.5%	23.8%	29.1%	20.7%	25.8%	27.7%	26.0%	33.1%
Mill Creek 4	67.4%	34.6%	63.0%	63.4%	62.2%	50.0%	38.7%	47.2%	42.2%	46.1%	30.7%	40.1%	42.5%	41.7%	45.5%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Paddy's Run 12	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Paddy's Run 13	53.0%	54.2%	51.5%	51.8%	39.2%	51.8%	52.5%	54.0%	51.4%	47.2%	39.5%	33.2%	36.4%	36.5%	38.0%
Trimble County 1	88.4%	81.9%	88.4%	75.9%	88.4%	82.5%	86.5%	82.0%	87.1%	81.5%	82.4%	73.0%	83.8%	79.0%	85.6%
Trimble County 10	53.3%	96.3%	45.3%	81.0%	79.6%	55.9%	44.4%	43.0%	41.6%	18.6%	11.3%	9.1%	11.9%	10.3%	12.0%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.4%	83.1%	83.3%	76.1%	83.3%	83.5%
Trimble County 5	85.8%	100.7%	70.0%	82.4%	96.9%	92.6%	73.2%	72.7%	59.4%	45.5%	28.0%	21.3%	28.9%	23.8%	27.6%
Trimble County 6	80.5%	100.7%	57.2%	96.3%	94.5%	89.3%	67.1%	54.5%	65.0%	39.1%	23.9%	18.0%	24.6%	20.2%	23.6%
Trimble County 7	74.4%	100.4%	60.4%	93.3%	75.8%	85.6%	60.9%	61.5%	58.8%	33.2%	20.1%	15.2%	20.8%	17.1%	20.0%
Trimble County 8	67.8%	100.0%	55.2%	76.2%	87.9%	81.3%	55.1%	55.1%	52.8%	27.8%	16.8%	12.8%	17.4%	14.5%	16.9%
Trimble County 9	60.6%	98.5%	50.1%	86.2%	74.2%	76.4%	49.6%	48.9%	47.0%	22.9%	13.8%	10.8%	14.4%	12.2%	14.3%
Zorn 1	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Zero Carbon															
Brown 1	0.7%	0.7%	0.9%	0.9%	1.0%	0.7%	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.0%	1.0%	1.2%
Brown 10	0.5%	0.6%	0.6%	0.6%	0.7%	0.5%	0.4%	0.5%	0.5%	0.5%	0.5%	0.6%	0.6%	0.6%	0.7%
Brown 11	0.3%	0.4%	0.4%	0.4%	0.5%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.5%
Brown 2	1.3%	1.2%	1.5%	1.4%	1.7%	1.1%	0.9%	1.0%	1.1%	1.1%	1.2%	1.4%	1.5%	1.5%	1.7%
Brown 3	33.0%	30.3%	33.0%	34.3%	33.0%	29.6%	32.9%	34.3%	32.9%	34.3%	33.0%	34.3%	29.6%	34.3%	33.0%
Brown 5	0.8%	0.9%	1.0%	1.0%	1.2%	0.8%	0.7%	0.7%	0.8%	0.8%	0.9%	0.9%	1.0%	1.0%	1.2%
Brown 6	3.1%	9.8%	2.5%	2.6%	7.2%	7.3%	4.9%	4.3%	4.7%	3.5%	2.6%	2.5%	3.1%	2.6%	3.2%
Brown 7	4.1%	11.9%	3.2%	3.4%	6.9%	9.1%	6.2%	5.6%	6.1%	4.5%	3.3%	3.1%	4.1%	3.2%	4.1%
Brown 8	0.3%	0.4%	0.5%	0.5%	0.6%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.6%
Brown 9	0.6%	0.7%	0.7%	0.8%	0.9%	0.6%	0.5%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%	0.8%	0.9%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	3.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	47.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	12.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	58.3%	21.1%	34.1%	15.2%	16.8%	15.4%	10.2%	12.5%	11.8%	13.1%	12.4%	26.2%	23.6%	25.6%	32.9%
Ghent 2	85.3%	64.3%	78.2%	78.0%	76.6%	55.8%	64.8%	69.5%	68.2%	73.8%	73.0%	74.9%	65.7%	75.5%	75.7%
Ghent 3	21.8%	10.3%	15.9%	8.7%	8.8%	7.3%	5.9%	6.2%	6.5%	6.9%	7.2%	7.4%	9.6%	8.4%	9.4%
Ghent 4	47.5%	57.0%	57.9%	55.6%	50.7%	54.0%	51.3%	42.2%	51.8%	54.1%	53.4%	53.7%	55.7%	53.8%	45.4%
Green River 3	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.2%	26.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Mill Creek 1	85.8%	38.7%	71.0%	58.3%	67.9%	67.1%	70.0%	63.4%	71.5%	72.0%	74.6%	72.8%	75.7%	72.2%	76.9%
Mill Creek 2	83.7%	52.3%	70.7%	72.3%	66.2%	76.4%	66.0%	77.2%	71.7%	81.0%	77.4%	83.4%	76.7%	83.4%	73.5%
Mill Creek 3	81.2%	76.7%	29.8%	23.3%	27.0%	25.3%	19.9%	28.9%	28.4%	46.0%	47.1%	54.4%	54.0%	50.3%	60.7%
Mill Creek 4	65.6%	20.8%	53.7%	51.1%	50.6%	49.4%	46.8%	56.4%	48.8%	66.5%	61.4%	74.6%	67.8%	72.8%	71.9%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	51.9%	54.2%	49.2%	51.8%	39.2%	51.8%	52.7%	54.2%	51.8%	53.9%	49.3%	47.8%	47.5%	50.1%	49.6%
Trimble County 1	88.4%	81.1%	88.4%	75.9%	88.2%	82.3%	87.7%	82.6%	87.9%	83.1%	88.4%	75.9%	88.4%	82.9%	88.4%
Trimble County 10	36.1%	90.2%	33.6%	65.5%	63.9%	58.0%	53.2%	52.6%	49.1%	34.8%	30.4%	21.3%	29.7%	22.6%	26.6%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	73.6%	100.5%	57.1%	77.6%	90.7%	95.3%	85.4%	84.2%	66.9%	74.2%	61.2%	51.8%	59.9%	54.6%	57.9%
Trimble County 6	66.4%	100.1%	47.1%	88.8%	86.3%	92.4%	79.5%	62.8%	75.8%	66.4%	54.2%	44.4%	53.4%	47.0%	50.9%
Trimble County 7	58.8%	99.1%	47.9%	83.7%	65.8%	88.6%	72.9%	73.1%	69.0%	58.2%	47.6%	37.5%	47.1%	39.8%	44.2%
Trimble County 8	50.9%	96.7%	43.0%	66.7%	75.5%	83.6%	66.1%	66.2%	62.0%	50.0%	41.4%	31.3%	40.9%	33.2%	37.8%
Trimble County 9	43.3%	94.0%	38.3%	72.5%	63.1%	77.8%	59.5%	59.3%	55.3%	42.1%	35.7%	25.9%	35.1%	27.5%	31.9%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Carbon Cap															
Brown 1	0.7%	0.7%	0.9%	0.9%	1.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.5%	0.6%	0.6%	0.6%	0.7%	0.5%	0.7%	0.7%	0.8%	0.8%	0.2%	0.2%	0.2%	0.3%	0.3%
Brown 11	0.3%	0.4%	0.4%	0.4%	0.5%	0.3%	0.5%	0.5%	0.5%	0.5%	0.1%	0.1%	0.2%	0.2%	0.2%
Brown 2	1.3%	1.2%	1.5%	1.4%	1.7%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.0%	30.3%	33.0%	34.3%	33.0%	29.6%	33.0%	34.3%	33.0%	34.4%	32.9%	34.3%	29.5%	34.3%	32.9%
Brown 5	0.8%	0.9%	1.0%	1.0%	1.2%	0.8%	1.1%	1.2%	1.2%	1.3%	0.4%	0.4%	0.4%	0.4%	0.5%
Brown 6	3.1%	9.8%	2.5%	2.6%	7.2%	7.3%	4.9%	4.3%	4.7%	3.5%	1.0%	0.6%	0.7%	0.6%	0.7%
Brown 7	4.1%	11.9%	3.2%	3.4%	6.9%	9.1%	6.2%	5.6%	6.1%	4.5%	1.4%	0.8%	0.9%	0.8%	1.0%
Brown 8	0.3%	0.4%	0.5%	0.5%	0.6%	0.3%	0.5%	0.6%	0.6%	0.6%	0.2%	0.2%	0.2%	0.2%	0.2%
Brown 9	0.6%	0.7%	0.7%	0.8%	0.9%	0.6%	0.8%	0.9%	0.9%	1.0%	0.3%	0.3%	0.3%	0.3%	0.3%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 4	3.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	47.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	12.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	58.3%	21.1%	34.1%	15.2%	16.8%	15.4%	10.2%	12.5%	11.8%	13.1%	6.5%	8.1%	7.9%	8.4%	10.7%
Ghent 2	85.3%	64.3%	78.2%	78.0%	76.6%	55.8%	64.8%	69.6%	68.2%	73.8%	61.6%	58.9%	50.4%	59.3%	62.9%
Ghent 3	21.8%	10.3%	15.9%	8.7%	8.8%	7.3%	5.8%	6.2%	6.5%	6.9%	3.1%	2.6%	3.0%	2.9%	3.1%
Ghent 4	47.5%	57.0%	57.9%	55.6%	50.7%	54.0%	51.3%	42.2%	51.8%	54.1%	50.5%	50.7%	51.7%	50.7%	42.1%
Green River 3	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.2%	26.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	85.8%	38.7%	71.0%	58.3%	67.9%	67.1%	70.0%	63.4%	71.5%	72.0%	69.2%	66.4%	67.8%	65.1%	70.8%
Mill Creek 2	83.7%	52.3%	70.7%	72.3%	66.2%	76.4%	66.0%	77.2%	71.7%	81.0%	69.4%	73.3%	65.7%	72.7%	66.5%
Mill Creek 3	81.2%	76.7%	29.8%	23.3%	27.0%	25.3%	19.9%	28.9%	28.4%	46.0%	34.0%	28.5%	29.9%	27.2%	34.9%
Mill Creek 4	65.6%	20.8%	53.7%	51.1%	50.6%	49.4%	46.8%	56.4%	48.8%	66.5%	49.7%	46.3%	46.8%	45.8%	49.1%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 13	51.9%	54.2%	49.2%	51.8%	39.2%	51.8%	52.7%	54.2%	51.8%	53.9%	42.8%	36.8%	38.9%	39.9%	40.5%
Trimble County 1	88.4%	81.1%	88.4%	75.9%	88.2%	82.3%	87.7%	82.6%	87.9%	83.1%	87.2%	75.0%	86.8%	81.3%	87.2%
Trimble County 10	36.1%	90.2%	33.6%	65.5%	63.9%	58.0%	53.2%	52.6%	49.1%	34.8%	21.3%	8.4%	11.2%	8.9%	10.2%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.6%	76.5%	83.6%	83.7%
Trimble County 5	73.6%	100.5%	57.1%	77.6%	90.7%	95.3%	85.4%	84.2%	67.0%	74.2%	45.1%	22.7%	31.0%	24.0%	27.9%
Trimble County 6	66.4%	100.1%	47.1%	88.8%	86.3%	92.4%	79.5%	62.8%	75.8%	66.4%	39.5%	18.7%	26.0%	19.8%	23.2%
Trimble County 7	58.8%	99.1%	47.9%	83.7%	65.8%	88.6%	72.9%	73.1%	69.0%	58.2%	34.4%	15.3%	21.5%	16.3%	19.1%
Trimble County 8	50.9%	96.7%	43.0%	66.7%	75.5%	83.6%	66.1%	66.2%	62.0%	50.0%	29.6%	12.6%	17.6%	13.3%	15.7%
Trimble County 9	43.3%	94.0%	38.3%	72.5%	63.1%	77.8%	59.5%	59.3%	55.4%	42.1%	25.3%	10.3%	14.1%	10.9%	12.7%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Mid Carbon															
Brown 1	0.7%	0.7%	0.9%	0.9%	1.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.5%	0.6%	0.6%	0.6%	0.7%	0.5%	2.5%	3.8%	2.6%	2.8%	4.6%	5.1%	16.2%	31.8%	41.5%
Brown 11	0.3%	0.4%	0.4%	0.4%	0.5%	0.3%	1.2%	1.8%	1.3%	1.2%	2.6%	3.1%	8.0%	17.0%	27.1%
Brown 2	1.3%	1.2%	1.5%	1.4%	1.7%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.0%	30.3%	33.0%	34.3%	33.0%	29.6%	33.0%	34.4%	32.9%	34.2%	32.9%	34.3%	29.7%	34.4%	33.1%
Brown 5	0.8%	0.9%	1.0%	1.0%	1.2%	0.8%	9.0%	12.0%	18.1%	15.4%	18.0%	19.4%	28.6%	32.0%	41.2%
Brown 6	3.1%	9.8%	2.5%	2.6%	7.2%	7.3%	94.9%	99.2%	88.0%	86.6%	79.4%	82.0%	85.7%	88.0%	91.4%
Brown 7	4.1%	11.9%	3.2%	3.4%	6.9%	9.1%	96.1%	99.7%	90.5%	88.7%	81.5%	84.1%	87.8%	89.9%	92.2%
Brown 8	0.3%	0.4%	0.5%	0.5%	0.6%	0.3%	1.6%	2.5%	1.7%	1.5%	3.3%	3.8%	9.8%	20.4%	31.1%
Brown 9	0.6%	0.7%	0.7%	0.8%	0.9%	0.6%	3.2%	5.0%	3.4%	3.5%	5.7%	6.4%	19.7%	35.9%	46.5%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 4	3.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	47.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	12.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	97.3%	81.6%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	58.3%	21.1%	34.1%	15.2%	16.8%	15.4%	6.2%	6.5%	2.2%	1.8%	1.2%	1.3%	1.5%	1.5%	1.6%
Ghent 2	85.3%	64.3%	78.2%	78.0%	76.6%	55.8%	34.0%	38.7%	22.5%	15.5%	14.7%	15.8%	13.2%	12.3%	11.0%
Ghent 3	21.8%	10.3%	15.9%	8.7%	8.8%	7.3%	3.4%	3.3%	0.5%	0.5%	0.6%	0.6%	0.6%	0.7%	0.7%
Ghent 4	47.5%	57.0%	57.9%	55.6%	50.7%	54.0%	39.5%	34.8%	30.7%	17.0%	12.7%	11.2%	9.4%	6.6%	4.8%
Green River 3	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.2%	26.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.2%	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	85.8%	38.7%	71.0%	58.3%	67.9%	67.1%	48.0%	47.9%	38.7%	34.1%	32.5%	34.8%	34.4%	27.2%	29.4%
Mill Creek 2	83.7%	52.3%	70.7%	72.3%	66.2%	76.4%	40.1%	52.8%	32.0%	27.2%	24.9%	33.1%	29.9%	25.0%	22.5%
Mill Creek 3	81.2%	76.7%	29.8%	23.3%	27.0%	25.3%	16.5%	19.8%	11.4%	8.1%	7.8%	8.1%	8.8%	6.9%	5.8%
Mill Creek 4	65.6%	20.8%	53.7%	51.1%	50.6%	49.4%	19.2%	19.6%	8.7%	5.4%	5.5%	5.6%	5.4%	3.8%	3.3%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 13	51.9%	54.2%	49.2%	51.8%	39.2%	51.8%	52.6%	54.1%	50.6%	52.4%	49.8%	50.5%	49.5%	50.0%	50.2%
Trimble County 1	88.4%	81.1%	88.4%	75.9%	88.2%	82.3%	72.1%	71.0%	60.1%	50.0%	49.6%	47.4%	52.1%	48.1%	51.6%
Trimble County 10	36.1%	90.2%	33.6%	65.5%	63.9%	58.0%	100.6%	100.7%	98.6%	98.3%	93.5%	94.2%	93.4%	94.1%	94.9%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	81.2%	81.8%	74.3%	72.7%	70.3%	71.3%	63.4%	68.8%	72.1%
Trimble County 5	73.6%	100.5%	57.1%	77.6%	90.7%	95.3%	100.7%	100.7%	80.7%	99.9%	95.5%	95.9%	95.6%	95.9%	96.1%
Trimble County 6	66.4%	100.1%	47.1%	88.8%	86.3%	92.4%	100.7%	80.9%	99.9%	99.8%	95.4%	95.8%	95.5%	95.7%	96.0%
Trimble County 7	58.8%	99.1%	47.9%	83.7%	65.8%	88.6%	100.7%	100.7%	99.8%	99.7%	95.3%	95.7%	95.4%	95.6%	95.8%
Trimble County 8	50.9%	96.7%	43.0%	66.7%	75.5%	83.6%	100.7%	100.7%	99.7%	99.3%	95.0%	95.5%	95.0%	95.3%	95.7%
Trimble County 9	43.3%	94.0%	38.3%	72.5%	63.1%	77.8%	100.7%	100.7%	99.3%	98.9%	94.4%	94.9%	94.4%	94.8%	95.4%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Zero Carbon															
Brown 1	9.7%	8.2%	11.3%	13.2%	14.2%	16.4%	11.5%	14.3%	13.1%	18.3%	17.0%	22.3%	23.7%	23.9%	30.8%
Brown 10	0.7%	0.7%	0.9%	0.9%	1.1%	0.8%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%	0.7%	0.8%	0.9%
Brown 11	0.5%	0.6%	0.6%	0.7%	0.8%	0.6%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.6%
Brown 2	19.9%	18.2%	20.0%	16.9%	22.9%	21.9%	16.8%	19.9%	21.2%	28.5%	25.9%	35.2%	42.3%	43.1%	44.7%
Brown 3	33.3%	30.5%	33.4%	34.8%	33.5%	30.0%	33.4%	34.9%	33.7%	35.4%	34.3%	35.9%	31.5%	36.4%	35.8%
Brown 5	0.9%	1.1%	1.1%	1.2%	1.3%	1.0%	0.7%	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.0%	1.2%
Brown 6	2.3%	2.3%	2.4%	2.5%	3.0%	2.4%	1.8%	2.1%	2.2%	2.4%	2.4%	2.8%	3.2%	3.1%	3.8%
Brown 7	2.9%	2.8%	2.9%	3.1%	3.1%	3.1%	2.2%	2.6%	2.7%	2.9%	3.0%	3.5%	4.1%	3.8%	4.8%
Brown 8	0.6%	0.7%	0.7%	0.8%	0.9%	0.7%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.6%	0.7%
Brown 9	0.8%	0.9%	1.0%	1.1%	1.3%	1.0%	0.5%	0.6%	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	28.7%	6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	76.8%	19.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	47.0%	13.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	92.9%	95.3%	79.2%	88.3%	78.2%	64.4%	38.8%	40.8%	42.7%	46.4%	39.7%	39.3%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	76.2%	61.0%	63.9%	66.6%	64.5%	69.7%	62.4%	67.7%	66.4%	77.0%	75.2%	78.2%	76.6%	78.8%	77.5%
Ghent 2	87.2%	78.0%	82.9%	84.6%	84.0%	72.1%	82.8%	82.4%	84.2%	83.3%	85.0%	83.7%	75.1%	85.9%	83.7%
Ghent 3	54.9%	60.4%	51.2%	54.7%	51.0%	52.4%	46.5%	54.2%	60.3%	68.3%	69.3%	64.4%	71.2%	73.5%	72.5%
Ghent 4	63.0%	52.2%	44.7%	39.2%	43.9%	46.8%	33.8%	34.9%	51.4%	60.4%	64.0%	69.1%	71.7%	68.3%	64.5%
Green River 3	16.8%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.5%	37.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.2%	0.3%	0.3%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Mill Creek 1	88.2%	71.7%	81.6%	77.4%	83.0%	80.4%	84.6%	73.5%	85.7%	81.1%	85.6%	81.8%	86.8%	81.0%	86.7%
Mill Creek 2	84.0%	75.6%	78.0%	85.3%	80.0%	87.7%	76.6%	88.9%	83.7%	89.1%	83.9%	89.2%	83.9%	89.1%	77.0%
Mill Creek 3	86.4%	87.6%	54.1%	65.0%	70.5%	64.3%	75.6%	73.4%	79.1%	74.7%	79.2%	75.5%	79.7%	69.5%	80.7%
Mill Creek 4	69.0%	66.9%	74.6%	82.8%	78.5%	85.8%	80.6%	87.3%	75.1%	88.5%	83.1%	88.9%	83.5%	89.3%	84.0%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	18.6%	16.8%	14.3%	12.6%	10.9%	13.8%	9.7%	10.9%	10.0%	10.7%	10.0%	11.0%	11.4%	10.3%	13.8%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 10	5.1%	4.5%	4.6%	5.3%	5.7%	4.3%	3.3%	3.9%	4.1%	4.5%	4.3%	5.1%	5.8%	5.2%	6.6%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	24.2%	19.8%	18.3%	14.8%	20.2%	20.7%	13.1%	15.2%	13.6%	16.4%	13.8%	16.6%	18.6%	16.5%	20.4%
Trimble County 6	18.8%	15.1%	13.7%	15.6%	15.6%	16.2%	10.0%	9.8%	12.6%	12.9%	11.0%	13.1%	15.0%	13.2%	16.6%
Trimble County 7	14.2%	11.3%	10.8%	11.9%	10.2%	12.4%	7.7%	9.5%	9.6%	10.0%	8.7%	10.3%	12.0%	10.5%	13.2%
Trimble County 8	10.2%	8.4%	8.3%	8.4%	9.8%	8.8%	5.7%	7.0%	7.2%	7.6%	6.9%	8.2%	9.5%	8.4%	10.8%
Trimble County 9	7.3%	6.1%	6.3%	7.0%	7.1%	6.6%	4.3%	5.3%	5.4%	5.8%	5.3%	6.4%	7.4%	6.7%	8.5%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Carbon Cap															
Brown 1	9.7%	8.2%	11.3%	13.2%	14.2%	16.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.7%	0.7%	0.9%	0.9%	1.1%	0.8%	0.4%	0.3%	0.3%	0.4%	0.5%	0.6%	0.6%	0.2%	0.2%
Brown 11	0.5%	0.6%	0.6%	0.7%	0.8%	0.6%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%	0.5%	0.1%	0.1%
Brown 2	19.9%	18.2%	20.0%	16.9%	22.9%	21.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.3%	30.5%	33.4%	34.8%	33.5%	30.0%	33.0%	34.4%	33.1%	36.0%	33.2%	36.2%	31.5%	34.4%	33.1%
Brown 5	0.9%	1.1%	1.1%	1.2%	1.3%	1.0%	0.7%	0.4%	0.4%	0.8%	0.6%	1.0%	1.1%	0.2%	0.2%
Brown 6	2.3%	2.3%	2.4%	2.5%	3.0%	2.4%	1.4%	0.9%	1.0%	1.2%	1.2%	1.5%	1.7%	0.5%	0.5%
Brown 7	2.9%	2.8%	2.9%	3.1%	3.1%	3.1%	1.7%	1.1%	1.2%	1.5%	1.5%	1.9%	2.1%	0.6%	0.6%
Brown 8	0.6%	0.7%	0.7%	0.8%	0.9%	0.7%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.1%	0.2%
Brown 9	0.8%	0.9%	1.0%	1.1%	1.3%	1.0%	0.5%	0.4%	0.4%	0.5%	0.5%	0.7%	0.7%	0.2%	0.2%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Cane Run 4	28.7%	6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	76.8%	19.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	47.0%	13.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	92.9%	95.3%	79.2%	97.3%	91.8%	96.5%	77.9%	97.3%	93.0%	97.3%	77.9%	48.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	76.2%	61.0%	63.9%	66.6%	64.5%	69.7%	41.3%	35.4%	31.6%	41.2%	35.4%	40.4%	41.7%	30.3%	32.5%
Ghent 2	87.2%	78.0%	82.9%	84.6%	84.0%	72.1%	70.5%	75.9%	76.5%	71.2%	69.9%	70.5%	61.3%	75.9%	75.3%
Ghent 3	54.9%	60.4%	51.2%	54.7%	51.0%	52.4%	23.3%	22.1%	23.8%	20.5%	24.4%	18.2%	23.8%	18.4%	11.9%
Ghent 4	63.0%	52.2%	44.7%	39.2%	43.9%	46.8%	10.2%	12.7%	14.3%	13.9%	14.4%	17.2%	18.0%	9.5%	6.7%
Green River 3	16.8%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.5%	37.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.2%	0.3%	0.3%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%
Mill Creek 1	88.2%	71.7%	81.6%	77.4%	83.0%	80.4%	76.4%	69.5%	78.5%	71.2%	75.5%	71.1%	74.6%	73.4%	79.2%
Mill Creek 2	84.0%	75.6%	78.0%	85.3%	80.0%	87.7%	69.0%	83.8%	77.8%	79.6%	74.9%	78.8%	73.1%	82.6%	72.7%
Mill Creek 3	86.4%	87.6%	54.1%	65.0%	70.5%	64.3%	61.1%	56.8%	57.4%	59.6%	54.2%	58.7%	60.9%	51.0%	59.7%
Mill Creek 4	69.0%	66.9%	74.6%	82.8%	78.5%	85.8%	63.8%	74.7%	65.0%	65.0%	59.5%	63.9%	61.3%	73.8%	70.3%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%
Paddy's Run 13	18.6%	16.8%	14.3%	12.6%	10.9%	13.8%	32.9%	5.8%	5.9%	26.1%	7.5%	25.0%	27.4%	3.0%	3.2%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	86.5%	82.8%	87.9%	81.7%	86.3%	74.8%	86.7%	82.8%	87.7%
Trimble County 10	5.1%	4.5%	4.6%	5.3%	5.7%	4.3%	8.6%	1.7%	1.8%	2.5%	2.1%	2.9%	4.3%	0.9%	0.9%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.6%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	24.2%	19.8%	18.3%	14.8%	20.2%	20.7%	30.0%	6.8%	6.5%	12.4%	7.9%	12.2%	16.5%	4.1%	3.1%
Trimble County 6	18.8%	15.1%	13.7%	15.6%	15.6%	16.2%	24.6%	4.6%	5.5%	9.2%	6.0%	9.3%	13.1%	3.1%	2.5%
Trimble County 7	14.2%	11.3%	10.8%	11.9%	10.2%	12.4%	19.7%	4.1%	4.1%	6.8%	4.6%	7.1%	10.2%	2.3%	1.9%
Trimble County 8	10.2%	8.4%	8.3%	8.4%	9.8%	8.8%	15.3%	3.1%	3.2%	4.9%	3.6%	5.3%	7.8%	1.7%	1.5%
Trimble County 9	7.3%	6.1%	6.3%	7.0%	7.1%	6.6%	11.6%	2.3%	2.4%	3.5%	2.8%	3.9%	5.9%	1.2%	1.1%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Mid Carbon															
Brown 1	9.7%	8.2%	11.3%	13.2%	14.2%	16.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.7%	0.7%	0.9%	0.9%	1.1%	0.8%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.2%	0.2%
Brown 11	0.5%	0.6%	0.6%	0.7%	0.8%	0.6%	0.2%	0.2%	0.3%	0.3%	0.1%	0.1%	0.1%	0.1%	0.1%
Brown 2	19.9%	18.2%	20.0%	16.9%	22.9%	21.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.3%	30.5%	33.4%	34.8%	33.5%	30.0%	33.0%	34.4%	33.0%	34.4%	32.9%	34.3%	30.6%	35.4%	34.1%
Brown 5	0.9%	1.1%	1.1%	1.2%	1.3%	1.0%	0.5%	0.5%	0.5%	0.6%	0.2%	0.2%	0.2%	0.3%	0.3%
Brown 6	2.3%	2.3%	2.4%	2.5%	3.0%	2.4%	1.2%	1.0%	1.1%	1.2%	0.4%	0.4%	0.4%	0.5%	0.5%
Brown 7	2.9%	2.8%	2.9%	3.1%	3.1%	3.1%	1.6%	1.4%	1.4%	1.5%	0.5%	0.5%	0.6%	0.6%	0.7%
Brown 8	0.6%	0.7%	0.7%	0.8%	0.9%	0.7%	0.3%	0.3%	0.3%	0.3%	0.1%	0.1%	0.1%	0.1%	0.2%
Brown 9	0.8%	0.9%	1.0%	1.1%	1.3%	1.0%	0.4%	0.4%	0.4%	0.5%	0.1%	0.2%	0.2%	0.2%	0.2%
Cane Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 4	28.7%	6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	76.8%	19.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	47.0%	13.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	92.9%	95.3%	79.2%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	76.2%	61.0%	63.9%	66.6%	64.5%	69.7%	44.3%	35.7%	31.8%	42.0%	23.7%	16.8%	19.6%	17.9%	19.9%
Ghent 2	87.2%	78.0%	82.9%	84.6%	84.0%	72.1%	70.5%	68.8%	69.2%	71.7%	57.2%	52.2%	45.0%	53.5%	56.1%
Ghent 3	54.9%	60.4%	51.2%	54.7%	51.0%	52.4%	35.3%	23.2%	24.8%	26.1%	15.7%	9.3%	12.3%	10.4%	11.0%
Ghent 4	63.0%	52.2%	44.7%	39.2%	43.9%	46.8%	23.2%	12.8%	14.5%	15.8%	8.3%	5.7%	6.4%	6.0%	7.4%
Green River 3	16.8%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.5%	37.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.2%	0.2%	0.3%	0.3%	0.4%	0.2%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%
Mill Creek 1	88.2%	71.7%	81.6%	77.4%	83.0%	80.4%	77.1%	64.8%	75.0%	72.3%	67.4%	62.1%	64.0%	61.3%	68.0%
Mill Creek 2	84.0%	75.6%	78.0%	85.3%	80.0%	87.7%	69.5%	79.9%	74.2%	81.3%	63.8%	65.9%	60.6%	66.2%	59.6%
Mill Creek 3	86.4%	87.6%	54.1%	65.0%	70.5%	64.3%	58.7%	52.4%	54.5%	58.2%	44.2%	34.3%	38.8%	33.9%	41.4%
Mill Creek 4	69.0%	66.9%	74.6%	82.8%	78.5%	85.8%	67.0%	62.8%	54.6%	65.4%	45.7%	34.4%	37.3%	36.1%	36.9%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 12	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 13	18.6%	16.8%	14.3%	12.6%	10.9%	13.8%	8.8%	7.2%	7.2%	8.0%	3.8%	3.2%	3.3%	3.2%	4.0%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	86.6%	81.2%	85.9%	81.7%	79.8%	67.6%	77.2%	74.3%	80.2%
Trimble County 10	5.1%	4.5%	4.6%	5.3%	5.7%	4.3%	2.6%	2.0%	2.1%	2.2%	0.8%	0.8%	0.8%	0.8%	1.0%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.6%	83.6%	83.6%	82.0%	81.7%	74.5%	81.9%	82.7%
Trimble County 5	24.2%	19.8%	18.3%	14.8%	20.2%	20.7%	14.1%	8.1%	7.7%	9.3%	4.1%	3.0%	3.3%	3.2%	3.8%
Trimble County 6	18.8%	15.1%	13.7%	15.6%	15.6%	16.2%	10.4%	5.4%	6.5%	7.1%	3.0%	2.3%	2.5%	2.4%	2.9%
Trimble County 7	14.2%	11.3%	10.8%	11.9%	10.2%	12.4%	7.5%	4.8%	4.9%	5.3%	2.1%	1.8%	1.9%	1.9%	2.2%
Trimble County 8	10.2%	8.4%	8.3%	8.4%	9.8%	8.8%	5.3%	3.5%	3.7%	4.0%	1.5%	1.3%	1.4%	1.4%	1.7%
Trimble County 9	7.3%	6.1%	6.3%	7.0%	7.1%	6.6%	3.7%	2.6%	2.7%	3.0%	1.1%	1.0%	1.1%	1.1%	1.3%
Zorn 1	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-High Load-Zero Carbon															
Brown 1	13.0%	11.0%	15.3%	18.0%	19.5%	12.7%	6.4%	7.7%	7.8%	10.6%	14.4%	19.4%	24.3%	26.7%	42.8%
Brown 10	1.3%	1.3%	1.6%	1.7%	2.0%	0.6%	0.4%	0.4%	0.5%	0.3%	0.4%	0.5%	0.5%	0.6%	0.7%
Brown 11	0.9%	1.1%	1.2%	1.3%	1.5%	0.4%	0.3%	0.3%	0.4%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%
Brown 2	24.5%	23.4%	25.9%	22.4%	30.1%	18.9%	8.8%	10.5%	11.9%	25.4%	25.3%	38.5%	49.4%	51.3%	56.4%
Brown 3	33.7%	30.8%	33.8%	35.3%	34.1%	29.8%	33.2%	34.6%	33.3%	34.9%	33.8%	35.3%	30.9%	35.7%	34.9%
Brown 5	1.7%	1.9%	1.9%	2.1%	2.4%	0.7%	0.5%	0.5%	0.6%	0.5%	0.5%	0.6%	0.7%	0.8%	0.9%
Brown 6	4.1%	3.9%	4.1%	4.4%	5.4%	2.0%	1.0%	1.1%	1.2%	1.4%	1.5%	1.8%	2.0%	2.1%	2.6%
Brown 7	5.0%	4.6%	4.7%	5.3%	5.1%	2.5%	1.2%	1.4%	1.6%	1.7%	1.9%	2.2%	2.6%	2.6%	3.2%
Brown 8	1.1%	1.2%	1.4%	1.5%	1.8%	0.4%	0.3%	0.4%	0.4%	0.2%	0.3%	0.3%	0.4%	0.4%	0.5%
Brown 9	1.6%	1.6%	1.8%	2.0%	2.4%	0.7%	0.5%	0.5%	0.6%	0.4%	0.5%	0.6%	0.7%	0.7%	0.9%
Cane Run 11	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	35.0%	8.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	79.5%	22.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	53.5%	17.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	93.0%	96.3%	80.2%	91.9%	83.6%	73.9%	48.7%	53.5%	56.1%	59.7%	54.0%	43.5%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	78.2%	63.7%	67.9%	71.4%	68.7%	63.4%	50.7%	61.0%	67.7%	78.5%	77.0%	79.4%	78.4%	80.4%	79.9%
Ghent 2	87.4%	78.4%	83.4%	85.1%	84.7%	71.1%	80.8%	81.5%	84.4%	84.0%	85.9%	84.4%	75.8%	86.7%	84.6%
Ghent 3	60.9%	65.5%	58.6%	62.3%	57.6%	46.6%	28.4%	43.3%	59.4%	71.9%	74.3%	68.1%	76.3%	78.7%	78.8%
Ghent 4	67.0%	60.3%	52.7%	48.2%	52.8%	40.6%	18.0%	25.1%	44.8%	69.6%	72.6%	76.8%	78.9%	76.5%	71.1%
Green River 3	21.2%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.7%	37.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.4%	0.5%	0.5%	0.6%	0.7%	0.2%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%
Mill Creek 1	88.7%	72.9%	82.6%	78.5%	84.0%	79.3%	83.4%	72.8%	85.4%	81.2%	85.7%	82.3%	87.5%	81.9%	87.7%
Mill Creek 2	84.1%	76.7%	79.2%	86.4%	81.2%	87.5%	76.8%	88.8%	83.7%	89.3%	84.1%	89.4%	84.1%	89.4%	77.2%
Mill Creek 3	87.3%	87.9%	57.4%	67.7%	73.2%	64.7%	73.5%	72.4%	78.9%	75.1%	80.2%	76.5%	81.5%	71.0%	83.6%
Mill Creek 4	69.4%	70.3%	76.8%	84.4%	80.2%	85.3%	78.8%	86.4%	74.3%	88.6%	83.7%	89.5%	84.1%	89.9%	84.6%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	23.0%	20.9%	18.2%	16.5%	13.9%	10.0%	5.7%	6.4%	6.1%	6.5%	6.5%	7.1%	8.1%	7.4%	9.7%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 10	8.4%	7.2%	7.4%	8.8%	9.4%	2.7%	1.8%	2.1%	2.3%	2.6%	2.6%	3.1%	3.5%	3.4%	4.3%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	32.1%	27.5%	25.5%	20.8%	28.4%	17.8%	6.4%	7.5%	7.3%	8.6%	7.9%	9.5%	11.0%	10.1%	12.8%
Trimble County 6	25.9%	21.7%	19.5%	22.4%	22.8%	13.9%	5.0%	5.1%	6.4%	6.8%	6.2%	7.5%	8.7%	8.1%	10.3%
Trimble County 7	20.4%	16.8%	16.2%	17.9%	15.4%	10.5%	3.9%	4.8%	5.0%	5.3%	5.0%	6.0%	7.0%	6.6%	8.1%
Trimble County 8	15.4%	12.9%	12.8%	12.9%	15.2%	7.4%	3.0%	3.6%	3.8%	4.1%	4.0%	4.8%	5.6%	5.4%	6.8%
Trimble County 9	11.6%	9.7%	9.9%	11.2%	11.3%	5.4%	2.3%	2.7%	2.9%	3.2%	3.2%	3.8%	4.4%	4.3%	5.3%
Zorn 1	0.2%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Zero Carbon															
Brown 1	6.9%	5.9%	7.9%	9.2%	9.8%	11.0%	7.3%	8.8%	8.2%	11.2%	10.5%	13.7%	15.2%	14.5%	20.3%
Brown 10	0.3%	0.4%	0.4%	0.5%	0.5%	0.3%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.5%
Brown 11	0.2%	0.3%	0.3%	0.3%	0.4%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%
Brown 2	15.5%	13.4%	14.7%	12.1%	16.4%	15.2%	10.9%	12.7%	13.4%	19.2%	17.2%	24.4%	32.0%	31.0%	32.5%
Brown 3	33.1%	30.4%	33.1%	34.5%	33.2%	29.7%	33.1%	34.5%	33.2%	34.7%	33.5%	34.9%	30.4%	35.1%	34.2%
Brown 5	0.5%	0.6%	0.6%	0.6%	0.7%	0.5%	0.4%	0.4%	0.4%	0.5%	0.5%	0.5%	0.6%	0.6%	0.7%
Brown 6	1.2%	1.3%	1.3%	1.4%	1.6%	1.1%	0.9%	1.0%	1.0%	1.0%	1.0%	1.2%	1.3%	1.2%	1.5%
Brown 7	1.6%	1.6%	1.7%	1.7%	1.7%	1.5%	1.1%	1.2%	1.3%	1.3%	1.4%	1.6%	1.7%	1.6%	2.0%
Brown 8	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.2%	0.3%	0.3%	0.3%	0.3%	0.4%	0.4%	0.4%	0.5%
Brown 9	0.4%	0.5%	0.5%	0.5%	0.6%	0.4%	0.4%	0.4%	0.4%	0.4%	0.5%	0.5%	0.6%	0.6%	0.7%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Cane Run 4	22.5%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	73.1%	16.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	40.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	92.8%	93.5%	77.4%	82.8%	71.0%	53.5%	28.5%	28.5%	29.2%	32.5%	25.6%	26.2%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	73.7%	57.5%	59.0%	60.7%	59.3%	64.6%	56.4%	62.3%	63.4%	73.1%	71.2%	74.6%	72.8%	75.1%	73.3%
Ghent 2	86.9%	77.4%	82.2%	83.9%	83.1%	71.0%	81.6%	81.2%	83.2%	82.2%	83.9%	82.5%	74.1%	84.7%	82.4%
Ghent 3	48.0%	54.2%	43.3%	45.8%	43.5%	44.3%	37.0%	45.3%	52.8%	61.1%	61.4%	58.2%	64.1%	65.6%	64.2%
Ghent 4	57.9%	43.4%	35.9%	30.0%	34.3%	35.9%	23.8%	24.7%	40.0%	48.7%	52.4%	57.7%	61.0%	55.9%	54.1%
Green River 3	12.6%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.3%	37.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Mill Creek 1	87.7%	70.3%	80.5%	76.1%	82.0%	79.5%	83.8%	72.8%	85.0%	80.4%	84.9%	81.0%	85.8%	79.8%	85.5%
Mill Creek 2	83.9%	74.4%	76.8%	83.8%	78.6%	86.8%	76.1%	88.5%	83.3%	88.7%	83.5%	88.8%	83.4%	88.7%	76.6%
Mill Creek 3	85.4%	87.3%	50.0%	61.7%	67.4%	61.6%	72.8%	71.2%	77.0%	72.5%	76.8%	73.2%	77.4%	67.4%	77.8%
Mill Creek 4	68.5%	62.9%	71.8%	80.8%	76.4%	84.1%	79.0%	86.0%	74.1%	87.4%	82.0%	87.9%	82.4%	88.3%	82.9%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Paddy's Run 13	14.4%	12.9%	10.5%	9.1%	8.0%	9.7%	6.4%	7.1%	6.4%	6.8%	6.3%	6.8%	7.1%	6.2%	8.4%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	88.4%	83.1%	88.4%	83.1%	88.4%	75.9%	88.4%	83.1%	88.4%
Trimble County 10	2.9%	2.6%	2.6%	3.0%	3.2%	2.2%	1.7%	1.9%	2.0%	2.1%	2.1%	2.4%	2.5%	2.3%	2.8%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	17.2%	13.4%	12.3%	9.8%	13.3%	13.2%	7.7%	8.8%	7.9%	9.4%	7.6%	9.2%	10.4%	8.7%	11.0%
Trimble County 6	12.7%	9.8%	8.9%	10.0%	9.8%	9.8%	5.7%	5.5%	6.9%	7.0%	5.9%	7.0%	7.9%	6.7%	8.5%
Trimble County 7	9.2%	7.1%	6.8%	7.4%	6.4%	7.2%	4.3%	5.2%	5.1%	5.2%	4.5%	5.3%	6.0%	5.1%	6.4%
Trimble County 8	6.2%	5.1%	5.1%	5.1%	5.8%	4.9%	3.1%	3.7%	3.7%	3.8%	3.5%	4.1%	4.5%	4.0%	5.0%
Trimble County 9	4.3%	3.6%	3.7%	4.0%	4.1%	3.5%	2.3%	2.7%	2.7%	2.8%	2.6%	3.0%	3.4%	3.0%	3.7%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Carbon Cap															
Brown 1	6.9%	5.9%	7.9%	9.2%	9.8%	11.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.3%	0.4%	0.4%	0.5%	0.5%	0.3%	0.6%	0.7%	0.7%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
Brown 11	0.2%	0.3%	0.3%	0.3%	0.4%	0.2%	0.4%	0.4%	0.5%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Brown 2	15.5%	13.4%	14.7%	12.1%	16.4%	15.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.1%	30.4%	33.1%	34.5%	33.2%	29.7%	33.1%	34.4%	35.0%	34.3%	33.0%	34.4%	29.8%	34.5%	33.2%
Brown 5	0.5%	0.6%	0.6%	0.6%	0.7%	0.5%	1.1%	1.2%	1.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%
Brown 6	1.2%	1.3%	1.3%	1.4%	1.6%	1.1%	1.8%	2.0%	2.0%	0.5%	0.4%	0.5%	0.5%	0.5%	0.6%
Brown 7	1.6%	1.6%	1.7%	1.7%	1.7%	1.5%	2.3%	2.6%	2.5%	0.6%	0.6%	0.6%	0.7%	0.7%	0.8%
Brown 8	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.5%	0.5%	0.5%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Brown 9	0.4%	0.5%	0.5%	0.5%	0.6%	0.4%	0.7%	0.9%	0.8%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 4	22.5%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	73.1%	16.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	40.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	92.8%	93.5%	77.4%	97.3%	93.0%	97.3%	76.6%	81.3%	71.8%	71.0%	68.0%	56.1%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	73.7%	57.5%	59.0%	60.7%	59.3%	64.6%	42.3%	45.7%	42.7%	43.7%	42.8%	44.8%	47.0%	44.8%	45.0%
Ghent 2	86.9%	77.4%	82.2%	83.9%	83.1%	71.0%	75.7%	75.1%	75.8%	72.9%	78.6%	77.3%	69.3%	78.6%	76.5%
Ghent 3	48.0%	54.2%	43.3%	45.8%	43.5%	44.3%	26.5%	19.7%	23.3%	29.1%	15.3%	17.2%	27.7%	17.5%	19.3%
Ghent 4	57.9%	43.4%	35.9%	30.0%	34.3%	35.9%	9.0%	6.8%	7.4%	16.8%	8.4%	9.9%	11.4%	9.1%	10.3%
Green River 3	12.6%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.3%	37.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.2%	0.2%	0.2%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	87.7%	70.3%	80.5%	76.1%	82.0%	79.5%	78.6%	66.8%	76.2%	74.2%	80.9%	76.5%	80.7%	76.4%	80.8%
Mill Creek 2	83.9%	74.4%	76.8%	83.8%	78.6%	86.8%	72.6%	82.7%	77.0%	83.9%	82.9%	86.5%	81.1%	86.0%	74.2%
Mill Creek 3	85.4%	87.3%	50.0%	61.7%	67.4%	61.6%	67.6%	67.4%	70.0%	57.2%	71.2%	67.8%	72.5%	61.5%	68.3%
Mill Creek 4	68.5%	62.9%	71.8%	80.8%	76.4%	84.1%	70.3%	75.4%	65.6%	75.0%	77.7%	83.5%	77.5%	82.6%	74.9%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 13	14.4%	12.9%	10.5%	9.1%	8.0%	9.7%	39.6%	43.5%	41.4%	5.1%	3.3%	3.8%	4.0%	3.7%	4.7%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	88.1%	82.8%	88.1%	82.4%	88.4%	75.9%	88.4%	83.1%	88.1%
Trimble County 10	2.9%	2.6%	2.6%	3.0%	3.2%	2.2%	12.0%	15.8%	14.5%	1.1%	0.9%	1.0%	1.0%	1.0%	1.2%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	83.7%	76.5%	83.7%	83.7%
Trimble County 5	17.2%	13.4%	12.3%	9.8%	13.3%	13.2%	36.9%	48.6%	40.4%	7.3%	3.4%	4.1%	4.5%	4.0%	5.0%
Trimble County 6	12.7%	9.8%	8.9%	10.0%	9.8%	9.8%	30.5%	36.0%	39.3%	5.1%	2.7%	3.1%	3.4%	3.2%	3.9%
Trimble County 7	9.2%	7.1%	6.8%	7.4%	6.4%	7.2%	24.9%	34.3%	31.8%	3.5%	2.0%	2.4%	2.6%	2.4%	2.8%
Trimble County 8	6.2%	5.1%	5.1%	5.1%	5.8%	4.9%	20.0%	27.2%	25.1%	2.5%	1.5%	1.8%	1.9%	1.8%	2.1%
Trimble County 9	4.3%	3.6%	3.7%	4.0%	4.1%	3.5%	15.7%	21.0%	19.3%	1.6%	1.1%	1.3%	1.4%	1.3%	1.6%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Capacity Factor (%)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Mid Carbon															
Brown 1	6.9%	5.9%	7.9%	9.2%	9.8%	11.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 10	0.3%	0.4%	0.4%	0.5%	0.5%	0.3%	0.5%	0.6%	0.1%	0.1%	0.2%	0.2%	0.2%	0.2%	0.2%
Brown 11	0.2%	0.3%	0.3%	0.3%	0.4%	0.2%	0.4%	0.4%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%
Brown 2	15.5%	13.4%	14.7%	12.1%	16.4%	15.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Brown 3	33.1%	30.4%	33.1%	34.5%	33.2%	29.7%	33.1%	34.5%	32.9%	34.3%	33.0%	34.3%	31.0%	35.7%	34.4%
Brown 5	0.5%	0.6%	0.6%	0.6%	0.7%	0.5%	0.8%	0.9%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%	0.4%
Brown 6	1.2%	1.3%	1.3%	1.4%	1.6%	1.1%	1.6%	1.9%	0.6%	0.5%	0.5%	0.6%	0.6%	0.6%	0.7%
Brown 7	1.6%	1.6%	1.7%	1.7%	1.7%	1.5%	2.1%	2.5%	0.8%	0.7%	0.7%	0.8%	0.8%	0.8%	0.9%
Brown 8	0.3%	0.3%	0.4%	0.4%	0.4%	0.3%	0.4%	0.5%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.2%
Brown 9	0.4%	0.5%	0.5%	0.5%	0.6%	0.4%	0.6%	0.7%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%
Cane Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 4	22.5%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 5	73.1%	16.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 6	40.0%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Cane Run 7	0.0%	65.2%	97.3%	92.8%	93.5%	77.4%	97.3%	93.0%	97.3%	77.9%	97.3%	93.0%	97.3%	93.0%	81.7%
Dix Dam 1-3	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%	29.6%	29.6%	29.6%	29.5%
Ghent 1	73.7%	57.5%	59.0%	60.7%	59.3%	64.6%	51.9%	55.8%	32.7%	30.6%	24.9%	28.9%	31.3%	29.4%	31.6%
Ghent 2	86.9%	77.4%	82.2%	83.9%	83.1%	71.0%	76.1%	75.3%	67.6%	68.1%	63.9%	66.4%	56.6%	66.9%	68.2%
Ghent 3	48.0%	54.2%	43.3%	45.8%	43.5%	44.3%	38.9%	41.4%	29.6%	16.8%	15.8%	15.5%	20.7%	16.8%	17.4%
Ghent 4	57.9%	43.4%	35.9%	30.0%	34.3%	35.9%	24.0%	24.8%	17.9%	9.2%	8.3%	9.8%	11.2%	9.5%	12.1%
Green River 3	12.6%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Green River 4	88.3%	37.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Haefling 1-2	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.2%	0.2%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.1%
Mill Creek 1	87.7%	70.3%	80.5%	76.1%	82.0%	79.5%	79.3%	68.2%	75.1%	70.1%	72.2%	69.4%	72.1%	68.5%	73.9%
Mill Creek 2	83.9%	74.4%	76.8%	83.8%	78.6%	86.8%	73.6%	85.0%	73.1%	78.3%	70.4%	77.2%	70.9%	76.5%	67.0%
Mill Creek 3	85.4%	87.3%	50.0%	61.7%	67.4%	61.6%	66.0%	64.3%	54.9%	51.0%	47.9%	49.9%	52.7%	46.9%	56.5%
Mill Creek 4	68.5%	62.9%	71.8%	80.8%	76.4%	84.1%	73.3%	78.4%	58.5%	55.1%	47.5%	53.2%	53.0%	54.4%	54.1%
Ohio Falls 1-8	41.0%	43.4%	45.5%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%	46.5%	46.5%	46.5%	46.4%
Paddy's Run 11	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 12	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Paddy's Run 13	14.4%	12.9%	10.5%	9.1%	8.0%	9.7%	11.0%	13.2%	6.2%	4.7%	4.4%	5.1%	5.2%	4.7%	6.1%
Trimble County 1	88.4%	82.9%	88.4%	75.9%	88.4%	83.0%	88.1%	82.9%	85.5%	80.5%	84.4%	73.7%	85.0%	80.4%	86.1%
Trimble County 10	2.9%	2.6%	2.6%	3.0%	3.2%	2.2%	3.2%	3.7%	1.4%	1.0%	1.0%	1.1%	1.2%	1.1%	1.3%
Trimble County 2	63.1%	83.2%	83.7%	83.7%	76.5%	83.7%	83.7%	83.7%	83.6%	83.5%	83.6%	83.6%	76.4%	83.6%	83.6%
Trimble County 5	17.2%	13.4%	12.3%	9.8%	13.3%	13.2%	14.5%	17.0%	9.4%	4.9%	4.3%	5.1%	5.6%	4.9%	6.1%
Trimble County 6	12.7%	9.8%	8.9%	10.0%	9.8%	9.8%	10.8%	10.7%	6.9%	3.6%	3.2%	3.8%	4.1%	3.7%	4.5%
Trimble County 7	9.2%	7.1%	6.8%	7.4%	6.4%	7.2%	8.0%	9.8%	4.7%	2.6%	2.4%	2.8%	3.0%	2.8%	3.3%
Trimble County 8	6.2%	5.1%	5.1%	5.1%	5.8%	4.9%	5.9%	7.2%	3.2%	1.9%	1.8%	2.1%	2.2%	2.1%	2.5%
Trimble County 9	4.3%	3.6%	3.7%	4.0%	4.1%	3.5%	4.3%	5.2%	2.1%	1.4%	1.4%	1.5%	1.6%	1.5%	1.8%
Zorn 1	0.0%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Zero Carbon															
Brown 1	128	93	138	193	256	275	240	314	277	321	308	372	365	362	376
Brown 10	7	8	9	10	11	8	4	4	5	5	6	7	8	8	10
Brown 11	5	6	7	7	8	6	2	3	3	3	4	4	5	5	6
Brown 2	322	299	397	393	623	585	543	610	650	606	566	713	729	718	737
Brown 3	1,207	1,103	1,214	1,270	1,244	1,139	1,253	1,326	1,291	1,368	1,351	1,493	1,366	1,609	1,622
Brown 5	10	11	12	13	15	12	6	7	7	8	9	10	11	12	14
Brown 6	27	26	28	29	36	29	22	26	27	30	31	36	41	39	49
Brown 7	34	32	35	39	39	39	28	34	35	39	38	45	52	48	61
Brown 8	6	7	8	8	10	7	3	3	3	4	4	5	6	6	7
Brown 9	9	9	11	12	14	10	5	6	6	7	8	9	10	10	12
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	414	102	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,130	298	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	993	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,595	2,534	2,275	2,254	1,782	1,571	1,636	1,750	1,373	1,627	1,708	1,919	1,640	1,675
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,277	2,589	3,166	3,303	3,159	3,295	3,149	3,217	2,896	3,291	3,230	3,356	3,298	3,376	3,324
Ghent 2	3,773	3,384	3,579	3,646	3,644	3,145	3,658	3,575	3,640	3,564	3,640	3,579	3,200	3,652	3,574
Ghent 3	2,263	2,489	3,032	3,090	2,807	2,818	2,854	2,921	2,921	2,909	2,953	2,738	3,054	3,091	3,033
Ghent 4	2,594	2,121	2,794	2,613	2,788	2,831	2,496	2,397	2,735	2,676	2,629	2,810	2,929	2,777	2,633
Green River 3	106	27	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,342	1,909	2,181	2,075	2,254	2,153	2,282	1,970	2,286	2,147	2,291	2,169	2,295	2,140	2,299
Mill Creek 2	2,216	1,981	2,087	2,285	2,161	2,315	2,005	2,319	2,182	2,319	2,189	2,322	2,182	2,319	2,010
Mill Creek 3	2,959	3,005	2,065	2,404	2,603	2,345	2,716	2,580	2,753	2,580	2,752	2,595	2,774	2,391	2,796
Mill Creek 4	2,883	2,773	3,228	3,493	3,393	3,628	3,417	3,634	3,123	3,636	3,424	3,643	3,420	3,645	3,438
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	181	159	141	122	108	132	96	109	106	120	117	128	138	122	167
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,944	2,758	2,935	2,758	2,944	2,521	2,935	2,758	2,944
Trimble County 10	67	56	59	67	70	52	40	48	50	55	53	62	70	64	81
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	301	241	221	160	230	231	144	162	149	188	162	188	212	187	235
Trimble County 6	234	181	165	186	182	180	113	109	137	148	130	150	171	152	192
Trimble County 7	176	136	136	144	121	139	89	108	111	119	102	119	141	124	159
Trimble County 8	129	103	102	106	120	107	68	83	84	92	81	96	114	101	129
Trimble County 9	93	77	77	87	86	80	53	63	66	71	66	78	91	80	103
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Carbon Cap															
Brown 1	128	93	138	193	256	275	0	0	0	0	0	0	0	0	0
Brown 10	7	8	9	10	11	8	4	3	4	5	5	5	6	6	6
Brown 11	5	6	7	7	8	6	3	2	3	3	4	4	4	5	5
Brown 2	322	299	397	393	623	585	0	0	0	0	0	0	0	0	0
Brown 3	1,207	1,103	1,214	1,270	1,244	1,139	1,360	1,240	1,194	1,515	1,248	1,438	1,177	1,514	1,369
Brown 5	10	11	12	13	15	12	8	5	5	10	6	9	8	10	8
Brown 6	27	26	28	29	36	29	16	11	12	16	15	19	19	21	20
Brown 7	34	32	35	39	39	39	20	14	15	21	19	24	23	26	24
Brown 8	6	7	8	8	10	7	3	3	3	4	4	5	5	5	5
Brown 9	9	9	11	12	14	10	5	4	4	6	5	6	7	7	7
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	414	102	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,130	298	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	993	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,595	2,534	2,275	2,254	1,782	5,469	4,343	4,550	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,277	2,589	3,166	3,303	3,159	3,295	1,806	1,499	1,348	1,718	1,507	1,703	1,769	1,661	1,672
Ghent 2	3,773	3,384	3,579	3,646	3,644	3,145	2,985	3,168	3,182	2,991	2,942	2,986	2,594	2,980	3,002
Ghent 3	2,263	2,489	3,032	3,090	2,807	2,818	865	955	1,030	839	897	884	1,135	984	987
Ghent 4	2,594	2,121	2,794	2,613	2,788	2,831	679	522	588	669	702	820	920	743	728
Green River 3	106	27	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,342	1,909	2,181	2,075	2,254	2,153	1,947	1,771	2,052	1,822	1,962	1,855	1,951	1,796	1,964
Mill Creek 2	2,216	1,981	2,087	2,285	2,161	2,315	1,723	2,141	2,010	1,995	1,914	1,993	1,894	1,979	1,765
Mill Creek 3	2,959	3,005	2,065	2,404	2,603	2,345	2,075	2,063	2,142	1,971	1,962	1,922	2,035	1,771	2,036
Mill Creek 4	2,883	2,773	3,228	3,493	3,393	3,628	2,508	2,944	2,524	2,569	2,344	2,540	2,476	2,513	2,409
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	181	159	141	122	108	132	409	70	72	308	94	113	115	104	119
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,881	2,743	2,912	2,713	2,873	2,482	2,873	2,705	2,887
Trimble County 10	67	56	59	67	70	52	107	24	25	35	30	36	37	37	37
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,022	4,036	4,023	3,677	4,022	4,034
Trimble County 5	301	241	221	160	230	231	381	89	84	166	103	135	143	129	135
Trimble County 6	234	181	165	186	182	180	310	61	73	124	81	104	110	101	105
Trimble County 7	176	136	136	144	121	139	247	54	55	92	63	80	84	79	82
Trimble County 8	129	103	102	106	120	107	192	40	41	67	48	61	63	61	63
Trimble County 9	93	77	77	87	86	80	146	30	31	49	38	47	49	48	48
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Base Load-Mid Carbon															
Brown 1	128	93	138	193	256	275	0	0	0	0	0	0	0	0	0
Brown 10	7	8	9	10	11	8	3	3	4	4	5	6	6	6	2
Brown 11	5	6	7	7	8	6	2	2	3	3	4	4	4	5	1
Brown 2	322	299	397	393	623	585	0	0	0	0	0	0	0	0	0
Brown 3	1,207	1,103	1,214	1,270	1,244	1,139	1,193	1,239	1,192	1,241	1,203	1,250	1,136	1,302	1,225
Brown 5	10	11	12	13	15	12	5	5	5	6	6	7	8	8	3
Brown 6	27	26	28	29	36	29	14	11	12	13	15	17	18	18	7
Brown 7	34	32	35	39	39	39	17	14	15	17	18	20	23	22	8
Brown 8	6	7	8	8	10	7	3	3	3	4	4	5	5	5	2
Brown 9	9	9	11	12	14	10	4	4	4	5	6	6	7	7	2
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	414	102	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,130	298	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	993	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,595	2,534	2,275	2,254	1,782	5,129	4,636	5,026	4,278	5,451	5,211	5,448	5,211	4,582
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,277	2,589	3,166	3,303	3,159	3,295	1,880	1,509	1,347	1,773	1,496	1,733	1,786	1,752	1,252
Ghent 2	3,773	3,384	3,579	3,646	3,644	3,145	3,110	3,063	3,019	3,100	2,990	3,043	2,637	3,063	2,669
Ghent 3	2,263	2,489	3,032	3,090	2,807	2,818	1,482	959	1,031	1,080	1,011	1,012	1,303	1,105	729
Ghent 4	2,594	2,121	2,794	2,613	2,788	2,831	947	522	589	642	585	691	814	686	544
Green River 3	106	27	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,342	1,909	2,181	2,075	2,254	2,153	2,088	1,748	2,014	1,916	1,998	1,902	1,979	1,865	1,883
Mill Creek 2	2,216	1,981	2,087	2,285	2,161	2,315	1,876	2,121	1,965	2,116	1,938	2,091	1,940	2,076	1,630
Mill Creek 3	2,959	3,005	2,065	2,404	2,603	2,345	2,096	1,989	2,006	1,977	1,933	1,981	2,076	1,837	1,753
Mill Creek 4	2,883	2,773	3,228	3,493	3,393	3,628	2,824	2,814	2,392	2,739	2,384	2,645	2,557	2,672	2,092
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	181	159	141	122	108	132	89	73	75	84	81	92	99	88	56
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,914	2,728	2,874	2,721	2,879	2,485	2,880	2,712	2,798
Trimble County 10	67	56	59	67	70	52	31	23	24	26	27	32	36	34	14
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	301	241	221	160	230	231	160	90	86	108	96	117	134	117	71
Trimble County 6	234	181	165	186	182	180	120	61	73	82	74	90	103	91	52
Trimble County 7	176	136	136	144	121	139	86	54	56	62	58	69	79	70	38
Trimble County 8	129	103	102	106	120	107	63	40	42	47	44	53	60	55	27
Trimble County 9	93	77	77	87	86	80	44	30	31	35	35	42	46	44	20
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-High Load-Zero Carbon															
Brown 1	170	125	189	253	318	359	347	440	387	450	441	515	506	513	519
Brown 10	14	14	17	18	21	6	4	5	5	4	4	5	6	6	8
Brown 11	10	11	13	14	16	4	3	3	4	2	3	3	3	4	5
Brown 2	402	388	492	484	732	709	703	782	833	786	735	909	915	922	929
Brown 3	1,228	1,118	1,239	1,305	1,291	1,105	1,317	1,592	1,677	1,783	1,805	2,077	1,846	2,148	2,131
Brown 5	18	19	21	24	28	9	6	6	7	5	6	7	8	9	11
Brown 6	48	44	48	51	63	24	12	14	15	18	20	23	26	27	33
Brown 7	58	53	57	66	64	31	16	18	20	23	25	29	33	33	41
Brown 8	11	13	14	16	19	5	3	4	5	2	3	4	4	5	6
Brown 9	17	17	19	21	26	8	5	6	6	4	5	6	7	8	9
Cane Run 11	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Cane Run 4	509	137	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,169	344	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	1,131	379	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,619	3,027	2,780	2,818	2,157	1,637	1,407	1,431	1,010	1,192	1,250	1,611	1,366	1,505
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,363	2,710	3,247	3,382	3,247	3,385	3,286	3,352	3,019	3,434	3,379	3,488	3,440	3,502	3,465
Ghent 2	3,782	3,400	3,585	3,655	3,652	3,169	3,688	3,605	3,671	3,599	3,677	3,611	3,232	3,686	3,613
Ghent 3	2,511	2,703	3,229	3,250	2,943	2,990	3,082	3,151	3,150	3,152	3,219	2,939	3,288	3,339	3,288
Ghent 4	2,758	2,453	2,995	2,876	3,008	3,093	2,823	2,667	3,032	3,018	2,976	3,124	3,222	3,110	2,900
Green River 3	134	38	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	723	305	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,354	1,935	2,202	2,094	2,276	2,168	2,302	1,988	2,306	2,167	2,313	2,186	2,316	2,168	2,325
Mill Creek 2	2,217	2,005	2,103	2,298	2,172	2,321	2,010	2,323	2,187	2,325	2,194	2,326	2,187	2,326	2,013
Mill Creek 3	2,987	3,011	2,122	2,464	2,672	2,403	2,794	2,662	2,844	2,666	2,850	2,692	2,879	2,478	2,893
Mill Creek 4	2,900	2,916	3,267	3,529	3,416	3,650	3,440	3,656	3,146	3,660	3,451	3,667	3,447	3,670	3,462
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	229	204	183	162	141	97	58	63	70	78	74	80	93	86	115
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,944	2,758	2,935	2,758	2,944	2,521	2,935	2,758	2,944
Trimble County 10	111	91	96	110	117	33	22	26	28	32	33	42	44	44	55
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	401	336	308	230	326	200	76	96	90	111	106	122	138	124	161
Trimble County 6	325	263	237	268	268	157	62	61	79	87	80	94	110	101	128
Trimble County 7	255	204	204	216	183	116	46	59	60	68	67	78	88	81	105
Trimble County 8	195	160	158	163	187	89	36	42	48	52	52	65	73	70	88
Trimble County 9	148	121	123	139	138	65	28	33	36	42	43	49	57	55	70
Zorn 1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Zero Carbon															
Brown 1	92	66	96	139	198	205	168	220	194	218	210	256	254	239	252
Brown 10	3	4	5	5	5	3	3	3	3	4	4	5	5	5	6
Brown 11	2	3	3	3	4	2	2	2	2	3	3	3	4	4	4
Brown 2	247	220	305	306	508	460	405	458	486	440	415	520	550	512	535
Brown 3	1,195	1,094	1,197	1,247	1,213	1,099	1,218	1,276	1,234	1,295	1,266	1,361	1,221	1,423	1,415
Brown 5	5	6	7	7	8	5	5	5	5	5	6	6	7	7	8
Brown 6	14	14	15	16	19	14	10	11	12	13	13	15	16	16	18
Brown 7	19	18	20	22	22	19	14	16	16	18	18	20	22	20	25
Brown 8	3	4	4	4	5	3	3	3	3	3	4	4	4	4	5
Brown 9	4	5	6	6	7	4	4	4	4	5	5	6	6	6	7
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	322	71	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,075	246	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	846	228	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,560	2,028	1,763	1,695	1,298	1,073	1,103	1,174	900	1,067	1,108	1,300	1,038	1,097
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,169	2,436	3,070	3,198	3,048	3,168	2,992	3,055	2,750	3,115	3,048	3,188	3,122	3,204	3,136
Ghent 2	3,761	3,365	3,569	3,636	3,630	3,113	3,617	3,534	3,594	3,515	3,589	3,529	3,157	3,599	3,520
Ghent 3	1,979	2,233	2,785	2,875	2,622	2,595	2,558	2,612	2,622	2,582	2,603	2,463	2,745	2,753	2,677
Ghent 4	2,384	1,763	2,542	2,286	2,497	2,483	2,086	2,033	2,324	2,209	2,160	2,347	2,499	2,273	2,208
Green River 3	80	18	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	719	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,327	1,880	2,162	2,058	2,229	2,133	2,260	1,949	2,261	2,125	2,264	2,145	2,267	2,107	2,266
Mill Creek 2	2,213	1,957	2,069	2,267	2,144	2,305	1,996	2,310	2,173	2,308	2,180	2,312	2,169	2,309	1,999
Mill Creek 3	2,925	2,996	2,003	2,342	2,529	2,280	2,631	2,497	2,667	2,495	2,654	2,501	2,674	2,305	2,684
Mill Creek 4	2,859	2,609	3,179	3,453	3,358	3,590	3,378	3,598	3,089	3,594	3,381	3,605	3,377	3,603	3,394
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	136	117	103	86	79	92	63	70	67	77	73	80	86	73	103
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,944	2,758	2,935	2,758	2,944	2,521	2,935	2,758	2,944
Trimble County 10	38	32	34	38	39	27	21	24	24	26	25	28	30	28	34
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	211	162	148	105	151	146	85	93	85	107	90	103	116	97	126
Trimble County 6	158	117	107	120	115	109	64	61	74	80	69	79	89	76	98
Trimble County 7	113	85	85	90	75	81	49	58	58	62	52	60	70	60	77
Trimble County 8	78	63	62	64	71	59	37	43	43	46	40	46	54	47	60
Trimble County 9	55	46	46	50	50	42	27	32	32	35	32	37	41	36	45
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Carbon Cap															
Brown 1	92	66	96	139	198	205	0	0	0	0	0	0	0	0	0
Brown 10	3	4	5	5	5	3	5	5	5	5	6	6	6	6	7
Brown 11	2	3	3	3	4	2	4	4	4	4	4	4	5	5	5
Brown 2	247	220	305	306	508	460	0	0	0	0	0	0	0	0	0
Brown 3	1,195	1,094	1,197	1,247	1,213	1,099	1,367	1,236	1,200	1,545	1,209	1,309	1,149	1,266	1,293
Brown 5	5	6	7	7	8	5	10	7	7	12	8	8	9	8	9
Brown 6	14	14	15	16	19	14	19	18	18	21	17	21	21	19	23
Brown 7	19	18	20	22	22	19	25	24	22	27	22	25	27	24	28
Brown 8	3	4	4	4	5	3	4	4	5	5	5	5	6	5	6
Brown 9	4	5	6	6	7	4	6	6	6	6	7	7	8	7	8
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	322	71	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,075	246	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	846	228	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,560	2,028	1,763	1,695	1,298	5,469	5,211	5,429	4,365	4,995	5,211	5,452	4,868	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,169	2,436	3,070	3,198	3,048	3,168	2,098	2,137	1,879	2,263	1,931	2,181	2,161	2,102	2,177
Ghent 2	3,761	3,365	3,569	3,636	3,630	3,113	3,184	3,190	3,242	3,134	3,291	3,184	2,811	3,300	3,171
Ghent 3	1,979	2,233	2,785	2,875	2,622	2,595	1,297	1,501	1,539	1,262	1,339	1,308	1,633	1,426	1,320
Ghent 4	2,384	1,763	2,542	2,286	2,497	2,483	1,012	830	942	1,036	790	917	1,062	776	1,016
Green River 3	80	18	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	719	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,327	1,880	2,162	2,058	2,229	2,133	2,013	1,763	2,076	1,884	2,094	1,950	2,041	1,944	2,036
Mill Creek 2	2,213	1,957	2,069	2,267	2,144	2,305	1,813	2,153	2,055	2,034	2,055	2,154	2,016	2,168	1,840
Mill Creek 3	2,925	2,996	2,003	2,342	2,529	2,280	2,272	2,236	2,259	2,201	2,383	2,217	2,304	2,100	2,360
Mill Creek 4	2,859	2,609	3,179	3,453	3,358	3,590	2,710	3,009	2,653	2,939	2,941	3,009	2,834	3,142	2,853
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	136	117	103	86	79	92	224	138	112	292	100	125	124	97	147
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,928	2,744	2,916	2,745	2,933	2,511	2,919	2,751	2,929
Trimble County 10	38	32	34	38	39	27	37	38	36	41	35	40	43	37	44
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	211	162	148	105	151	146	169	171	138	186	124	159	173	132	178
Trimble County 6	158	117	107	120	115	109	126	110	120	138	97	120	130	103	138
Trimble County 7	113	85	85	90	75	81	93	101	90	102	74	93	99	80	103
Trimble County 8	78	63	62	64	71	59	68	72	66	75	57	70	74	60	79
Trimble County 9	55	46	46	50	50	42	50	53	49	55	43	53	55	47	61
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: High Gas-Low Load-Mid Carbon															
Brown 1	92	66	96	139	198	205	0	0	0	0	0	0	0	0	0
Brown 10	3	4	5	5	5	3	5	6	6	6	7	2	2	2	2
Brown 11	2	3	3	3	4	2	4	4	4	5	5	1	1	1	2
Brown 2	247	220	305	306	508	460	0	0	0	0	0	0	0	0	0
Brown 3	1,195	1,094	1,197	1,247	1,213	1,099	1,203	1,253	1,205	1,255	1,216	1,234	1,109	1,276	1,240
Brown 5	5	6	7	7	8	5	8	8	9	9	10	3	3	3	3
Brown 6	14	14	15	16	19	14	18	20	21	23	23	8	7	7	8
Brown 7	19	18	20	22	22	19	23	26	26	29	28	10	9	9	10
Brown 8	3	4	4	4	5	3	5	5	5	6	6	2	2	2	2
Brown 9	4	5	6	6	7	4	6	7	7	8	9	3	2	3	3
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	322	71	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,075	246	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	846	228	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,560	2,028	1,763	1,695	1,298	5,342	5,113	5,372	4,356	5,469	5,209	5,432	5,209	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,169	2,436	3,070	3,198	3,048	3,168	2,203	2,363	2,071	2,596	2,259	1,816	1,315	1,240	1,336
Ghent 2	3,761	3,365	3,569	3,636	3,630	3,113	3,296	3,256	3,302	3,270	3,300	2,986	2,432	2,856	2,918
Ghent 3	1,979	2,233	2,785	2,875	2,622	2,595	1,621	1,724	1,761	1,850	1,658	1,184	858	695	726
Ghent 4	2,384	1,763	2,542	2,286	2,497	2,483	979	1,008	1,138	1,211	1,045	706	456	388	491
Green River 3	80	18	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	719	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,327	1,880	2,162	2,058	2,229	2,133	2,115	1,820	2,108	1,996	2,105	1,887	1,909	1,807	1,956
Mill Creek 2	2,213	1,957	2,069	2,267	2,144	2,305	1,922	2,217	2,077	2,218	2,065	2,082	1,845	1,992	1,748
Mill Creek 3	2,925	2,996	2,003	2,342	2,529	2,280	2,314	2,237	2,360	2,301	2,366	2,006	1,784	1,585	1,914
Mill Creek 4	2,859	2,609	3,179	3,453	3,358	3,590	3,060	3,264	2,791	3,293	2,969	2,683	2,186	2,231	2,226
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	136	117	103	86	79	92	114	130	129	143	133	67	54	49	65
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,758	2,933	2,751	2,923	2,751	2,934	2,484	2,834	2,674	2,867
Trimble County 10	38	32	34	38	39	27	38	45	45	48	45	18	14	14	17
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	211	162	148	105	151	146	165	192	170	218	181	107	65	59	73
Trimble County 6	158	117	107	120	115	109	124	121	149	164	136	75	48	44	54
Trimble County 7	113	85	85	90	75	81	92	113	112	123	104	53	35	33	41
Trimble County 8	78	63	62	64	71	59	68	83	81	90	78	37	26	25	30
Trimble County 9	55	46	46	50	50	42	51	60	59	66	60	27	19	19	22
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Zero Carbon															
Brown 1	13	12	15	16	18	14	3	3	4	4	5	6	7	7	8
Brown 10	10	12	12	14	16	12	3	3	3	3	4	4	5	5	6
Brown 11	6	7	8	9	11	7	2	2	2	2	3	3	3	3	4
Brown 2	34	32	40	36	45	33	9	8	9	10	12	14	15	16	18
Brown 3	1,188	1,091	1,184	1,228	1,181	1,058	1,176	1,221	1,173	1,221	1,177	1,222	1,055	1,223	1,179
Brown 5	18	19	20	22	26	21	5	5	5	6	7	7	8	9	10
Brown 6	71	180	56	59	149	160	64	30	33	26	19	20	24	22	27
Brown 7	88	208	67	75	133	190	77	38	42	33	24	25	30	27	34
Brown 8	7	9	10	11	12	9	2	2	2	3	3	3	4	4	5
Brown 9	12	15	14	16	20	15	4	4	4	4	5	5	6	6	7
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	72	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	786	33	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	334	14	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,688	1,114	1,703	897	967	944	346	290	296	317	327	623	604	661	848
Ghent 2	3,714	2,908	3,383	3,361	3,312	2,525	2,453	2,478	2,332	2,776	2,631	2,820	2,436	2,858	2,974
Ghent 3	1,115	624	901	525	539	471	185	152	163	176	192	203	246	236	261
Ghent 4	2,053	2,383	2,441	2,341	2,138	2,265	2,061	1,665	2,061	2,156	2,122	2,129	2,197	2,138	1,801
Green River 3	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	242	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,294	1,184	1,916	1,626	1,849	1,811	1,776	1,572	1,728	1,794	1,834	1,823	1,883	1,805	1,952
Mill Creek 2	2,211	1,497	1,898	1,945	1,801	2,038	1,594	1,802	1,623	1,987	1,835	2,038	1,842	2,029	1,829
Mill Creek 3	2,807	2,697	1,191	1,022	1,163	1,095	616	571	570	1,078	1,061	1,304	1,337	1,256	1,576
Mill Creek 4	2,782	1,127	2,402	2,354	2,318	2,319	1,759	1,547	1,383	2,067	1,852	2,378	2,293	2,371	2,464
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	677	697	652	667	504	667	671	689	649	663	582	533	547	576	582
Trimble County 1	2,966	2,736	2,944	2,519	2,932	2,741	2,892	2,705	2,868	2,741	2,915	2,510	2,914	2,733	2,930
Trimble County 10	615	1,292	543	1,015	995	894	669	471	456	269	258	185	257	203	240
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	1,105	1,385	877	1,108	1,298	1,347	1,059	868	714	694	582	453	585	493	556
Trimble County 6	1,019	1,381	719	1,281	1,253	1,317	985	648	758	592	506	382	508	416	478
Trimble County 7	923	1,377	746	1,227	984	1,281	907	713	676	497	436	320	436	349	407
Trimble County 8	822	1,358	676	992	1,134	1,232	826	628	598	411	371	267	370	292	344
Trimble County 9	718	1,327	609	1,102	953	1,168	747	547	525	335	312	223	310	244	288
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Carbon Cap															
Brown 1	13	12	15	16	18	4	0	0	0	0	0	0	0	0	0
Brown 10	10	12	12	14	16	3	4	4	5	5	6	7	8	2	2
Brown 11	6	7	8	9	11	2	3	3	3	4	4	5	5	1	2
Brown 2	34	32	40	36	45	12	0	0	0	0	0	0	0	0	0
Brown 3	1,188	1,091	1,184	1,228	1,181	1,053	1,177	1,222	1,175	1,223	1,180	1,225	1,058	1,221	1,177
Brown 5	18	19	20	22	26	7	7	8	9	9	10	11	13	4	4
Brown 6	71	180	56	59	149	97	30	30	33	26	19	20	24	7	7
Brown 7	88	208	67	75	133	110	38	38	42	33	24	25	30	9	9
Brown 8	7	9	10	11	12	2	3	4	4	4	5	6	6	2	2
Brown 9	12	15	14	16	20	5	5	5	6	6	7	8	9	3	3
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	72	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	786	33	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	334	14	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,688	1,114	1,703	897	967	549	251	290	297	318	328	624	605	393	265
Ghent 2	3,714	2,908	3,383	3,361	3,312	2,045	2,118	2,478	2,332	2,776	2,631	2,820	2,437	2,333	2,053
Ghent 3	1,115	624	901	525	539	258	143	151	162	175	191	203	246	99	94
Ghent 4	2,053	2,383	2,441	2,341	2,138	2,164	2,007	1,665	2,061	2,156	2,122	2,129	2,197	1,996	1,603
Green River 3	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	242	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,294	1,184	1,916	1,626	1,849	1,724	1,655	1,572	1,728	1,794	1,834	1,823	1,883	1,606	1,656
Mill Creek 2	2,211	1,497	1,898	1,945	1,801	1,934	1,488	1,802	1,623	1,987	1,835	2,038	1,842	1,767	1,476
Mill Creek 3	2,807	2,697	1,191	1,022	1,163	799	378	571	571	1,078	1,061	1,304	1,337	962	785
Mill Creek 4	2,782	1,127	2,402	2,354	2,318	1,747	1,269	1,547	1,383	2,067	1,851	2,378	2,293	1,824	1,394
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	677	697	652	667	504	663	667	689	649	663	582	533	547	453	409
Trimble County 1	2,966	2,736	2,944	2,519	2,932	2,728	2,843	2,705	2,868	2,741	2,915	2,510	2,914	2,604	2,758
Trimble County 10	615	1,292	543	1,015	995	671	511	471	457	269	258	185	257	104	97
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,035	4,023	4,023	4,023	4,036	4,023	3,677	3,997	4,005
Trimble County 5	1,105	1,385	877	1,108	1,298	1,217	890	868	714	694	582	454	585	319	254
Trimble County 6	1,019	1,381	719	1,281	1,253	1,162	804	648	758	592	506	382	508	259	212
Trimble County 7	923	1,377	746	1,227	984	1,100	724	713	676	497	436	320	436	208	175
Trimble County 8	822	1,358	676	992	1,134	1,029	648	628	598	411	371	267	370	166	145
Trimble County 9	718	1,327	609	1,102	953	952	578	547	525	335	312	223	310	132	119
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Base Load-Mid Carbon															
Brown 1	13	12	15	16	18	14	0	0	0	0	0	0	0	0	0
Brown 10	10	12	12	14	16	12	32	14	21	32	51	58	168	328	428
Brown 11	6	7	8	9	11	7	15	6	12	14	31	36	87	180	287
Brown 2	34	32	40	36	45	33	0	0	0	0	0	0	0	0	0
Brown 3	1,188	1,091	1,184	1,228	1,181	1,058	1,180	1,221	1,173	1,221	1,177	1,222	1,059	1,228	1,185
Brown 5	18	19	20	22	26	21	110	62	165	173	202	219	319	358	463
Brown 6	71	180	56	59	149	160	1,200	1,088	971	1,043	959	996	1,057	1,091	1,150
Brown 7	88	208	67	75	133	190	1,212	1,121	1,002	1,070	983	1,022	1,085	1,116	1,161
Brown 8	7	9	10	11	12	9	20	9	14	18	38	44	106	214	326
Brown 9	12	15	14	16	20	15	41	20	26	39	62	71	202	369	478
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	72	3	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	786	33	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	334	14	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,688	1,114	1,703	897	967	944	287	101	94	82	62	69	77	79	90
Ghent 2	3,714	2,908	3,383	3,361	3,312	2,525	1,549	919	545	619	609	660	566	538	496
Ghent 3	1,115	624	901	525	539	471	148	49	24	26	32	35	36	39	42
Ghent 4	2,053	2,383	2,441	2,341	2,138	2,265	1,648	1,116	520	588	455	409	359	266	201
Green River 3	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	242	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,294	1,184	1,916	1,626	1,849	1,811	1,284	790	691	821	794	858	862	694	757
Mill Creek 2	2,211	1,497	1,898	1,945	1,801	2,038	1,055	832	517	646	611	805	745	639	586
Mill Creek 3	2,807	2,697	1,191	1,022	1,163	1,095	607	384	248	268	270	282	309	252	223
Mill Creek 4	2,782	1,127	2,402	2,354	2,318	2,319	912	359	216	225	234	243	241	180	166
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	677	697	652	667	504	667	677	680	628	665	632	640	628	635	642
Trimble County 1	2,966	2,736	2,944	2,519	2,932	2,741	2,384	1,837	1,467	1,534	1,534	1,488	1,650	1,538	1,662
Trimble County 10	615	1,292	543	1,015	995	894	1,384	1,338	1,301	1,327	1,254	1,268	1,259	1,274	1,294
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	3,873	3,508	3,170	3,351	3,242	3,290	2,936	3,182	3,372
Trimble County 5	1,105	1,385	877	1,108	1,298	1,347	1,388	1,372	1,095	1,365	1,307	1,310	1,306	1,312	1,321
Trimble County 6	1,019	1,381	719	1,281	1,253	1,317	1,388	1,106	1,354	1,364	1,304	1,308	1,304	1,308	1,318
Trimble County 7	923	1,377	746	1,227	984	1,281	1,388	1,365	1,347	1,359	1,299	1,306	1,300	1,304	1,315
Trimble County 8	822	1,358	676	992	1,134	1,232	1,387	1,358	1,340	1,349	1,287	1,296	1,287	1,297	1,309
Trimble County 9	718	1,327	609	1,102	953	1,168	1,386	1,353	1,321	1,341	1,278	1,288	1,277	1,288	1,303
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-High Load-Zero Carbon															
Brown 1	22	20	25	28	31	10	7	8	9	3	4	4	5	5	6
Brown 10	19	20	22	25	30	9	6	7	7	2	3	3	4	4	5
Brown 11	12	14	15	18	20	5	4	4	5	1	2	2	2	3	3
Brown 2	58	52	67	58	77	27	15	17	20	7	8	9	11	12	14
Brown 3	1,195	1,098	1,192	1,238	1,192	1,055	1,179	1,224	1,177	1,221	1,177	1,222	1,054	1,223	1,179
Brown 5	32	32	34	38	47	15	10	11	12	4	5	5	6	7	8
Brown 6	116	246	90	99	222	158	56	55	62	20	12	13	16	16	19
Brown 7	137	273	105	121	189	173	68	68	77	25	15	16	20	20	24
Brown 8	14	16	18	20	24	6	4	5	6	2	2	2	3	3	4
Brown 9	23	26	26	30	37	12	7	8	9	3	3	4	4	5	6
Cane Run 11	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Cane Run 4	112	7	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	872	58	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	431	29	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,853	1,350	1,946	1,194	1,259	802	374	451	456	251	217	359	369	408	517
Ghent 2	3,731	3,012	3,422	3,405	3,365	2,239	2,409	2,711	2,610	2,526	1,978	2,211	1,954	2,308	2,487
Ghent 3	1,349	867	1,167	737	758	423	227	246	268	128	130	141	165	171	188
Ghent 4	2,162	2,459	2,533	2,432	2,232	2,213	2,068	1,718	2,120	2,131	1,957	2,023	2,054	2,040	1,728
Green River 3	18	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	722	262	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,309	1,330	1,957	1,705	1,908	1,770	1,743	1,620	1,811	1,723	1,592	1,641	1,677	1,629	1,805
Mill Creek 2	2,214	1,608	1,941	1,999	1,863	1,998	1,592	1,908	1,741	1,885	1,509	1,738	1,575	1,759	1,659
Mill Creek 3	2,832	2,760	1,361	1,260	1,417	1,020	538	793	803	980	698	869	935	877	1,118
Mill Creek 4	2,814	1,411	2,577	2,588	2,539	2,041	1,586	1,928	1,722	1,883	1,258	1,636	1,734	1,704	1,864
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	682	697	665	667	504	666	678	695	662	607	510	428	468	470	491
Trimble County 1	2,966	2,749	2,944	2,520	2,934	2,740	2,879	2,723	2,892	2,704	2,743	2,423	2,781	2,624	2,851
Trimble County 10	733	1,325	624	1,114	1,094	769	612	591	572	255	156	125	164	142	165
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,012	4,009	4,005	3,660	4,007	4,024
Trimble County 5	1,179	1,385	966	1,133	1,332	1,274	1,009	1,000	817	625	387	292	397	327	381
Trimble County 6	1,107	1,384	789	1,324	1,300	1,228	925	750	894	538	329	248	338	277	325
Trimble County 7	1,024	1,381	833	1,283	1,042	1,177	840	846	809	457	277	209	286	235	276
Trimble County 8	932	1,376	761	1,048	1,208	1,118	760	758	726	382	231	177	239	199	234
Trimble County 9	834	1,354	691	1,185	1,020	1,050	684	673	647	315	191	149	199	168	197
Zorn 1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Zero Carbon															
Brown 1	7	7	8	9	9	7	5	6	6	7	8	9	9	10	11
Brown 10	5	6	6	7	8	5	5	5	5	5	6	6	7	7	8
Brown 11	3	4	4	5	5	3	3	3	3	3	4	4	4	4	5
Brown 2	18	18	22	21	24	16	13	15	15	16	18	21	22	22	25
Brown 3	1,184	1,087	1,179	1,223	1,176	1,054	1,177	1,222	1,174	1,222	1,179	1,224	1,056	1,224	1,180
Brown 5	9	11	11	12	14	10	8	8	9	9	10	11	12	12	14
Brown 6	40	125	32	33	93	94	63	55	60	45	33	32	40	33	41
Brown 7	52	153	40	43	88	117	79	71	78	57	42	40	52	41	53
Brown 8	4	5	5	5	6	4	3	4	4	4	5	5	5	5	6
Brown 9	6	8	8	8	10	7	6	6	6	6	7	8	8	8	10
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	43	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	693	17	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	252	6	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,487	887	1,442	642	706	650	430	527	498	551	526	1,105	995	1,081	1,391
Ghent 2	3,692	2,783	3,332	3,313	3,255	2,371	2,760	2,955	2,896	3,137	3,112	3,184	2,791	3,210	3,224
Ghent 3	899	423	656	357	364	302	242	255	268	286	296	307	396	347	390
Ghent 4	1,955	2,319	2,361	2,262	2,061	2,194	2,089	1,716	2,105	2,198	2,177	2,181	2,265	2,186	1,852
Green River 3	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	718	216	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,276	1,017	1,871	1,533	1,785	1,764	1,844	1,666	1,879	1,892	1,966	1,914	1,988	1,897	2,026
Mill Creek 2	2,206	1,361	1,844	1,882	1,722	1,987	1,722	2,009	1,866	2,106	2,020	2,169	1,996	2,171	1,917
Mill Creek 3	2,779	2,625	1,008	787	909	852	673	973	959	1,550	1,593	1,833	1,821	1,695	2,053
Mill Creek 4	2,741	850	2,196	2,086	2,065	2,015	1,916	2,302	1,992	2,713	2,514	3,043	2,767	2,972	2,943
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	669	697	635	667	504	667	680	697	667	694	637	616	612	645	641
Trimble County 1	2,966	2,720	2,941	2,518	2,929	2,732	2,919	2,742	2,919	2,758	2,944	2,521	2,935	2,753	2,944
Trimble County 10	496	1,241	464	901	879	798	734	723	675	478	420	293	409	311	367
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	1,012	1,382	787	1,067	1,247	1,311	1,178	1,158	921	1,020	844	712	824	750	799
Trimble County 6	913	1,377	649	1,221	1,187	1,271	1,096	864	1,042	913	748	611	735	646	703
Trimble County 7	808	1,363	661	1,152	906	1,219	1,005	1,005	949	800	657	516	647	547	609
Trimble County 8	701	1,330	593	918	1,038	1,150	911	910	853	687	571	431	563	457	521
Trimble County 9	596	1,293	528	997	868	1,071	820	816	761	579	492	356	483	378	440
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)

75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Carbon Cap															
Brown 1	7	7	8	9	9	7	0	0	0	0	0	0	0	0	0
Brown 10	5	6	6	7	8	5	7	8	8	9	2	2	3	3	3
Brown 11	3	4	4	5	5	3	5	5	5	6	2	2	2	2	2
Brown 2	18	18	22	21	24	16	0	0	0	0	0	0	0	0	0
Brown 3	1,184	1,087	1,179	1,223	1,176	1,054	1,179	1,224	1,177	1,225	1,176	1,221	1,053	1,221	1,177
Brown 5	9	11	11	12	14	10	13	13	14	15	4	4	5	5	5
Brown 6	40	125	32	33	93	94	63	55	60	45	13	8	9	8	10
Brown 7	52	153	40	43	88	117	79	71	78	57	18	10	12	11	13
Brown 8	4	5	5	5	6	4	6	6	6	7	2	2	2	2	2
Brown 9	6	8	8	8	10	7	9	10	10	10	3	3	3	3	4
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	43	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	693	17	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	252	6	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,487	887	1,442	642	706	650	430	528	499	552	274	343	334	355	454
Ghent 2	3,692	2,783	3,332	3,313	3,255	2,371	2,760	2,956	2,896	3,137	2,624	2,502	2,143	2,522	2,679
Ghent 3	899	423	656	357	364	302	241	254	267	285	126	107	123	121	129
Ghent 4	1,955	2,319	2,361	2,262	2,061	2,194	2,089	1,716	2,105	2,198	2,058	2,062	2,103	2,059	1,715
Green River 3	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	718	216	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,276	1,017	1,871	1,533	1,785	1,764	1,844	1,666	1,879	1,892	1,823	1,746	1,781	1,711	1,866
Mill Creek 2	2,206	1,361	1,844	1,882	1,722	1,987	1,722	2,009	1,866	2,106	1,810	1,907	1,708	1,891	1,734
Mill Creek 3	2,779	2,625	1,008	787	909	852	673	973	959	1,551	1,150	963	1,008	916	1,180
Mill Creek 4	2,741	850	2,196	2,086	2,065	2,015	1,915	2,302	1,991	2,713	2,036	1,891	1,910	1,870	2,011
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	669	697	635	667	504	667	680	697	667	694	553	474	501	514	523
Trimble County 1	2,966	2,720	2,941	2,518	2,929	2,732	2,919	2,742	2,919	2,758	2,902	2,489	2,881	2,700	2,904
Trimble County 10	496	1,241	464	901	879	798	734	723	675	478	293	115	155	122	141
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,035	4,022	3,677	4,021	4,035
Trimble County 5	1,012	1,382	787	1,067	1,247	1,311	1,178	1,158	921	1,020	622	312	426	330	385
Trimble County 6	913	1,377	649	1,221	1,187	1,271	1,096	864	1,042	913	545	257	358	272	320
Trimble County 7	808	1,363	661	1,152	906	1,219	1,005	1,005	949	801	474	211	296	224	264
Trimble County 8	701	1,330	593	918	1,038	1,150	912	910	853	688	409	173	241	183	216
Trimble County 9	596	1,293	528	997	868	1,071	820	816	761	579	349	141	194	150	175
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Low Gas-Low Load-Mid Carbon															
Brown 1	7	7	8	9	9	7	0	0	0	0	0	0	0	0	0
Brown 10	5	6	6	7	8	5	27	41	28	30	49	54	172	337	441
Brown 11	3	4	4	5	5	3	13	19	14	12	28	32	84	181	288
Brown 2	18	18	22	21	24	16	0	0	0	0	0	0	0	0	0
Brown 3	1,184	1,087	1,179	1,223	1,176	1,054	1,179	1,224	1,172	1,220	1,176	1,221	1,057	1,225	1,181
Brown 5	9	11	11	12	14	10	105	140	211	180	211	226	333	373	481
Brown 6	40	125	32	33	93	94	1,218	1,269	1,126	1,107	1,019	1,049	1,096	1,126	1,172
Brown 7	52	153	40	43	88	117	1,233	1,276	1,158	1,135	1,046	1,076	1,123	1,151	1,183
Brown 8	4	5	5	5	6	4	17	27	18	15	35	40	104	216	331
Brown 9	6	8	8	8	10	7	34	53	37	37	60	68	209	381	495
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	43	1	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	693	17	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	252	6	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,211	5,454	4,574	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	2,487	887	1,442	642	706	650	264	272	91	74	52	56	61	61	68
Ghent 2	3,692	2,783	3,332	3,313	3,255	2,371	1,451	1,645	956	658	628	673	562	521	468
Ghent 3	899	423	656	357	364	302	142	135	21	20	25	26	27	27	29
Ghent 4	1,955	2,319	2,361	2,262	2,061	2,194	1,612	1,413	1,248	691	519	455	381	270	194
Green River 3	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	718	216	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,276	1,017	1,871	1,533	1,785	1,764	1,265	1,260	1,018	895	856	915	904	715	775
Mill Creek 2	2,206	1,361	1,844	1,882	1,722	1,987	1,047	1,374	834	708	649	861	778	651	587
Mill Creek 3	2,779	2,625	1,008	787	909	852	558	669	383	272	265	273	298	233	197
Mill Creek 4	2,741	850	2,196	2,086	2,065	2,015	786	798	357	221	223	227	220	155	136
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	669	697	635	667	504	667	679	696	651	675	643	650	637	644	649
Trimble County 1	2,966	2,720	2,941	2,518	2,929	2,732	2,400	2,356	1,994	1,659	1,650	1,572	1,731	1,596	1,716
Trimble County 10	496	1,241	464	901	879	798	1,387	1,385	1,356	1,351	1,289	1,296	1,285	1,294	1,309
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	3,914	3,933	3,573	3,498	3,391	3,427	3,050	3,307	3,477
Trimble County 5	1,012	1,382	787	1,067	1,247	1,311	1,389	1,385	1,109	1,374	1,317	1,318	1,315	1,318	1,326
Trimble County 6	913	1,377	649	1,221	1,187	1,271	1,389	1,113	1,374	1,373	1,316	1,318	1,313	1,316	1,324
Trimble County 7	808	1,363	661	1,152	906	1,219	1,389	1,385	1,373	1,371	1,315	1,317	1,311	1,314	1,321
Trimble County 8	701	1,330	593	918	1,038	1,150	1,389	1,385	1,371	1,366	1,310	1,313	1,307	1,311	1,319
Trimble County 9	596	1,293	528	997	868	1,071	1,389	1,385	1,365	1,360	1,301	1,306	1,299	1,304	1,315
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Zero Carbon															
Brown 1	90	76	105	123	132	152	107	132	122	170	159	207	220	222	287
Brown 10	7	8	9	10	11	8	4	5	5	5	6	7	8	8	10
Brown 11	5	6	7	7	8	6	2	3	3	3	4	4	5	5	6
Brown 2	289	264	292	246	333	319	246	289	308	415	378	512	615	626	651
Brown 3	1,196	1,096	1,194	1,239	1,195	1,070	1,195	1,244	1,200	1,261	1,225	1,279	1,121	1,298	1,280
Brown 5	11	13	13	14	16	12	9	7	8	8	9	10	11	12	14
Brown 6	30	29	31	33	39	30	23	27	28	30	31	36	41	40	49
Brown 7	37	36	37	40	40	39	28	33	35	38	38	45	52	49	62
Brown 8	6	7	8	8	10	7	3	3	3	4	4	5	6	6	7
Brown 9	9	10	11	12	13	10	5	6	6	7	8	9	10	10	12
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	390	89	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,130	290	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	988	291	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,207	5,342	4,437	4,960	4,384	3,611	2,175	2,293	2,395	2,601	2,227	2,209
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,251	2,570	2,700	2,809	2,719	2,939	2,638	2,853	2,800	3,246	3,176	3,298	3,230	3,322	3,274
Ghent 2	3,773	3,373	3,532	3,594	3,569	3,064	3,529	3,500	3,576	3,541	3,624	3,555	3,190	3,652	3,565
Ghent 3	2,263	2,488	2,115	2,253	2,103	2,158	1,923	2,232	2,486	2,815	2,862	2,655	2,933	3,027	2,998
Ghent 4	2,594	2,121	1,821	1,594	1,783	1,903	1,376	1,420	2,088	2,455	2,610	2,809	2,915	2,777	2,630
Green River 3	100	16	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,342	1,884	2,151	2,035	2,182	2,113	2,229	1,932	2,252	2,131	2,256	2,149	2,280	2,128	2,286
Mill Creek 2	2,216	1,968	2,035	2,218	2,080	2,281	1,998	2,313	2,178	2,319	2,189	2,322	2,182	2,319	2,010
Mill Creek 3	2,959	3,000	1,827	2,192	2,375	2,169	2,555	2,476	2,666	2,518	2,679	2,545	2,686	2,343	2,727
Mill Creek 4	2,883	2,730	3,052	3,379	3,203	3,501	3,297	3,565	3,067	3,613	3,402	3,628	3,409	3,645	3,438
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	240	217	184	162	140	178	125	141	129	137	129	141	147	132	178
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,757	2,944	2,758	2,935	2,758	2,944	2,521	2,935	2,758	2,944
Trimble County 10	70	61	63	73	78	59	45	54	56	62	59	71	80	72	91
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	333	273	253	203	277	285	180	208	188	226	190	229	256	226	281
Trimble County 6	259	207	188	214	214	223	138	135	173	177	152	181	207	181	229
Trimble County 7	195	155	149	164	141	170	106	131	133	137	120	142	165	144	182
Trimble County 8	140	115	115	116	134	121	78	96	99	104	95	113	130	116	149
Trimble County 9	100	84	86	96	97	90	60	72	75	80	74	88	102	92	117
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Carbon Cap															
Brown 1	90	76	105	123	132	152	0	0	0	0	0	0	0	0	0
Brown 10	7	8	9	10	11	8	4	3	4	5	5	6	7	2	2
Brown 11	5	6	7	7	8	6	3	2	3	3	4	4	5	1	1
Brown 2	289	264	292	246	333	319	0	0	0	0	0	0	0	0	0
Brown 3	1,196	1,096	1,194	1,239	1,195	1,070	1,179	1,228	1,181	1,284	1,185	1,289	1,123	1,225	1,183
Brown 5	11	13	13	14	16	12	8	5	5	9	7	11	12	2	3
Brown 6	30	29	31	33	39	30	17	12	13	15	16	19	21	6	6
Brown 7	37	36	37	40	40	39	21	15	15	20	19	24	27	7	8
Brown 8	6	7	8	8	10	7	3	3	3	4	4	5	6	1	2
Brown 9	9	10	11	12	13	10	5	4	4	5	6	7	8	2	2
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	390	89	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,130	290	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	988	291	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,207	5,342	4,437	5,469	5,142	5,406	4,365	5,469	5,211	5,454	4,364	2,734
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,251	2,570	2,700	2,809	2,719	2,939	1,746	1,492	1,331	1,737	1,496	1,704	1,756	1,277	1,375
Ghent 2	3,773	3,373	3,532	3,594	3,569	3,064	3,003	3,226	3,252	3,026	2,977	2,994	2,605	3,225	3,210
Ghent 3	2,263	2,488	2,115	2,253	2,103	2,158	963	909	981	843	1,008	750	983	757	493
Ghent 4	2,594	2,121	1,821	1,594	1,783	1,903	417	515	580	564	586	701	733	385	272
Green River 3	100	16	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,342	1,884	2,151	2,035	2,182	2,113	2,014	1,826	2,063	1,872	1,990	1,869	1,960	1,928	2,088
Mill Creek 2	2,216	1,968	2,035	2,218	2,080	2,281	1,799	2,180	2,024	2,071	1,954	2,051	1,901	2,150	1,896
Mill Creek 3	2,959	3,000	1,827	2,192	2,375	2,169	2,067	1,914	1,934	2,009	1,832	1,979	2,055	1,721	2,017
Mill Creek 4	2,883	2,730	3,052	3,379	3,203	3,501	2,612	3,049	2,652	2,652	2,437	2,610	2,501	3,011	2,879
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	240	217	184	162	140	178	425	75	75	335	97	322	353	38	41
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,757	2,881	2,748	2,918	2,712	2,873	2,483	2,878	2,748	2,918
Trimble County 10	70	61	63	73	78	59	118	24	25	35	29	40	60	12	12
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,022	4,036	4,023	3,677	4,023	4,036
Trimble County 5	333	273	253	203	277	285	414	94	89	170	108	168	227	56	43
Trimble County 6	259	207	188	214	214	223	339	64	76	127	82	129	181	43	35
Trimble County 7	195	155	149	164	141	170	271	56	57	93	64	97	141	31	26
Trimble County 8	140	115	115	116	134	121	211	42	43	68	49	73	108	23	20
Trimble County 9	100	84	86	96	97	90	160	31	33	49	39	54	81	17	15
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Base Load-Mid Carbon															
Brown 1	90	76	105	123	132	152	0	0	0	0	0	0	0	0	0
Brown 10	7	8	9	10	11	8	4	3	4	4	1	1	2	2	2
Brown 11	5	6	7	7	8	6	2	2	3	3	1	1	1	1	2
Brown 2	289	264	292	246	333	319	0	0	0	0	0	0	0	0	0
Brown 3	1,196	1,096	1,194	1,239	1,195	1,070	1,180	1,225	1,178	1,226	1,177	1,222	1,092	1,261	1,220
Brown 5	11	13	13	14	16	12	6	6	6	7	2	2	3	3	4
Brown 6	30	29	31	33	39	30	16	13	14	15	5	5	6	6	7
Brown 7	37	36	37	40	40	39	20	17	18	20	7	7	7	8	9
Brown 8	6	7	8	8	10	7	3	3	3	3	1	1	1	1	2
Brown 9	9	10	11	12	13	10	4	4	4	5	1	2	2	2	2
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	390	89	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,130	290	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	988	291	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,207	5,342	4,437	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,251	2,570	2,700	2,809	2,719	2,939	1,871	1,503	1,342	1,771	1,004	709	825	755	841
Ghent 2	3,773	3,373	3,532	3,594	3,569	3,064	3,004	2,923	2,942	3,048	2,438	2,217	1,911	2,272	2,390
Ghent 3	2,263	2,488	2,115	2,253	2,103	2,158	1,458	954	1,023	1,075	650	385	505	429	455
Ghent 4	2,594	2,121	1,821	1,594	1,783	1,903	947	522	588	642	338	232	261	243	302
Green River 3	100	16	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	721	303	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,342	1,884	2,151	2,035	2,182	2,113	2,032	1,703	1,971	1,900	1,777	1,631	1,683	1,612	1,793
Mill Creek 2	2,216	1,968	2,035	2,218	2,080	2,281	1,813	2,079	1,930	2,114	1,664	1,716	1,577	1,723	1,555
Mill Creek 3	2,959	3,000	1,827	2,192	2,375	2,169	1,984	1,767	1,837	1,963	1,495	1,155	1,309	1,143	1,400
Mill Creek 4	2,883	2,730	3,052	3,379	3,203	3,501	2,741	2,564	2,228	2,668	1,869	1,403	1,523	1,475	1,512
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	240	217	184	162	140	178	114	93	93	104	49	41	42	41	52
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,757	2,883	2,697	2,851	2,712	2,658	2,246	2,564	2,465	2,669
Trimble County 10	70	61	63	73	78	59	36	27	28	31	11	10	11	11	13
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,022	4,022	4,022	3,952	3,929	3,581	3,938	3,986
Trimble County 5	333	273	253	203	277	285	194	111	106	129	56	41	45	43	53
Trimble County 6	259	207	188	214	214	223	144	75	89	97	41	32	34	33	40
Trimble County 7	195	155	149	164	141	170	104	65	67	73	29	24	26	26	31
Trimble County 8	140	115	115	116	134	121	74	49	50	55	21	18	19	20	23
Trimble County 9	100	84	86	96	97	90	51	36	38	41	15	14	15	15	18
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-High Load-Zero Carbon															
Brown 1	121	102	142	167	181	118	59	72	72	98	134	180	225	248	399
Brown 10	14	14	17	18	21	6	4	5	5	4	4	5	6	6	8
Brown 11	10	11	13	14	16	4	3	4	4	2	3	3	3	4	5
Brown 2	357	340	377	326	438	275	129	153	173	369	369	560	718	746	822
Brown 3	1,209	1,107	1,209	1,257	1,216	1,062	1,185	1,233	1,189	1,245	1,209	1,259	1,100	1,274	1,247
Brown 5	20	22	22	25	28	8	6	6	7	5	6	7	8	9	11
Brown 6	53	49	52	57	69	25	13	15	16	18	20	23	26	27	33
Brown 7	64	59	61	67	65	32	16	18	20	22	24	29	33	34	41
Brown 8	12	13	15	15	19	5	4	4	4	2	3	4	4	5	6
Brown 9	17	17	19	21	25	8	5	6	6	4	5	6	7	8	9
Cane Run 11	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
Cane Run 4	476	120	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,169	335	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	1,126	365	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,210	5,396	4,494	5,167	4,686	4,141	2,727	3,007	3,146	3,344	3,028	2,445
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,337	2,686	2,869	3,008	2,898	2,672	2,144	2,570	2,854	3,309	3,253	3,348	3,304	3,387	3,378
Ghent 2	3,782	3,391	3,552	3,616	3,598	3,020	3,444	3,465	3,585	3,570	3,659	3,585	3,222	3,686	3,603
Ghent 3	2,511	2,701	2,421	2,568	2,372	1,922	1,173	1,786	2,448	2,964	3,072	2,808	3,144	3,244	3,255
Ghent 4	2,758	2,453	2,149	1,961	2,148	1,651	734	1,020	1,819	2,828	2,960	3,124	3,208	3,110	2,899
Green River 3	127	24	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	723	305	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,354	1,916	2,178	2,064	2,207	2,084	2,198	1,912	2,245	2,134	2,258	2,163	2,299	2,153	2,310
Mill Creek 2	2,217	1,994	2,065	2,247	2,111	2,277	2,003	2,311	2,177	2,325	2,194	2,326	2,187	2,326	2,013
Mill Creek 3	2,987	3,009	1,942	2,283	2,469	2,181	2,485	2,441	2,659	2,533	2,713	2,578	2,747	2,394	2,826
Mill Creek 4	2,900	2,869	3,142	3,444	3,275	3,481	3,224	3,528	3,032	3,616	3,425	3,653	3,433	3,670	3,462
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	297	269	235	212	179	128	74	82	78	83	84	91	104	95	125
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,757	2,944	2,758	2,935	2,758	2,944	2,521	2,935	2,758	2,944
Trimble County 10	116	100	102	121	129	37	25	29	31	35	36	43	48	47	59
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	442	378	352	286	390	244	88	103	100	118	109	130	152	138	177
Trimble County 6	357	298	269	308	314	191	68	71	88	94	85	103	120	111	143
Trimble County 7	281	232	224	246	211	145	54	66	69	73	69	82	97	91	112
Trimble County 8	212	177	176	178	210	102	41	49	53	56	55	66	77	74	94
Trimble County 9	159	133	137	153	155	75	32	38	40	44	44	52	61	59	73
Zorn 1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Zero Carbon															
Brown 1	65	55	74	85	91	102	68	82	76	104	98	128	141	135	189
Brown 10	4	4	5	5	5	3	3	3	3	4	4	5	5	5	6
Brown 11	2	3	3	3	4	2	2	2	2	3	3	3	4	4	4
Brown 2	225	195	214	176	238	221	159	185	195	279	251	355	466	450	473
Brown 3	1,188	1,090	1,184	1,229	1,183	1,060	1,183	1,229	1,183	1,238	1,198	1,245	1,082	1,253	1,221
Brown 5	6	7	7	7	8	5	4	5	5	5	6	6	7	7	8
Brown 6	16	16	17	17	20	14	11	12	12	13	13	15	16	16	19
Brown 7	20	21	21	22	22	19	14	16	16	17	17	20	22	21	25
Brown 8	3	4	4	4	5	3	3	3	3	3	4	4	4	4	5
Brown 9	4	5	6	6	7	4	4	4	4	4	5	6	6	6	7
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	305	62	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,075	240	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	842	219	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,200	5,242	4,339	4,653	3,978	2,997	1,597	1,602	1,639	1,819	1,434	1,472
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,146	2,423	2,495	2,557	2,501	2,721	2,382	2,626	2,672	3,081	3,009	3,144	3,070	3,165	3,097
Ghent 2	3,761	3,349	3,502	3,566	3,532	3,016	3,476	3,452	3,534	3,493	3,576	3,506	3,148	3,599	3,512
Ghent 3	1,979	2,233	1,791	1,889	1,791	1,826	1,527	1,867	2,175	2,518	2,537	2,397	2,643	2,702	2,653
Ghent 4	2,384	1,763	1,463	1,220	1,395	1,461	969	1,003	1,627	1,980	2,137	2,347	2,482	2,273	2,204
Green River 3	75	10	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	719	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,327	1,848	2,120	2,001	2,156	2,090	2,208	1,913	2,234	2,112	2,237	2,128	2,255	2,097	2,254
Mill Creek 2	2,213	1,936	2,003	2,181	2,044	2,258	1,986	2,302	2,166	2,308	2,180	2,312	2,169	2,309	1,999
Mill Creek 3	2,925	2,988	1,689	2,081	2,272	2,078	2,462	2,402	2,598	2,443	2,595	2,468	2,610	2,274	2,630
Mill Creek 4	2,859	2,569	2,939	3,296	3,119	3,431	3,233	3,512	3,024	3,569	3,357	3,589	3,365	3,603	3,394
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	185	166	136	117	103	125	83	91	82	88	81	88	91	79	109
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,756	2,944	2,758	2,935	2,758	2,944	2,521	2,935	2,758	2,944
Trimble County 10	39	36	36	42	43	31	23	27	27	29	28	33	35	31	39
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	236	184	170	135	183	181	106	121	109	129	105	126	143	120	152
Trimble County 6	175	135	123	138	135	135	78	76	95	96	81	96	109	92	118
Trimble County 7	126	98	93	102	88	99	59	71	70	72	62	72	83	70	89
Trimble County 8	86	70	70	70	80	67	42	50	51	53	48	56	62	55	69
Trimble County 9	59	50	52	56	56	48	31	37	37	39	36	42	46	42	52
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Carbon Cap															
Brown 1	65	55	74	85	91	102	0	0	0	0	0	0	0	0	0
Brown 10	4	4	5	5	5	3	7	7	7	2	2	2	2	2	2
Brown 11	2	3	3	3	4	2	4	5	5	1	1	1	1	1	2
Brown 2	225	195	214	176	238	221	0	0	0	0	0	0	0	0	0
Brown 3	1,188	1,090	1,184	1,229	1,183	1,060	1,182	1,227	1,247	1,224	1,181	1,226	1,060	1,229	1,185
Brown 5	6	7	7	7	8	5	13	14	14	2	2	3	3	3	3
Brown 6	16	16	17	17	20	14	23	26	25	7	6	6	7	7	8
Brown 7	20	21	21	22	22	19	29	33	32	8	7	8	9	9	10
Brown 8	3	4	4	4	5	3	5	6	6	1	1	2	2	2	2
Brown 9	4	5	6	6	7	4	8	9	9	2	2	2	2	3	3
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	305	62	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,075	240	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	842	219	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,200	5,242	4,339	5,469	5,211	5,454	4,295	4,567	4,025	3,978	3,809	3,151
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,146	2,423	2,495	2,557	2,501	2,721	1,786	1,926	1,802	1,843	1,809	1,890	1,982	1,887	1,901
Ghent 2	3,761	3,349	3,502	3,566	3,532	3,016	3,224	3,191	3,223	3,096	3,349	3,285	2,945	3,338	3,260
Ghent 3	1,979	2,233	1,791	1,889	1,791	1,826	1,095	814	962	1,198	631	707	1,140	722	796
Ghent 4	2,384	1,763	1,463	1,220	1,395	1,461	367	276	302	682	341	401	465	368	420
Green River 3	75	10	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	719	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,327	1,848	2,120	2,001	2,156	2,090	2,071	1,755	2,004	1,950	2,131	2,009	2,120	2,006	2,130
Mill Creek 2	2,213	1,936	2,003	2,181	2,044	2,258	1,895	2,152	2,002	2,183	2,163	2,251	2,109	2,237	1,935
Mill Creek 3	2,925	2,988	1,689	2,081	2,272	2,078	2,285	2,272	2,360	1,930	2,407	2,287	2,444	2,075	2,311
Mill Creek 4	2,859	2,569	2,939	3,296	3,119	3,431	2,876	3,076	2,677	3,062	3,182	3,408	3,162	3,372	3,065
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	185	166	136	117	103	125	511	560	534	66	43	49	52	47	61
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,756	2,932	2,750	2,924	2,734	2,944	2,521	2,935	2,758	2,932
Trimble County 10	39	36	36	42	43	31	165	217	199	15	12	13	14	14	17
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,023	4,023	4,036	4,023	3,677	4,023	4,036
Trimble County 5	236	184	170	135	183	181	508	669	556	101	47	56	61	55	68
Trimble County 6	175	135	123	138	135	135	421	495	541	70	37	43	47	44	54
Trimble County 7	126	98	93	102	88	99	344	472	438	49	28	33	35	32	39
Trimble County 8	86	70	70	70	80	67	275	374	345	34	21	24	26	24	29
Trimble County 9	59	50	52	56	56	48	216	289	265	23	16	18	19	18	21
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Generation (GWh)
75% Share of Trimble County 1 & 2

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Scenario: Mid Gas-Low Load-Mid Carbon															
Brown 1	65	55	74	85	91	102	0	0	0	0	0	0	0	0	0
Brown 10	4	4	5	5	5	3	6	6	2	1	2	2	2	2	2
Brown 11	2	3	3	3	4	2	4	4	1	1	1	1	1	2	2
Brown 2	225	195	214	176	238	221	0	0	0	0	0	0	0	0	0
Brown 3	1,188	1,090	1,184	1,229	1,183	1,060	1,184	1,229	1,174	1,222	1,178	1,223	1,104	1,272	1,230
Brown 5	6	7	7	7	8	5	9	10	3	3	3	3	4	4	5
Brown 6	16	16	17	17	20	14	21	24	8	6	7	7	8	8	9
Brown 7	20	21	21	22	22	19	28	32	11	8	9	10	10	11	12
Brown 8	3	4	4	4	5	3	5	5	1	1	1	2	2	2	2
Brown 9	4	5	6	6	7	4	7	7	2	2	2	2	2	3	3
Cane Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 4	305	62	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 5	1,075	240	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 6	842	219	0	0	0	0	0	0	0	0	0	0	0	0	0
Cane Run 7	0	3,652	5,469	5,200	5,242	4,339	5,469	5,211	5,454	4,365	5,469	5,211	5,454	5,211	4,589
Dix Dam 1-3	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Ghent 1	3,146	2,423	2,495	2,557	2,501	2,721	2,194	2,353	1,380	1,288	1,052	1,220	1,318	1,239	1,335
Ghent 2	3,761	3,349	3,502	3,566	3,532	3,016	3,245	3,200	2,875	2,894	2,725	2,823	2,405	2,842	2,905
Ghent 3	1,979	2,233	1,791	1,889	1,791	1,826	1,606	1,707	1,221	692	652	638	854	693	720
Ghent 4	2,384	1,763	1,463	1,220	1,395	1,461	979	1,008	727	375	339	399	456	388	491
Green River 3	75	10	0	0	0	0	0	0	0	0	0	0	0	0	0
Green River 4	719	302	0	0	0	0	0	0	0	0	0	0	0	0	0
Haefling 1-2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 1	2,327	1,848	2,120	2,001	2,156	2,090	2,090	1,791	1,974	1,841	1,903	1,824	1,896	1,800	1,948
Mill Creek 2	2,213	1,936	2,003	2,181	2,044	2,258	1,920	2,211	1,902	2,038	1,838	2,010	1,845	1,991	1,747
Mill Creek 3	2,925	2,988	1,689	2,081	2,272	2,078	2,230	2,168	1,850	1,720	1,621	1,681	1,776	1,582	1,911
Mill Creek 4	2,859	2,569	2,939	3,296	3,119	3,431	3,000	3,200	2,389	2,249	1,945	2,170	2,164	2,219	2,213
Ohio Falls 1-8	230	243	256	261	261	261	261	261	261	261	261	261	261	261	261
Paddy's Run 11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Paddy's Run 13	185	166	136	117	103	125	142	170	80	61	57	65	67	60	79
Trimble County 1	2,966	2,781	2,944	2,521	2,935	2,756	2,931	2,751	2,838	2,674	2,809	2,446	2,821	2,671	2,865
Trimble County 10	39	36	36	42	43	31	44	51	19	14	14	16	16	16	18
Trimble County 2	3,036	4,001	4,036	4,023	3,677	4,023	4,036	4,023	4,020	4,017	4,032	4,018	3,673	4,018	4,033
Trimble County 5	236	184	170	135	183	181	200	233	129	68	59	70	77	68	84
Trimble County 6	175	135	123	138	135	135	149	148	95	49	45	52	57	51	62
Trimble County 7	126	98	93	102	88	99	110	135	65	36	34	39	41	38	46
Trimble County 8	86	70	70	70	80	67	81	98	44	26	25	29	30	28	34
Trimble County 9	59	50	52	56	56	48	59	71	29	19	19	21	22	21	25
Zorn 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.7

Witness: Charles R. Schram

Q1.7. Please produce the energy market price forecasts used in the 2014 Resource Assessment, along with supporting analyses and workpapers.

A1.7. The Companies did not use any energy or capacity market price forecasts in developing the 2014 Resource Assessment. Consistent with past resource assessments, the analysis assumed the Companies had no access to energy from the market and made no off-system sales. These assumptions focus the analysis on finding the best resource for serving the Companies' native load, and eliminate the need to speculate about future power prices. The Companies do not plan generation to make off-system sales in a speculative power market.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.8

Witness: Charles R. Schram

Q1.8. Please produce the capacity market price forecasts used in the 2014 Resource Assessment, along with supporting analyses and workpapers.

A1.8. Please see the Companies' response to Question No. 1.7.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.9

Witness: David E. Huff

Q1.9. Please confirm that for the years 2015-2018, the Companies calculated demand reductions and energy savings based on the assumption that the Companies' 2015-2018 DSM Plan is approved by the Commission without modification in case 2014-00003.

A1.9. Yes, the energy and demand saving calculations are based on the assumption that the Companies' 2015-2018 DSM Plan is approved by the Commission in Case No. 2014-00003. In fact, the Commission approved the Companies' 2015-2018 DSM Plan in Case No. 2014-00003 by Order dated Nov. 14, 2014.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.10

Witness: David E. Huff

Q1.10. Please identify the annual, incremental energy savings that the Companies assume are achieved as a result of DSM programs each year from 2019-2028.

A1.10. The Companies have not assumed any incremental energy savings resulting from DSM programs from 2019-2028.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.11

Witness: Charles R. Schram

Q1.11. Please refer to the Strategist modeling conducted for the 2014 Resource Assessment.

a. Was the model able to make market purchases and sales from the PJM and/or MISO markets?
b. Please identify all constraints placed on the model's ability to select or not select existing generating units, such as must-run designations or operational constraints.
c. Was the model set up to select retirement of existing generating units, or were retirement decisions made after reviewing the modeling results? Please explain.

A1.11.

a. No. Please see the Companies' response to Question No. 1.7.

b. Real-time conditions within the transmission system can exist that require generation from the Brown station. To reflect this fact, E. W. Brown Unit 3 was designated as a must-run resource for modeling purposes.

c. The potential for retirement was evaluated after reviewing model results. Please see Section 4.2.1 of the 2014 Resource Assessment at page 39.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.12

Witness: Charles R. Schram

Q1.12. Please refer to the 2014 Resource Assessment. In developing the scenarios, did the Companies assume a relationship or correlation between any of the variables (load, natural gas prices, coal prices, and/or CO2 prices)?

a. If so, please identify the assumed correlations between each variable, and produce any analyses and workpapers supporting such correlation.

A1.12. In developing their scenarios, the Companies assumed that scenarios with high load and either mid CO_2 prices or a CO_2 mass emissions cap were not viable. Aside from this, the Companies assumed no relationship or correlation between any of the variables listed in the question above.

a. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.13

Witness: David E. Huff

Q1.13 Please refer to the 2014 Resource Assessment Addendum, page 5, Table 1.

a. Please confirm that from 2019 through 2028, the cumulative reduction in peak demand achieved by DSM remains flat, at 406 MW.
b. If confirmed, please explain the basis for the Companies' assumption that no incremental reduction in peak demand will be achieved through DSM programs between 2019 and 2028.
   i. Please provide all supporting documentation and workpapers.
c. If not confirmed, please identify the annual, incremental reduction in peak demand the Companies assume is achieved as a result of DSM programs each year from 2019-2028

A1.13.

a. The 2014 Resource Assessment's cumulative reduction in peak demand achieved by DSM remains flat from 2019 through 2028.

b. The IRP provides a resource assessment at a certain moment in time; it is a snapshot view. Therefore, in conducting the 2014 IRP analysis, the Companies used as the basis for future DSM-related savings their most recent DSM/EE Program Plan, which the Commission recently approved for calendar years 2015-2018. The Companies will review programs and update plans accordingly prior to the expiration of their currently approved programs, which are set to expire at the end of 2018. Therefore, the Companies are not precluding any future DSM programs or savings; rather, in the 2014 IRP they have tried to make conservative assumptions about the conditions known at the time of the analysis.

c. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.14

Witness: Gary H. Revlett

Q1.14. Please provide the comments submitted by LG&E and KU to EPA on the proposed rule for each of the following regulations:

a. Coal Combustion Residuals rule;
b. Effluent Limitations Guidelines;
c. 316(b) cooling water intake rule;
d. New, proposed NAAQS, including the proposal to lower the ozone standard;
e. Carbon regulations, including the Clean Power Plan.

A1.14.

a. Comments filed pursuant to the proposed Coal Combustion Rule are provided in Attachment SC 1-14.

b. Comments submitted in response to the proposed Effluent Limitations Guidelines are provided in Attachment SC 1-14.

c. Comments submitted pursuant to the proposed Section 316(b) cooling water intake rule are provided in Attachment SC 1-14.

d. EPA routinely proposes to lower NAAQS standards. However, EPA currently has not proposed revised NAAQS for which they have not issued a final rule. EPA has recently suggested lowering the ozone standard to concentration range of 60-70 ppb. However, EPA has not yet officially proposed to revise the ozone standard, so the comment period has not started

e. Comments filed to date relative to carbon include the proposed Greenhouse Gas New Source Performance Standards and Performance Standards for Modified and Reconstructed Existing Sources. The comments on these rules are provided in Attachment SC 1-14. Comments on EPA's proposed Greenhouse Gas Performance Standards for Existing Sources (Clean Power Plan) are due by December 1, 2014. The Companies will supplement this response within a reasonable time of the filing of any Clean Power Plan comments responsive to this request.

9/28/10

Comments of E.ON U.S.

Presented by Mike Winkler

My name is Mike Winkler. I am Manager of Environmental Programs for E.ON U.S., the parent company of Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU). I am responsible for environmental compliance for our CCR landfills, ash ponds, and beneficial reuse projects.

In Kentucky, we have had regulations governing CCR landfills and beneficial reuse since 1992 and impoundment safety regulations for an even longer period. LG&E and KU have CCR management protocols in place that ensure regulatory compliance and protection of public health and the environment. The Kentucky regulatory program works very well. There has never been a significant spill from any LG&E or KU CCR facility or any other CCR facility in Kentucky. No LG&E or KU CCR facility has ever posed a problem for local water supplies.

Any federal regulations should be adopted under the RCRA Subtitle D program, rather than the Subtitle C hazardous waste program. Regulation under Subtitle C would be administratively burdensome, unnecessarily expensive, and provide little environmental benefit. The fundamental problems with the Subtitle C approach are evident from the fact that virtually every state environmental agency in the nation opposes regulation of CCR's as a hazardous waste. E.ON U.S. supports the "D Prime" alternative that would allow continued operation of existing ash ponds that are operating in a manner ensuring appropriate protection of public health and the environment.

EPA should also avoid interfering with continued beneficial reuse of CCR's either through regulation under Subtitle C or potential restrictions on structural fill or other applications that involve placement of CCR's on the land. LG&E and KU have extensive experience with structural fill projects undertaken in an environmentally responsible manner. The Kentucky CCR regulations have appropriate restrictions including prohibitions on placement of CCR's near streams or other sensitive areas. Most structural fill projects involve use of CCRs in the construction of buildings, roadways, and parking lots. As a practical matter, pavement or the building structure itself generally provides a level of encapsulation. Considering the limited volumes of CCR's generally used in such projects, they are unlikely to pose significant risks to the environment. Restricting beneficial reuse involving structural fills would substantially reduce beneficial reuse because the cement and gypsum markets could not absorb the extra quantities of CCR's.

In closing, beneficial reuse has played a major role in our efforts to manage CCR's in the most cost-effective manner possible. Gutting the beneficial reuse program – through Subtitle C regulation of CCR's or restrictions on beneficial reuse involving structural fill – will result in substantial costs for the utility customers of Kentucky and other states, while providing little or no environmental benefits.

Michael Winkler, Manager
Environmental Programs
E.ON U.S. LLC
220 West Main Street
Louisville, Kentucky 40202

9/28/10

Comments of E.ON U.S.

Presented by John Voyles

My name is John Voyles. I am Vice President of Transmission and Generation Services for E.ON U.S., the parent company of Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU). LG&E and KU operate seven coal-fired power plants with a total generating capacity of approximately 6,000 MW and provide electricity to approximately 941,000 customers.

Let me begin by saying that safety and responsible environmental stewardship are key priorities for our company. We operate our facilities in strict compliance with state environmental regulations. We have never had a significant spill from any of our CCR facilities nor have those facilities every posed a problem for local water supplies. We recognize that the Kingston event has rightly focused scrutiny on the effectiveness of current regulation of CCR's. While we support EPA's objective of ensuring safe disposal of CCR's, we urge EPA to avoid regulatory approaches that would impose significant and unnecessary costs with little environmental benefit. Such burdens are ultimately borne by the utility customers who pay the costs of environmental compliance.

We strongly oppose regulation of CCR's under Subtitle C. Extensive study by EPRI and others has demonstrated that CCR's do not have hazardous characteristics and EPA has found in the past that CCR's do not warrant regulation as a hazardous waste. The landfill design standards are almost identical under both the Subtitle C and Subtitle D options and environmental benefits would be virtually the same. However, compliance costs would be substantially higher under the Subtitle C hazardous waste option.

In addition, Subtitle C regulation would raise potentially insurmountable obstacles to continued beneficial reuse of CCR's. Our CCR marketing partners have advised that some of their CCR end users have placed beneficial reuse opportunities on hold pending a final regulatory decision on CCR's. They have advised that regulation of CCR's under the Subtitle C hazardous waste program – regardless of whether they are characterized as "special waste" - would result in a stigma that will cause some end users to discontinue use of CCR's. With the regulatory uncertainty of the past few years, our company's beneficial reuse has dropped from almost 50% of our CCR's in 2008 to about 32% of our CCR's in 2009. Our own experience indicates that Subtitle C regulation will almost certainly result in dramatic reduction in beneficial reuse of CCR's and a corresponding increase in land disposal.

We firmly believe that any federal regulation of CCR's should be established under the Subtitle D program. We specifically support the "D Prime" option that would allow continued operation of existing ash ponds that are operating in a manner ensuring appropriate protection of public health and the environment.

John N. Voyles, Vice President
Transmission and Generation Services
E.ON U.S. LLC
220 West Main Street
Louisville, Kentucky 40202

Comments of
PPL Corporation on
Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

78 Fed. Reg. 34432 (June 7, 2013)

Submitted to the
U.S. Environmental Protection Agency

Docket No. EPA-HQ-OW-2009-0819

Docket No. EPA-HQ-RCRA-2013-0209

September 19, 2013

PPL Corporation (hereinafter "PPL") submits these comments on behalf of its wholly owned indirect subsidiaries, PPL Energy Supply, LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company, in response to the U.S. Environmental Protection Agency's proposed revisions to its Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, (hereinafter "ELGs"), published at 78 Fed. Reg. 34432 (June 7, 2013).

PPL is a global energy company that owns or controls merchant and regulated utility power generation assets in three states with a total generating capacity of 19,000 megawatts, including 11 coal-fired power plants in Pennsylvania, Kentucky, and Montana. PPL fully supports responsible environmental regulation aimed at protecting public health and the environment in a cost-effective manner that also provides appropriate protection for the economic well-being of the communities we serve and the markets in which we operate.

We urge EPA to take all appropriate steps to ensure that new rules applicable to the power generation industry – including the ELGs and the coal combustion residuals (CCRs) - are grounded in sound science and reflect an understanding of the challenges currently confronting the industry. Over the past several years, merchant and regulated utility power generators have been subject to an unprecedented number of new environmental rules under the air, water, and waste programs with major cost and operational implications for hundreds of power plants. If implemented in a piece-meal manner or if fashioned to include requirements which are unsupported by sound science, these new rules – including the ELGs – have the potential to impose significant, unnecessary costs and operational restrictions with little or no corresponding environmental benefit. PPL appreciates the opportunity for input into the ELGs and offers the following specific comments on the proposed rule and the coordination with the CCR rule:

1. The ELGs should avoid duplication and overlap with the CCR Rule.

We appreciate EPA's acknowledgement of the potential overlap between the new ELGs and the proposed Coal Combustion Residuals (CCR) Rule, both of which will regulate management of CCRs in surface impoundments. In adopting final ELGs, we urge EPA to avoid duplication, overlap, and conflicting requirements between these two environmental programs. Specifically, structural integrity requirements for surface impoundments are best addressed as part of the pending CCR Rule. The proposed Best Management Practices (BMPs) for surface impoundment structural integrity should be omitted from the final ELGs as unnecessary and duplicative. We also urge EPA to prevent the premature closure of CCR surface impoundments and to enable such impoundments to continue to manage and receive specified wastewaters as contemplated under the ELG Proposal by:

1. selecting the Subtitle D Prime option in the final CCR rule to enable CCR impoundments, which meet applicable groundwater monitoring and corrective action requirements, to remain operational and;
2. modifying the proposed Subtitle D Prime rule to ensure application of only specified location restrictions to existing CCR surface impoundments; and
3. Revising the proposed Subtitle D rule to eliminate the requirement that CCR units automatically commence closure upon the cessation of the receipt of CCRs.

Furthermore, we recommend that EPA develop a mechanism to allow for State implementation of the Subtitle D rule – as opposed to a self-implementing regime – in circumstances where a State is able to demonstrate to EPA that its CCR regulations are no less stringent than the final Subtitle D controls.

2. **EPA should clarify options for continued operation of surface impoundments containing legacy wastewater.**

The proposed ELGs include provisions prohibiting the discharge of ash transport waters, but do not clearly delineate requirements applicable to surface impoundments containing legacy ash transport waters. Facility owner/operators may find it beneficial to convert existing surface impoundments that formerly handled ash transport waters to other purposes (e.g., stormwater run-off retention). EPA should clarify that this option is available with appropriate safeguards. It would be cost-prohibitive – and operationally infeasible for many facilities – to "dry out" the surface impoundment and dispose of legacy wastewater prior to conversion of the impoundment to a different use. PPL urges EPA to consider mechanisms to allow conversion of existing surface impoundments including an exemption for legacy wastewaters contained within a converted surface impoundment or authorization for discharge from such surface impoundment through the time when legacy wastewaters are expected to have been flushed from the impoundment based on projected retention times.

3. **EPA should clarify the proposed compliance date for Best Available Technology.**

A clear and reasonable compliance schedule is a central requirement for any environmental regulation. As currently drafted in the proposed ELGs, the compliance date for Best Available Technology (BAT) is ambiguous. The proposed rule provides that BAT limits must be met as soon as possible "within the next permitting cycle beginning July 1, 2017," while the preamble refers to the next permit cycle <u>after</u> July 1, 2017. Based on EPA's August 20, 2013 Webcast, we understand that EPA intends that the first time a permit is reissued after July 1, 2017, it must contain a compliance date for BAT that has been determined to be "as soon as possible." However, EPA has also stated in the preamble that it anticipates that all facilities will be in compliance with BAT by July 1, 2022, which is not entirely consistent with the compliance date interpretation announced in the Webcast (i.e., facilities issued renewal permits immediately before July 1, 2017 would not have a BAT compliance date included in their permits until the next renewal in 2022 and that compliance date could potentially be up to an additional five years). In addition, it is not clear if EPA intends "compliance" to mean that the requisite provisions have been included in a permit or the facility has actually complied with those terms. We request that EPA provide appropriate clarification in the final rule that a compliance date for BAT must be included the first time a permit is reissued after July 1, 2017, with all facilities expected to be in compliance no later than 2027.

4. The "no discharge" requirement for PCBs must be clarified to ensure that it is properly implemented.

The current ELGs contain a "no discharge" requirement for polychlorinated biphenyls (PCBs) which EPA proposes to retain without change. As explained in the preambles to the 1974 and 1982 ELGs, the no discharge requirement was originally conceived as a "best management practice" (BMP) to prevent and control leaks or spills from transformers and other PCB-containing electrical equipment. It is a narrative standard, rather than a numeric discharge limit (i.e., zero). To the extent that the proposed ELGs adopt an interpretation of the requirement to mean zero or "non-detect" at the current detection limits (e.g., table 1-1 of the 2013 TDD at 1-6) such an interpretation would be both inappropriate and unachievable.

In addition to the preamble language indicating that the no discharge requirement was essentially conceived as a spill control BMP, EPA also did not perform a BPT or BAT analysis necessary to establish a numeric limit. Moreover, laboratory analyses, with detection limits far lower today than in 1982, would routinely detect PCBs attributable to background, rather than any discharge by the facility in question. It should be noted that EPA has banned the manufacture and distribution in commerce of PCBs since 1979 and as a consequence the steam electric industry has replaced oil-filled equipment with non-PCB oil or with new equipment. The ban has ended the use of PCBs and there is no basis to assume that steam electric plant operations will add any additional PCBs to wastewaters. Therefore, the steam electric industry must be considered an insignificant source of PCBs. Consequently, PPL urges EPA to clarify that the "no discharge" requirement will be met through implementation of housekeeping measures for avoiding and containing spills from electrical equipment and prompt cleanup if such spills occur.

5. The proposed limits for metals and nitrate/nitrite limits for FGD wastewaters are unsupported and inappropriate.

In setting the proposed metals and nitrate/nitrite limits for FGD wastewaters, EPA relied on data that is not representative of the typical facilities that will be subject to the rule. The sample locations used to characterize FGD influent differed from the sample locations used to characterize treatment effluent. EPA's data is insufficient to characterize the variable characteristics of most facilities or the actual performance of control technologies. For these reasons, EPA's cost effectiveness analysis was flawed. With respect to the proposed nitrate/nitrite limit, EPA relied on effluent data from the Allen and Belews Creek plants. As demonstrated through data submitted by the Utility Water Act Group, nitrate/nitrite levels in those plants' influent streams are unrepresentative of most power plants. The higher nitrate/nitrite levels found in the influents of most plants would require an increase in the size of the biological treatment systems or an increase in retention time within the system, with a resulting increase in nutrient feed. Some facilities would need to install a two-step biological treatment process. EPA's cost analysis did not properly evaluate the costs that would be incurred by the typical power plant and therefore has over-estimated the benefit of the treatment. With respect to the proposed metals limits, EPA did not properly evaluate the technologies and what they can consistently achieve. The limits are unsupported by a necessary and proper evaluation, which could not have been performed in any case since the data on which it was based was completely inadequate. The proposed metals and nitrate/nitrite limits cannot be met with the proposed treatment technologies and therefore should be revised.

However, it should not be assumed that zero liquid discharge (ZLD) is the answer to this concern. EPA claims that this technology is commercially available treatment. The reality is that ZLD is not a fully demonstrated technology and is not commercially available to meet the very stringent proposed limits in the rule. Besides the cost of the equipment needed for ZLD, which the EPA has not properly evaluated, the operational issues associated with ZLD are numerous and result in unusually high operation and maintenance costs which EPA has not taken into account at all. ZLD systems create a large volume of waste that can, at some facilities and under certain conditions, be hazardous waste. The EPA has not taken the cost of disposal or even the availability of facilities that can take such a waste into account. Crystallizers are not reliable under constantly changing conditions. Significant quantities of chemicals are needed for ZLD operation and the footprint needed for such a system may not be available at all facilities. Finally, ZLD systems have a very large parasitic load, significantly impacting the efficiency of the plant, which is counter to EPA's desire to encourage energy efficiency in the context of global climate change. For these reasons, the EPA should not consider ZLD proper treatment technology for FGD wastewater.

6. **In the final rule EPA should adopt a modified Option 3 approach to enhance regulatory certainty and cost-effectiveness.**

In the present regulatory environment of increased scrutiny of coal-fired generation, power plants – even when conducting operations in good faith and in strict compliance with applicable environmental rules – often find themselves subject to permit challenges, citizen suits, and other legal challenges. In some instances, the “second-guessing” inherent in such challenges has resulted in delays in implementing new regulatory requirements, unnecessary costs incurred by permittees forced to change compliance strategies, and controversies which serve the interested of neither EPA nor the facilities. Both merchant and regulated utility power generators have found this regulatory uncertainty to be a major impediment to efficient compliance planning.

EPA has proposed eight regulatory options for consideration in this rulemaking. To achieve compliance with the final ELGs (regardless of which option is ultimately adopted), it will be necessary for power plants to make substantial investments of both time and money. PPL views it as critical for EPA to adopt a regulatory approach in the final ELGs which promotes the most efficient implementation of new requirements and minimizes the risk of prolonged legal challenges of regulatory determinations made in good faith. At a minimum, such legal challenges create continuing uncertainty for the regulated community. However, these challenges also pose the risk of unnecessary costs that can substantially increase the price of electricity to the consumer.

We urge EPA to avoid regulatory approaches in the final rule which focus on subjective mechanisms (e.g., standards based on case-by-case application of best professional judgment) that only enhance the risk of second-guessing through subsequent legal challenges (e.g., Option 3a). A modified Option 3 that takes into account our concerns about the ELG numerical limitations and the capabilities of the technologies that EPA has evaluated is preferable. Biological treatment at many plants is infeasible due to factors including cost, physical constraints and the low numerical limits in the ELGs. EPA has not adequately demonstrated that biological treatment is BAT, therefore, PPL requests EPA to remove any biological treatment requirements from Option 3.

Concerning bottom ash handling, Option 3 allows for the continued use of impoundments for treatment of bottom ash transport water. It should be noted that EPA's characterization of bottom ash transport water is completely inaccurate. EPA states in the preamble that bottom ash includes the same levels of toxics as fly ash. This is simply not supported by the data. The data EPA used to make this assumption does not reflect transport water that contained only bottom ash. Further, EPA has always recognized that the small amount of toxics in bottom ash transport water does not justify limits that would require dry handling or closed-loop bottom ash systems. The justification remains the same and therefore EPA should not require dry handling or closed-loop systems for bottom ash transport water in the final ELG rule. This option also allows for the treatment of combustion residual leachate in impoundments, an approach that should continue as is currently required.

PPL believes that the best balance of environmental protection, cost-effectiveness, and regulatory finality is achieved by Regulatory Option 3, with the appropriate modification to remove requirements for biological treatment unless the specific limits for the parameters of concern or modified to properly reflect what the technology can achieve. Accordingly, we request EPA to adopt that approach in the final ELGs.

7. **The voluntary incentive program should be revised to make it available to a broader range of facilities.**

EPA is considering the establishment of a voluntary incentive program "to encourage individual power plants to install advanced pollution prevention technologies to make process changes that would further reduce releases of toxic pollutants to the environment beyond the limits that would be set by the proposed rule." In the proposed rule, EPA suggested allowing additional time for closure of impoundments and elimination of all process wastewaters with the exception of cooling water discharges.

PPL appreciates the consideration of a voluntary incentive program. However, the approach as detailed in the proposed regulation will likely be an option for only a very few facilities. It would be more effective to offer incentives to eliminate individual wastestreams. We suggest that a third tier be added that would allow additional time for the elimination of one or more wastewaters that the facility may have the ability to remove. In this way, there is an incentive for a facility to move toward the EPA's goal, even if they are not able to eliminate all wastewaters at this time.

8. Facilities whose permits have designated non-chemical metal cleaning wastes as low volume wastes should be allowed to operate without additional documentation.

EPA wishes to develop a list of generating units eligible for the exemption to the copper and iron limits. In order to be eligible, the discharger would be required to provide documentation (e.g., permit, fact sheets) in comments as part of this rulemaking to support a finding that the generating unit has been authorized to discharge nonchemical metal cleaning waste without copper or iron limits. For most facilities, this documentation is not found in the permit (other than the limits are not included) or described in the fact sheet. The reason for this is that EPA issued the so-called "Jordan Memorandum" in 1975. Most States incorporated this directive in their standard operating procedures. In Pennsylvania, for instance, the permit writer's manual states, "Non-chemical metal cleaning wastes are to be considered as low-volume wastes and therefore not subject to BPT-BAT limitations for copper and iron. EPA Region III has agreed to this approach for all steam electric cases." Because of this determination, the permits do not include copper and iron limits for nonchemical metal cleaning wastewaters and the fact sheet does not specifically address them. Even if more documentation could be provided, it is entirely inappropriate for the EPA to ask for that information to be included in public comments by the permit holder. To qualify for continued treatment as low volume waste, the discharger should merely affirm that it generates nonchemical metal cleaning wastes and that its most recent permit contains no technology-based iron and copper limits that pertain to nonchemical metal cleaning waste. Whether these two conditions are met should be evaluated by the permit agency as the permit comes up for review, not as part of public comments.

In addition to the above comments, PPL supports the comments submitted by the Utility Water Act Group (UWAG), the Utility Solid Waste Activities Group (USWAG), the Electric Power Research Institute (EPRI) and the Edison Electric Institute (EEI). As described above and in the comments of UWAG, USWAG, EPRI and EEI, PPL believes the proposed BAT for FGD wastewaters, BMPs for surface impoundments, and anti-circumvention provisions have serious flaws as currently proposed. We urge EPA to conduct additional evaluation of data more reflective of the steam electric power generation in order to develop final ELGs grounded in sound science and operational practicalities. PPL appreciates the opportunity to comment on the proposed ELG Rule and coordination with the CCR Rule and we look forward to continued participation in the rulemaking process.

Comments of PPL Corporation on

EPA's Proposed Section 316(b) Rule For Cooling Water Intake Structures

at Existing Facilities and New Units

76 Fed. Reg. 22,174 (April 20, 2011)

Submitted to the

U.S. Environmental Protection Agency

Docket No. EPA-HQ-OW-2008-0067
FRL-9289-2
RIN 2040-AE95
August 16, 2011

PPL Corporation (hereinafter "PPL") submits these comments on behalf of its wholly owned indirect subsidiaries, PPL Energy Supply, LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company in response to the U.S. Environmental Protection Agency's proposed Section 316(b) Rule For Cooling Water Intake Structures and Existing Facilities and New Units, 76 Fed Reg. 22,174 (April 20, 2011 (hereinafter "Proposed Rule").

PPL is a global energy company that owns or controls merchant and regulated power generation assets in three states with a total generating capacity of nearly 19,000 megawatts, including 13 coal-fired, natural gas-fired, and nuclear generating plants in Pennsylvania, Kentucky, and Montana. PPL's facilities are located on water bodies ranging from large rivers such as the Ohio to small rivers such as the Yellowstone. PPL's regulated transmission and distribution operations provide electricity to 2.3 million customers in Pennsylvania and Kentucky.

EPA's Proposed Rule will require changes in cooling water intake structures for a wide range of generating facilities and will have substantial economic, energy, and environmental implications for the power generation industry. PPL supports EPA's decision not to require installation of closed-cycle cooling technology at all existing facilities as installation of such technology is infeasible at many locations and may cause adverse environmental and energy impacts in some instances. PPL also supports EPA's proposal to treat plant upgrades and replacement units as existing facilities, rather than new units, to avoid discouraging efficiency improvements and environmental compliance measures. PPL applauds EPA's decision to provide substantial flexibility in addressing entrainment concerns which allows consideration of site-specific and cost-benefit factors. However, EPA proposes stringent fish mortality and water intake velocity standards for impingement that may be unachievable at many sites and requirements for state agencies to evaluate technology options for entrainment including closed-cycle cooling that could result in significant costs with limited environmental benefits. The Proposed Rule adopts a bifurcated approach to the assessment of impingement and entrainment concerns and therefore prevents implementation of mitigation measures in a comprehensive manner that makes the most sense for a particular facility. The Proposed Rule falls short of providing an effective framework that ensures that impingement and entrainment concerns are addressed on a site-specific and cost-effective basis that avoids implementation of costly mitigation measures that provide few corresponding environmental benefits. If not revised to provide for selection of impingement and entrainment controls on a case-by-case basis, the rule could result in premature power plant retirements, capacity shortfalls, and unnecessary costs for utility customers, particularly in conjunction with the other environmental rules currently confronting the power generation industry. PPL urges EPA to address these concerns in promulgating a final rule. PPL's specific comments include the following:

1. EPA's numeric performance standards for impingement are flawed and should be discarded.

EPA's impingement mortality limits (12 percent annually, 31 percent monthly) are based on the assumption that a single technology – traveling screens with fish return capability or the equivalent - is capable of achieving the same level of protection at every site. However, this assumption may be incorrect for many facilities depending on differences in site and aquatic environment. Furthermore, rigid numeric standards do not allow consideration of site-specific factors, such as characteristics of aquatic species, impacts of compliance technologies, natural variability in aquatic ecosystems, seasonable changes in populations, effects of disease or ambient temperature on populations, or cost-benefit assessments, in determining best technology available. The numeric performance standards should be deleted or revised to become goals rather than enforceable requirements. At a minimum, EPA should provide state agencies with the authority to depart from impingement limits where the impingement is *de minimis*, the technologies identified by EPA are infeasible or cost-prohibitive, the technologies identified by EPA will not meet impingement performance standards, or other technologies will achieve comparable or more cost-effective impingement control. It would be far more appropriate for EPA, in lieu of rigid numerical performance standards, to identify types of technologies that will meet the rule's impingement control requirements, while providing the flexibility to depart from such technology if unwarranted or infeasible or if less costly alternatives that will provide comparable benefits are available. Finally, EPA should delete monitoring requirements for facilities that demonstrate installation and proper operation of appropriate control technology as continuing monitoring would provide little meaningful data.

2. The impingement provisions should be revised to provide for identification of mitigation measures on a case-by-case basis.

Unlike the entrainment provisions of the Proposed Rule that allow for consideration of site-specific factors and cost-benefit assessments in identifying mitigation measures, the proposed impingement provisions leave a facility with the choice of complying with stringent numeric fish mortality limits or a design velocity standard with accompanying fish handling requirements. In PPL's experience, the natural variability inherent in most water bodies will make it impossible for the vast majority of facilities to determine that they will remain in compliance with the mortality standards at all times under all conditions. Consequently, as a practical matter, most facilities will be forced to meet the design velocity requirements in the Proposed Rule. In most instances, this will require enlargement of the intake to lower intake velocity which EPA has acknowledged is infeasible for some facilities. Furthermore, impingement is not a concern at every plant. The Proposed Rule mandates, without exception, certain retrofits including screens, fish returns, low pressure wash, etc. Unless the Proposed Rule is revised, PPL will be required to undertake impingement control measures at significant expense at plants where there will be no benefit for aquatic life. For example, the intake at PPL's Brown plant is located in a lake at a depth where fish are not impinged. The lack of flexibility in determining impingement controls fails to account for the site-specific conditions, varying substantially from plant to plant, which characterize impingement no less than they characterize entrainment. PPL urges EPA to revise the Proposed Rule to provide for identification of impingement controls on a case-by-case basis similar to the approach used for identification of entrainment controls. Consideration of site-specific factors and cost benefit assessments will ensure that mitigation measures adopted for each and every facility are technically feasible, cost-effective, and environmentally protective.

3. The proposed entrainment provisions should be refined to avoid unnecessary costs and procedures.

EPA is correct in concluding that entrainment controls should be evaluated and selected on a site-specific basis. PPL strongly supports the case-by-case approach of EPA's "preferred Option 1" in lieu of the "one size fits all" approach mandating closed-cycle cooling under options 2 and 3. The available scientific data establishes that power plants with once-through cooling systems do not generally result in significant adverse impacts on aquatic life. However, PPL urges EPA to revise the Proposed Rule to avoid unnecessary steps in the regulatory review process aimed at identifying entrainment controls. EPA should not require extensive new studies if the state agency determines that entrainment issues have been adequately addressed at an existing facility and additional studies are unnecessary. EPA should not require states to consider additional control technologies for facilities that already utilize closed-cycle cooling systems. While closed-cycle cooling systems should not be mandatory for all plants, closed-cycle cooling, where feasible, is demonstrated to be "best technology available" for fish protection as it minimizes water withdrawal and thereby reduces entrainment. In such instances, further site-specific evaluation would provide no real benefit. EPA should incorporate an entrainment control exemption for facilities that withdraw less than 5% of stream flow, which exemption was included in EPA's 2004 rule. Cooling water intake flows of that magnitude do not pose a significant threat to the aquatic life in a given water body. Finally, the requirement for peer review of various entrainment studies and plans prior to submission to a state agency is both unnecessary and burdensome. The technical staffs of the state agencies have substantial expertise in determining the impacts of cooling water intakes on aquatic life and the effectiveness of proposed entrainment control measures. Requirements for peer review of studies and plans will add extra time and expense to the process, while providing information of limited value to agency staff. We request that the extra step be eliminated as redundant. Finally, entrainment controls should be selected based on a cost-benefit assessment that ensures maximum net benefits. EPA should clarify that in providing that "social benefits must justify costs," the agency means that the value of any likely benefits must at least be comparable to the costs.

4. The Proposed Rule should be revised to ensure that impingement and entrainment controls are determined on a comprehensive, site-specific basis.

As currently drafted, the Proposed Rule requires impingement control determinations to be made, before entrainment control determinations can be made, although technologies that reduce entrainment often reduce impingement. In setting an inflexible eight-year compliance deadline for impingement controls and requiring new facilities to comply with impingement requirements before they begin operating, with determinations on entrainment controls to be made later, the Proposed Rule establishes a disjointed review process which will ensure sub-optimal control strategies for many facilities. PPL urges EPA to revise the Proposed Rule to provide for a comprehensive assessment of impingement and entrainment controls to ensure that the most environmentally protective and cost-effective suite of mitigation actions providing maximum net benefits are implemented for each facility.

5. EPA has defined closed-cycle cooling too narrowly.

EPA has defined closed-cycle cooling to exclude many cooling ponds and basins that were specifically designed to provide closed-cycle cooling. Consequently, even facilities designed with closed-cycle cooling systems will potentially face new impingement control requirements. The EPA definition requires cooling towers to be operated at three cycles of concentration or more. Many companies such as PPL change the cycles of concentration for their cooling towers depending on operational conditions and periodically operate them at less than three cycles. New chemical addition systems would be required to consistently operate cooling towers at three cycles of concentration or more. EPA should define closed-cycle cooling broadly to include facilities that have been designed and operated to be closed-cycle and avoid excluding ponds or basins that have since been deemed to be waters of the United States. In addition, EPA should refrain from dictating minimum cycles of concentration or at least avoid setting an absolute floor. For example, specifying an averaging period for the standard (e.g., 30 days) would provide a facility with the flexibility to adjust its operations to address site conditions.

PPL appreciates the opportunity to provide EPA with comments on the Proposed Rule. In addition to the specific comments included herein, PPL supports and incorporates by reference the comments of the Utility Water Act Group (UWAG). In closing, PPL points out that the power generation industry has worked successfully with the states for more than 30 years to implement effective mitigation measures under Section 316(b) on a site-by-site basis. A site-specific approach continues to be the most scientifically valid and cost-effective manner of mitigating the impacts of cooling water intake structures. PPL urges EPA to revise the final cooling water intake structure rule to provide for continued protection of the environment, while avoiding unnecessary costs for electricity customers.

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Attention Docket ID No. EPA-HQ-OAR-2013-0603

Environmental Protection Agency Docket Center, U.S. EPA, Mailcode 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460
Email: a-and-r-docket@epa.gov, Attn: Docket ID No. EPA-HQ-OAR-2013-0603

Comments of PPL Corporation on the Proposed Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units

PPL Corporation (hereinafter, "PPL") submits these comments regarding the proposed rule entitled "Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units," Federal Register of June 18, 2014 at 79 Fed. Reg. 34960 (hereinafter, "Proposal" or "Proposed Rule"). PPL is a global energy company that owns or controls merchant and regulated utility power generation assets with a total generating capacity of 19,000 megawatts, including 11 coal-fired power plants in Pennsylvania, Kentucky, and Montana. PPL's regulated utility operations provide electricity to more than 2.3 million customers in Pennsylvania and Kentucky.

PPL fully supports responsible environmental regulation aimed at protecting public health and the environment in a cost-effective manner that also provides appropriate protection for the economic well-being of the states served by PPL. PPL is concerned that EPA's final rule for modified and reconstructed units would penalize good faith efforts to comply with other environmental regulations and therefore urges EPA to finalize a rule which recognizes the inherent physical and operational constraints that limit the range of emissions control options for these units.

Consistent with EPA's existing section 111 implementing regulations, units undertaking pollution control projects are exempt from the proposed standards and remain subject to regulation under section 111(d). Under section 111(d), states must consider the remaining useful life of units when setting standards. To the extent that units undertaking other pollution control efforts are *not* exempt, EPA must demonstrate that the proposed standards are "achievable." Achievable standards ensure that good faith compliance investments are not penalized and recognize existing unit limitations.

EPA has proposed a complicated set of standards that apply to the different types of coal- and gas-based units that may undertake a modification or reconstruction. Further complicating the Proposal, EPA creates different standards for units depending on whether modification or reconstruction occurs before or after a state submits its compliance plan under section 111(d).

The legality of EPA's approach to these standards aside, EPA has cited little data to demonstrate that the myriad proposed standards are achievable, as required under the Clean Air Act.

PPL respectfully submits the detailed comments below to assist EPA in developing a final rule that is legally defensible, grounded in sound policy, and designed to promote regulatory certainty, which is critical for the long-term investment decisions that will need to be made by PPL Corporation and its peers in the power sector to comply with CO_2 standards for all units, as well as other environmental requirements.

1. <u>The Existing Pollution Control Project Exemption is Key to Ensuring that Good Faith Efforts to Comply with Other Environmental Regulations Are Not Penalized.</u>

   As proposed, units that are retrofitted with control equipment necessary to comply with EPA's recently finalized MATS Rule[1] (or other recent air quality requirements) may be subject to CO_2 standards under the proposed rule. If this is the case, it is critical that these CO_2 standards are achievable. If not, they may strand investments made in good faith to comply with other environmental rules.

   PPL Corporation has invested significantly in control technology studies and retrofit projects to meet the new MATS Rule requirements, including approximately $2 billion in control retrofits for its plants in Kentucky and is expecting to spend over $35 million for its share of the Montana and Pennsylvania plants combined. Because the proposed section 111 standards are applicable from the date of proposal, they technically are already applicable to modified units. If the proposed standards are not achievable, this will have immediate implications for MATS compliance investments that already have been made. Despite the statutory language, EPA states that the standards are applicable when they are finalized. *See* 79 *Fed. Reg.* at 1,489. Whether the standards are applicable on, for example, June 1, 2015, instead of June 18, 2014, units that made investments to comply with MATS cannot be subject to standards that are not achievable. This would penalize, rather than recognize, these good faith compliance efforts.

   Coal-fired electric utilities and the trade associations that represent them have consistently argued that the pollution control project (PCP) exemption included in EPA's section 111 implementing regulations is the key to ensuring that subsequently issued section 111 standards do not penalize good faith efforts to comply with other regulations. CAA section 111(a)(4) defines "modification" as any physical or operational change that increases the amount of any air pollutant emitted by an "affected facility." EPA's implementing regulations further refine this definition by requiring that the physical or operation change result in an increase in the facility's hourly emissions rate. *See* 40 C.F.R § 60.14(a) and (b). Under the PCP exemption, projects that involve the installation of pollution control equipment needed to meet various CAA requirements are exempt from the definition of modification, regardless of whether there is an increase in the hourly emissions rate of CO_2. *See* 40 C.F.R. § 60.14(e)(5).

   Units that benefit from the PCP exemption are not unregulated. They continue to be regulated under section 111(d) because they remain existing units—defined by the Act as

[1] *National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, 77 Fed. Reg.* 9,304 (Feb. 16, 2012).

all units that are not new or modified. Importantly, section 111(d) requires state permitting authorities to consider the remaining useful life of units when setting emission rate standards. This would include pollution control modification investments that have extended a unit's operating life. Section 111(d) regulation of the unit, therefore, allows states to balance emission reductions with good faith investments made to comply with other air quality regulations. In the Proposal, EPA correctly assumes the continuing validity of the exemption.

2. EPA Must Demonstrate That The Final Standards for Modified and Reconstructed Units Are Achievable.

Under CAA section 111, EPA must set performance standards for modified and reconstructed sources that are "achievable," and that are based on "adequately demonstrated" technological controls or other "systems of emission reduction." A "standard of performance" under CAA section 111(b) is defined as a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) which the Administrator determines has been adequately demonstrated taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements.

The proposed rule and the supporting information that has been placed in the docket for this rulemaking, however, do not meet either the requirements of CAA section 111 or CAA section 307(b)(3) for any of the proposed standards. This fact is consistent with EPA's note that there is little historical data about what CO_2 emission rates are achievable by units undertaking section 111 modifications and reconstructions. *See* 79 *Fed. Reg.* at 34,970. This lack of data calls into question whether EPA has a rational basis for the proposed standards. Further, this lack of data prevents EPA from showing that the proposed standards are achievable.

More specific concerns about each of the proposed standards for the different modified and reconstructed units are discussed below.

3. EPA's Proposed Standards Prohibit Reconstructions

For reconstructed utility boilers and IGCC units, the Agency proposes an emission limit of 1,900 lb CO_2/MWh-net if units have a heat input rating of > 2,000 MMBtu/h and 2,100 lb CO_2/MWh-net if units have a heat input rating of ≤ 2,000 MMBtu/h. *See* 79 *Fed. Reg.* at 34,975. EPA bases these proposed standards on its selected BSER that these units should be reconstructed using "the most efficient generation technology available." *Id.* at 34,983. Regardless of the current design of the unit, EPA asserts that the most efficient technology is supercritical pulverized coal or a supercritical circulating fluidized bed (CFB) boiler for large sources, and subcritical pulverized coal for small sources. *Id.*

EPA's proposed standards raise several significant problems. First, EPA did not demonstrate that the proposed standards for reconstructed coal-based boilers and IGCC units are "achievable" in a modified/reconstructed unit context. Second, compliance with such standards would essentially require the building of new units, effectively prohibiting reconstructions.

4. EPA Has Not Provided a Sufficient Basis for the Proposed Standards Covering Modified and Reconstructed Natural Gas-Based Stationary Combustion Turbines, and Those Standards Are Arbitrary

EPA's proposed emission standards for modified and reconstructed natural gas-based stationary CTs are based on the emission rate EPA asserts is achieved by efficient *new* natural gas combined cycle (NGCC) units. Specifically, EPA proposes to set an emission standard for modified sources of 1,000 lb CO_2/MWh-gross for units with heat input ratings > 850 MMBtu/h, and 1,100 lb CO_2/MWh-gross for units with heat input ratings of ≤850 MMBtu/h. Notably, EPA proposes to set the same emission standards, on the same technology basis, for modified and reconstructed CTs as the Agency proposes for new CTs. *See* 79 *Fed. Reg.* at 1,446-47, 1,461 and 1,485-87.

Setting the same emission standards for both new and modified and reconstructed sources is anomalous on its face. New sources may have several inherent advantages over existing, yet-to-be-modified or reconstructed sources that would make less stringent standards for modified and reconstructed sources reasonable. New sources are constructed so that all component parts are integrated from the start. Sources that undergo modifications or reconstructions, by contrast, must contend with the added expense and technical hurdles of adapting new technology to existing infrastructure. The potential achievability, costs and energy impacts of the standards may differ dramatically for modified and reconstructed sources compared to new sources. Similarly, new greenfield development projects can be sited on plots of land of sufficient size to accommodate required emission control technology. Existing, yet-to-be-modified or reconstructed sources, by contrast, must work within the confines of their existing sites. EPA nowhere indicates that it considered these and other important distinguishing factors in proposing the same emission standards for new sources as well as modified and reconstructed sources.

EPA provides no data or analysis to support its assertions that NGCC technology is "likely to be cost effective," "likely to be made to return the unit to close to its original operating performance," and "pays for itself in fuel savings alone" for all modified and reconstructed CTs—including both NGCC and simple-cycle CTs. *See 79 Fed. Reg.* at 34,990. Similarly, while EPA notes that NGCC technology is broadly deployed and widely used in the power sector, the Agency fails to include any specific analysis demonstrating that the proposed standards are achievable by modified or reconstructed units, or explaining how the Agency reached its conclusions. Moreover CTs are designed and built to provide specific grid support services. EPA has not explained how NGCC units can provide the same services as simple-cycle CTs. It is not appropriate to assume that NGCC units can serve as the basis for simple-cycle CT standards.

5. EPA's Proposed Standards Prohibit Reconstructions of CTs

As with the proposed standards for reconstructed utility boilers and IGCC units, EPA has created standards that effectively prohibit reconstruction and modification of any type of CT. The only way that an existing CT of any type can comply with the proposed standards is to become a new NGCC unit. Again, if a unit can only comply with standards for modified and reconstructed units by becoming a new unit of a different type, the proposed standards are not achievable by that unit.

6. <u>The Clean Air Act is Clear that No Unit Can Be Subject to Regulation under Both Sections 111(b) and (d) at the Same Time</u>

EPA proposes that "an existing source that becomes subject to requirements under CAA § 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction." EPA also proposes that an EGU that undergoes a modification or reconstruction *before* becoming subject to a section 111(d) state plan would similarly be regulated under both the section 111(b) modified and reconstructed source rule and section 111(d): "an existing source would continue to be subject to CAA section 111(d) requirements after it becomes a modified source, *whether the modification occurs before or after* the promulgation of a CAA section 111(d) plan." *Id.* at 34,965 (emphasis added). In other words, EPA will treat such modified or reconstructed sources as both "new sources" and "existing sources" simultaneously. EPA is quite explicit in noting that all existing sources that become modified or reconstructed sources and which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction, will remain in the CAA section 111(d) plan and remain subject to any applicable regulatory requirements in the plan, in addition to being subject to regulatory requirements under CAA section 111(b). This is illogical on its face. A plant cannot simultaneously be both a new plant as well as an existing plant.

PPL appreciates the opportunity to submit comments on the proposed rule for EPA's consideration. If you have any questions regarding these comments, please feel free to contact me at (610) 774-5466 or at akhanwalkar@pplweb.com.

Sincerely,

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Air Docket, Attention Docket ID No. EPA–HQ–OAR–2011-0660
Environmental Protection Agency Docket Center, US EPA Mailcode: 2822TT
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Subject: **PPL Corporation Comments on Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating**

PPL Corporation (hereinafter PPL) submits these comments regarding the proposed rule entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units," Federal Register / Vol. 77, No. 72 (Friday, April 13, 2012) (hereinafter, "Proposed Rule" or "GHG NSPS Rule").

PPL is a global energy company that owns or controls merchant and regulated utility power generation assets with a total generating capacity of 19,000 megawatts, including 11 coal-fired power plants in Pennsylvania, Kentucky, and Montana. PPL's regulated utility operations provide electricity to 2.3 million customers in Pennsylvania and Kentucky. PPL fully supports responsible environmental regulation aimed at protecting public health and the environment in a cost-effective manner that also provides appropriate protection for the economic well-being of the states served by PPL. However, PPL is concerned that the proposed rule would effectively eliminate new coal-fired generation from the nation's energy portfolio by setting a standard which could only be achieved by coal units through the use of carbon capture and sequestration (CCS) technology – a currently undemonstrated technology that is not cost-effective under current market conditions. Furthermore, based on our experience in planning and designing our current natural gas combined cycle (NGCC) project, we are concerned that the proposed rule sets a standard that is not continuously achievable for new NGCC units. In addition, EPA's proposal to hold coal-fired units to the same standard as gas-fired units sets a bad precedent for any future standards that may be promulgated for existing or modified sources and creates serious problems with respect to Best Available Control Technology (BACT) determinations for modified units under the Prevention of Significant Deterioration (PSD) program.

Therefore, PPL offers the following comments on the proposed rule:

1. A separate standard for coal-fired units is critical in order to ensure a diverse, cost-effective energy portfolio.

The proposed 1,000 lb/MWh CO_2 standard is a "one size fits all" standard applicable to new generating units – both natural gas-fired and coal fired. Because the standard is based on EPA's assessment of the level of emissions that can be achieved by new NGCC units and demonstrated control technology that would permit coal-fired units to achieve that level is currently unavailable, the standard effectively eliminates coal-fired generation as on option to meet future energy needs. CAA section 111(b)(2) provides that the Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing NSPS standards. Over the 40-year history of the Act, EPA has never set a single NSPS for all fossil-fueled power plants based on an emissions rate achievable only by the fuel type with the lowest emissions rate. In fact, in past rulemakings EPA has routinely established subcategories based on different fuels, industrial processes, equipment, and other factors.

The proposed standard assumes that CCS technology sufficient to capture and store at least 50% of CO2 emissions is available for new coal-fired units. PPL fully supports continued research and development for CCS technology, but points out that CCS is neither demonstrated nor cost-effective at present. Of the 15 transitional plants mentioned in EPA's preamble, only six allegedly employ CCS and none of the six are operational. While EPA's proposal for a framework to establish compliance under a sliding scale over a 30-year period certainly provides additional flexibility for new coal units with CCS, it also implicitly acknowledges the uncertainties as to when or if CCS technology will be developed.

The power industry is committed to working with the Administration and Congress to accelerate the development and deployment of CCS. However, mandating CCS for new coal-fired plants before the technology is commercially viable could ultimately impede, rather than accelerate, its development. Significant technological, financial, legal and regulatory barriers still exist to the commercial deployment of CCS. Consequently, at present there is no basis for EPA to consider CCS as the best system of emission reduction (BSER) or best demonstrated technology (BDT) under the CAA. Currently efficiency measures constitute the best available control technology for CO2 reduction at full-scale, for base load units.

The Clean Air Act does not allow EPA to mandate a particular technology which is exactly what the agency has done in requiring coal-fired generation to comply with a standard based on natural gas plants using a specified technology. Although low natural gas prices may currently favor new natural gas plants over coal plants, there can be no guarantee that natural gas prices will remain at those levels indefinitely. Therefore, as a matter of statutory compliance and sound energy policy, it is critical for EPA to set a separate NSPS standard for new coal-fired units that will permit those units to remain an option in the future. More than 42% of the nation's power is supplied by coal-fired plants that utilize various boiler designs and fuel combinations. Therefore, EPA should develop a separate NSPS for new coal-fired plants with standards specific to fuel type and unit type and with control technology that has been demonstrated feasible on full scale applications. Such an approach is consistent with the relevant provisions of the Clean Air Act as implemented by EPA in the past and this Administration's stated energy policy objective of achieving a diverse energy portfolio.

2. The proposed standard does not allow continuous compliance for new NGCC units.

The proposed standard of 1,000 lb CO2/MWH and the methodology used to determine compliance do not take into account the full range of operation normally experienced by a NGCC unit. The proposed standard is based on EPA's assumption that the standard is capable of being achieved by an NGCC unit at all times of operation including startup, shutdown, and malfunction. It appears from the preamble of the proposed rule that the EPA estimated the emissions rate for a new NGCC unit based on limited design performance specifications, without consideration of real-world operating conditions. Based on the extensive analysis conducted by PPL in the course of planning and design for our current NGCC project, PPL points out that during periods of startup and shutdown, although weighted mass emissions are low, the emission rate based on the ratio of mass emissions to electric generation can easily exceed the 1,000 lb/MWH standard. Because NGCC units will generally be deployed as intermediate load units, they will likely experience daily startups and shutdowns that will pose a substantial challenge in meeting the emissions standard.

In addition, the calculation methodology for the 12-month rolling average utilizes the average for each individual month, weighted by total mass emissions and divided by total generation. The quotient of the individual month is added to the sum of the quotients of the previous 11 months and divided by 12 for the resulting 12-month rolling average. In the case of a unit that is off line until almost the end of a month, the weighted average for that month could well exceed the standard. In that instance the unit could be determined to be out of compliance despite the fact that its mass emissions were lower than if it had operated the whole month. Thus, the proposed calculation methodology effectively penalizes a unit for downtime associated with minimal operation and emissions.

As currently proposed, the emissions standard and calculation methodology create a compliance challenge for all NGCC units, but units that are used as backup to intermittent renewable sources will find it especially difficult to achieve compliance. PPL points out that during startup an NGCC unit typically operates in simple cycle mode for 1.5 to 3 hours to achieve sufficient heat for the steam generation phase. During startup while on simple cycle operation only, an NGCC configuration is in fact not operating as an NGCC but as a simple cycle unit. EPA has provided that simple cycle units are not subject to the rule. Consequently, it is entirely appropriate for EPA to revise the proposed rule to exclude NGCC unit emissions from the 12-month rolling average calculations to the extent that they occur during startup, shutdown, or any other operation during which the unit effectively fits the description of a simple cycle unit. In the alternative, if EPA does not exclude emissions during periods of startup or shutdown, it should adopt a higher standard in the range of 1,100 lb CO_2/MWH. To remedy the problem with the calculation methodology, PPL requests that compliance be calculated on an annual average basis for the calendar year, rather than on a 12-month rolling average.

3. Failure to provide a separate standard for coal-fired units establishes an unworkable regulatory precedent in the case of existing, modified, and reconstructed sources.

PPL fully supports EPA's decision to defer promulgation of standards for modified or reconstructed facilities and guidelines for existing facilities. EPA states that it "anticipates" that existing and modified sources will be required to comply with a future standard "at the appropriate time." While PPL acknowledges that EPA has the authority to set separate standards for new and modified sources, PPL remains concerned about the potential precedent of a single standard for new fossil-fired units that could potentially increase the risk of such a standard for existing or modified sources if EPA ultimately opts to proceed with standards for such facilities or EPA's deferral is overturned by the courts.

While extremely problematic for new facilities, a single standard for all existing or modified fossil-fired units would have even more extreme impacts. A standard requiring existing coal-fired units to achieve CO_2 reductions equivalent to a NGCC unit would likely result in shutdown of virtually all coal-fired units in the nation. With coal-fired generation providing more than 42% of the nation's power needs in 2011, such a result would wreak havoc with the nation's energy supply in terms of both cost and reliability. Some of the states served by PPL obtain more than 90% of their electricity supply from coal-fired generation. Such an outcome would be disastrous to the economies of those states. While establishing a NGCC-equivalent standard for modified or reconstructed facilities would not have the same immediate impact as establishing such a standard for existing facilities (as modifications would occur over a period of time), the end result would be the same – extreme disruption of the energy supply as large numbers of coal-fired plants were forced to retire.

Although contrary to EPA's stated policy, a single NSPS standard could also create a precedent for combining coal-fired and gas-fired units into one category for criteria air pollutant regulation and subjecting those units to standards that can only be achieved by NGCC units. An equally bad precedent could be set for determining Best Available Control Technology (BACT) under the Prevention of Significant Deterioration (PSD) program. Because the NSPS serves as the floor for individual BACT permitting determinations, a NSPS requiring new coal-fired facilities to achieve emissions equivalent to a NGCC unit could potentially result in applying such a target to existing facilities that undertake a modification.

The implications for the PSD program are of particular concern in light of the extensive requirements of the Cross-State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards (MATS) which may require some plants to undertake modifications in order to achieve compliance. It is critical for existing coal-fired units that undertake modifications for compliance purposes to be subject to the same standards as other existing facilities in order to retain compliance flexibility and avoid billions of dollars in stranded costs. PPL urges EPA to avoid the unworkable and potentially dangerous precedent of a single standard for all new fossil-fired sources. EPA could substantially reduce the risk and uncertainty of the proposed rule by promulgating a separate standard for coal-fired sources.

4. EPA should avoid penalizing generating units that undertake modifications for compliance purposes.

EPA has stated that its proposal does not apply to modified units, but the proposed rule does not contain express language to that effect. While EPA expects that most modifications to generating units that would increase their maximum achievable hourly rate of CO2 emissions would constitute pollution control projects and would be exempted from the definition of modification, *see 40 CFR 60.14(e)(5)*, reliance on the Pollution Control Project (PCP) exemption is insufficient as not all future modifications will fall into the PCP category. Additionally, the PCP exemption does not protect sources from citizen suits alleging that modifications do not qualify for the PCP exemption or that non-PCP modifications are required to meet the rule. As a result, without express regulatory language clarifying that the proposal does not apply to modifications, third parties may attempt to impose the rule on modified units through litigation, contrary to EPA's intent. To avoid regulatory uncertainty and unintended consequences, EPA should clarify that the proposed rule does not apply to existing modified units by including clear and unambiguous language in the Code of Federal Regulations stating that the performance standard established by the proposal "does not apply to modified units."

While EPA has proposed deferring standards for existing and modified units, it has left the door open to regulation by specifying in the preamble that the proposal should be treated as an advanced notice of proposed rulemaking for modified units (as opposed the pre-publication draft of the rule which contained no such provision). The potential for future standards applicable to modified sources results in substantial uncertainties, particularly for units facing major projects for purposes of compliance with MATS and CSAPR. EPA should take steps to provide regulatory certainty that any compliance efforts undertaken to comply with MATS or CSAPR will not trigger any requirements not applicable to existing sources.

EPA should provide guidance that any planned near-term environmental retrofits do not constitute modifications under Section 111(b) of the Clean Air Act and that such facilities will instead be subject to regulation as existing facilities under Section 111(d). EPA should bolster the agency's position that such projects would fall within the Pollution Control Project (PCP) exemption, rather than leaving the interpretation open to doubt by merely soliciting comments on the continued validity of the PCP exemption in light of the decision in *New York v. EPA* invalidating a similar provision under the PSD program. The agency should fully analyze the case law which clarifies that EPA may adopt different interpretations of the definition of "modification" under the NSPS and PSD programs and point to the fact that the 60-day period for challenging the PCP exemption expired many years ago. Finally, EPA should provide guidance that the NSPS for new units does not set the floor for any BACT analysis for modified units.

5. Any future NSPS for existing sources should be based on unit energy efficiency and recognize the diversity of existing fossil generation.

Any future emissions guidelines promulgated by EPA under Section 111(d) of the Clean Air Act will provide a framework for the states to impose NSPS standards on existing sources. The Administrator has stated that the agency currently has no plans to address existing sources. However, if EPA opts to consider such guidelines in the future, the agency should carefully consider their potential impact on the thousands of existing fossil-fired units in the nation's generating fleet. Any existing source guideline promulgated by EPA should avoid the problems posed by the proposed NSPS for new sources. It should avoid mandating any particular fuel source or generation technology and should account for the diversity of the existing fossil generation fleet.

In setting guidelines for existing sources under Section 111(d), EPA is free to adopt a different approach that it uses in regulating new sources under Section 111(b). PPL urges EPA, in considering existing source guidelines, to focus on unit-level energy efficiency improvements, consistent with existing BACT guidance. However, it is important to note that opportunities to increase energy efficiency will vary from unit to unit depending on plant-specific factors. Any future NSPS emissions guidelines for existing sources should take these plant-specific factors into account. EPA should consider the use of work practices or operational standards as an appropriate mechanism to improve energy efficiency. PPL points out that a "one size fits all" numeric emissions limit for all existing plants could prove extremely problematic. Instead, work practices or operational standards that would allow each plant to maximize its energy efficiency, within its own unique operational constraints, offers a potentially workable approach. In the event that EPA opts to proceed with existing source guidelines, PPL also urges the agency to consider appropriate subcategories based on size, type, and class. Finally, if EPA sets guidelines that focus on energy efficiency, it will be important for the agency to clarify that such projects will not constitute modifications resulting in enforcement actions.

6. PPL supports the concept of the 30-year compliance framework, although its use is impractical in the present circumstances.

EPA has provided a framework in the proposed rule for new coal-fired generation with CCS technology to establish compliance over a 30-year period. The method involves a sliding scale providing for a higher emission limit for the first 10 years followed by a lower emission limit for the remaining 20 years. The end result over the 30-year period is the same mass emissions as if the unit had complied with the 12-month rolling average for 30 years. PPL supports the concept of the sliding scale 30-year average for coal-fired units deploying CCS as an appropriate compliance mechanism that provides significant regulatory flexibility. PPL also supports the underlying principle that such an approach achieves an acceptable reduction for purposes of NSPS.

However, the basic concept as applied to coal-fired facilities with CCS is grounded on the assumption that CCS is commercially available and technically feasible. Because that is not the case at present, the mechanism provides only an illusory option for future coal plants at best. Under the present circumstances, it appears highly infeasible for a company to undertake a coal-fired plant with CCS given all of the uncertainties. While PPL applauds the regulatory flexibility inherent in the 30-year compliance framework proposed by EPA, PPL does not view it as a meaningful provision that preserves the option of future coal-fired generation.

7. PPL supports EPA's proposed decision not to regulate minimal emissions of nitrous oxide and methane.

EPA has proposed to exclude emissions of nitrous oxide (N2O) and methane (CH4) from the rule because these constituents account for an estimated 0.4 percent of total CO2 equivalent emissions from fossil-fired power plants. The costs of monitoring and reporting these de minimis emissions would outweigh any trivial benefits that might result from regulation. Accordingly, PPL supports EPA's proposed action as a sound exercise of regulatory judgment.

8. PPL opposes any mandatory use of Part 75 missing data procedures and bias factors as inappropriate and inconsistent with past EPA practice.

EPA requests comment on the appropriateness of applying backup monitor requirements in 40 CFR Part 75.10(e), the missing data procedures in 40 CFR Part 75.31 – 75.37, and Appendix C. EPA proposes to require use of missing data substitution procedures for CO2 concentration, stack gas flow rate, fuel flow rate, GCV (or high heating value of fuel), and fuel carbon content. PPL points out that the missing data procedures can significantly overstate emissions. EPA has never required use of the missing data procedures in an NSPS relating to EGUs and has provided no justification for its use in this instance. In fact, every NSPS has specifically stated that missing data procedures do not apply and has required that periods for which missing data procedures are applied be reported as monitor system downtime. Consequently, PPL opposes mandatory use of missing data procedures.

PPL also opposes use of bias factors associated with the Part 75 quality assurance procedures. The bias adjustment factor is a one-way (positive) adjustment adopted under the Acid Rain Program to assure that allowance consumption is not under-reported. While the bias factors are aimed at preventing under-reporting of emissions, in practice they can result in over-reporting. EPA has never required use of bias-adjusted data to determine compliance under the NSPS. While use of bias factors under the Acid Rain program might result in surrender of additional allowances in the worst case, use of bias factors to determine compliance with the NSPS could result in a determination that a source is in noncompliance and subject to substantial penalties. PPL opposes use of bias factors in the proposed rule because such a mechanism is inappropriate for determining compliance with an emission-based standard.

PPL appreciates the opportunity to submit comments on the proposed rule for EPA's consideration. If you have any questions regarding these comments, please feel free to contact to contact me at 610-774-5475 or email me at rtclemmer@pplweb.com.

Sincerely,

Reid T. Clemmer

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LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.15

Witness: John N. Voyles

Q1.15. For each of the Companies' existing coal-fired units, please produce the most recent estimate that the Companies have prepared or caused to be prepared of the capital and O&M costs to comply with the following regulations.

a. Mercury and Air Toxics Standards;
b. Coal Combustion Residuals rule;
c. Effluent Limitations Guidelines;
d. 316(b) cooling water intake rule;
e. NAAQS, including any new ozone standard;
f. Cross State Air Pollution Rule; and
g. Carbon regulations, including the Clean Power Plan.
h. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

A1.15. Please see attached. The information provided is taken from the Companies' 2015 Business Plan. Capital and fixed O&M costs for existing units were not an input to the IRP analysis. Please note the following:

- Variable O&M cost estimates are available by unit but not by regulation. Variable O&M includes the cost of consumables for SO_2, NO_x, SO_3, and mercury controls.
- Capital cost estimates are available only by station for parts b-d and are not available for parts e-h. Fixed O&M cost estimates are available only by station for part b, in total for part f, and are not available for parts c-e and g-h.
    - Part a includes estimated costs for new fabric filters and scrubbers.
    - Part b includes estimated costs for closing ash and other ponds.
    - Part c includes estimated costs for Kentucky's Mercury 51 parts per trillion limits as well as the effluent guidelines to be issued by the EPA.

Capital Costs to Comply with Regulations ($ Millions)
2015 Business Plan

(a) Mercury and Air Toxics Standards

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brown 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brown 3	41.0	32.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cane Run 7	124.4	30.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 1	82.6	37.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 2	38.9	64.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 3	51.2	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ghent 4	58.4	8.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek 1	61.0	33.7	5.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek 2	90.7	32.0	6.9	0.5	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek 3	27.5	165.3	49.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek 4	142.4	21.5	7.4	1.3	0.0	0.0	0.0	0.0	0.0	0.0
Trimble 1	37.5	60.3	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0

(b) Coal Combustion Residuals Rule

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown	0.0	0.4	7.3	4.5	4.6	7.9	8.5	0.0	0.0	0.0
Ghent	0.2	1.7	70.6	37.3	37.9	70.9	73.0	0.0	0.0	0.0
Green River	0.0	0.0	0.8	9.0	20.4	0.7	7.3	0.0	0.0	0.0
Pineville	0.0	0.0	0.2	2.9	0.2	1.3	0.0	0.0	0.0	0.0
Tyrone	0.0	0.0	0.2	3.0	0.2	1.6	0.0	0.0	0.0	0.0
Cane Run	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek	0.1	0.7	7.1	4.8	6.9	13.3	13.5	0.0	0.0	0.0
Trimble	0.1	0.8	18.7	15.5	15.9	25.3	27.4	0.0	0.0	0.0

(c) Effluent Limitations Guidelines

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown	0.0	0.5	0.0	25.0	45.0	50.0	50.0	30.0	0.0	0.0
Ghent	0.0	0.5	0.0	25.0	50.0	50.0	50.0	50.0	0.0	0.0
Green River	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cane Run	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek	0.5	1.0	25.0	50.0	119.0	75.0	60.0	0.0	0.0	0.0
Trimble	0.0	0.5	25.0	50.0	50.0	50.0	45.0	0.0	0.0	0.0

(d) 316(b) Cooling Water Intake Rule

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown	0.0	0.0	0.0	1.5	1.5	0.0	0.0	0.0	0.0	0.0
Ghent	0.0	0.0	0.0	1.5	1.5	0.0	0.0	0.0	0.0	0.0
Mill Creek	0.0	0.0	0.0	1.5	1.5	0.0	0.0	0.0	0.0	0.0
Trimble	0.0	0.0	0.0	1.1	1.1	0.0	0.0	0.0	0.0	0.0

Fixed O&M to Comply with Regulations ($ Millions)
2015 Business Plan

(a) Mercury and Air Toxics Standards

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brown 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Brown 3	0.0	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6
Cane Run 7	0.0	11.9	17.5	18.4	17.7	21.4	17.3	18.7	18.2	23.0
Ghent 1	0.1	1.9	2.7	2.7	2.6	2.7	2.9	3.0	3.0	3.1
Ghent 2	0.0	0.2	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6
Ghent 3	1.5	2.1	2.1	2.3	2.3	2.4	2.4	2.5	2.5	2.6
Ghent 4	0.3	2.3	2.2	2.3	2.3	2.4	2.4	2.5	2.5	2.6
Mill Creek 1	0.0	1.5	2.5	2.4	2.5	2.5	2.5	2.5	2.6	2.6
Mill Creek 2	0.0	1.5	2.4	2.5	2.4	2.6	2.6	2.6	2.7	2.7
Mill Creek 3	0.0	0.2	2.0	2.8	2.9	2.7	2.9	2.9	3.0	3.1
Mill Creek 4	0.2	2.9	3.1	3.2	3.2	3.4	3.3	3.4	3.5	3.6
Trimble 1	0.0	0.3	2.8	2.6	3.1	2.9	2.8	2.8	2.8	2.9
Trimble 2	1.2	2.9	3.0	3.2	3.0	3.3	3.4	3.5	3.6	3.7

(b) Coal Combustion Residuals Rule

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Ghent	0.4	2.2	2.5	2.6	2.6	2.7	0.5	0.5	0.6	0.6
Mill Creek	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Trimble	-0.1	1.1	1.2	1.5	3.8	4.3	4.5	4.6	4.7	4.7

(f) Cross State Air Pollution Rule

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
LG&E/KU	0.45	0.19	0.07	0.04	0.04	0.04	0.04	0.04	0.04	0.04

Variable O&M ($/MWh)
2015 Business Plan

1.90% Escalation Rate

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015	1/2016	2/2016
Brown 1	1.47	1.47	1.47	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	3.01	2.82	2.82
Brown 2	1.42	1.42	1.42	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.75	2.76	2.76
Brown 3	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	2.34	3.32	3.32	3.66	3.66
Cane Run 4	4.39	4.39	4.39	4.39										
Cane Run 5	4.09	4.09	4.09	4.09										
Cane Run 6	5.98	5.98	5.98	5.98										
Ghent 1	2.51	2.51	2.51	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.35	3.35
Ghent 2	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	1.76	2.31	2.31	2.73	2.73
Ghent 3	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.34	3.44	3.44
Ghent 4	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.44	3.44
Mill Creek 1	0.78	0.78	0.78	0.78	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.65	1.65
Mill Creek 2	0.78	0.78	0.78	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.68	1.68
Mill Creek 3	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.41	1.39	1.39
Mill Creek 4	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.39	2.39
Trimble 1	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	1.93	2.63	2.63	2.74	2.74
Trimble 2	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.25	2.25

Variable O&M ($/MWh)
2015 Business Plan

	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016	1/2017	2/2017	3/2017	4/2017
Brown 1	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.59	2.59	2.59	2.59
Brown 2	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.76	2.78	2.78	2.78	2.78
Brown 3	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.66	3.58	3.58	3.58	3.58
Cane Run 4														
Cane Run 5														
Cane Run 6														
Ghent 1	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.35	3.63	3.63	3.63	3.63
Ghent 2	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.92	2.92	2.92	2.92
Ghent 3	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.77	3.77	3.77	3.77
Ghent 4	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.44	3.82	3.82	3.82	3.82
Mill Creek 1	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.68	1.68	1.68	1.68
Mill Creek 2	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.70	1.70	1.70	1.70
Mill Creek 3	1.39	1.39	1.39	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.45	2.45	2.45	2.45
Mill Creek 4	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.45	2.45	2.45	2.45
Trimble 1	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.89	2.89	2.89	2.89
Trimble 2	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.39	2.39	2.39	2.39

Variable O&M ($/MWh)
2015 Business Plan

	5/2017	6/2017	7/2017	8/2017	9/2017	10/2017	11/2017	12/2017	1/2018	2/2018	3/2018	4/2018	5/2018	6/2018
Brown 1	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.93	2.93	2.93	2.93	2.93	2.93
Brown 2	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.90	2.90	2.90	2.90	2.90	2.90
Brown 3	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	4.05	4.05	4.05	4.05	4.05	4.05
Cane Run 4														
Cane Run 5														
Cane Run 6														
Ghent 1	3.63	3.63	3.63	3.63	3.63	3.63	3.63	3.63	3.94	3.94	3.94	3.94	3.94	3.94
Ghent 2	2.92	2.92	2.92	2.92	2.92	2.92	2.92	2.92	3.23	3.23	3.23	3.23	3.23	3.23
Ghent 3	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	4.11	4.11	4.11	4.11	4.11	4.11
Ghent 4	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	4.23	4.23	4.23	4.23	4.23	4.23
Mill Creek 1	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.68	1.74	1.74	1.74	1.74	1.74	1.74
Mill Creek 2	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.77	1.77	1.77	1.77	1.77	1.77
Mill Creek 3	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.52	2.52	2.52	2.52	2.52	2.52
Mill Creek 4	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.52	2.52	2.52	2.52	2.52	2.52
Trimble 1	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.89	3.17	3.17	3.17	3.17	3.17	3.17
Trimble 2	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.66	2.66	2.66	2.66	2.66	2.66

Variable O&M ($/MWh)
2015 Business Plan

	7/2018	8/2018	9/2018	10/2018	11/2018	12/2018	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019
Brown 1	2.93	2.93	2.93	2.93	2.93	2.93	3.12	3.12	3.12	3.12	3.12	3.12	3.12	3.12
Brown 2	2.90	2.90	2.90	2.90	2.90	2.90	3.04	3.04	3.04	3.04	3.04	3.04	3.04	3.04
Brown 3	4.05	4.05	4.05	4.05	4.05	4.05	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
Cane Run 4														
Cane Run 5														
Cane Run 6														
Ghent 1	3.94	3.94	3.94	3.94	3.94	3.94	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Ghent 2	3.23	3.23	3.23	3.23	3.23	3.23	3.51	3.51	3.51	3.51	3.51	3.51	3.51	3.51
Ghent 3	4.11	4.11	4.11	4.11	4.11	4.11	4.59	4.59	4.59	4.59	4.59	4.59	4.59	4.59
Ghent 4	4.23	4.23	4.23	4.23	4.23	4.23	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67
Mill Creek 1	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74	1.74
Mill Creek 2	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77	1.77
Mill Creek 3	2.52	2.52	2.52	2.52	2.52	2.52	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51
Mill Creek 4	2.52	2.52	2.52	2.52	2.52	2.52	2.51	2.51	2.51	2.51	2.51	2.51	2.51	2.51
Trimble 1	3.17	3.17	3.17	3.17	3.17	3.17	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33
Trimble 2	2.66	2.66	2.66	2.66	2.66	2.66	2.73	2.73	2.73	2.73	2.73	2.73	2.73	2.73

Variable O&M ($/MWh)
2015 Business Plan

	9/2019	10/2019	11/2019	12/2019	1/2020	2/2020	3/2020	4/2020	5/2020	6/2020	7/2020	8/2020	9/2020	10/2020
Brown 1	3.12	3.12	3.12	3.12	3.18	3.18	3.18	3.18	3.18	3.18	3.18	3.18	3.18	3.18
Brown 2	3.04	3.04	3.04	3.04	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.10	3.10
Brown 3	4.43	4.43	4.43	4.43	4.51	4.51	4.51	4.51	4.51	4.51	4.51	4.51	4.51	4.51
Cane Run 4														
Cane Run 5														
Cane Run 6														
Ghent 1	4.11	4.11	4.11	4.11	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19	4.19
Ghent 2	3.51	3.51	3.51	3.51	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58	3.58
Ghent 3	4.59	4.59	4.59	4.59	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68
Ghent 4	4.67	4.67	4.67	4.67	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76
Mill Creek 1	1.74	1.74	1.74	1.74	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78
Mill Creek 2	1.77	1.77	1.77	1.77	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Mill Creek 3	2.51	2.51	2.51	2.51	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55	2.55
Mill Creek 4	2.51	2.51	2.51	2.51	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Trimble 1	3.33	3.33	3.33	3.33	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39	3.39
Trimble 2	2.73	2.73	2.73	2.73	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78

Variable O&M ($/MWh)
2015 Business Plan

	11/2020	12/2020	1/2021	2/2021	3/2021	4/2021	5/2021	6/2021	7/2021	8/2021	9/2021	10/2021	11/2021	12/2021
Brown 1	3.18	3.18	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24
Brown 2	3.10	3.10	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15	3.15
Brown 3	4.51	4.51	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60	4.60
Cane Run 4														
Cane Run 5														
Cane Run 6														
Ghent 1	4.19	4.19	4.27	4.27	4.27	4.27	4.27	4.27	4.27	4.27	4.27	4.27	4.27	4.27
Ghent 2	3.58	3.58	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64	3.64
Ghent 3	4.68	4.68	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77
Ghent 4	4.76	4.76	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85
Mill Creek 1	1.78	1.78	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81
Mill Creek 2	1.80	1.80	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84
Mill Creek 3	2.55	2.55	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60
Mill Creek 4	2.56	2.56	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60	2.60
Trimble 1	3.39	3.39	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46	3.46
Trimble 2	2.78	2.78	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83

Variable O&M ($/MWh)
2015 Business Plan

	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022	1/2023	2/2023
Brown 1	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.36	3.36
Brown 2	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.28	3.28
Brown 3	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.68	4.77	4.77
Cane Run 4														
Cane Run 5														
Cane Run 6														
Ghent 1	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.35	4.43	4.43
Ghent 2	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.71	3.78	3.78
Ghent 3	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.86	4.95	4.95
Ghent 4	4.94	4.94	4.94	4.94	4.94	4.94	4.94	4.94	4.94	4.94	4.94	4.94	5.04	5.04
Mill Creek 1	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.85	1.88	1.88
Mill Creek 2	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.87	1.91	1.91
Mill Creek 3	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.70	2.70
Mill Creek 4	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.65	2.70	2.70
Trimble 1	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.52	3.59	3.59
Trimble 2	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.89	2.94	2.94

Variable O&M ($/MWh)
2015 Business Plan

	3/2023	4/2023	5/2023	6/2023	7/2023	8/2023	9/2023	10/2023	11/2023	12/2023
Brown 1	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36
Brown 2	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28	3.28
Brown 3	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77
Cane Run 4										
Cane Run 5										
Cane Run 6										
Ghent 1	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43	4.43
Ghent 2	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78
Ghent 3	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95
Ghent 4	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04	5.04
Mill Creek 1	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88	1.88
Mill Creek 2	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91	1.91
Mill Creek 3	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Mill Creek 4	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70	2.70
Trimble 1	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59	3.59
Trimble 2	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.16

Witness: Charles R. Schram

Q1.16. Please refer to the 2014 Resource Assessment.

a. Please confirm that aside from CO2 and SO2 and NOx costs, no other environmental compliance costs (capital or O&M) were used as inputs for the Strategist modeling.
   i. If that is not correct, please list all state and/or federal regulations for which compliance costs were considered
      l. Please provide the capital and O&M costs for each regulation for each unit for each year of the analysis.

A1.16.

a. The statement is not correct. Although CO_2, SO_2, and NO_x costs are the only explicit environmental-compliance-cost inputs to the Strategist model, numerous other environmental-compliance costs are implicit in other model inputs.

   i. Capital and O&M cost estimates for the generation technology options considered in the IRP reflect the cost of the Mercury and Air Toxics Standards, the Coal Combustion Residuals rule, the Effluent Limitations Guidelines, the 316(b) cooling water intake rule, NAAQS, and the Clean Air Interstate Rule. The IRP also considered various forms of carbon regulations in its scenario analysis.

      Capital and fixed O&M costs for existing units were not inputs to the IRP analysis. Variable O&M costs for existing units reflect the cost of the Mercury and Air Toxics Standards, the Coal Combustion Residuals rule, the Effluent Limitations Guidelines, the 316(b) cooling water intake rule, NAAQS, and the Clean Air Interstate Rule.

      1. For the generation technology options considered in the IRP, see the 2013 LGE-KU Generation Technology Assessment provided in response to KPSC 1-23. Capital and O&M costs are not available by regulation. Capital and O&M costs are assumed to escalate at 1.8% per year.

Please see the Companies' response to Question No. 1.17 for variable O&M cost estimates for existing units. Variable O&M cost estimates for existing units are available by unit but not by regulation.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.17

Witness: Charles R. Schram

Q1.17. Please refer to the 2014 Resource Assessment. For each existing coal-fired unit owned by LG&E and/or KU, please identify the capital and O&M costs incurred each year from 2019-2028 to comply with the following regulations:

a. Mercury and Air Toxics Standards;
b. Coal Combustion Residuals rule;
c. Effluent Limitations Guidelines;
d. 316(b) cooling water intake rule;
e. NAAQS, including any new ozone standard;
f. Cross State Air Pollution Rule; and
g. carbon regulations, including the proposed Clean Power Plan.

A1.17. Capital and fixed O&M costs for existing units were not inputs to the IRP analysis. Please see the Companies' response to Question No. 1.3 for variable O&M cost estimates by unit. The path and filename of the file is SC1-3\ResourceAssessment\Expansion Planning\Strategist\Support\MaxCapacitiesforPowerBase_2014IRP.xlsx. Variable O&M costs are not available by regulation.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.18

Witness: John N. Voyles

Q1.18. Have the Companies prepared or caused to be prepared any analyses of how the Clean Power Plan may affect its existing generating units? If so, please produce all such analyses.

A1.18. No.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.19

Witness: Charles R. Schram

Q1.19. Please refer to the 2014 Resource Assessment, page 19.

a. Please confirm that the Resource Assessment used the low, mid, and nigh natural gas price forecasts from the EIA for all years through 2033. If denied, please identify the source and date of the gas price forecast used in the Resource Assessment.
b. Please confirm that for the years after 2033, the Resource Assessment escalated the EIA prices at the 2023-2033 compound annual growth rates. If denied, please identify the source, date, and method for deriving natural gas prices after 2033.
c. Please provide the workpapers used to develop the coal prices for each year of the analysis in the Resource Assessment.

A1.19. a. EIA is the source of the Henry Hub natural gas prices that are a basis for the delivered natural gas prices used in the analysis and shown in Table 14 in the 2014 Resource Assessment. The delivered prices include a delivery cost in addition to the EIA's Henry Hub prices.

b. The escalation noted in the 2014 Resource Assessment is correct.

c. Please see the Companies' response to Question No. 1.3. The path and filename of the file is SC1-3\ResourceAssessment\Expansion Planning\Strategist\Support\20130717_2014Plan_FuelforPROSYM_Iteration3.xlsx.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.20

Witness: Charles R. Schram

Q1.20. Please refer to the 2014 Resource Assessment, page 38, Table 29. Please explain why the coal costs for the Brown units are substantially higher than the other coal units.

A1.20. The difference is explained by higher coal transportation costs at the Brown station.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.21

Witness: John N. Voyles

Q1.21. Please refer to the 2014 IRP, Volume I, page 5-5.

a. Please state whether the Companies have decided whether to "extend[] the life of Green River units 3 and 4."
b. Have the Companies decided whether to seek extensions of the MATS compliance deadline for Green River units 3 and 4?
c. Please produce all analyses the Company has prepared or caused to be prepared regarding whether to seek an extension of the MATS compliance deadline for Green River units 3 and 4.

A1.21.

a. Please see response to Commission Staff Question No. 1.

b. Please see response to Commission Staff Question No. 1.

c. Please see the attached the reliability study, which was performed to assess the issues involved in the decision to request a one-year extension of the Green River Units 3 and 4 operation. The study identifies solutions for the current reliability concerns which, upon completion, will alleviate the conditions identified by the study.

   Please note that the attached reliability study contains non-public transmission function information. FERC's Standards of Conduct for Transmission Providers prohibit providing such information to the marketing-function personnel of any entity, including the Company's own marketing-function employees. The Companies are therefore filing the attached reliability study under a Joint Petition for Confidential Protection to limit the release of this non-public information to marketing function employees, whether of the Company or any other entity. All other entities receiving this information, including the Sierra Club, must similarly keep confidential this information until the Companies post the study for public review. The Companies will notify the Commission when the study becomes public and no longer requires or qualifies for confidential protection.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.22

Witness: John N. Voyles

Q1.22. Please refer to the 2014 IRP, Volume I, page 5-48, stating that "Black and Veatch performed a remaining life assessment on Brown 1 and 2 in 2012." Please produce the study referenced in the preceding sentence.

A1.22. Please see the Companies' response to Commission Staff Question No. 7.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
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Dated November 7, 2014

Case No. 2014-00131

Question No. 1.23

Witness: Gary H. Revlett

Q1.23. Please refer to the 2014 IRP, Volume I, page 8-85.

a. Please explain the basis for the Companies' assertion that Jefferson County's "issues with attainment status are expected to be mitigated."
   i. Provide any supporting documentation and/or workpapers.
b. Have the Companies conducted and/or reviewed any air dispersion modeling regarding Jefferson County's attainment status under the new 24-hour NAAQS for PM2.5? If so, please provide all such dispersion modeling.
c. Have the Companies conducted and/or reviewed any air dispersion modeling performed for sources that may impact Jefferson County's attainment status under the new 24-hour NAAQS for PM2.5? If so, please provide all such dispersion modeling.

A1.23.

a. This statement from the IRP is associated with the NAAQS annual standard for $PM_{2.5}$ which was lowered from 15 $\mu g/m^3$ to 12 $\mu g/m^3$. Both the Louisville Metro Air Pollution Control District and the Kentucky Division for Air Quality proposed to reclassify Jefferson County from non-attainment to attainment. However, in the Federal Register Notice dated August 29, 2014, EPA did not accept their proposed attainment status and instead classified Jefferson County as non-attainment for $PM_{2.5}$ based on air quality data in Jeffersonville, IN and the lack of quality assured data in Jefferson County, KY. The Jeffersonville IN monitor data for 2011 – 2013 shows a 12.1 $\mu g/m^3$ concentration compared to the annual standard of 12.0 $\mu g/m^3$. Thus, an excess amount of 0.8%. Based on 2013 Speciation Monitoring at this Jeffersonville site the $PM_{2.5}$ consist of approximately 30% sulfate/sulfur components and 10% nitrate components. LG&E is replacing the coal generation at Cane Run with a natural gas combined-cycle plant and adding additional controls on the air emissions at the Mill Creek plant. The combined effect of these emission reductions will be an approximate 75% reduction in Jefferson County's SO_2 (sulfate/sulfur) emissions and a 36% reduction in the county's NO_x (nitrate) emissions. These SO_2 and NO_x reductions should more than mitigate the needed 0.8% reduction needed to meet the $PM_{2.5}$ standard and allow the county to be designated as attainment. Supporting documentation is provided in Attachment SC 1-23.

b. The Companies have not conducted or reviewed any 24-hour NAAQS dispersion modeling for $PM_{2.5}$.

c. Please see the Companies' response to b. above.

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2013 Fine Particles ($PM_{2.5}$) Summary Report

Office of Air Quality
(800) 451-6027
www.idem.IN.gov/airquality/2391.htm

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2013 Fine Particles Monitoring

Purpose

This Fine Particles ($PM_{2.5}$) Season Summary Report provides an overview of $PM_{2.5}$ levels from 2013, as well as $PM_{2.5}$ trends over the last 10 years (2004 through 2013).

Summary

Monitoring and reporting of fine particles occurs on a year-round basis as mandated by the United States Environmental Protection Agency (U.S. EPA).

- There were 7 exceedance days in 2013.
- There were no Air Quality Action Days in 2013.

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Background of Particulate Matter

What is particulate matter?

Particulate matter is a complex mixture of small particles found in the air, including dust, dirt, smoke, and liquid droplets.

Where does PM come from?

Sources of PM include all types of combustion activities:

- Motor vehicles, coal-fired power plants, open burning, etc.
- Certain industrial processes.

Health effects of PM:

- Increased respiratory symptoms:
  - Irritation of the airways.
  - Coughing or difficulty breathing.
  - Decreased lung function.
  - Aggravated asthma.
  - Development of chronic bronchitis.
- Irregular heartbeats.
- Nonfatal heart attacks.
- Premature death in people with heart or lung disease.

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How Big Is Particulate Matter?

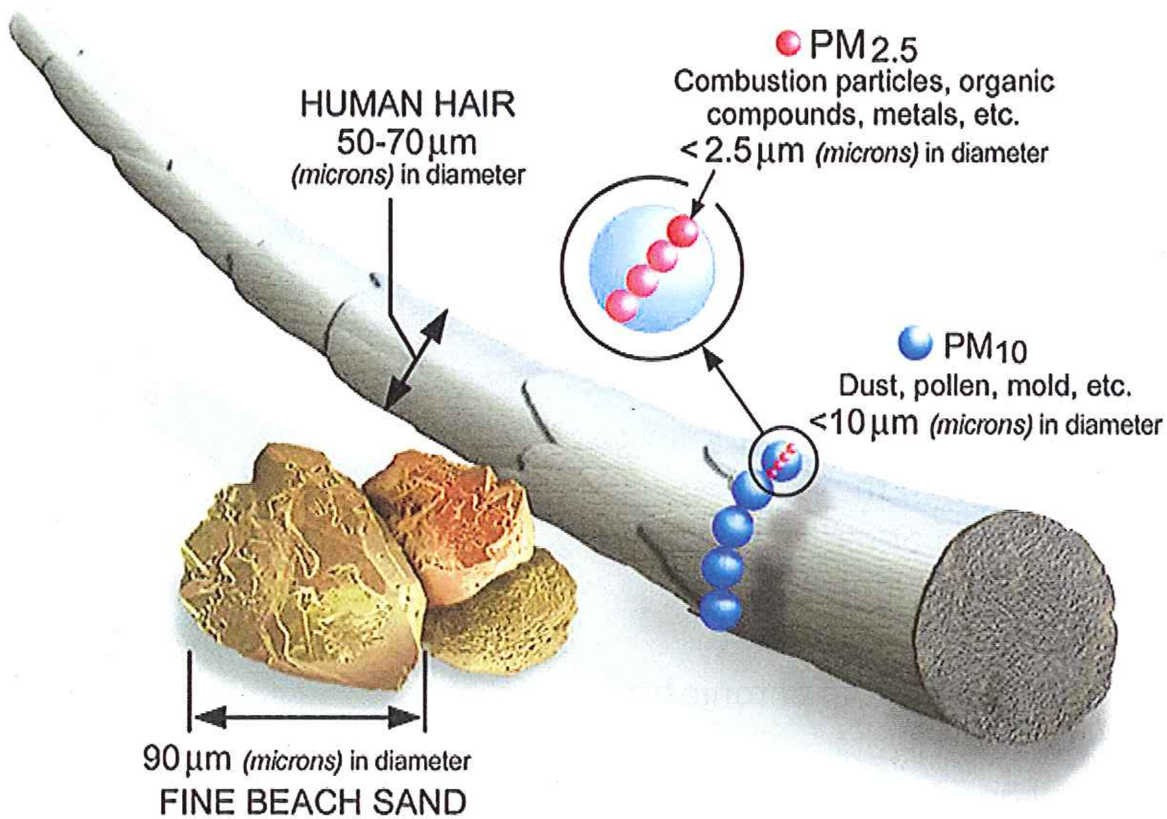

Image courtesy of the U.S. EPA

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National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$

Primary Standards

Primary standards, also known as health standards, are limits set to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly.

Secondary Standards

Secondary standards are set to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings.

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History of the PM Standards

1971
U.S. EPA issued first NAAQS for Total Suspended Particles (TSP)

1987
U.S. EPA revised the NAAQS and replaced TSP with PM_{10}

1997
U.S. EPA revised NAAQS and included $PM_{2.5}$

Annual 15 µg/m³

24-hour 65 µg/m³

Industry and state governments challenged NAAQS

2001
U.S. Supreme Court upheld U.S. EPA's authority to enforce Clean Air Act and rules, U.S. EPA not allowed to consider cost

2002
D.C. Circuit Court rejected all remaining legal challenges to the 1997 NAAQS

2006
U.S. EPA strengthened the 24-hour NAAQS to 35 µg/m³ and retained the existing annual standard at 15 µg/m³

2009
D.C. Circuit Court remanded the 2006 $PM_{2.5}$ NAAQS to U.S. EPA for reconsideration, but did not vacate the standards

2012
U.S. EPA strengthened the annual primary $PM_{2.5}$ NAAQS to 12 µg/m³ and retained the existing secondary standard at 15 µg/m³

Retained existing 24-hour NAAQS at a level of 35 µg/m³

µg/m³ = micrograms per cubic meter

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Attaining the Standards

Annual Standard

To attain the 2012 annual standard, the three-year average of weighted annual mean $PM_{2.5}$ concentrations from a monitor must not exceed 12 µg/m³.

Exceedance versus a Violation of the Standard

- An ***exceedance*** occurs when the annual mean is measured above the standard. A ***violation*** occurs when the three-year average of the annual mean is above the standard. ***A monitor can exceed the standard without being in violation.***

24-Hour Standard

To attain the 2006 24-hour standard, the three-year average of the 98th percentile of 24-hour concentrations at each monitor must not exceed 35 µg/m³.

Exceedance versus a Violation of the Standard

- An ***exceedance*** occurs when the 98th percentile is measured above the standard. A ***violation*** occurs when the three-year average of the 98th percentile is measured above the standard. ***A monitor can exceed the standard without being in violation.***

µg/m³ = micrograms per cubic meter

Attainment Status

2006 Daily Standard

U.S. EPA attainment designations for the 2006 24-hour standard were effective December 14, 2009.

- All Indiana counties were designated as attaining the standard and remain in attainment.

1997 Annual Standard

U.S. EPA attainment designations for the 1997 annual standard were effective on April 5, 2005.

- 12 full and five partial counties were designated as nonattainment.
- Dubois, Vanderburgh and Warrick counties, as well as Montgomery Township in Gibson County, Ohio Township in Spencer County, and Washington Township in Pike County were redesignated to attainment on October 27, 2011.
- Lawrenceburg Township in Dearborn County, which is part of the Cincinnati-Hamilton OH-KY-IN Fine Particles Nonattainment Area, was redesignated to attainment on December 23, 2011.
- Lake and Porter counties were redesignated to attainment on February 6, 2012.
- Hamilton, Hendricks, Johnson, Marion, and Morgan counties were redesignated to attainment on July 11, 2013.
- Clark and Floyd counties, as well as Madison Township in Jefferson County are pending redesignation with U.S. EPA.
- All areas of the state currently meet the 1997 annual air quality standard.

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Attainment Status

2012 Standard

On December 14, 2012, U.S. EPA strengthened the annual primary NAAQS to a level of 12 $\mu g/m^3$ and retained the existing secondary annual standard at a level of 15 $\mu g/m^3$ and primary and secondary 24-hour standards at a level of 35 $\mu g/m^3$. The standards were finalized by U.S. EPA on January 15, 2013, and became effective on March 18, 2013.

Area Designations

- On December 12, 2013, Indiana submitted preliminary recommendations to U.S. EPA concerning air quality designations for the 2012 primary annual $PM_{2.5}$ standard. Based on quality assured 2010 through 2012 monitoring data, preliminary and projected monitoring data for 2013, and a probability forecast for 2014, Indiana recommended all monitored counties within the state be designated as attainment under the primary annual $PM_{2.5}$ standard.
- Indiana requested that U.S. EPA designate all other areas attainment/unclassifiable under the standard. U.S. EPA is scheduled to designate areas under the primary annual $PM_{2.5}$ standard by December 12, 2014.
- U.S. EPA is scheduled to respond to initial state recommendations by August 14, 2014.
- U.S. EPA scheduled to make final designations by December 12, 2014; those designations will likely become effective in early 2015.
- State implementation plans due to U.S. EPA three years after designations become effective.

Attainment Status

2012 Standard (continued)

- States are required to meet the standard no later than six years after designations become effective. States may request a possible extension of up to five additional years to attain the standard, depending on the severity of an area's fine particles pollution problems and the availability of pollution controls.
- Based on 2013 monitoring data, no monitor in the state's 2013 annual ambient air $PM_{2.5}$ monitoring network recorded annual arithmetic mean values above the 2012 annual health standard.
- Based on quality assured 2011 through 2013 monitoring data, the Jeffersonville – Walnut Street fine particles monitor (Clark County) was the only monitor in the state's 2013 annual ambient air $PM_{2.5}$ monitoring network that recorded a three-year average annual arithmetic mean above the 2012 annual health standard.

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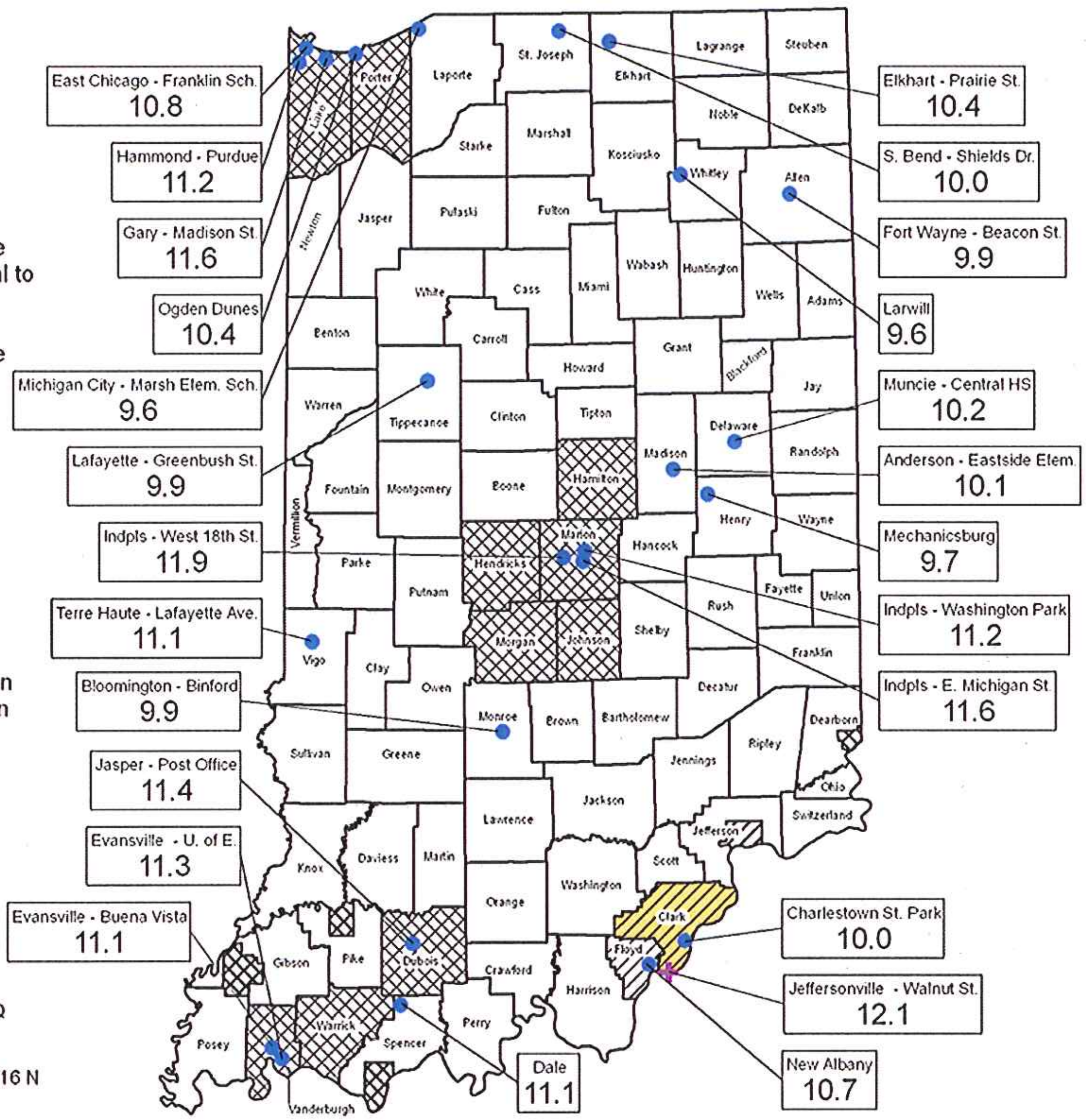
Annual $PM_{2.5}$ Design Values (Based on Valid 3-Year Arithmetic Means) 2011 - 2013 with Area Designation Status

Standard set at $12.0\ \mu g/m^3$

Legend

- $PM_{2.5}$ Design Value Less Than or Equal to $12.0\ \mu g/m^3$
- $PM_{2.5}$ Design Value Greater Than $12.0\ \mu g/m^3$
- Attainment with a Maintenance Plan
- Nonattainment (Redesignation Pending)
- Unclassifiable /Attainment
- County With Design Value Greater Than $12.0\ \mu g/m^3$



N W E S

0 25 50 mi

0 25 50 km

Notes:
- Posted Data Are Quality Assured But Not Yet Certified
- Posted Data Are in Units of Micrograms Per Cubic Meter ($\mu g/m^3$)

Mapped By: C. Mitchell, OAQ
Date: 03/05/2014
Source: IDEM Air Monitoring
Map Projection: UTM Zone 16 N
Map Datum: NAD83

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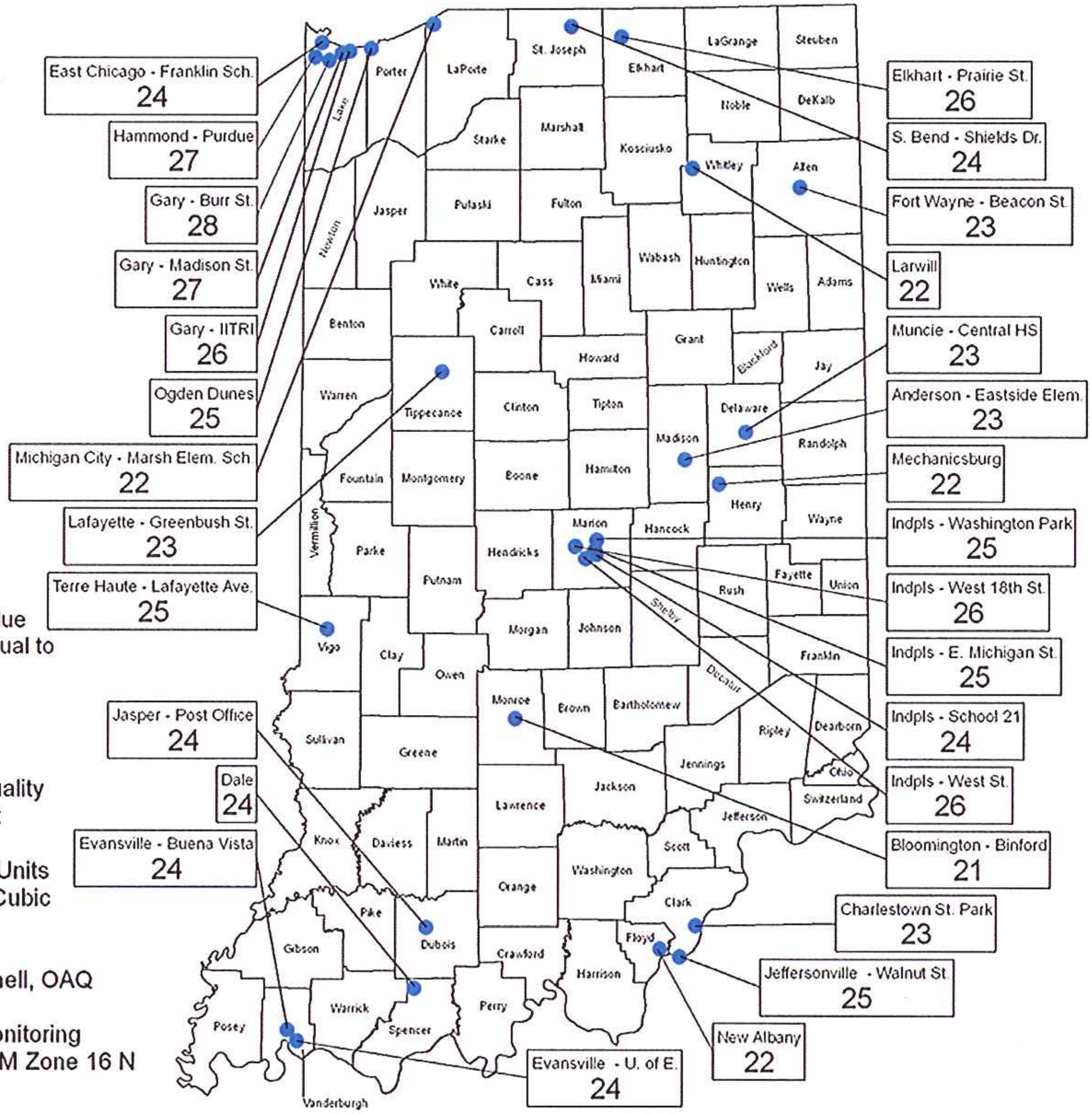
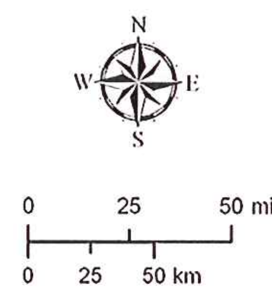
Daily $PM_{2.5}$ Design Values Based on Valid 3-Year Average of the 98th Percentile (2011 - 2013)

Standard set at 35.0 µg/m^3





Legend

- $PM_{2.5}$ Design Value Less Than or Equal to 35 µg/m^3

Notes:
- Posted Data Are Quality Assured But Not Yet Certified
- Posted Data Are in Units of Micrograms Per Cubic Meter (ug/m^3)

Mapped By: C. Mitchell, OAQ
Date: 03/05/2014
Source: IDEM Air Monitoring
Map Projection: UTM Zone 16 N
Map Datum: NAD83

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2013 Monitoring Network

Placement

- U.S. EPA provides guidance on placement of monitors.
- Monitors placed based on population density and manufacturing levels.

Monitors

- 27 annual fine particle monitors in 20 counties across Indiana.
- 31* 24-hour fine particle monitors in 20 counties across Indiana.

Calculating the Design Value

- A monitor's design value is calculated at the end of the year, once all of the data has been quality assured.
  - Annual Design Value: three-year average of the weighted annual mean $PM_{2.5}$ concentrations.
  - 24-Hour Design Value: three-year average of the 98^{th} percentile of 24-hour concentrations.

* Four monitoring sites reflect air quality in a relatively small area, are directly influenced by a specific source, and are intended to be used for attainment status under the 24-hour standard only.

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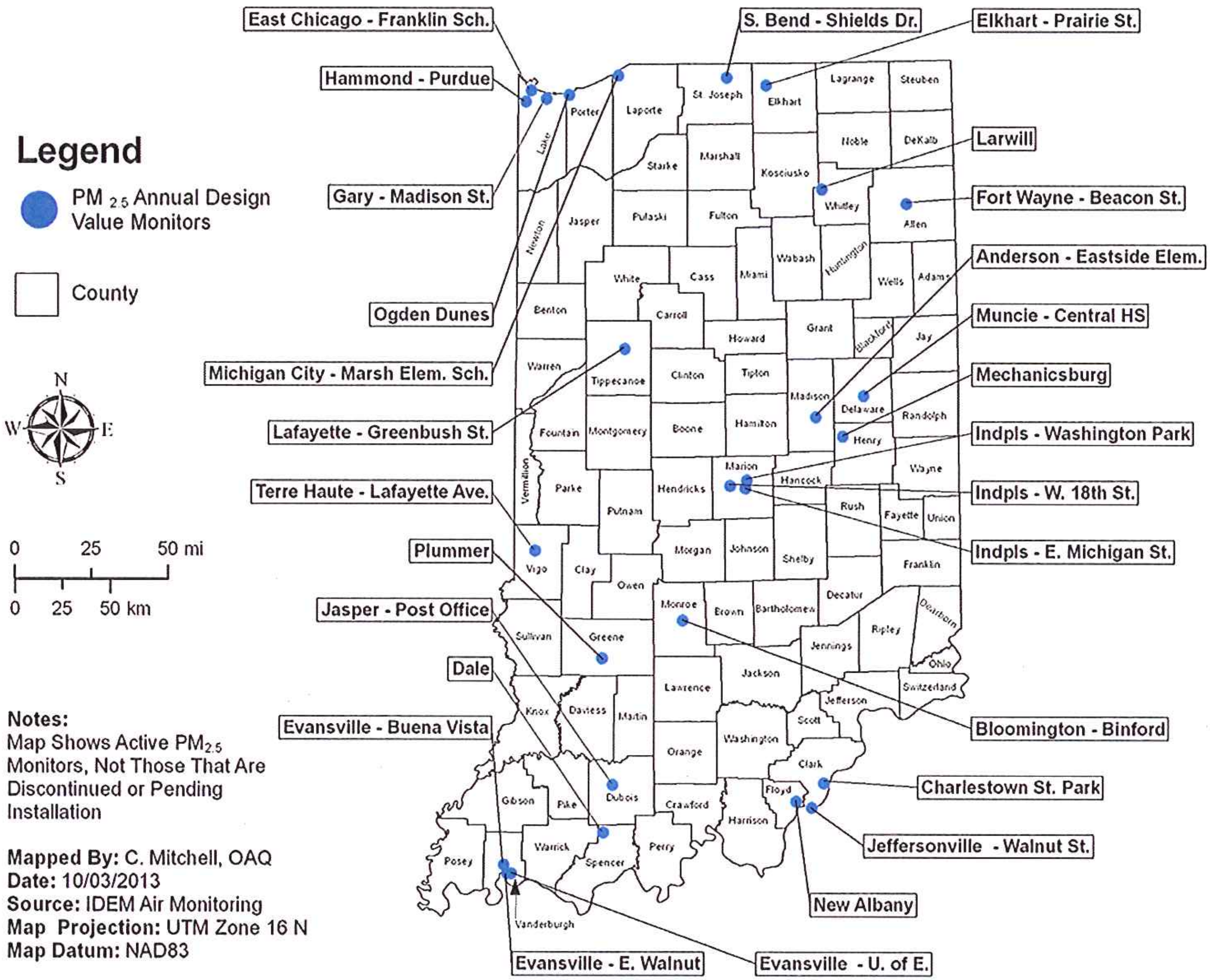
2013 Annual Ambient Air $PM_{2.5}$ Monitoring Network



Notes:
Map Shows Active $PM_{2.5}$ Monitors, Not Those That Are Discontinued or Pending Installation

Mapped By: C. Mitchell, OAQ
Date: 10/03/2013
Source: IDEM Air Monitoring
Map Projection: UTM Zone 16 N
Map Datum: NAD83

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2013 Daily Ambient Air $PM_{2.5}$ Monitoring Network

Legend

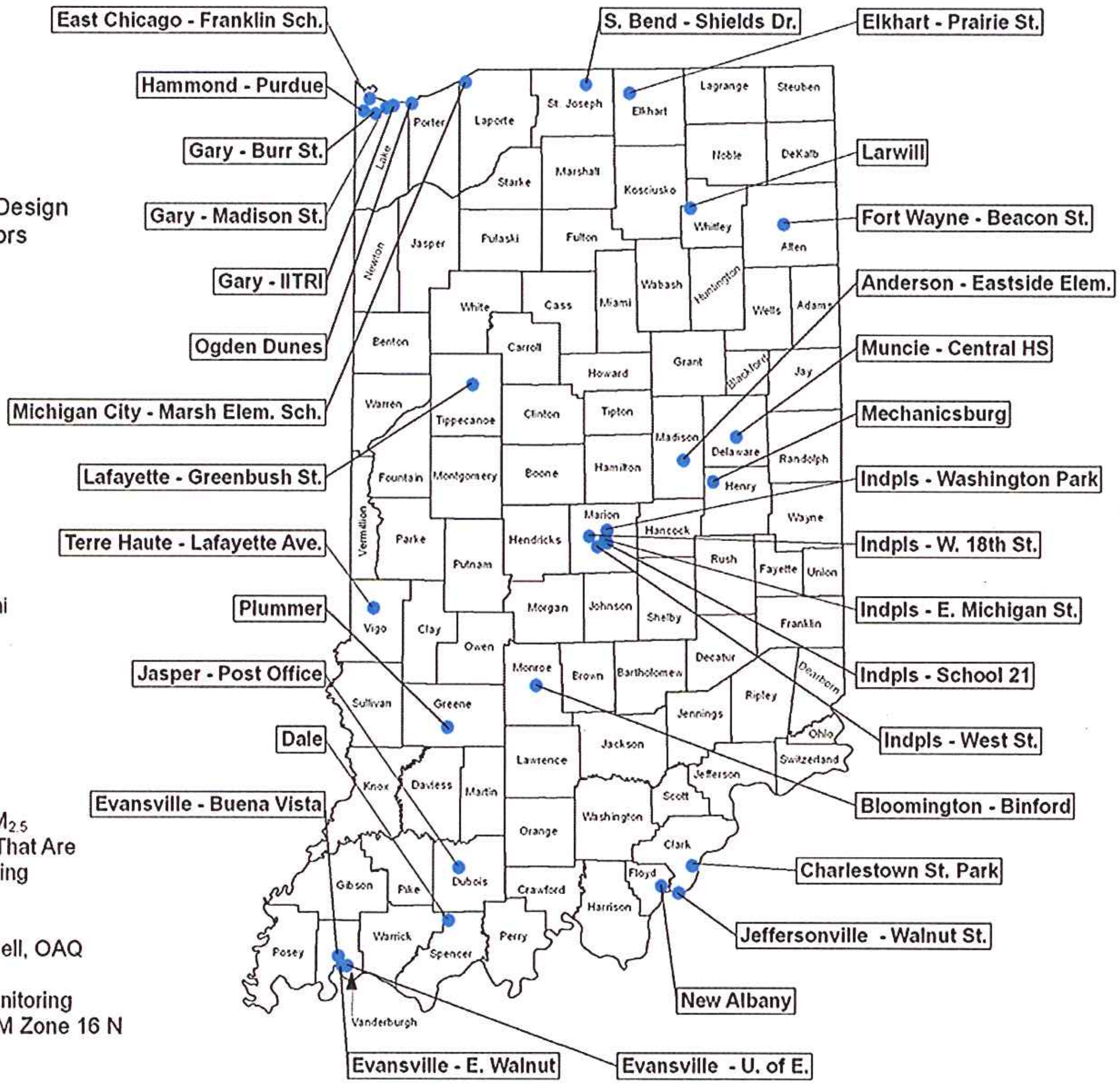
$PM_{2.5}$ Daily Design Value Monitors

County

N W E S

0 25 50 mi

0 25 50 km



Notes:
Map Shows Active $PM_{2.5}$ Monitors, Not Those That Are Discontinued or Pending Installation

Mapped By: C. Mitchell, OAQ
Date: 01/30/2014
Source: IDEM Air Monitoring
Map Projection: UTM Zone 16 N
Map Datum: NAD83

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$PM_{2.5}$ Monitors by Area

Area	Counties
Central	Madison, Marion
East Central	Delaware, Henry
Northeast	Allen, Whitley
Northwest	Lake, LaPorte, Porter
North Central	Elkhart, St. Joseph
Southeast	Clark, Floyd
Southwest	Dubois, Greene, Spencer, Vanderburgh
West Central	Monroe, Tippecanoe, Vigo

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2013 Monitoring Summary

- Based on 2013 monitoring data, no monitor in the state's 2013 annual ambient air $PM_{2.5}$ monitoring network recorded annual arithmetic mean values above the 2012 annual health standard.

- Based on quality assured 2011 through 2013 monitoring data, the Jeffersonville – Walnut Street fine particles monitor (Clark County) was the only monitor in the state's 2013 annual ambient air $PM_{2.5}$ monitoring network that recorded a three-year average annual arithmetic mean above the 2012 annual health standard.

- Based on 2013 monitoring data, no monitor in the state's 2013 daily ambient air $PM_{2.5}$ monitoring network recorded 24-hour 98th percentile values that exceeded the 2006 24-hour health standard.

- Based on quality assured 2011 through 2013 monitoring data, no monitor in the state's 2013 daily ambient air $PM_{2.5}$ monitoring network recorded a three-year average 98th percentile value that exceeded the 2006 24-hour health standard.

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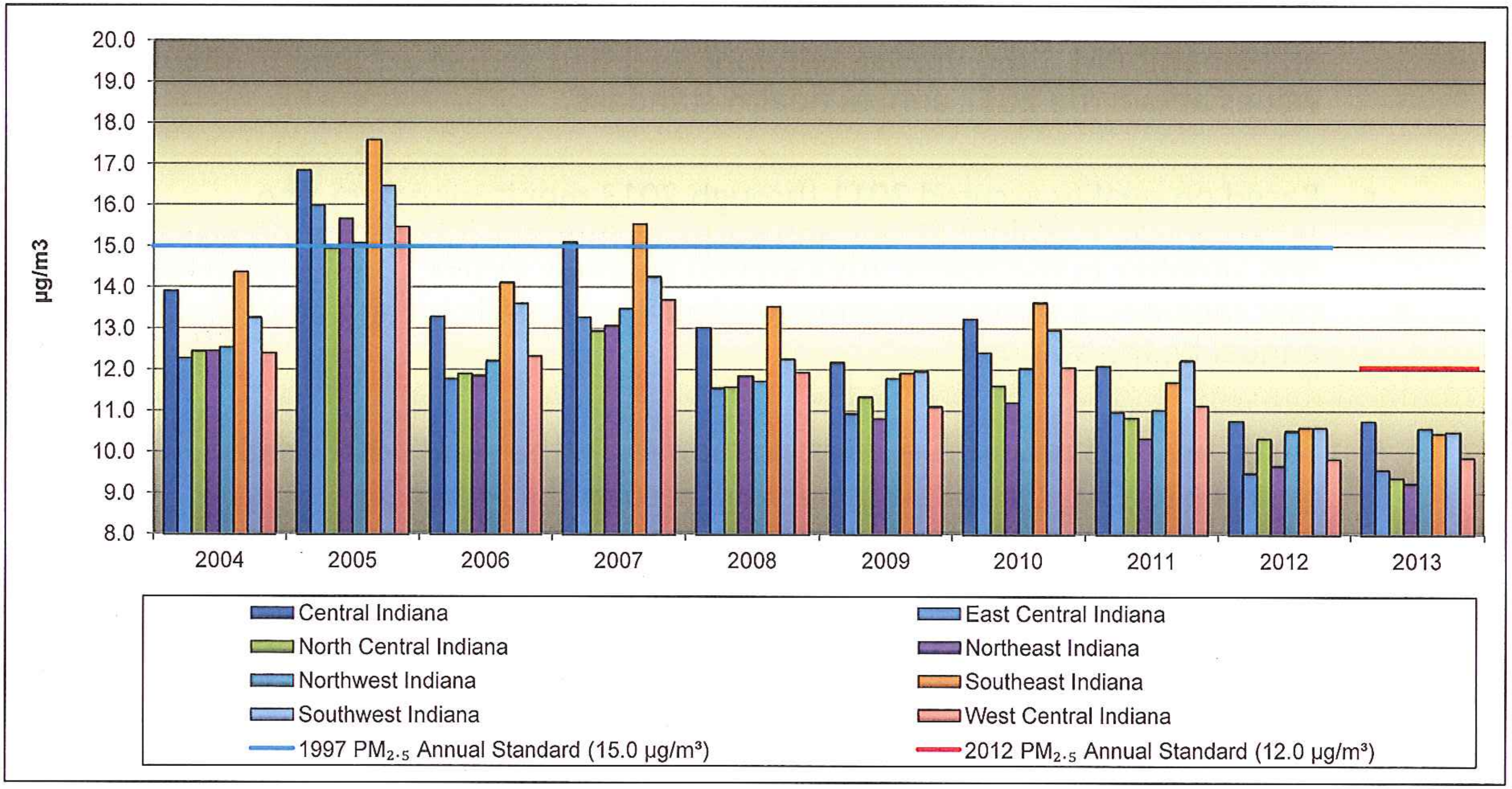
Annual Arithmetic Mean Trends 2004-2013



µg/m³ = micrograms per cubic meter

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Annual $PM_{2.5}$ Design Value Trends 2004-2013

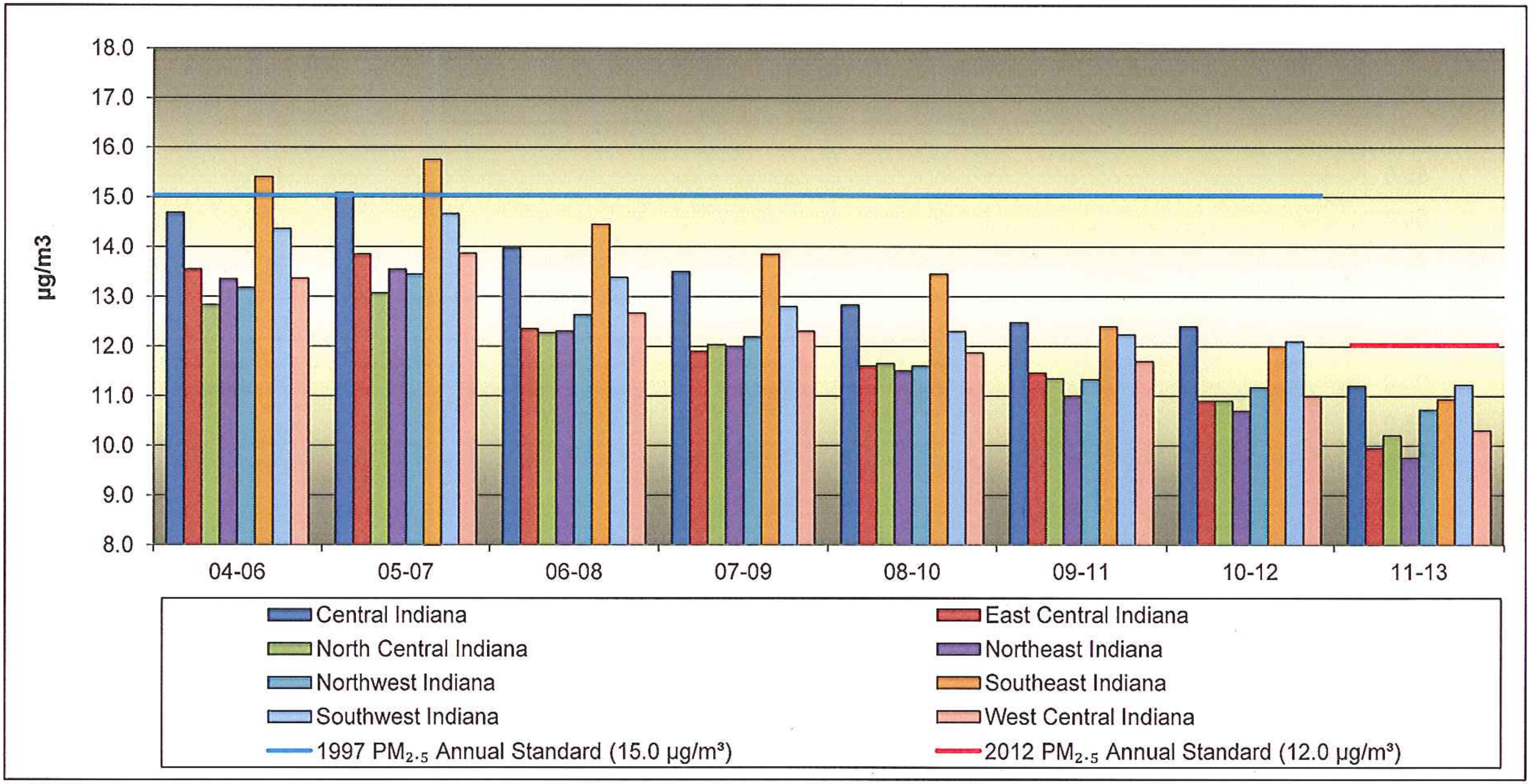

Chart excludes monitors with incomplete data and/or less than three full years of monitoring data.
$\mu g/m^3$ = micrograms per cubic meter

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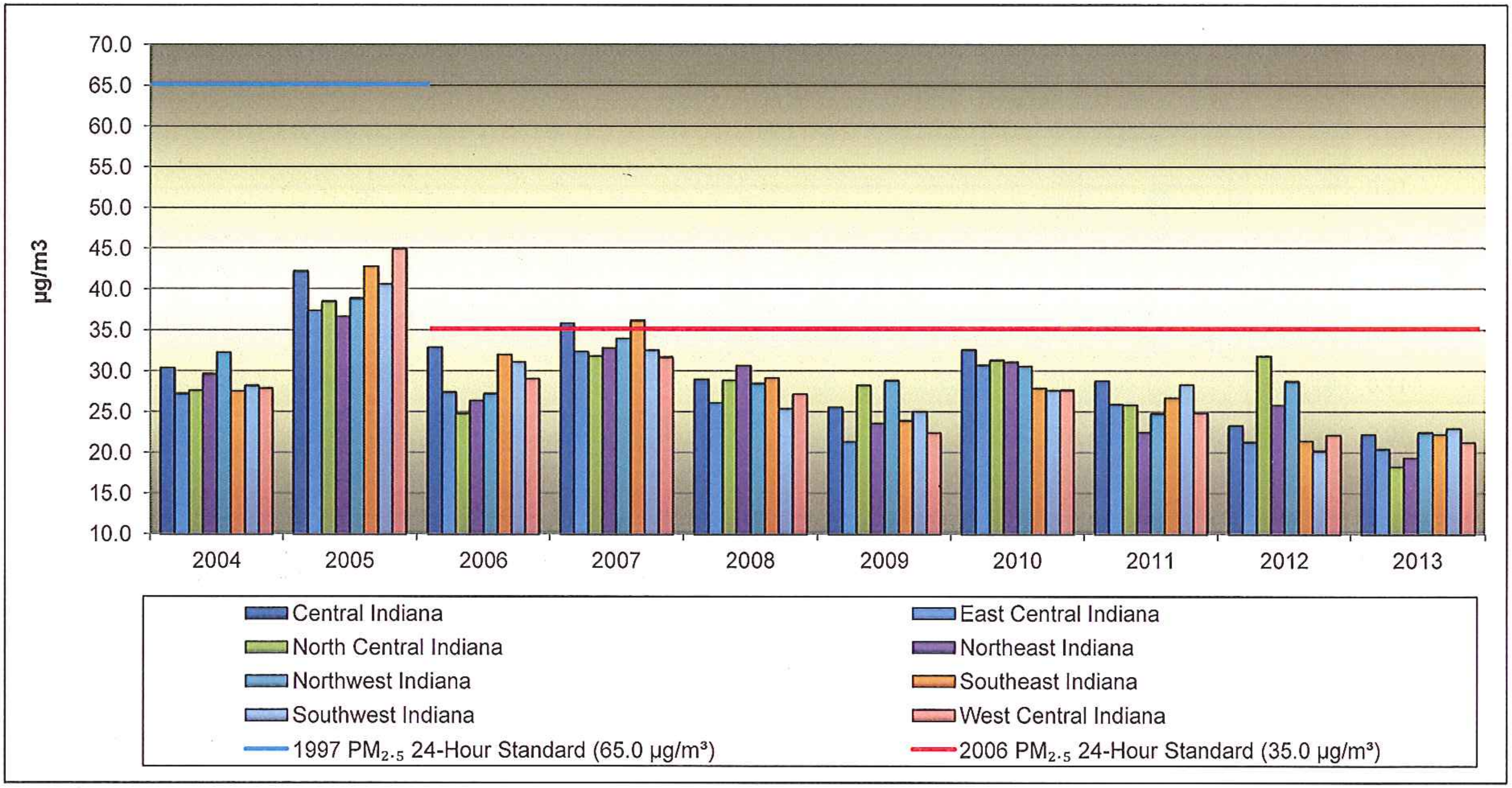
24-Hour 98th Percentile Trends 2004-2013



µg/m³ = micrograms per cubic meter

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24-Hour $PM_{2.5}$ Design Value Trends 2004-2013

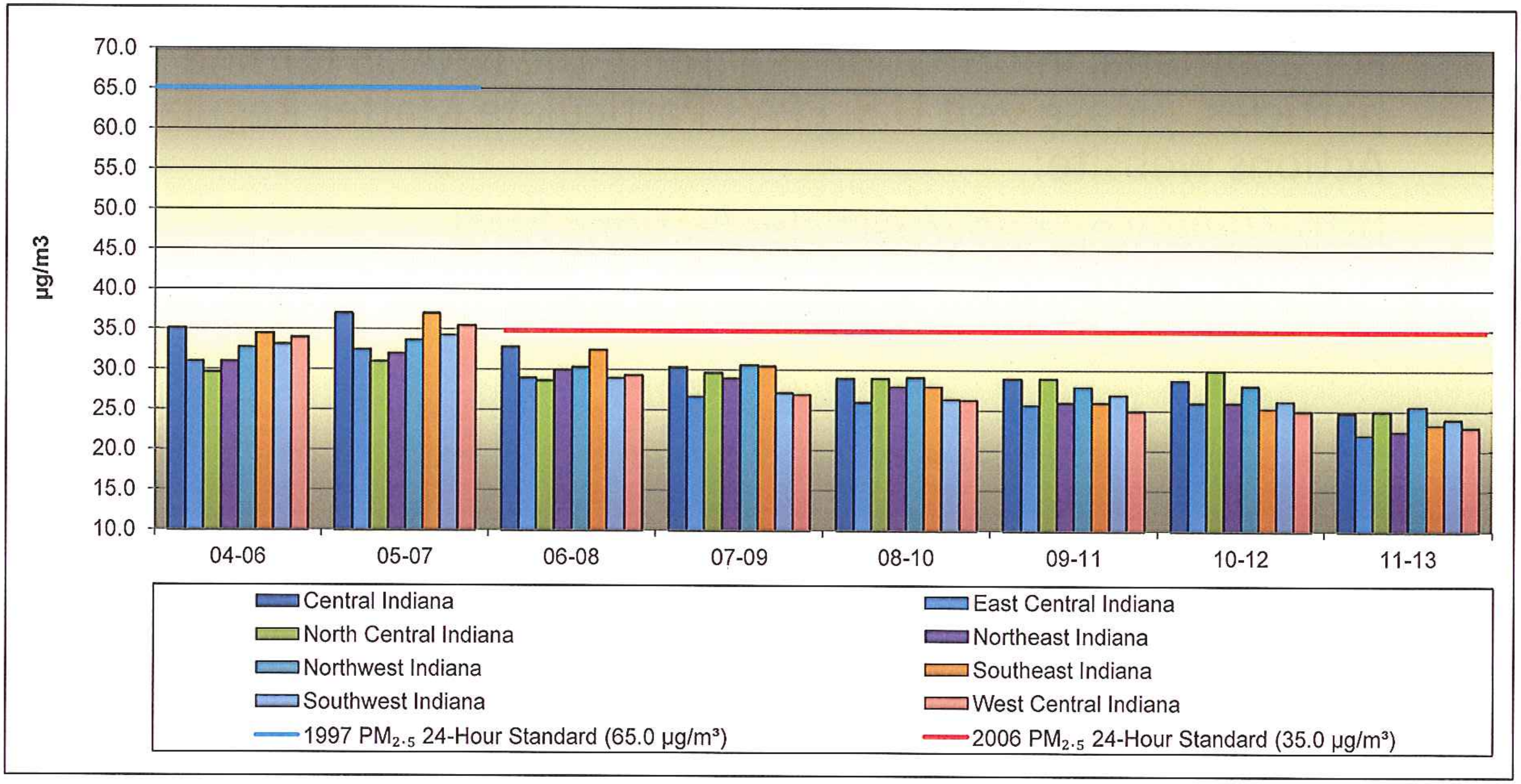

Chart excludes monitors with incomplete data and/or less than three full years of monitoring data.
µg/m³ = micrograms per cubic meter

Additional Information

For additional information regarding the NAAQS for fine particles, please visit U.S. EPA's Particulate Matter Regulatory Actions website:

http://www.epa.gov/particles/actions.html

Contact

For more information regarding the particulate matter designation process, or Indiana's redesignation petition and maintenance plans, visit www.idem.IN.gov/airquality/2392.htm or contact Mr. Gale Ferris of the Office of Air Quality at (800) 451-6027, (317) 234-3653, or gferris@idem.IN.gov.

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Annual $PM_{2.5}$ Design Values (Based on Valid 3-Year Arithmetic Means) 2011 - 2013 with Area Designation Status

Standard set at $12.0\ \mu g/m^3$

Legend

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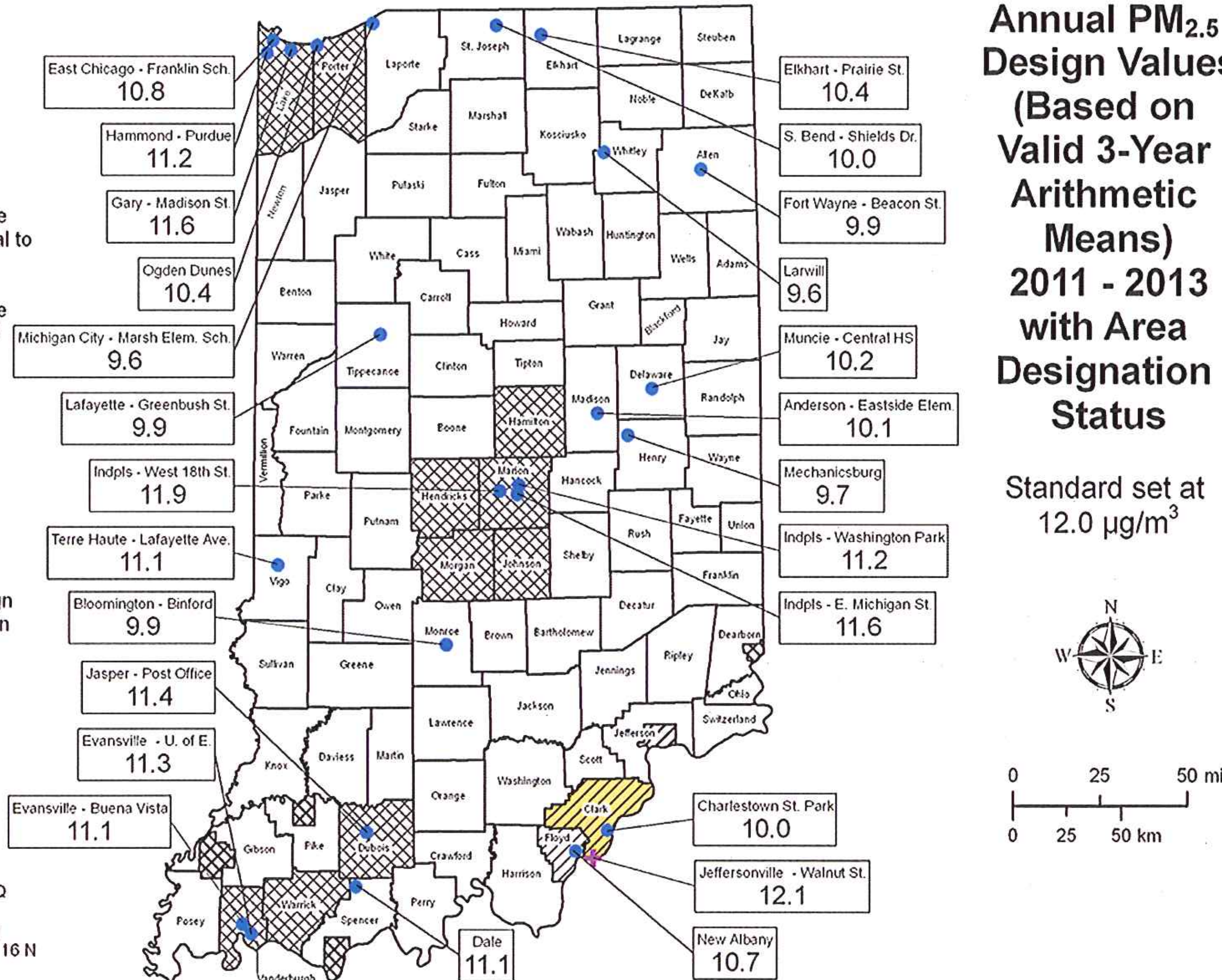

Notes:
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Mapped By: C. Mitchell, OAQ
Date: 03/05/2014
Source: IDEM Air Monitoring
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Indiana Department of Environmental Management

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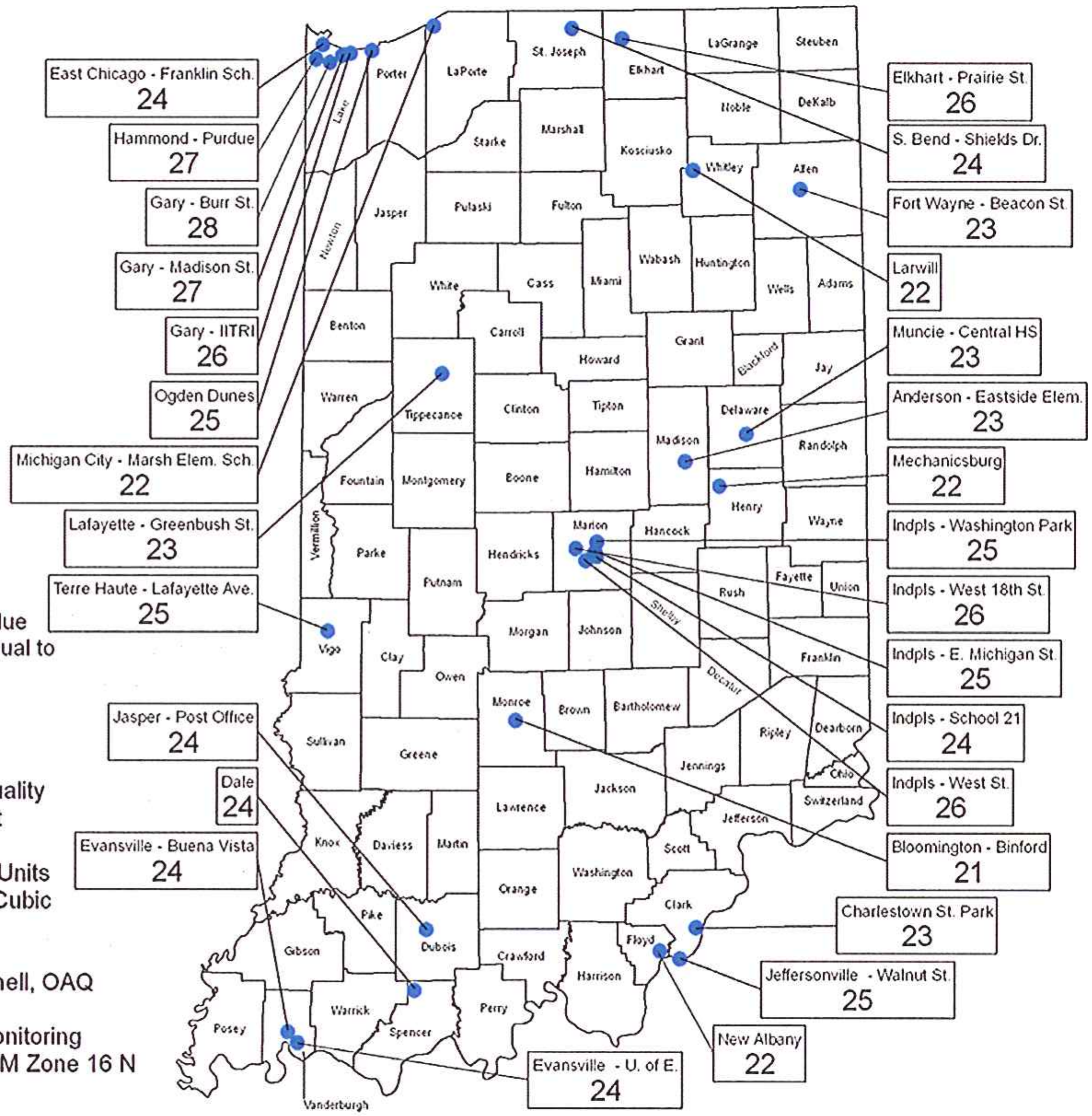
Daily $PM_{2.5}$ Design Values Based on Valid 3-Year Average of the 98th Percentile (2011 - 2013)

Standard set at 35.0 µg/m^3



Legend

- $PM_{2.5}$ Design Value Less Than or Equal to 35 µg/m^3

Notes:
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Mapped By: C. Mitchell, OAQ
Date: 03/05/2014
Source: IDEM Air Monitoring
Map Projection: UTM Zone 16 N
Map Datum: NAD83

Indiana Met One Speciation PM2.5 Conc.

NOTE: Indpls. Washington Park runs on 1/3 alternate schedule but only 1/6 sample data is shown

Sample Date	Elkhart Prairie Street (ug/m^3) Speciation Met 1	Evansville Buena Vista Road (ug/m^3) Speciation Met 1	Gary Iitri (ug/m^3) Speciation Met 1	Jasper Post Office (ug/m^3) Speciation Met 1	Jeffersonville Walnut Street (ug/m^3) Speciation Met 1	Mechanicsburg (ug/m^3) Speciation Met 1	Indpls. Wa (u Sp I
04-Jan-12	10.53392544	6.718346253	16.1357054	7.530431195	9.009009009	7.238134629	
10-Jan-12	15.16245487		15.9123786	18.86987008	25.52180203	13.71841155	
16-Jan-12	13.33746898	8.465826967	12.0070386	8.482466122	9.384345674	8.173823073	
22-Jan-12	15.88939331	13.10764785	13.6518771	11.35190918	13.92901362	12.37113402	
28-Jan-12	5.149860954	5.882960058	3.92561983	10.10621842	8.347073372	6.502890173	
03-Feb-12	31.60177631	8.464079273	23.7603306	12.59159872	10.21988232	16.19725575	
09-Feb-12	13.83011663	8.370362716	15.3019024	9.697720004	8.981108702	12.79009799	
15-Feb-12	15.66848778		13.8301166	14.57364341	14.38178996	10.11456291	
21-Feb-12			9.20181969	6.400991121	7.643048957	7.742335088	
27-Feb-12	10.94024151	7.437248218	12.1005275	10.73160665	8.370362716	5.475206612	
04-Mar-12	8.559348252	7.843946744	9.30232558	7.229164515		6.409593714	
10-Mar-12	7.434944238	7.646998037	7.44956027	5.976916735	9.395003097	6.9179143	
16-Mar-12	12.27057125			7.528101475	7.632800413	5.469556244	
22-Mar-12	18.89519876	9.691720796	18.5854414	11.31221719	13.70992681	14.421096	
28-Mar-12	7.125154895	15.88611512	9.19231564	15.26875064	17.75209	7.531208088	
03-Apr-12	14.34616575	14.62711166	16.7286245	13.60965048	15.2640264	13.21085767	
09-Apr-12	4.030591153	6.297099205	24.581698	5.367464905	8.669625348	4.849860695	
15-Apr-12	16.51357209	13.60123648	14.9269096	16.10073279	13.90462458	14.34320504	
21-Apr-12	3.821919223	9.601486682	5.48256957	5.88174595	8.26019618	5.36968195	
27-Apr-12	3.614955588	4.953049221	4.86089565			5.056759546	
03-May-12	8.249974219	6.795016988	9.15355343	8.643753859	14.20045277	9.794824209	
09-May-12	5.470120755	5.978148835	7.85367366	5.769627035	7.111202721	3.916718202	
15-May-12	9.699721391	13.91322271		14.01050788	22.8583196	8.568184164	
21-May-12	7.116336634	10.61308604	6.09504132	11.4397609	11.60164271	7.937326049	
27-May-12	12.59159872	17.08170405	13.8529929	16.60821126	23.6179868	20.09687725	
02-Jun-12	5.678298575	9.587628866	8.16621873	7.211290821	9.390155815	5.472945064	
08-Jun-12	11.25219366	14.22093982	11.8189103	11.4456589	17.50051472	8.047044259	
14-Jun-12	9.697720004	14.20337587	8.78280636	12.98835172	9.781713344	5.779750232	
20-Jun-12	15.14527097	17.93259817	10.6119926	20.62068254	23.17914907	22.37574758	
26-Jun-12	5.571030641	5.047903575	9.71475816	5.257731959	6.084983498	6.084983498	
02-Jul-12	16.59622719	20.91274338	19.1293558		21.04828725	16.81105611	
08-Jul-12	7.432641685	18.89324799	7.83182193	19.6402729	21.45435792		
14-Jul-12	9.688723974	8.560231023	18.3789365		7.852050832	7.625721352	
20-Jul-12	10.40164779	10.96854305	11.8483412	12.15617596	10.72607261	10.52522959	
26-Jul-12	9.996908173	10.11351909	9.38241056	11.55473022	15.1405912	8.976475444	
01-Aug-12	9.685729006	12.38390093	13.5163021	12.98969072	14.9330587	8.972772277	
07-Aug-12	10.21460999		11.3577697	14.20337587		9.582689335	
13-Aug-12	10.93008868	11.33086115	11.6566949		15.95142534	10.12396694	
19-Aug-12	11.03661681	7.822149033	14.3328521			7.533539732	
25-Aug-12	20.20410267	18.56244199	18.5547882	17.40115321	18.98472967	15.07174564	
31-Aug-12	9.485513971	8.147689769	11.2545173	7.613952053	9.377576257	10.09788769	
06-Sep-12	9.284093254	14.24883841	11.8324931	15.57022066	22.1147912	10.84822812	
12-Sep-12	11.25916744	14.91462662	12.3966942	13.98457584	16.88632619	12.49870881	

Total Carbon - 3.286
Sulfate - 2.737
Sulfur - 0.975
Nitrate - 1.156
Ammonium - 0.997

9.151

OTHER - 12.906
− 9.151
3.755

Sulfate/Sulfur % -
$\frac{3.712}{12.906} = 28.8\%$

Nitrate % -
$\frac{1.156}{12.906} = 9.0\%$

18-Sep-12	3.406979145	5.776173285	10.1281521	5.982465188	4.844361987	4.12371134	5
24-Sep-12	5.051546392	7.942238267	6.29709921	8.136780307	9.995877988	4.952027236	
30-Sep-12	10.11143211	13.81443299	3.92886683	11.44447881	15.95635166	9.488448845	
06-Oct-12	5.266962718	4.336155276	9.91428276	3.202148538	4.545454545	4.335707649	3
12-Oct-12	5.677126342		4.65404902	9.911212059	14.64370424	5.058847822	
18-Oct-12	5.268050821	5.670103093	5.68123128	5.983699577	5.671857275	5.266418835	5
24-Oct-12	14.02929647	10.50138989	12.3685838	11.43858203	14.74682892	12.27183665	1
30-Oct-12	2.377506719	6.083101351		3.82231405	4.545924166	1.962404462	3
05-Nov-12	22.8913178		6.82523268	12.27816756	14.05539479	11.36363636	
11-Nov-12	9.601486682	10.10413445	9.48551397	8.658901144	9.288884302	9.194214876	9
17-Nov-12		20.74517494	30.4815044	18.27945885	20.44187487		2
23-Nov-12	6.076210093	5.364696172	11.587006	6.186842648	7.220961419	5.780346821	
29-Nov-12	20.84623323	15.08576152	17.7777778	16.90547366	27.0913039	18.54140915	2
05-Dec-12	4.228547855	7.950438823	4.23466226	6.493506494	8.365176082	4.126689363	4
11-Dec-12		7.01681973	9.20467473	6.70379538	12.29211858	10.39736463	1
17-Dec-12	17.46950589	15.79436358	19.3321617	14.23854726	8.672310551	15.94158182	1
23-Dec-12	18.57201816	9.596532866	11.7975784	7.637527093	11.3554248	12.1474161	1
29-Dec-12	20.94294852	11.84102142	23.3996495	12.78350515	11.76470588	14.31661345	1
Annual Average	10.98675262	10.71204056	12.0958381	10.85372017	12.9064848	9.490079356	1

Indiana URG Speciation Total Carbon Conc.

NOTE: Indpls. Washington Park runs on 1/3 alternate schedule but only 1/6 sample data is shown

Sample Date	Elkhart Prairie Street (ug/m^3) Speciation URG	Evansville Buena Vista Road (ug/m^3) Speciation URG	Gary Iitri (ug/m^3) Speciation URG	Jasper Post Office (ug/m^3) Speciation URG	Jeffersonville Walnut Street (ug/m^3) Speciation URG	Mechanicsburg (ug/m^3) Speciation URG	Indpls. Washington Park (ug/m^3) Speciation URG
04-Jan-12	2.846412088	2.317548713	4.30281139	2.348224612	3.088675383	1.846881671	2.140521256
10-Jan-12	4.549846904	4.965873197	4.46402328	4.665778025		3.379557647	6.278033325
16-Jan-12	2.446072946	2.474169593	2.97380522	2.228896285		1.810364667	
22-Jan-12	1.700595143	1.782572135	1.73509828	1.89456677	3.127409302		1.968963022
28-Jan-12	0.883037532	1.939651918	1.10386943	1.270138491	1.841056224	1.044747234	1.547307258
03-Feb-12	6.418482411	3.164172606	2.54310987	3.344326015	4.211530161	2.169750016	
09-Feb-12	1.743842152	1.477764566	2.1157393	1.430099325	1.474539141	1.247485412	0.111738511
15-Feb-12	1.83631059	1.931615106	2.27169043	2.712195781	3.370989867	1.511214836	1.901995306
21-Feb-12	1.504171438	1.665703451	1.29100443	1.572765516	1.550054979	1.548300082	
27-Feb-12	2.618365156	2.907710574	2.66871566	2.961686336	3.240703645		
04-Mar-12	1.362816213	1.753530139	1.93844439	1.723550498	1.309761206	1.131562991	1.192177943
10-Mar-12	2.066535199	2.836113218	2.93952203	1.573174017	2.709152712	1.540517874	2.424075224
16-Mar-12	3.499771557		4.34608096	2.141199059	2.462655616	1.138528842	
22-Mar-12	6.454905137	2.777268886	5.6359858	3.189229514	3.753325487	4.18573229	5.834751398
28-Mar-12	1.918983804	5.231203282	2.61309091	4.787618497	5.826370313	1.922283836	2.573731878
03-Apr-12	3.045402391	3.307787708	3.4488603	3.170638572	3.811964855	2.573995817	3.22126159
09-Apr-12	0.941439325	2.047453399	10.8485745	1.60056279	2.132319867	1.151192814	
15-Apr-12		3.519661515	5.57184897	3.605763082	3.397545234	3.35441436	1.611375803
21-Apr-12	1.030344311	1.93862666	1.52259724	1.152826381	1.944995349	0.689912255	1.209934408
27-Apr-12		1.684929467	1.47584981	1.425915235	1.412206917	0.880561438	
03-May-12	2.12537812	2.255696559	2.48198518	2.549552363	4.205457338	2.365184579	3.125373689
09-May-12	1.754407719	1.535714885	2.70218041	1.518904571	1.452212836	1.417228239	2.146373594
15-May-12	2.783064278		3.04233789	2.931033298	4.77297342	2.075823109	3.459777596
21-May-12	1.644080605	2.314629975	1.87025778	2.225115794	2.667644703	1.742253031	
27-May-12	3.357030927	4.587598118	3.19175032	4.30595976	5.887329794	4.752431407	5.761840884
02-Jun-12	1.646048271	2.55342308	2.16073697	2.042324711	2.393649788	1.693413054	2.104392906
08-Jun-12	4.353706562	3.514850161	5.11718032	2.684610373	4.90596688	2.324750139	
14-Jun-12	3.594989325		3.37791442	2.574819324	2.92498645	1.532871584	1.944713771
20-Jun-12	3.61328824	5.617877942	3.60952216	5.071193255	6.598597778	4.402938341	4.443513586
26-Jun-12	2.039733535	1.389421124	2.79961881	1.531801699	1.444141321	0.982562801	1.546532919
02-Jul-12	3.901256776	4.588839337	5.32063836	4.430018459	5.029865844	3.53204029	
08-Jul-12	2.655290243	3.004799722	3.33330288	3.289833215	3.888750414	2.609903785	2.985400732
14-Jul-12	1.871768297	1.299207771	3.75168054	1.134797379	1.711325096	1.041949508	1.247421584
20-Jul-12	3.169706423	1.943634383	3.90724694	2.040953997	2.030489851	2.046116587	
26-Jul-12	2.235526669		2.40699623	2.585548306	2.775492835	2.129262454	1.804976547
01-Aug-12	3.899672334	3.488898541	5.52149185	3.511174106	3.687196128	3.289343495	3.691015462
07-Aug-12	3.109424069	2.439680158	4.55539553	3.076131163	3.474869896	1.874621571	2.316379382
13-Aug-12	3.608454946	2.888933981	3.33254685	2.904079564	4.04936922	2.234712057	
19-Aug-12	4.601150284		4.89445851	2.215165366	2.757180019	2.562229732	3.259695024

25-Aug-12	5.315770782	4.67599101	4.59639376	4.134512114	4.544836109	2.941201553	4.896075589
31-Aug-12	1.931277621	1.439766871	3.07229951	1.625309489	2.388297735	2.015995136	
06-Sep-12	3.977073268	3.315256308	4.79678298	2.18195868	2.756359001	2.912024121	3.208775109
12-Sep-12	2.93717947	3.794066522	3.58729849	3.322177247	4.792588957	2.510225773	3.265129063
18-Sep-12	1.172794959		5.05453669	1.580461105	1.696138464	1.114433981	1.362658196
24-Sep-12	1.579496391		2.27529871	2.04519011	3.628084743	1.12778409	
30-Sep-12	4.761343091		2.1948455	3.658088993	4.778093335	3.23060592	6.511520953
06-Oct-12	1.321480808	1.399386128	2.77129738	1.232980057	1.573113668	1.287778933	1.114449375
12-Oct-12	3.400753563	3.655941963	1.86665458		4.394933554	1.594106095	
18-Oct-12	1.415281407	1.627120051	1.73524107	1.9484847	1.989993944	1.685890626	1.427622834
24-Oct-12		3.777819281	4.10635987	3.830330905	4.849886035	4.222378928	3.50898929
30-Oct-12	0.519854662	1.427295393		1.528265241	1.653823654	0.68624236	0.799422246
05-Nov-12	10.79672365	3.979075421	2.53992974	3.016486383	4.393356648	3.294661666	
11-Nov-12	3.090311609	0.702360629	2.1210225	3.227951164	3.190378586	3.503898492	3.135361168
17-Nov-12	12.31435645	5.872961717	7.7851444	5.059769398	6.490661585	3.310177943	6.030745274
23-Nov-12	1.373092736	1.314226793	3.92282587	1.399185653	1.731615516	1.043183155	1.074271512
29-Nov-12	3.454502877	5.799733361	3.20651963	4.182431393	9.179238201	3.177137091	4.888373796
05-Dec-12	1.450573556	3.217021925	1.60082558	2.521120675	2.648930654	1.098520259	1.531598486
11-Dec-12	1.048229833	1.897689214	1.4349773	1.483210107	2.113564785	1.047207167	1.433447441
17-Dec-12	2.256272618	3.108905655	2.39240792	2.585590211	2.048797456	1.534841905	1.801989956
23-Dec-12	3.122242479	3.824659318	2.10120845	2.657090375	3.690681534	2.471128662	3.071943388
29-Dec-12	3.09855689	1.751629271	2.86758795	1.472662801	2.018008302	1.974702625	2.053397981
Annual Average	2.98566346	2.825046579	3.32029037	2.601923805	3.286002345	2.127470616	2.732645472

Indiana Met One Speciation Sulfate Conc.

NOTE: Indpls. Washington Park runs on 1/3 alternate schedule but only 1/6 sample data is shown

Sample Date	Elkhart Prairie Street (ug/m^3) Speciation Met 1	Evansville Buena Vista Road (ug/m^3) Speciation Met 1	Gary Iitri (ug/m^3) Speciation Met 1	Jasper Post Office (ug/m^3) Speciation Met 1	Jeffersonville Walnut Street (ug/m^3) Speciation Met 1	Mechanicsburg (ug/m^3) Speciation Met 1	Indpls. Washington Park (ug/m^3) Speciation Met 1
04-Jan-12	0.829094151	0.692227672	2.31505531	0.84893905	1.797784679	0.8150617	0.802371081
10-Jan-12	0.753709702	2.683300186	1.04549339	2.27167682	2.699786481	1.083758779	1.120417742
16-Jan-12	2.039192312	1.489543272	1.55562306	1.930694631	1.443543755	1.607992655	
22-Jan-12	5.643474885	4.487521182	5.25588527	4.727408143	4.596196416	4.482633099	5.002744411
28-Jan-12	0.853178987	1.108875504	0.80032682	1.841156759	2.059129214	1.66874562	1.678609164
03-Feb-12	5.066260049	1.973412891	6.09775656	1.958173315	1.360571185	2.860962888	
09-Feb-12	2.144588696	2.472064689	2.05895228	2.659433729	2.954693508	2.610422862	2.886297793
15-Feb-12	2.744455382	2.945879098	2.70999535	2.966463604	2.247014485	2.973402197	2.614725346
21-Feb-12	2.018519605		1.72849525	1.800697225	2.222883979	2.11176241	
27-Feb-12	1.981770014	1.200386582	2.15603698	1.495557537	1.521830939	1.254644185	
04-Mar-12	2.55265986	1.556854272	2.86293073	1.430830752	1.87491158	2.115556932	2.307982913
10-Mar-12	1.384803896	1.544076064	1.40960652	1.25879168	1.079850646	1.357337877	1.273568438
16-Mar-12	2.846221541	2.05788523	2.67930223	1.401348239	1.143193385	1.285549962	
22-Mar-12	2.675252142	1.935195482	3.12571193	1.810065504	2.102398248	2.561609681	2.388676425
28-Mar-12	1.727210665	2.801254388	1.79745251	2.710571465	2.916001805	1.611289758	1.721013653
03-Apr-12	3.508608937	4.315072886	2.91168156	3.729278064	3.761117905	3.978006656	3.893782329
09-Apr-12	1.078223894	1.154902229	3.4351043	1.132144922	1.50697105	1.268250798	
15-Apr-12	4.035670568	3.593175369	3.72225433	3.274442383	3.152600567	3.399261434	3.394237585
21-Apr-12	1.045124987	3.566446798	1.01620497	1.399880989	2.491974241	1.541091153	1.265413183
27-Apr-12	0.984766276	1.402266037	1.28401296	1.519802394	1.874512635	1.127851027	
03-May-12	1.969192984	1.304177414	1.95125941	1.696477893	2.369331566	2.310226056	2.393408974
09-May-12	1.006423443	1.157473174	1.24766722	1.52938726	1.352847272	1.252912629	1.128209835
15-May-12	1.634313054	4.23478741	1.55083574	4.187938416	7.528223162	1.929330935	2.051956511
21-May-12	1.47503719	2.813691005	0.57096773	2.905534682	3.071068519	1.754176474	
27-May-12	2.788650974	2.965537024	2.92791044	3.562301477	4.943492879	4.698936115	4.052878039
02-Jun-12	1.337928123	2.207800835	1.41671615	1.95072994	2.681686623	1.623191994	1.61669176
08-Jun-12	1.744262384	3.773101642	2.02782126	1.986527778	3.290784941	1.459111564	
14-Jun-12	1.570984012	4.013059567	1.44872059	3.184411081	2.675539125	1.201139342	1.412156231
20-Jun-12	2.352626083	2.695035309	1.69895829	4.250192645	3.865064169	3.304405575	3.884285199
26-Jun-12	0.599426837	0.901365182	1.99115053	1.101081932	0.379585826	1.006281569	0.850649511
02-Jul-12	3.626881372	0.539858534	3.75700196	3.84878074	5.042561133	3.708523056	
08-Jul-12	0.645873612	5.406103943	0.40363435	4.869657495	5.304996381	2.740818472	2.144590862
14-Jul-12	3.30793003	2.178074938	5.4732005		1.800917935	2.536105913	2.121626494
20-Jul-12	1.434604246	3.843311301	1.81452149	3.442761193	2.990223985	2.872089695	
26-Jul-12	2.609044747	2.87610985	1.8992183	2.399722739	3.856625077	1.897200217	1.758834964
01-Aug-12	0.702205095	2.825309502	1.62362523	2.796428313	3.484542221	0.71780207	0.85294245
07-Aug-12	1.794921384	2.350227577	1.79504592	4.49718589	5.160286075	2.084873065	1.811816637
13-Aug-12	1.388054755	2.687792951	1.81415885		3.282364872	2.191403495	
19-Aug-12	1.453658688	1.923024185	2.99325382		1.661903474	1.258495001	1.433117347

25-Aug-12	5.320092889	4.014367187		4.289487728	4.659820029	3.964789601	4.437669034
31-Aug-12	2.788714058	2.444082602	2.61578259	2.580747192	2.27870422	2.58240155	
06-Sep-12	1.92132852	4.750453466	1.79615545	6.265922207	7.854054626	3.35130203	3.489799743
12-Sep-12	3.834756601	3.34244117	2.7553622	3.482675751	3.768498453	2.654663605	2.754908351
18-Sep-12	0.427167751	1.493484895	1.49035493	1.112005778	1.49006991	1.295264408	1.455140594
24-Sep-12	0.583875	1.599137193	0.74959995	1.536261364	1.652834176	0.631918317	
30-Sep-12	0.715582737	2.227286532	0.74816366	2.633143137	4.314208369	1.383630157	1.828834604
06-Oct-12	1.029914121	0.620860787	1.30795455	0.799164945	0.491486738	0.697590078	0.507438641
12-Oct-12	0.354069384		0.56552366	2.133924521	2.447508252	0.772085182	
18-Oct-12	0.889657859	0.733504798	0.37458398	0.768966887	1.115634425	0.798493904	
24-Oct-12	2.068984327	1.506868546	2.35859938	2.2712433	2.864779245	1.945281356	2.148655454
30-Oct-12	0.289653079	0.756395313		0.729995875	0.99779725	0.295988846	0.834101691
05-Nov-12	1.138817526	2.515167907	1.23631554	1.762349258	2.060929818	1.361939767	
11-Nov-12	2.09661321	2.374027105	1.48952388	2.376314717	2.016095714	1.907530201	2.015253354
17-Nov-12	2.716464131	2.758039049	2.93475031	2.758384921	2.78414299		2.347054724
23-Nov-12	1.557650826	1.599550005	2.78540406	1.990582361	2.050540987	1.599445445	1.617929285
29-Nov-12	2.262104424	1.950478351	2.06494165	2.801444639	3.33521582	2.931545586	2.764942419
05-Dec-12	0.34239474	0.479340027	0.69952978	0.604035405	0.664641307	0.509963914	0.474806738
11-Dec-12	1.334602091	1.629909405	1.34802801	1.978293659	2.685670983	2.526718589	2.344399649
17-Dec-12	3.621213171	2.512731266	3.59772809	3.068735935	2.273416013	3.918484166	3.961428018
23-Dec-12	1.905621908	4.462983488	1.42000491	1.304266102	1.811805355	1.589949659	1.471066753
29-Dec-12	3.458730638	4.179537724	5.24755128	4.342730817	3.777850212	4.629757389	5.076704826
Annual Average	1.967423189	2.400454712	2.13490522	2.447709538	2.736798637	2.060182644	2.213480426

Indiana Met One Speciation Sulfur Conc.

Indpls. Washington Park runs on 1/3 alternate schedule but only 1/6 sample data is shown

e Date	Elkhart Prairie Street (ug/m^3) Speciation Met 1	Evansville Buena Vista Road (ug/m^3) Speciation Met 1	Gary Iitri (ug/m^3) Speciation Met 1	Jasper Post Office (ug/m^3) Speciation Met 1	Jeffersonville Walnut Street (ug/m^3) Speciation Met 1	Mechanicsburg (ug/m^3) Speciation Met 1	Indpls. Washington Park (ug/m^3) Speciation Met 1
Jan-12	0.281658831	0.173632939	0.84413221	0.254982157	0.598936274	0.288453211	0.27491144
Jan-12	0.286023724	0.991992533	0.38720785	0.830922744	0.891357731	0.401753481	0.392775922
Jan-12	0.766956162	0.59157547	0.54290446	0.664324043	0.533463958	0.631557165	
Jan-12	1.844965411	1.484010375	1.83061578	1.283499013	1.427700785	1.58762041	1.473056416
Jan-12	0.341577853	0.339549664	0.25836668	0.565505977	0.657138784	0.522005996	0.468664789
Feb-12	1.698528989	0.660532705	1.91271738	0.625317088	0.468386808	0.96164807	
Feb-12	0.717275227	0.753500979	0.66567258	0.816818862	0.969545716	0.862518452	0.862290732
Feb-12	0.989701898		0.88640155	0.966727672	0.714659819	1.023255878	0.860896203
Feb-12	0.74005219		0.63766828	0.689893816	0.79237381	0.729732933	
Feb-12	0.588532784	0.381263121	0.69869025	0.449161766	0.542724158	0.453008362	
Mar-12	0.899979218	0.543877432	0.92072937	0.516326793	0.617933587	0.690248812	0.667770262
Mar-12	0.477826638	0.454258248	0.40739335	0.397616188	0.327842329	0.445908851	0.415748391
Mar-12	1.00917715	0.667850281	0.94466926	0.417313533	0.377919088	0.444824092	
Mar-12	0.89156545	0.721826992	1.09785141	0.624023036	0.70980063	0.838350585	0.801004335
Mar-12	0.610526491	0.9587072	0.57120555	0.950392603	1.012682698	0.555470019	0.564297747
Apr-12	1.222459285	1.461361908	1.0071964	1.338200898	1.322348819	1.297182619	1.229693081
Apr-12	0.356626762	0.383329316	1.08191839	0.425719219	0.46657314	0.404272279	
Apr-12	1.49737794	1.154366433	1.23030617	1.164244633	1.027941412	1.156789081	1.225207049
Apr-12	0.290718033	1.084954929	0.34068863	0.520835668	0.766655705	0.507604892	0.295054531
Apr-12	0.307733827	0.432370812	0.40776159	0.510961611	0.558833522	0.348100756	
May-12	0.678442118	0.483240027	0.70937118	0.67075314	0.935215698	0.836720203	0.920361322
May-12	0.37715584	0.389910215	0.42530493	0.500279151	0.447173131	0.413449786	0.355947667
May-12	0.569590078	1.39074619	0.58690488	1.641083754	2.33937397	0.754619593	0.723670094
May-12	0.504991825	1.009786397	0.22884228	1.067451944	1.028585632	0.729236257	
May-12	1.036786488	1.261073721	1.05445343	1.511153173	1.783757095	1.947377691	1.573768309
Jun-12	0.406177602	0.766292026	0.495653	0.681162184	0.844461092	0.56174139	0.524029589
Jun-12	0.641500312	1.323282867	0.68632515	0.726542693	1.161114319	0.557979964	
Jun-12	0.540562715	1.440891192	0.49046437	1.176159819	0.848654434	0.381944548	0.486689145
Jun-12	1.057370082	1.278985881	0.6875008	1.785371106	1.713196662	1.670447515	1.614897409
Jun-12	0.18049911	0.308910942	0.6903138	0.359482124	0.700729945	0.362085401	0.307537175
Jul-12	1.48682036	1.546680952	1.55539049	1.643129374	2.196779461	1.452562789	
Jul-12	0.316152233	1.977604297	0.20981168	1.798802192	1.840333036	0.545707143	0.839860448
Jul-12	1.278086992	0.842742369	2.1307329		0.737472879	0.952502548	0.787050831
Jul-12	0.605246387	1.432053303	0.68128266	1.26672255	1.022860243	0.902616738	
Jul-12	1.033416851	0.902590707	0.73115101	0.955987811	1.39940322	0.749710812	0.655018943
Aug-12	0.250130536	1.10278939	0.60423439	1.040890996	1.240619087	0.266552852	0.292475869
Aug-12	0.556798872	0.85277442	0.67092843	1.70580106	1.80901587	0.765943225	0.617122139
Aug-12	0.658898742	1.227853317	0.69744628		1.332715859	0.951033058	
Aug-12	0.582806795	0.723485989	1.06003578			0.495759921	0.475605209
Aug-12	2.028551865	1.610093849	1.72906086	1.74205475	1.770719327	1.599835616	1.759104459
Aug-12	1.016547953	0.852646651	1.06226615	0.909187373	0.820391994	1.041493347	
Sep-12	0.684053788	1.760105268	0.60612123	2.260078767	2.788910669	1.285303842	1.298495685
Sep-12	1.051421404	1.386815804	1.12248106	1.390395225	1.404736835	1.077130567	1.13188065

18-Sep-12	0.152263708	0.529857874	0.59387094	0.476760812	0.535057329	0.488764026	0.4950
24-Sep-12	0.22957744	0.592922014	0.19677468	0.549864937	0.601082796	0.273507214	
30-Sep-12	0.33924729	0.903926841	0.29520841	1.049402188	1.522674069	0.555896018	0.6715
06-Oct-12	0.375034898	0.239681563	0.49248476	0.283315897	0.189351929	0.27049356	0.2037
12-Oct-12	0.141224573		0.20631762	0.673725693	0.855965619	0.322905491	
18-Oct-12	0.266753536	0.212709919	0.14205994	0.243713825	0.370040449	0.301413731	0.2309
24-Oct-12	0.828124708	0.548936503		0.836266375	0.964707115	0.730461156	0.7424
30-Oct-12	0.121908007	0.278191227	0.88885786	0.282324546	0.369857324	0.111749204	0.2871
05-Nov-12	0.460360578		0.447211	0.599482838	0.693643189	0.564765478	
11-Nov-12	0.796378408	0.908378095	0.50445325	0.799855491	0.665225717	0.689908426	0.6958
17-Nov-12		0.994723524	1.20582765	0.85789528	1.026064499		0.8181
23-Nov-12	0.533528162	0.557123808	0.94799892	0.712733576	0.700654553	0.597992198	0.5566
29-Nov-12	0.832288964	0.785152559	0.72863171	0.909644059	1.236182142	0.988983845	0.8904
05-Dec-12	0.133942993	0.198642916	0.20483637	0.225772765	0.232170012	0.182530265	0.1561
11-Dec-12	0.512921987	0.542605804	0.50714339	0.668852198	0.955547773	0.937068728	0.916
17-Dec-12	1.295671153	0.97904408	1.29451167	0.963655419	0.806347631	1.366347583	1.5810
23-Dec-12	0.561494016	0.701681973	0.57452881	0.420145523	0.519355838	0.54506633	0.5077
29-Dec-12	1.206005644	1.361322821	1.68593566	1.529297848	1.277762602	1.43567693	1.7439
Annual Average	0.702466648	0.867459976	0.77511378	0.87806872	0.974545497	0.746926516	0.7642

Indiana Met One Speciation Nitrate Conc.

NOTE: Indpls. Washington Park runs on 1/3 alternate schedule but only 1/6 sample data is shown

Sample Date	Elkhart Prairie Street (ug/m^3) Speciation Met 1	Evansville Buena Vista Road (ug/m^3) Speciation Met 1	Gary Iitri (ug/m^3) Speciation Met 1	Jasper Post Office (ug/m^3) Speciation Met 1	Jeffersonville Walnut Street (ug/m^3) Speciation Met 1	Mechanicsburg (ug/m^3) Speciation Met 1	Indpls. Washington Park (ug/m^3) Speciation Met 1
04-Jan-12	2.655936121	1.294908622	2.10909775	1.711404959	1.365445652	1.913862299	1.790026042
10-Jan-12	3.949609126	3.369270069	4.10888071	3.97160635	3.642448621	4.548463902	4.618291361
16-Jan-12	2.977039934	0.548383249	2.02585181	0.817399141	0.803137204	1.322042257	
22-Jan-12	3.646893132	1.804248295	2.38999664	1.359829446	1.554537754	1.263113392	1.580046616
28-Jan-12	1.689657727	1.972078379	1.34212675	2.257106944	2.027902833	2.965678844	2.910870271
03-Feb-12	10.08998892	1.517142636	7.83404992	2.145575393	1.938859178	6.038017446	
09-Feb-12	4.898772007	2.30945386	5.58752456	2.775054667	1.850844015	2.558859201	2.631456326
15-Feb-12	5.57213992	4.155230375	5.88499173	3.794741353	2.654361355	2.755773754	3.765338869
21-Feb-12	2.442275651		2.29481065	0.820854571	0.712413695	1.274415202	
27-Feb-12	2.650049907	1.165858382	2.55478904	1.390881152	0.694016177	1.453083041	
04-Mar-12	2.399388665	1.914865947	2.30648911	1.590006712	1.46387451	1.452690461	1.537645313
10-Mar-12	1.782810476	1.537743644	1.76277288	1.518891814	1.477329974	1.17733607	1.486356094
16-Mar-12	2.119428248	0.878888631	1.62081457	0.679449034	0.753026691	1.725608777	
22-Mar-12	1.534208475	0.551039303	2.12609886	0.518275222	0.508773828	1.405125129	0.756320482
28-Mar-12	0.802730487	0.989724344	0.71646784	1.382983488	0.607226921	0.581806227	0.527194745
03-Apr-12	4.294644512	1.334997425	4.88456625	0.990360711	0.72953225	1.178303581	1.225121844
09-Apr-12	0.515639882	0.43382881	0.77017322	0.403049133	0.530723501	0.507010707	
15-Apr-12	1.602415696	0.64606052	1.08027403	0.452793496	0.483181537	0.729907808	0.659159025
21-Apr-12	0.399793578	1.691939566	0.14081372	1.596927922	1.692274159	1.177855115	1.106795448
27-Apr-12	0.758437211	0.55521692	0.28354229	0.438403931	0.398428571	1.090363665	
03-May-12	0.837846929	0.385302311	0.52451531	0.502764867	0.569590497	0.515897528	0.467182155
09-May-12	0.490240211	0.290162763	0.56777534	0.366566436	0.258799629	0.366324485	0.465456488
15-May-12	0.938478518	1.285550568	0.69585741	1.799388797	1.774941735	0.585440391	0.79558863
21-May-12	0.754920196	0.718085046	0.28933196	1.4101827	0.590012116	1.068207391	
27-May-12	0.515496291	0.421538521	0.61529965	0.516774318	0.57159485	0.763707625	0.596123043
02-Jun-12	0.731021265	0.699772118	0.95380357	0.928312448	0.652330202	1.327317652	1.06131123
08-Jun-12	0.448313467	0.510922982	0.38143317	0.568092214	0.965011088	0.289828502	
14-Jun-12	0.796596441	0.493859464	0.48383074	0.698461995	0.393704965	0.31241591	0.236334331
20-Jun-12	0.416957508	0.324726804	0.41476438	0.469979111	0.782288166	0.350187196	0.285652914
26-Jun-12	0.284428638	0.160185529	0.35115672	0.348830358	0.075940788	0.176221524	0.153285641
02-Jul-12	1.394026362	0.328690992	0.8596957	0.6673587	0.595748298	0.718590519	
08-Jul-12	0.162097645	0.608963666	0.14202783	0.70514299	0.910616275	0.440072158	0.479337937
14-Jul-12	0.413351294	0.403476466	1.74416916		0.37230036	0.646265378	0.216889164
20-Jul-12	0.469012506	0.634554432	0.40747887	1.257858221	0.56858453	1.550514494	
26-Jul-12	0.46670198	0.334323878	0.49441636	0.486299824	0.352334502	0.3423239	0.29396344
01-Aug-12	0.313597272	0.455221036	0.31840219	0.989371903	0.491389318	0.574015503	0.339919554
07-Aug-12	0.888997319	0.334937185	0.56448684	0.936334519	0.571825111	0.316495356	0.30135643
13-Aug-12	0.991762042	0.536020303	1.52194499		0.71137221	0.318868182	

19-Aug-12	0.534789001	0.233181467	0.45747447		0.290320295	0.47771905	0.397404568
25-Aug-12	1.099740427	0.46929874		0.467076415	0.595119379	0.336729141	0.587948698
31-Aug-12	0.59295321	0.445862674	0.76333668	0.501835772	0.475244506	0.651697416	
06-Sep-12	1.024438886	1.261311848	0.80126726	1.262556267	1.633816863	1.350337935	1.381444216
12-Sep-12	1.466240976	0.438528744	0.60869321	0.634765665	0.697226147	0.31183882	0.542049995
18-Sep-12	0.146520033	0.487665223	0.27416563	0.65134286	0.720770302	0.410720151	0.718880404
24-Sep-12	0.555501029	0.477681481	0.71787061	0.561146178	0.594311519	0.322483498	
30-Sep-12	0.936187528	0.699216252	0.25687636	0.983871734	1.185074475	1.2939671	1.486779128
06-Oct-12	0.776499537	0.571159506	0.86900336	0.968342543	0.623647177	0.872883027	0.616742034
12-Oct-12	0.441121062		0.28809729	1.869988915	1.319407169	0.708297389	
18-Oct-12	0.416215812	0.357833815	0.28001809	0.359805292	0.289345435	0.282620364	
24-Oct-12	1.185479738	0.44274241	0.79420547	0.474803649	0.567163452	0.480815212	0.515799453
30-Oct-12	0.127526348	0.736550176		0.721819049	0.664597808	0.114706961	0.485453538
05-Nov-12	2.757503093	4.156410932	1.26784699	2.572366522	3.348774788	3.487900351	
11-Nov-12	0.843755921	0.297661806	0.48467716	0.553322762	0.371092108	0.423003098	0.500285088
17-Nov-12	9.17049062	5.375033529	10.4555061	7.096502429	4.474564263		7.988735416
23-Nov-12	1.127819731	1.223743678	1.00080991	1.277188306	1.068091575	1.276806227	1.318248352
29-Nov-12	7.709527006	3.466125515	6.68716746	5.758502734	5.276720622	7.337238115	6.072833092
05-Dec-12	0.659288656	1.398732191	0.82394944	1.615471976	1.548730101	1.088314259	1.315507958
11-Dec-12	2.682745957	1.045029682	3.19336076	1.72953785	2.494231503	2.326712677	2.125425872
17-Dec-12	5.802749204	4.033382687	6.40896119	4.148762517	1.599512957	4.963524009	5.809074667
23-Dec-12	6.20588649	2.831985036	4.97944947	1.275103737	1.352195109	4.758884242	4.824294845
29-Dec-12	8.879443928	3.445069573	6.53902613	3.158941186	2.202549809	7.236740647	5.371729008
Annual Average	2.020297209	1.211718305	1.88315738	1.412247745	1.155561155	1.471599171	1.644219539

Indiana Met One Speciation Ammonium Conc.

NOTE: Indpls. Washington Park runs on 1/3 alternate schedule but only 1/6 sample data is shown

Sample Date	Elkhart Prairie Street (ug/m^3) Speciation Met 1	Evansville Buena Vista Road (ug/m^3) Speciation Met 1	Gary Iitri (ug/m^3) Speciation Met 1	Jasper Post Office (ug/m^3) Speciation Met 1	Jeffersonville Walnut Street (ug/m^3) Speciation Met 1	Mechanicsburg (ug/m^3) Speciation Met 1	Indpls
04-Jan-12	0.710072345	0.220803304	1.3973457	0.384071539	0.830186594	0.541220312	
10-Jan-12	0.832175044	1.533296828	1.4813758	1.555543366	1.485950119	1.511576121	
16-Jan-12	1.103514049	0.303013787	0.65771244	0.543537033	0.427050315	0.39507086	
22-Jan-12	2.425683239	0.985945185	2.00481189	1.657358345	1.926150191	1.335843737	
28-Jan-12	0.604365255	0.637102678	0.39877915	0.999028178	1.0703001	1.286196414	
03-Feb-12	4.630531849	0.856679224	3.70604094	0.761093427	0.810202096	2.556054506	
09-Feb-12	1.99641743	1.367843857	2.18243098	1.628175864	1.481462942	1.644156599	
15-Feb-12	2.263220674	1.655190299	2.15174496	1.594393134	1.248006725	1.79160683	
21-Feb-12	1.148056242		1.06714839	0.73171817	0.755394832	0.785987332	
27-Feb-12	1.216726572	0.594232259	1.22343176	0.6938994	0.664444645	0.654169077	
04-Mar-12	1.602447659	0.866724093	1.47034815	0.492080752	0.576260827	1.064201507	
10-Mar-12	0.778555567	0.531525762	0.62299689	0.516941379	0.468746512	0.622322129	
16-Mar-12	1.29548908	0.380708617	1.09607011	0.254981153	0.291973981	0.655637208	
22-Mar-12	1.169735986	0.414260367	1.40614223	0.425757169	0.399643998	0.99376931	
28-Mar-12	0.568899701	1.032615115	0.52640099	1.112980392	1.050536101	0.524357694	
03-Apr-12	2.165563478	1.482831204	2.0243801	1.355374099	1.163080237	1.439025126	
09-Apr-12	0.396573291	0.339992777	1.18721112	0.397446067	0.501759211	0.469081128	
15-Apr-12	1.593300247	0.871087607	1.359702	0.981434498	1.036851728	1.138764421	
21-Apr-12	0.266607824	1.44959969	0.16033886	0.553899473	1.129301827	0.599537525	
27-Apr-12	0.387223079	0.463801777	0.36937597	0.473657775	0.674730789	0.483435211	
03-May-12	0.508952268	0.167079808	0.43092374	0.360218747	0.340601256	0.604436148	
09-May-12	0.211356287	0.214890374	0.21783289	0.461133079	0.365404507	0.349784021	
15-May-12	0.54488332	1.597516254	0.5268603	1.804228131	2.707944725	0.696302672	
21-May-12	0.385194215	1.035763451	0.10713191	1.166744684	0.896657816	0.85209585	
27-May-12	0.926223344	0.794595167	0.94185664	1.266951157	1.553577511	1.625586038	
02-Jun-12	0.418731336	0.655721798	0.50940953	0.79674376	0.841275547	0.608014804	
08-Jun-12	0.556473168	1.255137828	0.73921347	0.425033302	0.931347602	0.419553074	
14-Jun-12	0.555002303	1.231103146	0.43593321	0.777121543	0.741407062	0.434526671	
20-Jun-12	0.678892842	0.768695103	0.25934806	1.371295131	1.149635862	0.980713879	
26-Jun-12	0.080472062	0.282117089	0.45148106	0.248762512	0.039231483	0.263716112	
02-Jul-12	1.43842215	0.034109462	1.23788334	1.464684336	1.727883564	1.430908033	
08-Jul-12	0.051526121	1.851607917	0.02849597	1.674164258	1.621637111	0.837810535	
14-Jul-12	0.985809271	0.472185952	2.07581019		0.412290822	0.746148299	
20-Jul-12	0.474142147	1.156742613	0.38883194	1.181316119	0.830913248	1.115423974	
26-Jul-12	0.754060728	0.37732491	0.37098233	0.657302509	0.882369045	0.455364336	
01-Aug-12	0.120436438	0.764870783	0.29879785	0.849575506	0.830078101	0.153505871	
07-Aug-12	0.564152748	0.573558851	0.47815428	1.430302257	1.50983263	0.515744582	
13-Aug-12	0.419393269	0.64898485	0.79630981		0.943056273	0.534795082	
19-Aug-12	0.434028322	0.512723288	0.89847277		0.557146465	0.37714514	
25-Aug-12	1.875408453	1.3564782		1.468931113	1.524191161	1.339684531	
31-Aug-12	0.849610172	0.474949148	0.74651468	0.532931568	0.485061385	0.70241447	
06-Sep-12	0.663448169	1.531475054	0.44594884	2.387898771	2.75963987	1.203370338	
12-Sep-12	1.484696009	1.050582361	0.92311519	1.296487819	1.2529082	0.833527758	

18-Sep-12	0.027115087	0.337937416	0.77743775	0.509508615	0.501953101	0.245466329
24-Sep-12	0.182805813	0.428735564	0.23675852	0.476277893	0.570422172	0.188489841
30-Sep-12	0.241794157	0.591623182	0.128365	0.902714293	1.361965084	0.636872228
06-Oct-12	0.406184562	0.204777445	0.53112423	0.309632049	0.141107699	0.246182377
12-Oct-12	0.036496809		0.12032448	0.66593344	0.776727953	0.264465225
18-Oct-12	0.155609454	0.122743525	0.04178501	0.104388539	0.248027525	0.150566432
24-Oct-12	0.960555269	0.353526694	0.79883944	0.69078489	0.901665721	0.596063331
30-Oct-12	0	0.365575831		0.364553424	0.353778174	0.009733295
05-Nov-12	0.879382216	1.827802232	0.37215043	1.137681148	1.5236258	1.185902986
11-Nov-12	0.860174784	0.66850639	0.3192194	0.75771942	0.749580929	0.700756066
17-Nov-12	3.385952896	2.128358609	4.10705743	2.849898718	1.946390381	
23-Nov-12	0.73944344	0.645755238	1.20163064	0.960965786	0.855340182	0.762505147
29-Nov-12	2.972337963	1.337371134	2.55442657	2.4491683	2.707070684	3.036424933
05-Dec-12	0.130196881	0.253553841	0.16664202	0.295851569	0.330432603	0.18435947
11-Dec-12	1.133621871	0.501559467	1.24544186	0.95102241	1.478756836	1.369641168
17-Dec-12	3.147969921	1.891220413	3.47658659	1.918671931	1.033592298	2.282444117
23-Dec-12	2.298726041	0.38747291	1.62429033	0.533734517	0.747502322	1.625878253
29-Dec-12	3.459124845	1.777301079	3.55237727	2.263647888	1.715992825	2.916179767
Annual Average	1.035310914	0.824055742	1.03487379	0.980644006	0.997377989	0.899575271

Pollutant	CR7 Project Potential Emissions (tpy)	Baseline Actual Emission (tpy)	Project Net Emissions (tpy)
NOx	679	5,989	(5,311)
PM10	240	458	(218)
PM2.5	240	327	(87)
SO2	19	10,593	(10,574)

Pollutant	Jefferson Co. 2011 Emissions Inventory
NOx	18,269
PM10	4,351
PM2.5	3,655
SO2	39,010

Pollutant	MC Controls Project Potential Emissions (tpy)	Baseline Actual Emission (tpy)	Project Net Emissions (tpy)
NOx	7,692	9,049	(1,357)
PM10	922	1,911	(989)
PM2.5	662	1,372	(710)
SO2	8,463	28,240	(19,777)

** For NOx, the permit application states a 15% reduction. Net emissions were calculated using 2013 NOx emissions and applying a 15% reduction.

Total Reduction

NOx	SO_2
5,311	10,574
1,357	19,777
6,668.	30,351

% of Jefferson Co. Emission

$$SO_2 = \frac{30,351}{39,010} = 77.8\%$$

$$NOx = \frac{6,668}{18,269} = 36.5\%$$

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.24

Witness: Gary H. Revlett

Q1.24. Please refer to the 2014 IRP, Volume I, pages 8-82 to 8-83.

a. Have the Companies conducted any assessment and/or modeling of the effect of lowering the ozone NAAQS to between .060 and .070 ppm on the attainment status of counties affected by emissions from LG&E and KU's existing coal-fired units?

b. Have the Companies conducted any assessment, study, and/or modeling of the impact on LG&E and KU's existing coal units of EPA lowering the ozone NAAQS to between .060 and .070 ppm? If so, please produce all such documents.

A1.24.

a. No.

b. No.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.25

Witness: Charles R. Schram

Q1.25. Have the Companies conducted any analysis comparing prior load forecasts to actual load over any of the last 10 years? If so, please produce all such analyses.

A1.25. Please see attached. Certain information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

Key Performance Indicators
Used Basis

December 2005

Total Utilities

REPORTING MONTH VS. BUDGET		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Electric								
Residential	GWh	1,160	1,104	913	247	27.1%	191	20.9%
Commercial	GWh	670	666	686	(16)	-2.4%	(21)	-3.0%
Industrial/Mine Power	GWh	742	742	789	(47)	-5.9%	(47)	-5.9%
Public Authority/Other	GWh	241	240	252	(11)	-4.2%	(11)	-4.5%
Total Retail	**GWh**	**2,814**	**2,752**	**2,640**	**174**	**6.6%**	**112**	**4.2%**
Municipal	GWh	177	173	165	12	7.4%	9	5.3%
Total Electric Sales Volume	**GWh**	**2,991**	**2,926**	**2,805**	**186**	**6.6%**	**121**	**4.3%**
Gas*								
Sales Volumes	BCF	6.16	5.55	6.22	(0.06)	-1.0%	(0.67)	-10.8%
Transportation Volumes	BCF	1.44	1.36	1.54	(0.09)	-6.1%	(0.18)	-11.6%
Total Gas Volumes	**BCF**	**7.60**	**6.91**	**7.75**	**(0.16)**	**-2.0%**	**(0.85)**	**-10.9%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	1,004		901	103	11.4%		
Louisville HDD 65	HDD	946		848	98	11.6%		
Lexington CDD 65	CDD	-		-	0	0.0%		
Louisville CDD 65	CDD	-		-	0	0.0%		

YTD VS. BUDGET		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	10,864	10,490	10,169	695	6.8%	321	3.2%
Commercial	GWh	8,149	8,096	8,208	(60)	-0.7%	(112)	-1.4%
Industrial/Mine Power	GWh	9,338	9,338	9,171	167	1.8%	167	1.8%
Public Authority/Other	GWh	2,918	2,914	2,980	(62)	-2.1%	(66)	-2.2%
Total Retail	**GWh**	**31,268**	**30,838**	**30,528**	**740**	**2.4%**	**310**	**1.0%**
Municipal	GWh	2,014	1,991	1,994	20	1.0%	(4)	-0.2%
Total Electric Sales Volume	**GWh**	**33,282**	**32,828**	**32,522**	**760**	**2.3%**	**306**	**0.9%**
Gas*								
Sales Volumes	BCF	33.08	33.56	36.35	(3.26)	-9.0%	(2.79)	-7.7%
Transportation Volumes	BCF	12.66	12.77	13.41	(0.75)	-5.6%	(0.64)	-4.8%
Total Gas Volumes	**BCF**	**45.75**	**46.33**	**49.76**	**(4.01)**	**-8.1%**	**(3.43)**	**-6.9%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	4,503		4,548	(45)	-1.0%		
Louisville HDD 65	HDD	4,056		4,094	(38)	-0.9%		
Lexington CDD 65	CDD	1,456		1,206	250	20.7%		
Louisville CDD 65	CDD	1,806		1,548	258	16.7%		

YTD VS. LAST YEAR		Actual 2005 YTD	WN Actual 2005 YTD	Actual !004 YTD	'N Actual !004 YTD	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	10,864	10,490	10,085	10,249	779	7.7%	241	2.4%
Commercial	GWh	8,149	8,096	7,857	7,862	292	3.7%	234	3.0%
Industrial/Mine Power	GWh	9,338	9,338	9,150	9,150	188	2.1%	187	2.0%
Public Authority/Other	GWh	2,918	2,914	2,844	2,845	73	2.6%	69	2.4%
Total Retail	GWh	**31,268**	**30,838**	**29,936**	**30,106**	**1,332**	**4.5%**	**732**	**2.4%**
Municipal	GWh	2,014	1,991	1,959	1,982	55	2.8%	8	0.4%
Total Electric Sales	GWh	**33,282**	**32,828**	**31,895**	**32,088**	**1,387**	**4.3%**	**740**	**2.3%**
Gas*									
Gas Sales	BCF	33.1	33.6	33.8	35.3	(0.68)	-2.0%	(1.77)	-5.0%
Transportation Volumes	BCF	12.7	12.8	13.8	14.2	(1.17)	-8.5%	(1.44)	-10.1%
Total Gas Volumes	**BCF**	**45.7**	**46.3**	**47.6**	**49.54**	**(1.85)**	**-3.9%**	**(3.21)**	**-6.5%**
*Does not include Intracompany sales									
Lexington HDD 65	HDD	4,503		4,381		122	2.8%		
Louisville HDD 65	HDD	4,056		3,836		220	5.7%		
Lexington CDD 65	CDD	1,456		995		461	46.3%		
Louisville CDD 65	CDD	1,806		1,594		212	13.3%		

Regulated Utilities | **December**
Key Performance Indicators | **2006**
Used Basis

ACTUAL to BUDGET — Total Utilities

CURRENT MONTH		Actual	Fcst	Var to Fcst
Residential	GWh	986	987	(1)
Other Retail	GWh	1,786	1,951	(165)
Retail Electric Sales Volume	GWh	2,772	2,938	(166)
Gas Sales & Transport	BCF	5.9	7.8	(1.9)
Lexington HDD 65	HDD	711	901	(190)
Louisville HDD 65	HDD	670	848	(178)
Lexington CDD 65	CDD	-	-	-
Louisville CDD 65	CDD	-	-	-

Weather: December 2006 was the third warmest December in both service territories since 1976. There were 190 fewer HDDs in Lexington and 178 fewer HDDs in Louisville than normal. As a result, Combined Company electricity sales were 120 GWh lower than they would have been if weather had been normal; 102 GWh of the weather adjustment was in the Residential class. Natural Gas volumes were 1.3 BCF lower than they would have been if weather had been normal.

Electric: The Residential class and all classes on Other Retail were below budget. In the Residential class, a negative variance in use per customer was offset by a positive variance in number of customers.

Gas: Largely as a result of weather, natural gas sales were 24.4% below forecast. Due to its size, the Residential class contributed 55% of the total variance. Generally speaking, however, all classes shared equally in the variance on a percentage basis. The Residential, Commercial, and Industrial classes were between 24 and 26% below forecast. The Public Authority class was 15.7% below forecast.

YTD		Actual	Budget	Var to Budget
Residential	GWh	10,330	10,698	(367)
Other Retail	GWh	22,309	22,969	(660)
Retail Electric Sales Volume	GWh	32,639	33,667	(1,027)
Gas Sales & Transport	BCF	40.9	50.1	(9.2)
Lexington HDD 65	HDD	4,172	4,548	(376)
Louisville HDD 65	HDD	3,684	4,094	(410)
Lexington CDD 65	CDD	1,129	1,206	(77)
Louisville CDD 65	CDD	1,468	1,548	(80)

Electric: Through December, Residential sales were 367 GWh below budget (-3.4%). Virtually all of this variance was the result of weather. The Residential weather adjustment through December was 377 GWh. Other Retail sales are 660 GWh below budget, with only 107 GWh attributable to mild weather (16%). Of the 553 GWh in Other Retail that is not weather-related, the Industrial class contributed 71% (393 GWh) and the Public Authority class contributed 21% (114 GWh).

Gas: Through December, natural gas sales are 18.3% below budget (-9.2 BCF). 36% of this variance (3.3 BCF) is weather-related. Of the remaining variance (5.9 BCF), the Residential class contributed 54% (3.2 BCF), the Commercial class contributed 15% (0.9 BCF), and the Industrial class contributed 30% (1.8 BCF).

ACTUAL to PRIOR YEAR — Total Utilities

YTD		Actual	Prior Year	Var to Prior Year
Residential	GWh	10,330	10,864	(534)
Other Retail	GWh	22,309	22,418	(109)
Retail Electric Sales Volume	GWh	32,639	33,282	(643)
Gas Sales & Transport	BCF	40.9	45.8	(4.8)
Lexington HDD 65	HDD	4,172	4,503	(331)
Louisville HDD 65	HDD	3,684	4,056	(372)
Lexington CDD 65	CDD	1,129	1,456	(327)
Louisville CDD 65	CDD	1,468	1,806	(338)

Electric: On a year-over-year, year-to-date basis (through December 2006), Residential sales have declined 534 GWh (-4.9%); Other Retail sales have declined 109 GWh (-0.5%). Under normal weather, both segments would have grown through December 2006. Residential sales would have grown 84 GWh (+0.8%); Other Retail sales would have grown 131 GWh (+0.6%).

Gas: Through December, natural gas volumes in 2006 are 4.8 BCF lower than they were in 2005 (-10.6%). Under normal weather, natural gas volumes would have declined 1.5 BCF (-3.4%).

FORECAST to BUDGET — Total Utilities

FULL YEAR		Forecast	Budget	Var to Budget
Residential	GWh	10,330	10,698	(367)
Other Retail	GWh	22,309	22,969	(660)
Retail Electric Sales Volume	GWh	32,639	33,667	(1,027)
Gas Sales & Transport	BCF	40.93	50.10	(9.17)
Lexington HDD 65	HDD	4,172	4,548	(376)
Louisville HDD 65	HDD	3,684	4,094	(410)
Lexington CDD 65	CDD	1,129	1,206	(77)
Louisville CDD 65	CDD	1,468	1,548	(80)

See Actual to Budget YTD section for explanations.

See Actual to Budget YTD section for explanations.

Regulated Utilities **December**
Key Performance Indicators **2007**
Used Basis

ACTUAL to BUDGET — **Total Utilities**

CURRENT MONTH		**Actual**	**Budget**	**Var to Budget**
Residential	GWh	1,021	1,004	17
Other Retail	GWh	1,772	1,985	(214)
Retail Electric Sales Volume	GWh	2,793	2,989	(197)
Gas Sales & Transport	BCF	6.36	7.48	(1.12)
Lexington HDD 65	HDD	765	894	(129)
Louisville HDD 65	HDD	712	845	(133)
Lexington CDD 65	CDD	-	-	-
Louisville CDD 65	CDD	-	-	-

Weather: December 2007 was warmer than normal in both service territories. There was a -129 and -133 deviation in HDDs in the KU and LG&E service territories, respectively. As a result, Combined Company electricity sales were 81 GWh lower than they would have been if weather had been normal; 68 GWh of the weather adjustment was in the Residential class. Natural gas volumes were 0.974 BCF lower than they would have been if weather had been normal.

Electric: Total retail sales were 6.6% or 197 GWh below budget in December on an actual basis. On a weather-normalized basis, total retail sales were 116 GWh below budget (-3.9%). 122 GWh of this variance occurred in the industrial class. Residential sales were above budget (84.99 GWh, or 8.5%); Commercial sales were below budget (-49.9 GWh, or -7.1%); Pub ic Authority sales were below budget (-23.5) GWh, or -9.7%); KU Major Accounts were 40.2 GWh below budget. [redacted] accounted for the majority of the negative variance (-30 GWh or -29%). LG&E Major Accounts were 30 GWh below budget. Contributors to the negative variance include [redacted] (-11 GWh), [redacted] (-4.7 GWh) and [redacted] (-4 GWh).

Gas: Gas volumes (sales plus transportation) were 14.9% below budget on an actual basis and 1.9% below on a weather-normalized basis. Weather-normalized Residential sales were above budget (0.07 BCF, or 1.9%); Commercial sales were below budget (-0.05 BCF, or -3.0%); Industrial sales were below budget (-0.06 BCF, or -26.4%); Public Authority sales were above budget (0.02 BCF, or 5.1%); Transportation volumes were below budget (-8.1%). Major Accounts were 0.13 BCF below budget including [redacted] (-0.090 BCF), [redacted] (-0.048 BCF), [redacted] (-0.046) and [redacted] (-0.010 BCF).

YTD		**Actual**	**Budget**	**Var to Budget**
Residential	GWh	11,333	10,960	373
Other Retail	GWh	22,968	23,364	(395)
Retail Electric Sales Volume	GWh	34,301	34,324	(23)
Gas Sales & Transport	BCF	43.47	46.95	(3.48)
Lexington HDD 65	HDD	4,272	4,529	(257)
Louisville HDD 65	HDD	3,791	4,079	(288)
Lexington CDD 65	CDD	1,636	1,225	411
Louisville CDD 65	CDD	2,213	1,570	643

Electric: Through December 2007, total electric sales were 0.1% or 23 GWh below budget on an actual basis and 1.8% or 618 GWh below budget on a weather-normalized basis. On a weather-normalized basis, Residential sales were below budget (-29 GWh, or -0.3%); Commercial sales were above budget (135.12 GWh, or 1.6%); Industrial sales were below budget (-637.5 GWh, or -6.4%); Public Authority sales were below budget (-45.6 GWh, or -1.5%); Major Accounts: LG&E Major Accounts were 161 GWh below budget through December.

Gas: Through December 2007, total gas volumes (sales plus transportation) were 7.4% below budget on an actual basis and 3.2% below budget on a weather-normalized basis. On a weather-normalized basis, Residential sales were below budget (-0.10 BCF, or -0.5%); Commercial sales were below budget (-0.15 BCF, or -1.6%); Industrial sales were below budget (-0.08 BCF, or -4.8%); Public Authority sales were above budget (0.02 BCF, or 1.2%); Transportation volumes were below budget (-1.22 BCF, or -9.1%). Major Accounts were 0.8 BCF below budget.

ACTUAL to PRIOR YEAR — **Total Utilities**

YTD		**Actual**	**Prior Year**	**Var to Prior Year**
Residential	GWh	11,333	10,330	1,003
Other Retail	GWh	22,968	22,309	659
Retail Electric Sales Volume	GWh	34,301	32,639	1,662
Gas Sales & Transport	BCF	43.47	40.94	2.53
Lexington HDD 65	HDD	4,272	4,172	100
Louisville HDD 65	HDD	3,791	3,684	107
Lexington CDD 65	CDD	1,636	1,129	507
Louisville CDD 65	CDD	2,213	1,468	745

Electric: Compared to the same period last year, total electricity sales were 1662 GWh higher through December on an actual basis (5.1%) and 643 GWh higher on a weather-normalized basis (1.9%). On a weather-normalized basis, Residential sales were 262 GWh higher (2.5%); Other Retail sales were 380 GWh higher (1.7%). Commercial sales were higher (335.78 GWh, or 4.1%); Industrial sales were lower (-121.7 GWh, or -1.3%);

Gas: Compared to the same period last year, total gas volumes (sales plus transportation) through December were 2.53 BCF higher on an actual basis (6.2%) and 1.38 BCF higher on a weather-normalized basis (3.1%). On a weather-normalized basis, Residential sales were higher (1.42 BCF, or 7.2%); Commercial sales were higher (0.21 BCF, or 2.4%); Industrial sales were lower (-0.03 BCF, or -1.8%); Transportation volumes were lower (-0.18 BCF, or -1.4%).

FORECAST to BUDGET — **Total Utilities**

FULL YEAR		**Forecast**	**Budget**	**Var to Budget**
Residential	GWh	11,333	10,960	373
Other Retail	GWh	22,968	23,364	(395)
Retail Electric Sales Volume	GWh	34,301	34,324	(23)
Gas Sales & Transport	BCF	43.47	46.95	(3.48)
Lexington HDD 65	HDD	4,272	4,529	(257)
Louisville HDD 65	HDD	3,791	4,079	(288)
Lexington CDD 65	CDD	1,636	1,225	411
Louisville CDD 65	CDD	2,213	1,570	643

Confidential Information Redacted

Regulated Utilities
Key Performance Indicators
Used Basis

December
2008

Total Utilities

REPOR ING MON H VS BUDGE					Actual Variance		W/N Variance	
Electric		**Actual**	**WN Actual**	**Budget**	**GWh/BCF**	**%**	**GWh/BCF**	**%**
Residential	GWh	1 098	1,09	1,027	71	6.9%	67	6.5%
Commercial	GWh	705	70	715	(10)	-1. %	(11)	-1.5%
Industr al/Mine Power	GWh	6 5	6 5	869	(22)	-25.8%	(22)	-25.8%
Public Authority/Other	GWh	2 9	2 9	250	(1)	-0.6%	(2)	-0.6%
otal Retail	**GWh**	**2 696**	**2 691**	**2 861**	**(165)**	**5 8%**	**(170)**	**5 9%**
Mun cipal	GWh	167	167	172	( )	-2.5%	(5)	-2.7%
otal Electric Sales Volume	**GWh**	**2 863**	**2 858**	**3 032**	**(169)**	**5 6%**	**(174)**	**5 8%**
Gas								
Sales Volumes	BCF	5.75	5.65	5.76	(0.01)	-0.2%	(0.11)	-1.8%
Transportation Volumes	BCF	1.16	1.15	1. 1	(0.25)	-17.7%	(0.26)	-18.5%
otal Gas Volumes	**BCF**	**6 91**	**6 80**	**7 17**	**(0 26)**	**3 6%**	**(0 37)**	**5 1%**
Lexington HDD 65	HDD	899		885	1	1.6%		
Louisville HDD 65	HDD	8 9		83	15	1.8%		
Lexington CDD 65	CDD	-		-	0	0.0%		
Louisville CDD 65	CDD	1		-	1	0.0%		

REPORTING MONTH VS. BUDGET

Weather: In December 2008, heating degree-days in the KU and LG&E service territories were only slightly above normal, being 1 and 15 HDD above, respectively. As a result, Combined Company e ectricity sales were only 5.5 GWh higher (0.2%) than they wou d have been if weather had been normal. Natural gas sales were 0.107 BCF higher (1.6%) than they wou d have been if weather had been normal.

Electric: Total sa es for the month of December 2008 were 169 GWh be ow budget (-5.6%). This was mostly driven by a -22 GWh variance in Industrial sales which was partially offset by a 71 GWh variance in Residential sa es. Commercial, Public Authority, and KU Municipal sales were also below budget. More than two-thirds of the positive Residential variance occurred in KU (9 GWh), driven by non-weather-related use-per-customer. More than two-thirds of the negative variance in Industrial sales (168 GWh) occurred in KU, as well. Most of the -56 GWh variance in LG&E industr al sales was driven by major accounts, which were 35 GWh below budget.

Gas: Natural gas volumes (sales plus transportation) were 0.26 BCF below budget (-3.6%), but if weather had been normal, they would have been even further be ow budget (-0. BCF, -5.1%).

					Actual Variance		W/N Variance	
Y D VS BUDGE		**Actual**	**WN Actual**	**Budget**	**GWh/BCF**	**%**	**GWh/BCF**	**%**
Residential	GWh	11 009	10,886	10,978	31	0.3%	(93)	-0.8%
Commercial	GWh	8, 37	8, 11	8,592	(155)	-1.8%	(181)	-2.1%
Industr al/Mine Power	GWh	8 8 6	8,8 5	10,060	(1,21)	-12.1%	(1,215)	-12.1%
Public Authority/Other	GWh	3 009	3,005	3,0	(35)	-1.2%	(39)	-1.3%
otal Retail	**GWh**	**31 302**	**31 147**	**32 675**	**(1 373)**	**4 2%**	**(1 528)**	**4 7%**
Mun cipal	GWh	1 971	1,968	2,056	(85)	- .1%	(88)	- .3%
otal Electric Sales Volume	**GWh**	**33 273**	**33 115**	**34 731**	**(1 458)**	**4 2%**	**(1 616)**	**4 7%**
Gas								
Sales Volumes	BCF	33.93	32.98	32.6	1.29	3.9%	0.3	1.0%
Transportation Volumes	BCF	11.30	11.17	12.51	(1.20)	-9 6%	(1 3)	-10 7%
otal Gas Volumes	**BCF**	**45 23**	**44 15**	**45 15**	**0 08**	**0 2%**	**(1 00)**	**2 2%**
Lexington HDD 65	HDD	786		,5 9	237	5.2%		
Louisville HDD 65	HDD	253		,08	169	.1%		
Lexington CDD 65	CDD	1 201		1,219	(18)	-1.5%		
Louisville CDD 65	CDD	1 602		1,578	2	1.5%		

YTD VS. BUDGET

Electric: For the year 2008, total e ectric sa es were .2% or 1, 58 GWh below budget on an actual basis and .7% or 1,616 GWh be ow budget on a weather-normalized basis. Industrial sales accounted for 75% of the negative variance and were 1,215 GWh below budget (-12.1%). KU Industr al sales were 898 GWh below budget, with major accounts contributing a l ttle more than ha f of that. LG&E Industr al sales were 317 GWh below budget, mostly caused by major accounts, which were 2 9 GWh below budget.

Gas: In 2008, natural gas volumes (sales plus transportation) were 0.2% above budget on an actual basis and 2.2% below on a weather-normalized basis. Weather-normalized Commercial and Residential volumes were above budget (0.35 BCF or 3.9% and 0.12 BCF or 0.6%, respectively), while all other classes were be ow budget. The largest negative variance, by far, was in Transportation volumes, which were 1.3 BCF be ow budget (-10.7%). Again, most of the variance was in [redacted] and the two [redacted] plants, wh ch were a combined 1.2 BCF below budget.

		Actual	WN Actual	Actual	WN Actual	Actual Variance		W/N Variance	
Y D VS LAS YEAR		**2008 Y D**	**2008 Y D**	**2007 Y D**	**2007 Y D**	**GWh/BCF**	**%**	**GWh/BCF**	**%**
Residential	GWh	11 009	10,886	11,333	10,980	(32)	-2.9%	(95)	-0.9%
Commercial	GWh	8, 37	8, 11	8,611	8, 38	(17)	-2.0%	(27)	-0.3%
Industr al/Mine Power	GWh	8 8 6	8,8 5	9,265	9,260	(19)	- .5%	(15)	- .5%
Public Authority/Other	GWh	3 009	3,005	3,033	3,013	(2)	-0.8%	(8)	-0.3%
otal Retail	GWh	**31 302**	**31 147**	**32 242**	**31 691**	**(941)**	**2 9%**	**(544)**	**1 7%**
Mun cipal	GWh	1 971	1,968	2,059	2,009	(87)	- .2%	(1)	-2.0%
otal Electric Sales	GWh	**33 273**	**33 115**	**34 301**	**33 700**	**(1 028)**	**3 0%**	**(585)**	**1 7%**
Gas									
Gas Sales	BCF	33.9	33.0	31.6	33.5	2.38	7.5%	(0.57)	-1.7%
Transportation Volumes	BCF	11.3	11.2	11.9	12.2	(0.61)	-5.2%	(1.07)	-8.8%
otal Gas Volumes	**BCF**	**45 2**	**44 1**	**43 5**	**45 8**	**1 76**	**4 1%**	**(1 64)**	**3 6%**

Y D VS LAS YEAR

Electric: 2008 Combined Company electric ty sa es were 1 028 GWh (-3.0%) lower than 2007 sales on an actual basis, and on a weather-normalized basis, sales were 585 GWh lower (-1.7%) in 2008. All classes declined from 2007 to 2008. Industrial sales accounted for 71% of the decline in weather-normalized sales. In KU, a 306 GWh decline in Industrial sales was offset by a 32 GWh increase in Mine Power sales, whi e LG&E Industrial sales were 1 1 GWh lower in 2008. The dec ine in KU Industrial was driven largely by the automobile industry and its supp iers: the two [redacted] plants fell a combined 6 GWh and [redacted] declined by 18 GWh. [redacted] also declined 19 GWh. In LG&E Industrial major accounts, [redacted] dec ined by 6 GWh; [redacted] declined 36 GWh, and [redacted] fell 33 GWh. The reductions in Residential and Commercial sales was driven by LG&E.

Gas: 2008 total natural gas volumes (sales plus transportation) were 1.76 BCF (.1%) higher than 2007 on an actual bas s and 1.6 BCF (3.6%) lower on a weather-norma ized basis. The increase in sales volumes was largely weather-related as 2008 had 12% more hea ing degree-days than 2007. Transportation volumes dec ined by 0.61 BCF from 2007 to 2008 (-5.2%). Large declines at [redacted] (-0.71 BCF or - 9.2%) and the two [redacted] plants (-0.33 BCF or -15.5%) were offset by increases at other major accounts. On a weather-normal zed basis, Transportation volumes explained the majority (65%) of t e o e all decli e

Regulated Utilities **December**
Key Performance Indicators **2009**
Used Basis

Total Utilities

REPORTING MONTH VS. BUDGET					Actual Variance		W/N Variance	
Electric		**Actual**	**WN Actual**	**Budget**	**GWh/BCF**	**%**	**GWh BCF**	**%**
Residential	GWh	1,180	1,157	1,084	96	8.9%	73	6.8%
Commercial	GWh	696	693	695	1	0.2%	(2)	-0.3%
Industrial/Mine Power	GWh	736	736	764	(28)	-3.7%	(28)	-3.7%
Public Au hor ty/Other	GWh	239	239	246	(6)	-2.5%	(7)	-2.7%
Total Retail	**GWh**	**2,852**	**2,825**	**2,788**	**64**	**2.3%**	**37**	**1.3%**
Municipal	GWh	169	168	178	(9)	-4 9%	(10)	-5 7%
Total Electric Sales Volume	**GWh**	**3,021**	**2,993**	**2,966**	**55**	**1.8%**	**26**	**0.9%**
Gas								
Sales Volumes	BCF	5.83	5.60	5.58	0.25	4.5%	0.02	0.3%
Transportation Volumes	BCF	1.36	1.34	1.32	0.04	3.2%	0.02	1.5%
Total Gas Volumes	**BCF**	**7.19**	**6.94**	**6.90**	**0.29**	**4.2%**	**0.04**	**0.6%**
Does not include Intracompany sales								
Lexington HDD 65	HDD	919		884	35	4.0%		
Louisvi le HDD 65	HDD	873		832	41	4.9%		

REPORTING MONTH VS. BUDGET

Weather December 2009 weather was colder than normal in both service territories. There were 35 more HDDs than normal in the KU service territory and 41 more HDDs than normal in the LG&E service territory. Combined Company electricity sales were 29 GWh higher than they would have been if weather had been normal.

Electric Total sales for the month of December 2009 were 55 GWh above budget (1.8%). On a weather-normalized basis, sales were 26 GWh above budget (0.9%). A rather large posi ive variance in the residential class offset smaller negative variances in other revenue classes.

Gas Natural gas volumes (sales plus transportation) were 0.29 BCF above budget (4.2%). On a weather-norma ized basis, volumes were 0.04 BCF above budget (0.6%). Weather-norma ized transportation volumes were 0 02 BCF above budget (1.5%); weather-norma ized sales volumes were 0.02 BCF above budget (0.3%).

					Actual Variance		W/N Variance	
YTD VS. BUDGET		**Actual**	**WN Actual**	**Budget**	**GWh/BCF**	**%**	**GWh BCF**	**%**
Residential	GWh	10,690	10,887	10,997	(307)	-2.8%	(109)	-1.0%
Commercial	GWh	8,136	8,237	8,613	(478)	-5.5%	(377)	-4.4%
Industrial/Mine Power	GWh	8,065	8,072	9,300	(1,235)	-13.3%	(1,228)	-13.2%
Public Au hor ty/Other	GWh	2 927	2 939	3 128	(201)	-6.4%	(189)	-6.0%
Total Retail	**GWh**	**29,818**	**30,135**	**32,037**	**(2,220)**	**6.9%**	**(1,902)**	**5.9%**
Municipal	GWh	1 848	1 858	2 108	(260)	-12.4%	(250)	-11.9%
Total Electric Sales Volume	**GWh**	**31,665**	**31,993**	**34,145**	**(2,480)**	**7.3%**	**(2,152)**	**6.3%**
Gas								
Sales Volumes	BCF	30.92	30.55	31.55	(0.62)	-2.0%	(1.00)	-3.2%
Transportation Volumes	BCF	10.62	10.59	11.56	(0.93)	-8.1%	(0.97)	-8.4%
Total Gas Volumes	**BCF**	**41.54**	**41.14**	**43.10**	**(1.56)**	**3.6%**	**(1.97)**	**4.6%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	4,635		4,527	108	2.4%		
Louisvi le HDD 65	HDD	4,132		4,068	64	1.6%		
Lexington CDD 65	CDD	1,031		1,203	(172)	-14.3%		
Louisvi le CDD 65	CDD	1,324		1,597	(273)	-17.1%		

YTD VS. BUDGET

Electric Total sales through December 2009 were 2,480 GWh below budget (-7.3%). On a weather-normalized basis, YTD sales were 2,152 GWh below budget (-6.3%). Industrial sales were primarily responsible for the negative variance.

Gas Total natural gas volumes (sales plus transportation) through December 2009 was 1.56 BCF below budget (-3.6%). On a weather-norma ized basis, YTD gas volumes were 1.97 BCF below budget (-4.6%). The weather-normalized variance was explained primarily by the transportation class, which were 0.97 BCF below budget (-8.4%) while sales volumes were 1.00 BCF below budget (-3.2%).

		Actual	WN Actual	Actual	WN Actual	Actual Variance		W/N Variance	
YTD VS. LAST YEAR		**2009 YTD**	**2009 YTD**	**2008 YTD**	**2008 YTD**	**GWh/BCF**	**%**	**GWh BCF**	**%**
Residential	GWh	10 690	10 887	11 009	10 849	(319)	-2.9%	39	0.4%
Commercial	GWh	8,136	8,237	8,434	8,416	(299)	-3.5%	(179)	-2.1%
Industrial/Mine Power	GWh	8,065	8,072	8,848	8,846	(783)	-8.9%	(774)	-8.8%
Public Au hor ty/Other	GWh	2 927	2 939	3 007	3 006	(80)	-2.7%	(67)	-2.2%
Total Retail	GWh	**29,818**	**30,135**	**31,299**	**31,117**	**(1,482)**	**4.7%**	**(982)**	**3.2%**
Municipal	GWh	1 848	1 858	1 963	1 963	(115)	-5.9%	(105)	-5.3%
Total Electric Sales	GWh	**31,665**	**31,993**	**33,262**	**33,080**	**(1,597)**	**4.8%**	**(1,086)**	**3.3%**
Gas									
Gas Sales	BCF	30.9	30.5	33.9	32.8	(3.01)	-8.9%	(2.28)	-7.0%
Transportation Volumes	BCF	10.6	10.6	11.3	11.2	(0.67)	-6.0%	(0.63)	-5.6%
Total Gas Volumes	**BCF**	**41.5**	**41.1**	**45.2**	**44.0**	**(3.68)**	**8.1%**	**(2.91)**	**6.6%**
Does not include Intracompany sales									
Lexington HDD 65	HDD	4,635		4,786		(151)	-3.2%		
Louisvi le HDD 65	HDD	4,132		4,253		(121)	-2.8%		
Lexington CDD 65	CDD	1,031		1,201		(170)	-14.2%		
Louisvi le CDD 65	CDD	1,324		1,602		(278)	-17.4%		

YTD VS. LAST YEAR

Electric Through December 2009, Combined Company electricity sales were 1,597 GWh (-4.8%) lower than the same period last year on an actual basis and 1,086 GWh lower (-3.3%) on a weather-normalized basis. While sales to all classes have declined on a year-over-year basis (except Residential, which has remained flat), industrial sales were primar ly responsible for the overall decline.

Gas Through December 2009, total natural gas volumes (sales plus transportation) were 3.68 BCF (-8.1%) lower than the same period last year on an actual basis and 2.91 BCF (-6.6%) lower on a weather-normalized basis. On a weather-normalized basis, sales volumes declined by 2.28 BCF (-7.0%) and transportation volumes declined by 0.63 BCF (-5.6%).

Confidential Information Redacted

Regulated Utilities
Key Performance Indicators
Used Basis

December 2010

Total Utilities

REPORTING MONTH VS. BUDGET		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Electric								
Residential	GWh	1,382	1,251	1,120	261	23.3%	131	11.7%
Commercial	GWh	757	730	686	71	10.4%	43	6.3%
Industrial/Mine Power	GWh	813	811	655	158	24.1%	156	23.8%
Public Author ty/Other	GWh	289	284	243	46	19.1%	41	17.0%
Total Retail	**GWh**	**3,241**	**3,076**	**2,705**	**536**	**19.8%**	**372**	**13.7%**
Municipal	GWh	185	184	167	18	10.7%	16	9.7%
Total Electric Sales Volume	**GWh**	**3,427**	**3,260**	**2,872**	**554**	**19.3%**	**388**	**13.5%**
Gas								
Sales Volumes	BCF	7.19	6.10	5.39	1.79	33.3%	0.70	13.1%
Transportation Volumes	BCF	1.48	1.38	1.19	0.29	24.8%	0.19	16.4%
Total Gas Volumes	**BCF**	**8.67**	**7.48**	**6.58**	**2.09**	**31.7%**	**0.90**	**13.7%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	1,157		937	220	23.4%		
Louisville HDD 65	HDD	1,065		879	186	21.1%		
Lexington CDD 65	CDD	-		-	0	0.0%		
Louisville CDD 65	CDD	-		-	0	0.0%		

REPORTING MONTH VS. BUDGET

Weather December 2010 weather was colder than normal in both service territories. There were 220 more HDDs than normal in the KU service terr tory and 186 more HDDs than normal in the LG&E service territory. Combined Company electricity sales were 166 GWh higher than they would have been f weather had been normal.

Electric Total sales for the month of December 2010 were 554 GWh above budget (19.3%). On a weather-normalized basis, sales were 388 GWh above budget (13.5%). The Industrial customer class continued its strength by recording a large positive variance of 156 GWh (23.8%). While not as large as the industrial variance, all other customer classes also experienced a positive variance in December. The residential class was the next largest above budget at 131 GWh (11.7%). The commercial class sales were 43 GWh above budget (6.3%), and pub ic authority sales were 41 GWh above budget (17.0%).
Within the industrial class, preliminary figures show a large increase in sales compared to budget to major customers [redacted] (25.3 GWh, 38.0%), [redacted] (8.1 GWh, 52.5%), and [redacted] (2.0 GWh, 35.3%), which helped drive the positive variance.

Gas Natural gas volumes (sales plus transportation) were 2.09 BCF above budget (31.7%). On a weather-normalized basis, volumes were 0.90 BCF above budget (13.7%). The weather-normalized variance was explained mostly by sales volumes, which were 0.70 BCF above budget (13.1%), while transportation volumes were 0.19 BCF above budget (16.4%).

YTD VS. BUDGET		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	11,774	10,898	10,965	809	7.4%	(67)	-0.6%
Commercial	GWh	8,363	8,082	8,348	15	0.2%	(266)	-3.2%
Industrial/Mine Power	GWh	9,061	9,024	7,760	1,301	16.8%	1,264	16.3%
Public Author ty/Other	GWh	3 076	3 038	2 962	114	3.8%	75	2.5%
Total Retail	**GWh**	**32,274**	**31,042**	**30,036**	**2,238**	**7.5%**	**1,006**	**3.3%**
Municipal	GWh	2 002	1 965	1 937	65	3.3%	28	1.4%
Total Electric Sales Volume	**GWh**	**34,276**	**33,007**	**31,973**	**2,303**	**7.2%**	**1,034**	**3.2%**
Gas								
Sales Volumes	BCF	32.81	31.31	31.21	1.60	5.1%	0.09	0.3%
Transportation Volumes	BCF	11.08	10.96	10.46	0.62	5.9%	0.49	4.7%
Total Gas Volumes	**BCF**	**43.89**	**42.27**	**41.68**	**2.21**	**5.3%**	**0.59**	**1.4%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	4,892		4,574	318	7.0%		
Louisville HDD 65	HDD	4,461		4,261	200	4.7%		
Lexington CDD 65	CDD	1,584		1,208	376	31.1%		
Louisville CDD 65	CDD	1,991		1,446	545	37.7%		

YTD VS. BUDGET

Electric Total sales through December 2010 were 2,303 GWh above budget (7.2%). On a weather-normalized basis, sales were 1,034 GWh above budget (3.2%). A large positive variance in the Industrial/Mine Power class of 1,264 GWh (16.3%) more than offsets the negative variance in the Commercial class (-3.2%). The only other class w th a negative variance was the residential class, which only had a slight negative variance of 67 GWh (-0.6%). Public Authority and Municipal had small variances of 2.5% and 1.4%, respectively.
Within the industrial class, preliminary figures show a large increase in sales compared to budget for major customers [redacted] (370.4 GWh, 51.5%), [redacted] (18.2 GWh, 39.1%), and [redacted] (15.7 GWh, 23.2%), which helped drive the positive variance. The variance to budget for [redacted] makes up 28.5% of the total industrial sales variance to budget.

Gas Total natural gas volumes (sales plus transportation) through December 2010 were 2.21 BCF (5.3%) above budget. On a weather-normalized basis, YTD gas volumes were 0.59 BCF (1.4%) above budget. The weather-normalized variance is explained mostly by transportation volumes, which were 0.49 BCF (4.7%) above budget, with sales volumes being 0.9 BCF (0.3%) above budget.

YTD VS. LAST YEAR		Actual 2010 YTD	WN Actual 2010 YTD	Actual 2009 YTD	WN Actual 2009 YTD	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	11,774	10,898	10,690	10,858	1,084	10.1%	40	0.4%
Commercial	GWh	8,363	8,082	8,136	8,179	228	2.8%	(97)	-1.2%
Industrial/Mine Power	GWh	9,061	9,024	8,065	8,070	996	12.4%	954	11.8%
Public Author ty/Other	GWh	3 076	3 038	2,927	2 934	149	5.1%	103	3.5%
Total Retail	GWh	**32,274**	**31,042**	**29,818**	**30,041**	**2,456**	**8.2%**	**1,001**	**3.3%**
Municipal	GWh	2,002	1,965	1,848	1,868	155	8.4%	97	5.2%
Total Electric Sales	GWh	**34,276**	**33,007**	**31,665**	**31,910**	**2,611**	**8.2%**	**1,098**	**3.4%**
Gas									
Gas Sales	BCF	32.8	31.3	31.0	31.6	1.83	5.9%	(0.34)	-1.1%
Transportation Volumes	BCF	11.1	11.0	10.6	10.7	0.46	4.3%	0.28	2.6%
Total Gas Volumes	**BCF**	**43.9**	**42.3**	**41.6**	**42.3**	**2.29**	**5.5%**	**(0.06)**	**0.1%**
*Does not include Intracompany sales									
Lexington HDD 65	HDD	4,892		4,635		257	5.5%		
Louisville HDD 65	HDD	4,461		4,132		329	8.0%		
Lexington CDD 65	CDD	1,584		1,031		553	53.6%		
Louisville CDD 65	CDD	1,991		1,324		667	50.4%		

YTD VS. LAST YEAR

Electric Through December 2010, Combined Company electric ty sales were 2,611 GWh (8.2%) above the same period last year on an actual basis and were 1,098 GWh (3.4%) higher than last year on a weather-normalized basis. The positive year-over-year variance of [redacted] is 370.4 GWh, which accounts for 38.8% of the total year-over-year weather normalized positive variance in industrial sales.

Gas Through December 2010, total natural gas volumes (sales plus transportation) were 2.29 BCF (5.5%) higher than the same period last year on an actual basis and 0.06 BCF (-0.1%) lower on a weather-normalized basis. On a weather-normalized basis, sales volumes decreased by 0.34 BCF (-1.1%) and transportation volumes increased by 0.28 BCF (2.6%).

Confidential Information Redacted

Key Performance Indicators
Used Basis

December
2011

Total Utilities

REPOR ING MON H VS BUDGE		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Electric								
Res dential	GWh	992	1,075	1,0 3	(50)	- .8%	32	3.1%
Commercial	GWh	609	623	680	(71)	-10. %	(57)	-8.3%
Industrial/Mine Power	GWh	732	732	703	29	.1%	29	.2%
Publ c Authority/Other	GWh	195	197	2 1	(7)	-19 3%	( )	-18 %
otal Retail	**GWh**	**2 528**	**2 627**	**2 667**	**(139)**	**5 2%**	**(40)**	**1 5%**
Municipal	GWh	157	157	168	(12)	-6.8%	(11)	-6.5%
otal Electric Sales Volume	**GWh**	**2 685**	**2 784**	**2 835**	**(150)**	**5 3%**	**(51)**	**1 8%**
Gas*								
Sales Volumes	BCF	.39	5.07	5.17	(0.78)	-15.0%	(0.10)	-1.9%
Transportat on Volumes	BCF	1.15	1.19	1.31	(0.16)	-12.6%	(0.12)	-8.9%
otal Gas Volumes	**BCF**	**5 54**	**6 27**	**6 48**	**(0 94)**	**14 5%**	**(0 21)**	**3 3%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	7 6		866	(120)	-13.9%		
Louisville HDD 65	HDD	685		811	(126)	-15.5%		
Lexington CDD 65	CDD	-		-	0	0.0%		
Louisville CDD 65	CDD	-		1	(1)	-100.0%		

REPORTING MONTH VS. BUDGET

E ectr c: Total sa es for December were 150 GWh below budget (-5.3%). On a weather-norma ized basis, sa es were 51 GWh below budget (-1.8%). The combined company peak occurred at 8:00 a.m. on Monday, December 12th at 5,12 MW, which was over 1200 MW ower than the all-time high peak for December. The residential class was affec ed most by the warmer December weather w th sa es being higher than budget compared to forecast after weather normal zation. Commerc al sales were weak due o stagnant economic cond tions as well as cus omers sw tching to the Industrial sales c ass.
W thin the Industrial c ass, LG&E was below budget by 19%, but KU was 17% above budget, wh ch resu ted in a 29 GWh combined company positive variance to budget (.2%). Preliminary f gures show a large sales variance to budget for major customers [redacted] (25 GWh, 32%), [redacted] (5 GWh, 79%), and [redacted] (2 GWh, 36%). If the [redacted] exp osion had not occurred, usage would have been 2 GWh higher, taking combined company industr al sales from 29 GWh above budget to 53 GWh above budget. [redacted] also had a weak month w th a negatives sales variance to budget of 7.5 GWh (-31%).

Gas: Natural gas volumes (sales plus transporta ion) were 0.9 BCF below budget (-1 .5%). On a weather-normalized bas s, volumes were 0.21 BCF below budget (-3.3%). The weather-normalized variance was explained mos ly by transportation volumes, which were 0.12 BCF below budget (-8.9%), while sales volumes were 0.1 BCF be ow budget (-1.9%).

Weather: December is the first month of the 2011/2012 Heating Season and s ranked in terms of Heating Degree Days (HDDs). December was sign ficantly warmer than usual. LEX was the 6th warmest of the last 30 years in terms of HDDs. LOU was the th warmest of the last 30 years. To put the mild December weather in perspective, a typical December in Lou sville has about 5 days where the high temperature is at or below freezing (32 degrees), but this December did not have any days where the high was at or below freezing. In fact, there was only one day in a l of December 2011 where the high was not at east 0 degrees.

Y D VS BUDGE		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Res dential	GWh	10,810	10,685	10,985	(175)	-1.6%	(300)	-2.7%
Commercial	GWh	8,015	7,920	8,638	(622)	-7.2%	(718)	-8.3%
Industrial/Mine Power	GWh	9,128	9,125	8,970	159	1.8%	155	1.7%
Publ c Authority/Other	GWh	2,9	2,939	3,06	(119)	-3 9%	(125)	- 1%
otal Retail	**GWh**	**30 897**	**30 668**	**31 656**	**(758)**	**2 4%**	**(988)**	**3 1%**
Municipal	GWh	1,906	1,902	2,019	(113)	-5.6%	(117)	-5.8%
otal Electric Sales Volume	**GWh**	**32 803**	**32 570**	**33 675**	**(871)**	**2 6%**	**(1 105)**	**3 3%**
Gas*								
Sales Volumes	BCF	29.96	31.36	31. 8	(1.53)	- .9%	(0.13)	-0. %
Transportat on Volumes	BCF	11.2	11.3	11.12	0.12	1.1%	0 22	2.0%
otal Gas Volumes	**BCF**	**41 20**	**42 70**	**42 61**	**(1 41)**	**3 3%**	**0 09**	**0 2%**
*Does not include Intracompany sa es								
Lexington HDD 65	HDD	,391		,521	(130)	-2.9%		
Louisville HDD 65	HDD	3,899		,187	(288)	-6.9%		
Lexington CDD 65	CDD	1,310		1,211	99	8.2%		
Louisville CDD 65	CDD	1,727		1, 36	291	20.3%		

YTD VS. BUDGET

E ectr c: For 2011 weather-norma ized sales were below budget by 1,105 GWh (-3.3%). For the industr al class, KU's strength has been driven by strong production from [redacted] at 205 GWh (21%) above budget. Other strong performers in the KU service territory were [redacted] and [redacted] combining for a positve var ance to budget of 9.6 GWh. In the LG&E service terr tory, aside from [redacted] and [redacted] being down, another cus omer well below budget in 2011 was [redacted] with a negative var ance to budget of 77.1 GWh (-26%).
The Commercial class has been the weakest customer class in 2011 against budget (KU Large Commercial -16.9%, LG&E Small Commerc al -6.7%). The budgeted growth in this customer c ass d d not material ze due to some rate-swi ching and slower than expected economic growth.

Gas: 2011 total gas actual volumes were 1. 1 Bcf be ow budget (-3.3%). Weather-normalized total gas volumes were 0.09 BCF above budget (0.2%).

Y D VS LAS YEAR		Actual 2011 Y D	WN Actual 2011 Y D	Actual 2010 Y D	WN Actual 2010 Y D	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Res dential	GWh	10,810	10,685	11,77	10,83	(96)	-8.2%	(1 9)	-1. %
Commercial	GWh	8,015	7,920	8,363	8,038	(3 8)	- .2%	(118)	-1.5%
Industrial/Mine Power	GWh	9,128	9,125	9,061	9,0 5	67	0.7%	80	0.9%
Publ c Authority/Other	GWh	2,9	2,939	3,075	3,039	(131)	- 2%	(100)	-3 3%
otal Retail	GWh	**30 897**	**30 668**	**32 273**	**30 955**	**(1 375)**	**4 3%**	**(287)**	**0 9%**
Municipal	GWh	1,906	1,902	2,002	1,966	(96)	- .8%	(6)	-3.2%
otal Electric Sales	GWh	**32 803**	**32 570**	**34 275**	**32 921**	**(1 472)**	**4 3%**	**(351)**	**1 1%**
Gas									
Gas Sales	BCF	30.0	31.	32.8	30.6	(2.86)	-8.7%	0 75	2.5%
Transportat on Volumes	BCF	11.2	11.3	11.1	11.0	0.16	1.5%	0 36	3.2%
otal Gas Volumes	**BCF**	**41 2**	**42 7**	**43 9**	**41 6**	**(2 69)**	**6 1%**	**1 11**	**2 7%**
*Does not include Intracompany sa es									
Lexington HDD 65	HDD	,391		,892		(501)	-10.2%		
Louisville HDD 65	HDD	3,899		, 61		(562)	-12.6%		
Lexington CDD 65	CDD	1,310		1,58		(27)	-17.3%		
Louisville CDD 65	CDD	1,727		1,991		(26)	-13.3%		

Y D VS LAS YEAR

E ectr c: 2011 sales were 1, 72 GWh below last year (- .3%). On a weather-normal zed basis, the var ance to 2010 s a negative 351 GWh (-1.1%). For key customers, 2011 var ance to 2010 usage for [redacted] is 31 GWh (3%) and fo [redacted] is 20.1 GWh (26%). However, large negative variances to last year come from [redacted] at 190 GWh (72) below last year, [redacted] is 0 GWh (-19%) below ast year, and [redacted] is 0 GWh (-16%) below.

Gas: 2011 YTD produced gas volumes with a variance of 2.69 BCF be ow last year (-6.1%). On a weather-normalized basis, gas volumes were 1.1 BCF above last year (2.7%).

Confidential Information Redacted

Key Performance Indicators
Used Basis

December
2012

Total Utilities

REPORTING MONTH VS. BUDGET

Electric		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	959	1,131	1,140	(180)	-15.8%	(8)	-0.7%
Commercial	GWh	612	643	711	(100)	-14.0%	(69)	-9.7%
Industrial/Mine Power	GWh	772	772	769	3	0.4%	4	0.5%
Public Authority/Other	GWh	224	228	267	(44)	-16.3%	(39)	-14.7%
Total Retail	**GWh**	**2,566**	**2,774**	**2,887**	**(320)**	**-11.1%**	**(112)**	**-3.9%**
Municipal	GWh	154	162	176	(21)	-12.2%	(14)	-7.8%
Total Electric Sales Volume	**GWh**	**2,721**	**2,936**	**3,062**	**(342)**	**-11.2%**	**(126)**	**-4.1%**
Gas*								
Sales Volumes	BCF	4.38	5.54	5.32	(0.95)	-17.8%	0.22	4.2%
Transportation Volumes	BCF	1.17	1.25	1.50	(0.33)	-21.9%	(0.24)	-16.3%
Total Gas Volumes	**BCF**	**5.54**	**6.80**	**6.82**	**(1.27)**	**-18.7%**	**(0.02)**	**-0.3%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	714		886	(172)	-19.4%		
Louisville HDD 65	HDD	628		846	(218)	-25.8%		
Lexington CDD 65	CDD	-		-	0	0.0%		
Louisville CDD 65	CDD	3		-	3	0.0%		

Electric: Total sales for December were 342 GWh below budget (-11.2%) as December was the warmest in 20 years in Louisville and the second warmest in 20 years in Lexington. On a weather-normalized basis, sales were 126 GWh below budget (-4.1%). Consistent with prior months, weather-normalized load fell short of budget due to anemic economic growth. KU Commercial sales continued to be one of the largest negatives to budget in December coming in 62 GWh (-15.4%) below budget on a weather normalized basis. Combined company commercial sales were 69 GWh below budget (-9.7%). Industrial sales were above budget by 17.3% in LG&E but below budget by -5.1% in KU, which resulted in a weather-normalized combined company variance to budget of 4 GWh (0.5%). The negative variance to the KU industrial sales was driven by the large negative variance of KU mine power companies. The Combined Company (CC) peaked on December 12th at 5,264 MW. Last December CC peaked at 5,124 MW. Major customers seeing a positive variance to budget were [redacted] (11.9 GWh, 142%) and [redacted] (1.6 GWh, 13%) in the LG&E territory. [redacted] was 3.3 GWh (-25%) below budget, as the expected impact of their expansion plans has not materialized. [redacted] also continued to have a large negative variance to budget as the recently built HR center is not using the electricity that was expected. [redacted] negative variance has a large impact on Public Authority which was 39 GWh (-14.7%) below budget. In the KU territory, [redacted] was 3.9 GWh (4%) above budget while the [redacted] was 2.6 GWh (11%) below budget.

Gas: Natural gas volumes (sales plus transportation) were 1.27 BCF below budget (-18.7%). On a weather-normalized basis, volumes were 0.02 BCF below budget (-0.3%). On a weather-normalized basis, the Sales Volumes were 0.22 BCF above budget (4.2%) while the Transportation Volumes were 0.24 BCF below budget (-16.3%).

Weather: December was much warmer than normal in both Louisville and Lexington. Louisville had 628 HDD compared to the 20 year average of 886 which is 172 HDD above normal. Lexington was also warmer than normal with 172 fewer HDD than normal. Lexington had 714 HDD compared to the 20 year average of 886 CDD.

****** Budgeted volumes by revenue class are based on CCS values in early 2011 during the development of the 2012 MTP Load Forecast. Later in 2011, some customers moved from the Large Commercial revenue class to the Industrial revenue class, creating volume variances between the classes. Directionally, this change moves Commercial volumes unfavorable to budget and Industrial volumes favorable to budget. Since customers are NOT changing rate classes, total revenues are not impacted.

YTD VS. BUDGET

Electric		Actual	WN Actual	Budget	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	10,567	10,752	10,835	(268)	-2.5%	(83)	-0.8%
Commercial	GWh	7,887	7,889	8,427	(540)	-6.4%	(538)	-6.4%
Industrial/Mine Power	GWh	9,594	9,594	9,337	258	2.8%	257	2.8%
Public Authority/Other	GWh	2,859	2,864	3,215	(356)	-11.1%	(351)	-10.9%
Total Retail	**GWh**	**30,907**	**31,100**	**31,814**	**(907)**	**-2.9%**	**(714)**	**-2.2%**
Municipal	GWh	1,886	1,894	2,026	(140)	-6.9%	(132)	-6.5%
Total Electric Sales Volume	**GWh**	**32,793**	**32,993**	**33,840**	**(1,047)**	**-3.1%**	**(847)**	**-2.5%**
Gas*								
Sales Volumes	BCF	26.46	31.01	30.78	(4.33)	-14.1%	0.22	0.7%
Transportation Volumes	BCF	11.53	11.80	12.56	(1.03)	-8.2%	(0.76)	-6.1%
Total Gas Volumes	**BCF**	**37.99**	**42.81**	**43.35**	**(5.36)**	**-12.4%**	**(0.54)**	**-1.2%**
*Does not include Intracompany sales								
Lexington HDD 65	HDD	3,976		4,573	(597)	-13.1%		
Louisville HDD 65	HDD	3,376		4,251	(875)	-20.6%		
Lexington CDD 65	CDD	1,359		1,233	126	10.2%		
Louisville CDD 65	CDD	1,854		1,463	391	26.7%		

Electric: For 2012, weather-normalized sales were below budget by 847 GWh (-2.5%). For the industrial class, KU's strongest production came from [redacted] at 14 GWh (1%) above budget. [redacted] also was a strong performer in the KU service territory with a positve variance to budget of 7.7 GWh (2%). In the LG&E service territory, [redacted] continued to show strong production at 104 GWh (128%) above budget for the year. Commercial sales struggled all year as the budgeted growth in this customer class has not materialized due to some class switching and slower than expected economic growth primarily in the KU territory.

Gas: 2012 total gas actual volumes were 5.36 Bcf below budget (-12.4%). Weather-normalized total gas volumes were 0.54 BCF below budget (-1.2%).

YTD VS. LAST YEAR

Electric		Actual 2012 YTD	WN Actual 2012 YTD	Actual 2011 YTD	WN Actual 2011 YTD	Actual Variance GWh/BCF	%	W/N Variance GWh/BCF	%
Residential	GWh	10,567	10,752	10,810	10,826	(242)	-2.2%	(73)	-0.7%
Commercial	GWh	7,887	7,889	8,015	7,991	(128)	-1.6%	(102)	-1.3%
Industrial/Mine Power	GWh	9,594	9,594	9,128	9,127	466	5.1%	466	5.1%
Public Authority/Other	GWh	2,859	2,864	2,944	2,946	(86)	-2.9%	(81)	-2.8%
Total Retail	GWh	**30,907**	**31,100**	**30,897**	**30,890**	**10**	**0.0%**	**210**	**0.7%**
Municipal	GWh	1,886	1,894	1,906	1,907	(20)	-1.0%	(14)	-0.7%
Total Electric Sales	GWh	**32,793**	**32,993**	**32,803**	**32,797**	**(10)**	**0.0%**	**196**	**0.6%**
Gas*									
Gas Sales	BCF	26.5	31.0	30.0	31.8	(3.50)	-11.7%	(0.78)	-2.5%
Transportation Volumes	BCF	11.5	11.8	11.2	11.4	0.29	2.6%	0.44	3.9%
Total Gas Volumes	**BCF**	**38.0**	**42.8**	**41.2**	**43.2**	**(3.21)**	**-7.8%**	**(0.35)**	**-0.8%**
*Does not include Intracompany sales									
Lexington HDD 65	HDD	3,976		4,391		(415)	-9.5%		
Louisville HDD 65	HDD	3,376		3,899		(523)	-13.4%		
Lexington CDD 65	CDD	1,359		1,310		49	3.7%		
Louisville CDD 65	CDD	1,854		1,727		127	7.4%		

Electric: Through December 2012 sales were 10 GWh below last year (-0.0%). On a weather-normalized basis, the variance to 2011 is a positive 196 GWh (0.6%). For key customers, 2012 variance to 2011 usage for [redacted] is a positive 55.4 GWh (5%) and for [redacted] is a positive 68.9 GWh (26%). However, [redacted] is 39.5 GWh (-33%) below last year and [redacted] is 35.1 GWh (-37%) below last year.

Gas: 2012 YTD produced gas volumes with a variance of 3.21 BCF below last year (-7.8%). On a weather-normalized basis, gas volumes were 0.35 BCF below last year (-0.8%).

Key Performance Indicators - December 2013

Actual Sales

Electric		Month vs. Budget Actual	Budget	Variance	%	YTD vs. Budget Actual	Budget	Variance	%	YTD vs. Last Year 2013 YTD Actual	2012 YTD Actual	Variance	%
Residential	GWh	1,114	1,018	96	9.4%	10,761	10,912	(150)	-1.4%	10,761	10,567	194	1.8%
Commercial	GWh	618	658	(41)	-6.2%	7,779	8,063	(284)	-3.5%	7,779	7,887	(108)	-1.4%
Industrial/Mine Power	GWh	755	833	(77)	-9.3%	9,734	9,891	(157)	-1.6%	9,734	9,594	139	1.5%
Public Authority/Other	GWh	221	242	(21)	-8.7%	2,814	2,901	(87)	-3.0%	2,814	2,859	(45)	-1.6%
Total Retail	**GWh**	**2,708**	**2,751**	**(43)**	**-1.6%**	**31,088**	**31,766**	**(678)**	**-2.1%**	**31,088**	**30,908**	**181**	**0.6%**
Municipal	GWh	164	164	1	0.4%	1,880	1,944	(64)	-3.3%	1,880	1,886	(6)	-0.3%
Total Electric Sales Volume	**GWh**	**2,872**	**2,914**	**(42)**	**-1.5%**	**32,968**	**33,710**	**(742)**	**-2.2%**	**32,968**	**32,794**	**174**	**0.5%**
Gas (does not include Intercompany sales)													
Sales Volumes	BCF	5.65	5.68	(0.03)	-0.6%	33.60	32.42	1.18	3.6%	33.60	26.46	7.14	27.0%
Transportation Volumes	BCF	1.26	1.34	(0.08)	-6.0%	11.99	11.41	0.58	5.0%	11.99	11.53	0.45	3.9%
Total Gas Volumes	**BCF**	**6.91**	**7.03**	**(0.11)**	**-1.6%**	**45.59**	**43.83**	**1.76**	**4.0%**	**45.59**	**37.99**	**7.60**	**20.0%**
HDD / CDD													
Lexington HDD 65	HDD	831	866	(35)	-4.1%	4,650	4,594	56	1.2%	4,650	3,976	674	17.0%
Louisville HDD 65	HDD	840	816	24	2.9%	4,482	4,199	283	6.7%	4,482	3,376	1,106	32.8%
Lexington CDD 65	CDD	-	0	(0)	-100.0%	1,244	1,189	55	4.6%	1,244	1,359	(115)	-8.5%
Louisville CDD 65	CDD	-	1	(1)	-100.0%	1,446	1,476	(30)	-2.0%	1,446	1,854	(408)	-22.0%

Electric: Actual residential sales were above budget by 27 GWh (7.9%) in LG&E and above budget by 69 GWh (10.2%) in KU/ODP. December commercial sales were below budget by 22 GWh (-6.3%) in KU/ODP, and LG&E was below budget by 18 GWh (-6%). KU/ODP industrial sales were 65 GWh (10.7%) below budget while LG&E industrial sales were below budget by 12 GWh (-5.5%). Among LG&E major customers, [redacted] was 3.7 GWh (14%) and [redacted] was 1.9 GWh (11%) favorable to budget this month. [redacted] and [redacted] were below budget this month by 6.7 GWh (-29%) and 4.6 GWh (-37%), respectively. Among KU major customers, [redacted] and [redacted] were 4.8 GWh (21%) and 1.5 GWh (11%) above budget, respectively, while [redacted] and [redacted] were below budget by 4.1 GWh (-12%) and 4.8 GWh (-51%), respectively.

YTD Actual residential sales were below budget by 168 GWh (-3.9%) in LG&E and above budget by 18 GWh (0.3%) in KU/ODP. December commercial sales were below budget by 112 GWh (-2.7%) in KU/ODP, and LG&E was below budget by 172 GWh (-4.5%). KU/ODP industrial sales were 41 GWh (2%) below budget while LG&E industrial sales were below budget by 16 GWh (-0.6%). Among LG&E major customers in 2013, [redacted] was 29 GWh (9%) and [redacted] was 6.8 GWh (3%) favorable to budget. [redacted] and [redacted] were below budget by 67.1 GWh (-24%) and 26.3 GWh (-17%), respectively. Among KU major customers, [redacted] was 27.4 GWh (16%) above budget while [redacted] was below budget by 56.1 GWh (-54%).

Gas: Actual residential sales were below budget by 222 BCF (-5.8%), and commercial sales were above budget by 66 BCF (4.5%). Industrial sales were above budget by 108 BCF (104.9%).

Weather: December 2013 temperatures were below normal in Louisville and above normal in Lexington compared to 20 year HDD averages. Louisville, as reported by Bowman Field (LOU), had 840 HDD. The average for the past twenty years is 816 HDD. Last December, LOU reported 660 HDD. For comparison, Standiford Field (SDF) recorded 811 HDD in December 2013. December 2013 ranked as the 12th coolest compared to the previous 20 years and 16th coolest compared to the previous 30 years. Lexington (LEX) reported 831 HDD. The average for the past twenty years is 865 HDD. Last December, LEX reported 714 HDD. December 2013 ranked as the 13th coolest compared to the previous 20 years and 18th coolest compared to the previous 30 years.

Weather Normal Sales

Electric		Month vs. Budget WN Actual	Budget	Variance	%	YTD vs. Budget WN Actual	Budget	Variance	%	YTD vs. Last Year 2013 YTD WN Actual	2012 YTD WN Actual	Variance	%
Residential	GWh	1,129	1,018	111	10.9%	10,776	10,912	(136)	-1.2%	10,776	10,752	23	0.2%
Commercial	GWh	620	658	(38)	-5.8%	7,788	8,063	(274)	-3.4%	7,788	7,889	(101)	-1.3%
Industrial/Mine Power	GWh	755	833	(77)	-9.3%	9,736	9,891	(154)	-1.6%	9,736	9,590	146	1.5%
Public Authority/Other	GWh	221	242	(21)	-8.5%	2,815	2,901	(86)	-3.0%	2,815	2,865	(50)	-1.7%
Total Retail	**GWh**	**2,726**	**2,751**	**(25)**	**-0.9%**	**31,115**	**31,766**	**(651)**	**-2.0%**	**31,115**	**31,097**	**19**	**0.1%**
Municipal	GWh	166	164	2	1.2%	1,879	1,944	(65)	-3.4%	1,879	1,894	(15)	-0.8%
Total Electric Sales Volume	**GWh**	**2,892**	**2,914**	**(23)**	**-0.8%**	**32,994**	**33,710**	**(716)**	**-2.1%**	**32,994**	**32,991**	**4**	**0.0%**
Gas (does not include Intercompany sales)													
Sales Volumes	BCF	5.51	5.68	(0.17)	-3.1%	32.03	32.42	(0.39)	-1.2%	32.03	31.01	1.02	3.3%
Transportation Volumes	BCF	1.25	1.34	(0.10)	-7.1%	11.80	11.41	0.38	3.3%	11.80	11.80	(0.01)	-0.1%
Total Gas Volumes	**BCF**	**6.76**	**7.03**	**(0.27)**	**-3.8%**	**43.82**	**43.83**	**(0.01)**	**0.0%**	**43.82**	**42.81**	**1.01**	**2.4%**
HDD / CDD													
Lexington HDD 65	HDD	831	866	(35)	-4.1%	4,650	4,594	56	1.2%	4,650	3,976	674	17.0%
Louisville HDD 65	HDD	840	816	24	2.9%	4,482	4,199	283	6.7%	4,482	3,376	1,106	32.8%
Lexington CDD 65	CDD	-	0	(0)	-100.0%	1,244	1,189	55	4.6%	1,244	1,359	(115)	-8.5%
Louisville CDD 65	CDD	-	1	(1)	-100.0%	1,446	1,476	(30)	-2.0%	1,446	1,854	(408)	-22.0%

Electric: Weather-normalized residential sales were above budget by 23 GWh (6.7%) in LG&E and above budget by 88 GWh (13.1%) in KU/ODP. December commercial sales were below budget by 19 GWh (-5.4%) in KU/ODP, and LG&E was below budget by 19 GWh (-6.4%). KU/ODP industrial sales were 65 GWh (10.6%) below budget while LG&E industrial sales were below budget by 12 GWh (-5.5%).

YTD Weather-normalized residential sales were below budget by 142 GWh (-3.3%) in LG&E and above budget by 6 GWh (0.1%) in KU/ODP. December commercial sales were below budget by 109 GWh (-2.6%) in KU/ODP, and LG&E was below budget by 166 GWh (-4.3%). KU/ODP industrial sales were 139 GWh (1.9%) below budget while LG&E industrial sales were below budget by 15 GWh (-0.6%).

Gas: Weather-normalized residential sales were below budget by 222 BCF (-5.8%), and commercial sales were above budget by 66 BCF (4.5%). Industrial sales were above budget by 108 BCF (104.9%).

Key Performance Indicators - September 2014

Actual Sales

		Month vs. Budget				YTD vs. Budget				YTD vs. Last Year			
Electric		**Actual**	**Budget**	**Variance**	**%**	**Actual**	**Budget**	**Variance**	**%**	**2014 YTD Actual**	**2013 YTD Actual**	**Variance**	**%**
Residential	GWh	727	901	(174)	-19.3%	8,382	8,533	(150)	-1.8%	8,382	8,176	206	2.5%
Commercial	GWh	660	669	(9)	-1.4%	5,994	6,061	(68)	-1.1%	5,994	5,922	72	1.2%
Industrial/Mine Power	GWh	831	795	36	4.6%	7,490	7,479	11	0.1%	7,490	7,317	173	2.4%
Public Authority/Other	GWh	251	227	24	10.6%	2,166	2,104	62	2.9%	2,166	2,124	42	2.0%
Total Retail	**GWh**	**2,469**	**2,592**	**(123)**	**-4.8%**	**24,032**	**24,177**	**(145)**	**-0.6%**	**24,032**	**23,538**	**494**	**2.1%**
Municipal	GWh	148	171	(23)	-13.4%	1,442	1,506	(63)	-4.2%	1,442	1,430	13	0.9%
Total Electric Sales Volume	**GWh**	**2,617**	**2,764**	**(146)**	**-5.3%**	**25,475**	**25,683**	**(209)**	**-0.8%**	**25,475**	**24,968**	**507**	**2.0%**
Gas (does not include Intercompany sales)													
Sales Volumes	BCF	0.78	0.80	(0.02)	-1.9%	24.43	21.30	3.13	14.7%	24.43	22.19	2.24	10.1%
Transportation Volumes	BCF	0.79	0.67	0.12	17.3%	8.67	7.60	1.07	14.1%	8.67	8.63	0.04	0.5%
Total Gas Volumes	**BCF**	**1.57**	**1.47**	**0.10**	**6.9%**	**33.11**	**28.90**	**4.20**	**14.5%**	**33.11**	**30.82**	**2.29**	**7.4%**
Weather													
Lexington Avg Temp Heating Season	°F	-	-	-	0.0%	39	43	(4)	-8.2%	39	42	(2)	-5.9%
Louisville Avg Temp Heating Season	°F	-	-	-	0.0%	40	45	(4)	-9.2%	40	43	(3)	-6.0%
Lexington Avg Temp Cooling Season	°F	69	60	-	14.5%	72	71	-	0.6%	72	72	(0)	-0.2%
Louisville Avg Temp Cooling Season	°F	70	62	-	12.8%	74	73	-	0.4%	74	73	0	0.4%
Lexington HDD 65	HDD	-	5	(5)	-100.0%	3,127	2,893	234	8.1%	3,127	4,650	(1,523)	-32.8%
Louisville HDD 65	HDD	-	4	(4)	-100.0%	2,992	2,645	347	13.1%	2,992	4,482	(1,490)	-33.2%
Lexington CDD 65	CDD	4	2	2	109.0%	1,246	1,173	73	6.3%	1,246	1,244	2	0.2%
Louisville CDD 65	CDD	4	2	2	72.4%	1,491	1,443	48	3.3%	1,491	1,446	45	3.1%

Electric: Actual residential sales were below budget by 73 GWh (-18.3%) in LG&E and below budget by 102 GWh (-20.2%) in KU/ODP. September commercial sales were below budget by 22 GWh (-6.2%) in KU/ODP, and LG&E was above budget by 13 GWh (4.3%). KU/ODP industrial sales were 16 GWh (2.7%) above budget while LG&E industrial sales were above budget by 20 GWh (9.6%).

YTD Actual residential sales were below budget by 71 GWh (-2.1%) in LG&E and below budget by 79 GWh (-1.5%) in KU/ODP. September commercial sales were below budget by 85 GWh (-2.6%) in KU/ODP, and LG&E was above budget by 17 GWh (0.6%). KU/ODP industrial sales were 57 GWh (1.1%) above budget while LG&E industrial sales were below budget by 47 GWh (-2.2%).

Gas: Actual residential sales were below budget by 19 BCF (-4.4%), and commercial sales were below budget by 27 BCF (-9.4%). Industrial sales were above budget by 25 BCF (42.7%).

Weather Normal Sales

Electric		**WN Actual**	**Budget**	**Variance**	**%**	**WN Actual**	**Budget**	**Variance**	**%**	**2014 YTD**	**2013 YTD WN**	**Variance**	**%**
Residential	GWh	738	901	(164)	-18.2%	8,129	8,533	(403)	-4.7%	8,129	8,217	(88)	-1.1%
Commercial	GWh	661	669	(7)	-1.1%	5,902	6,061	(159)	-2.6%	5,902	5,936	(34)	-0.6%
Industrial/Mine Power	GWh	832	795	37	4.7%	7,484	7,479	5	0.1%	7,484	7,320	164	2.2%
Public Authority/Other	GWh	251	227	24	10.8%	2,147	2,104	43	2.0%	2,147	2,127	20	1.0%
Total Retail	**GWh**	**2,483**	**2,592**	**(109)**	**-4.2%**	**23,662**	**24,177**	**(515)**	**-2.1%**	**23,662**	**23,599**	**63**	**0.3%**
Municipal	GWh	147	171	(24)	-14.2%	1,409	1,506	(96)	-6.4%	1,409	1,427	(18)	-1.2%
Total Electric Sales Volume	**GWh**	**2,630**	**2,764**	**(134)**	**-4.8%**	**25,071**	**25,683**	**(612)**	**-2.4%**	**25,071**	**25,026**	**45**	**0.2%**
Gas (does not include Intercompany sales)													
Sales Volumes	BCF	0.78	0.80	(0.02)	-2.2%	21.95	21.30	0.65	3.1%	21.95	21.49	0.46	2.1%
Transportation Volumes	BCF	0.79	0.67	0.12	17.3%	8.46	7.60	0.86	11.3%	8.46	8.56	(0.10)	-1.2%
Total Gas Volumes	**BCF**	**1.57**	**1.47**	**0.10**	**6.7%**	**30.41**	**28.90**	**1.51**	**5.2%**	**30.41**	**30.05**	**0.36**	**1.2%**

Electric: Weather-normalized residential sales were below budget by 79 GWh (-19.8%) in LG&E and below budget by 89 GWh (-17.8%) in KU/ODP. September commercial sales were below budget by 20 GWh (-5.5%) in KU/ODP, and LG&E was above budget by 12 GWh (4%). KU/ODP industrial sales were 18 GWh (3%) above budget while LG&E industrial sales were above budget by 20 GWh (9.5%).

YTD Weather-normalized residential sales were below budget by 197 GWh (-5.9%) in LG&E and below budget by 284 GWh (-5.5%) in KU/ODP. September commercial sales were below budget by 96 GWh (-3%) in KU/ODP, and LG&E was below budget by 2 GWh (-0.1%). KU/ODP industrial sales were 52 GWh (1%) above budget while LG&E industrial sales were below budget by 48 GWh (-2.3%).

Gas: Weather-normalized residential sales were below budget by 20 BCF (-4.8%), and commercial sales were below budget by 28 BCF (-9.6%). Industrial sales were above budget by 25 BCF (42.6%).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No.1.26

Witness: Charles R. Schram

Q1.26. Please refer to the 2014 Resource Assessment, page 39, stating that "[f]or the purpose of this analysis, if an existing coal unit's capacity factor was consistently less than 10 percent in a given load-CO2 price scenario, the unit was assumed to be retired in the year when its capacity factor consistently dropped below 10 percent."

a. Please explain what "consistently" means as used in the sentence above.

b. What is the quantitative meaning of "consistently" as used in the sentence above?

c. Does the sentence quoted above mean that if the capacity factor was less than 10% for a given number of years, or the average was less than 10% for a given number of years, that the unit was assumed to retire in the first year with a capacity factor less than 10%? If no, please explain the correct interpretation of the sentence quoted above.

A1.26.

a. The Companies used the word "consistently" in this context to mean three or more consecutive years.

b. Please see the Companies' response to a. above.

c. Yes.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.27

Witness: Charles R. Schram

Q1.27. Please refer to the 2014 Resource Assessment, page 39, stating that "[f]or the purpose of this analysis, if an existing coal unit's capacity factor was consistently less than 10 percent in a given load-CO2 price scenario, the unit was assumed to be retired in the year when its capacity factor consistently dropped below 10 percent."

a. Please explain how the Companies decided on 10% as the capacity factor below which a unit would be assumed to retire (if the unit consistently had a capacity factor below 10%).
   i. Please provide all supporting workpapers or documents relied on in settling on a 10% capacity factor.
b. As part of the 2014 IRP, did the Companies conduct or cause to be conducted any economic analysis, under any of the scenarios, of when existing units would have costs (fixed and variable costs) that exceed their revenues? If so, please provide any such analyses.
c. As part of the 2014 IRP, did the Companies conduct or cause to be conducted any economic analysis, under any of the scenarios, of when it would be economic to retire any existing generating units? If so, please provide any such analyses.
d. Within the last five years, have the Companies prepared or caused to be prepared any study of whether to continue to operate or retire any of their existing generating units? If so, please produce such studies.
e. Have the Companies prepared or caused to be prepared any studies of the reliability impacts of retiring existing units, including but not limited to Brown units 1 and 2? If so, please produce such studies.

A1.27. a. The 10% capacity factor threshold was not based on a financial analysis. Instead, it was simply selected for the purposes of this analysis to reflect a level of operation that would potentially not justify the fixed costs of a coal unit.

   i. Not applicable.

b. No.

c. No.

d. Yes. Please see attached. Please see also the records of Case Nos. 2011-00161, *The Application Of Kentucky Utilities Company For Certificates Of Public Convenience And Necessity And Approval Of Its 2011 Compliance Plan For Recovery By Environmental Surcharge,* and 2011-00162, *The Application Of Louisville Gas And Electric Company For Certificates Of Public Convenience And Necessity And Approval Of Its 2011 Compliance Plan For Recovery By Environmental Surcharge.*

e. Yes. Please see the Companies' response to part d. above. Please see also the records of Case Nos. 2011-00375, *Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity And Site Compatibility Certificate For The Construction Of A Combined Cycle Combustion Turbine At The Cane Run Generating Station And The Purchase Of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC In Lagrange, Kentucky,* Case No. 2014-00002, *Joint Application Of Louisville Gas And Electric Company And Kentucky Utilities Company For Certificates Of Public Convenience And Necessity For The Construction Of A Combined Cycle Combustion Turbine At The Green River Generating Station And A Solar Photovoltaic Facility At The E.W. Brown Generating Station*, and Case No. 2014-00321, *Verified Application Of Louisville Gas And Electric Company Any And Kentucky Utilities Company For A Declaratory Order And Approval Pursuant To KRS 278.300 For A Capacity Purchase And Tolling Agreement.*

f. No.

Brown 1-2 Baghouse Retrofit Analysis

PPL companies

Generation Planning & Analysis
March 2013

Table of Contents

1 Executive Summary

In the 2011 ECR Plan filing, LG&E and KU (the "Companies") proposed to retrofit Brown 1-2 with a fabric filter baghouse ("baghouse") to comply with EPA regulations. Because of the marginal economics of this decision compared to retiring the units, the Companies ultimately agreed with interveners to revisit the Brown 1-2 baghouse retrofit decision – at the earliest – on July 1, 2013.

Table 1 summarizes the Companies' reserve margin ("RM") shortfall with and without Brown 1-2 beginning in 2015. With Brown 1-2, the Companies will be short 64 MW in 2015. Without Brown 1-2, the Companies will be short 336 MW in 2015.

Table 1 – Reserve Margin Shortfall (MW)

	2015	2016	2017	2018	2019	2020	2021
RM Shortfall (16% RM) w/ BR1-2	(64)	(135)	(183)	(298)	(358)	(435)	(514)
RM Shortfall (16% RM) w/o BR1-2	(336)	(404)	(452	(567)	(627)	(704)	(783)

Several key inputs to the Brown 1-2 baghouse retrofit decision have changed since the 2011 ECR Plan filing:

1. Capital and operating cost assumptions for the baghouse have decreased. The updated operating cost assumptions are based on the Companies' experience operating the Trimble County 2 baghouse.
2. The outlook for natural gas prices is lower by approximately \$3/mmBtu. This reduces the generation cost of a combined cycle gas turbine ("CCGT"), the likely replacement for Brown 1-2, by approximately \$21/MWh.
3. The risk of CO_2 regulations is increasing. While no federal legislation mandating a cap-and-trade scheme or carbon tax has advanced, the EPA is expected to propose CO_2 regulations for existing power plants.

In the updated analysis, the Companies evaluated the Brown 1-2 retire/retrofit decision under three gas price scenarios, two load scenarios, and two CO_2 price scenarios. The differences in present value revenue requirements ("PVRR") between the "Brown 1-2 retirement" and "Brown 1-2 retrofit" alternatives are summarized in Table 2. Compared to the Brown 1-2 retirement alternative, the PVRR of the Brown 1-2 retrofit alternative ranges from approximately \$300 million lower (i.e., favorable) to approximately \$700 million higher (i.e., unfavorable). If all scenarios are assumed to be equally probable, the Brown 1-2 retrofit alternative is on average \$170 million *unfavorable* to the Brown 1-2 retirement alternative. The Brown 1-2 retrofit alternative is not the least-cost alternative in any mid CO_2 price scenario or any scenario with low natural gas prices. In the mid gas, zero CO_2 price scenarios, the favorability of the Brown 1-2 retrofit alternative is the result of two key assumptions:

1. Brown 1 and 2 will operate through the end of the analysis period in 2042.
2. Brown 1 and 2 will require no additional environmental controls through 2042.

If either of these assumptions is not realized, the Brown 1-2 retrofit alternative is not least-cost in the mid gas price scenarios. The impacts of lower gas prices and the increasing risk of CO_2 regulations more than offset the impact of lower baghouse capital and operating expenses. The merits of the baghouse retrofit alternative today are unfavorable compared to the evaluation in the 2011 ECR Plan filing.

Table 2 – Brown 1-2 Retire/Retrofit Analysis Results ($2013, $M)

	Scenario (Gas/Load/CO_2)			**PVRR Difference[1] (Brown 1-2 Retirement Less Retrofit Brown 1-2)***
1	Mid Gas	Base Load	Zero CO_2	55
2			Mid CO_2	(337)
3		Low Load	Zero CO_2	100
4			Mid CO_2	(305)
5	High Gas	Base Load	Zero CO_2	281
6			Mid CO_2	(125)
7		Low Load	Zero CO_2	124
8			Mid CO_2	(194)
9	Low Gas	Base Load	Zero CO_2	(222)
10			Mid CO_2	(681)
11		Low Load	Zero CO_2	(243)
12			Mid CO_2	(481)

*Positive values indicate that the Brown 1-2 retrofit is favorable to retirement.

Based on this analysis, it is recommended that the Companies do not proceed with the installation of a baghouse on Brown 1-2 at this time. However, a decision to retire Brown 1-2 has not been reached, as the Companies are currently testing chemical additives for Brown 1-2 that may enable the units to comply with EPA regulations at a much lower capital cost.

[1] PVRR differences reflect differences in operating revenue requirements beginning in 2018 and all differences in capital revenue requirements (see discussion in Section 4.1). Further updates to transmission cost estimates may result in changes to these values, but will not affect the recommendation.

2 LG&E/KU Resource Summary and Brown 1-2 Retrofit Alternatives

If the Companies do not retrofit Brown 1-2 with any mercury control technology, they must be retired by April 16, 2015 to comply with the EPA's Mercury and Air Toxic Standards ("MATS" or "Utility MACT" rule). Depending on whether Brown 1-2 are retired, the Companies will be 64-336 MW short of a 16% reserve margin in 2015 (see Table 3). The Companies optimal reserve margin range is 15-17%. For planning purposes, the Companies target the middle of this range (16%).

Table 3 – LG&E/KU Resource Summary

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	7,885
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Existing Resources[2]	7,814	7,802	7,819	7,781	7,800	7,801	7,801
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demands	137	137	137	137	137	137	137
Total Supply w/ Brown 1-2 (BR1-2)	8,103	8,091	8,108	8,070	8,089	8,091	8,091
Brown 1-2[3]	272	269	269	269	269	269	269
Total Supply w/o Brown 1-2 (BR1-2)	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin ("RM") w/ BR1-2	15.1%	14.1%	13.4%	11.9%	11.1%	10.1%	9.1%
Reserve Margin ("RM") w/o BR1-2	11.2%	10.3%	9.7%	8.1%	7.4%	6.4%	5.4%
RM Shortfall (16% RM) w/ BR1-2*	(64)	(135)	(183)	(298)	(358)	(435)	(514)
RM Shortfall (16% RM) w/o BR1-2*	(336)	(404)	(452	(567)	(627)	(704)	(783)
RM Shortfall (15% RM) w/ BR1-2*	7	(64)	(111)	(226)	(285)	(362)	(440)
RM Shortfall (15% RM) w/o BR1-2*	(265)	(333)	(380)	(495)	(554)	(631)	(709)

*Negative values reflect reserve margin shortfalls.

Two alternatives exist for retrofitting Brown 1-2 to comply with the MATS:

1. Install a fabric filter baghouse ("baghouse").
2. Utilize chemical additives to remove mercury from station emissions. Tests are underway at the Brown Station to understand the viability of this alternative.

The chemical additive alternative has a much lower capital cost than the baghouse alternative and does not preclude the Companies from installing a baghouse on Brown 1-2 in the future. This analysis is limited to evaluating the merits of installing a baghouse on Brown 1-2 in April 2016.

[2] 'Existing Resources' include Cane Run 7 and Brown 1-2.
[3] 3 MW derate beginning in 2016 reflects the addition of a baghouse.

3 Updated Input Assumptions

The baghouse alternative was originally evaluated in the 2011 ECR Plan analysis. Since that analysis, several key input assumptions have changed:

1. The estimated capital cost for the Brown 1-2 baghouse has decreased by $34 million (from $228 million to $194 million).
2. The operating cost assumptions for the Brown 1-2 baghouse have decreased by approximately $13 per megawatt-hour. When the 2011 Air Compliance Plan was developed, the Companies had limited operating experience with the Trimble County 2 baghouse. The updated operating expense estimates are based on almost two years of experience operating the Trimble County 2 baghouse.
3. The outlook for natural gas prices is lower by approximately $3/mmBtu. This reduces the generation cost of a CCGT, the likely replacement for Brown 1-2, by approximately $21/MWh.
4. The risk of CO_2 regulations is increasing. While no federal legislation mandating a cap-and-trade scheme or carbon tax has advanced, the EPA is expected to propose CO_2 regulations for existing power plants.

4 Brown 1-2 Baghouse Analysis

4.1 Summary of Alternatives

To evaluate the Brown 1-2 baghouse retrofit alternative, the Companies compared the costs of installing a baghouse at Brown 1-2 to the costs of retiring Brown 1-2 and replacing the capacity. The Brown 1-2 baghouse retrofit and Brown 1-2 retirement alternatives are summarized in more detail in Table 4. In both alternatives, a 2X1 CCGT is constructed in 2018.[4] The differences in cost between the alternatives are driven by the longer-term implications of retrofitting Brown 1-2 (e.g., retiring Brown 1-2 accelerates the need for additional generating capacity commissioned after 2018; retrofitting Brown 1-2 results in a higher weighting of coal generation in the Companies' generating portfolio). For this reason, with the exception of the difference in capital costs related to the baghouse, the difference in present value of revenue requirements ("PVRR") between the two alternatives is driven by cost differences beginning in 2018. Prior to 2018, the analysis assumes that replacement capacity and energy can be acquired for Brown 1-2 at a cost not materially different than that of retaining and operating Brown 1-2. Retaining Brown 1-2, the projected reserve margin shortfall is 64 MW in 2015, increasing to 183 MW in 2017. For both alternatives, the analysis assumes similar costs for meeting this shortfall.

[4] The earliest that replacement capacity can be constructed is 2018.

Table 4 – Summary of Alternatives

Alternative	Description
Brown 1-2 Baghouse Retrofit	• 4/2016: Retrofit Brown 1-2 with fabric filter baghouse. • 2015-2017: Purchase capacity and energy to meet 64-135 MW RM shortfall. • 1/2018: Build 2X1 CCGT.
Brown 1-2 Retirement	• 2015-2017: Retire Brown 1-2 in 2015 and purchase replacement capacity OR operate Brown 1-2 with fuel additive. • 2015-2017: Purchase capacity and energy to meet 64-135 MW RM shortfall. • 1/2018: Build 2X1 CCGT.

4.2 Analysis Methodology

To understand the impact on the analysis associated with the uncertainty in natural gas prices, native load, and potential CO_2 regulations, each alternative was evaluated under three natural gas price scenarios, two native load scenarios, and two CO_2 price scenarios (12 scenarios in all). Charts detailing the price and load scenarios are included in *Appendix A – Natural Gas, Load, and CO2 Price Scenarios*.

For each alternative and each 'gas price-native load-CO_2 price' scenario, Strategist was used to develop a least-cost resource expansion plan for meeting the Companies' forecasted energy requirements. Then, detailed production costs were computed for each alternative and associated expansion plan using PROSYM. The analysis period was 30 years (2013-2042).

If Brown 1-2 are retired, the Brown Station's on-going capital, fixed O&M, landfill costs, and costs for complying with the EPA's effluent guidelines will be impacted. In addition, the Companies' transmission plan will be impacted. The analysis considers all of these cost impacts in addition to impacts to expansion plans and production costs.

4.3 Analysis Results

If Brown 1-2 are retired, the Companies' need for generating capacity beyond 2018 will be accelerated, resulting in a higher-cost expansion plan. In the base load scenario, retrofitting Brown 1-2 (and retaining their 269 MW of capacity for the longer-term) defers the need for additional generating capacity by four years. In the low load scenario, retrofitting Brown 1-2 defers the need for additional generating capacity by eight years. The table in *Appendix B – Brown 1-2 Retire/Retrofit Analysis Results* lists the first generating resource ("1st long-term generating resource" or "1st LGR") that is added after 2018 for each of the 12 'gas price-load-CO2 price' scenarios.

Table 5 compares the two alternatives under each of the 12 'gas price-load-CO_2 price' scenarios. The PVRR values include operating revenue requirements beginning in 2018 and all capital revenue requirements. A complete summary of the analysis results are contained in *Appendix B – Brown 1-2 Retire/Retrofit Analysis Results*. The following conclusions can be drawn from these results:

1. Compared to the Brown 1-2 retirement alternative, the PVRR of the Brown 1-2 baghouse retrofit alternative ranges from approximately \$300 million lower (i.e., favorable) to approximately \$700 million higher (i.e., unfavorable). If all scenarios are assumed to be equally probable, the Brown 1-2 retrofit alternative is on average \$170 million *unfavorable* to the Brown 1-2 retirement alternative.

2. The Brown 1-2 baghouse retrofit alternative is not the least-cost alternative in any mid CO_2 price scenario or any scenario with low natural gas prices.
3. In the zero CO_2 price scenarios, the Brown 1-2 baghouse retrofit alternative is the least-cost alternative in the base and high gas price scenarios.

Table 5 – Analysis Results ($2013, $M)

	Scenario (Gas/Load/CO_2)[5]			Total PVRR		PVRR Difference[6]
				Brown 1-2 Retrofit	Brown 1-2 Retirement	(Retire Less Retrofit)
1	MG	BL	0C	21,628	21,573	55
2			MC	35,340	35,677	(337)
3		LL	0C	18,866	18,766	100
4			MC	32,179	32,485	(305)
5	HG	BL	0C	22,760	22,479	281
6			MC	37,631	37,756	(125)
7		LL	0C	19,504	19,380	124
8			MC	33,790	33,984	(194)
9	LG	BL	0C	18,553	18,775	(222)
10			MC	30,195	30,876	(681)
11		LL	0C	16,450	16,693	(243)
12			MC	28,161	28,642	(481)

In the mid gas, zero CO_2 price scenarios, the PVRR of the Brown 1-2 baghouse retrofit alternative is $55-100 million favorable to the Brown 1-2 retirement alternative. Two assumptions drive this difference:

1. Brown 1 and 2 operate through the end of the analysis period (2042).
2. Brown 1 and 2 will require no additional environmental controls through 2042.

In 2013, Brown 1 and 2 will be 56 and 50 years old, respectively. In 2042, Brown 1 and 2 will be 85 and 79 years old, respectively (see Table 6). If Brown 1-2 do not operate beyond 2030, the PVRR of the Brown 1-2 baghouse retrofit alternative is increased (i.e., becomes less favorable) by approximately $160 million in the base load scenario and $300 in the low load scenario. If SCR is needed for Brown 1-2 in 2025, the cost of the Brown 1-2 retrofit is increased by approximately $110 million. Furthermore, if SCR is needed before 2025, the cost impact is greater.

Clearly, if any one of these assumptions is not realized, the Brown 1-2 baghouse retrofit alternative is not least-cost in the mid gas scenarios. Furthermore, if Brown 1-2 do not operate beyond 2030, the retrofit alternative is favored only in the high gas/base load/zero CO_2 price scenario. The impacts of lower gas prices and the increasing risk of CO_2 regulations more than offset the impact of lower baghouse capital and operating expenses.

[5] Gas: Mid (MG), High (HG), Low (LG); Load: Base (BL), Low (LL); CO_2: Zero (0C), Mid (MC).
[6] Further updates to transmission cost estimates may result in changes to these values, but will not affect the recommendation.

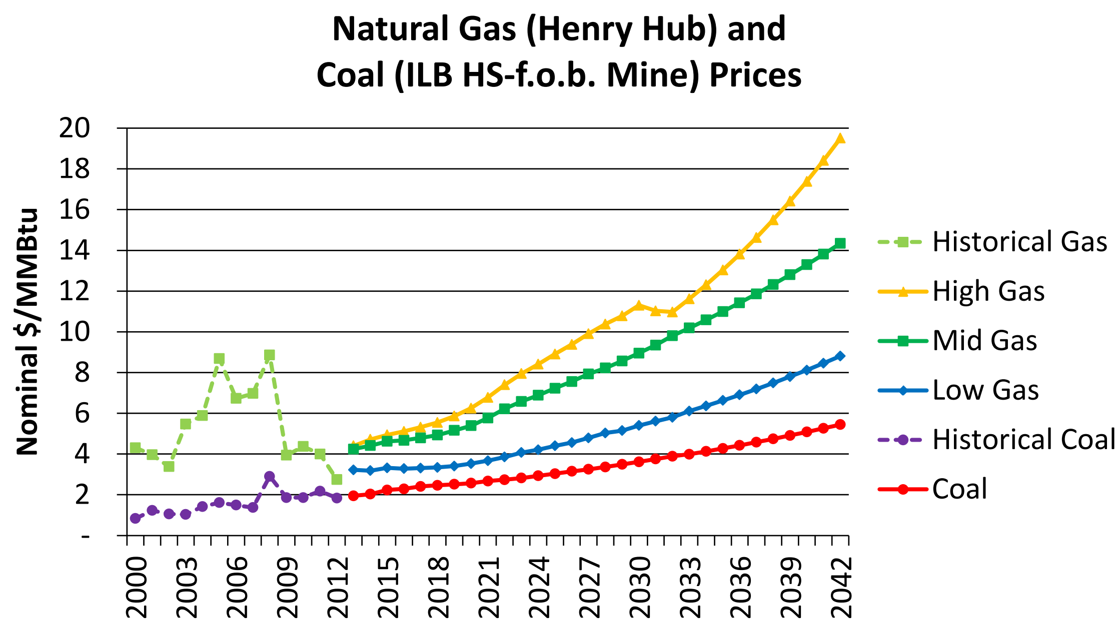
Table 6 – Age of Brown 1 and 2 (years)

Year	Brown 1	Brown 2
2013	56	50
2025	68	62
2030	73	67
2035	78	72
2042	85	79

5 Conclusion

Based on this analysis, it is recommended that the Companies do not proceed with the installation of a baghouse on Brown 1-2 at this time. However, a decision to retire Brown 1-2 has not been reached, as the Companies are currently testing chemical additives for Brown 1-2 that may enable the units to comply with EPA regulations at a much lower capital cost.

6 Appendix A – Natural Gas, Load, and CO_2 Price Scenarios



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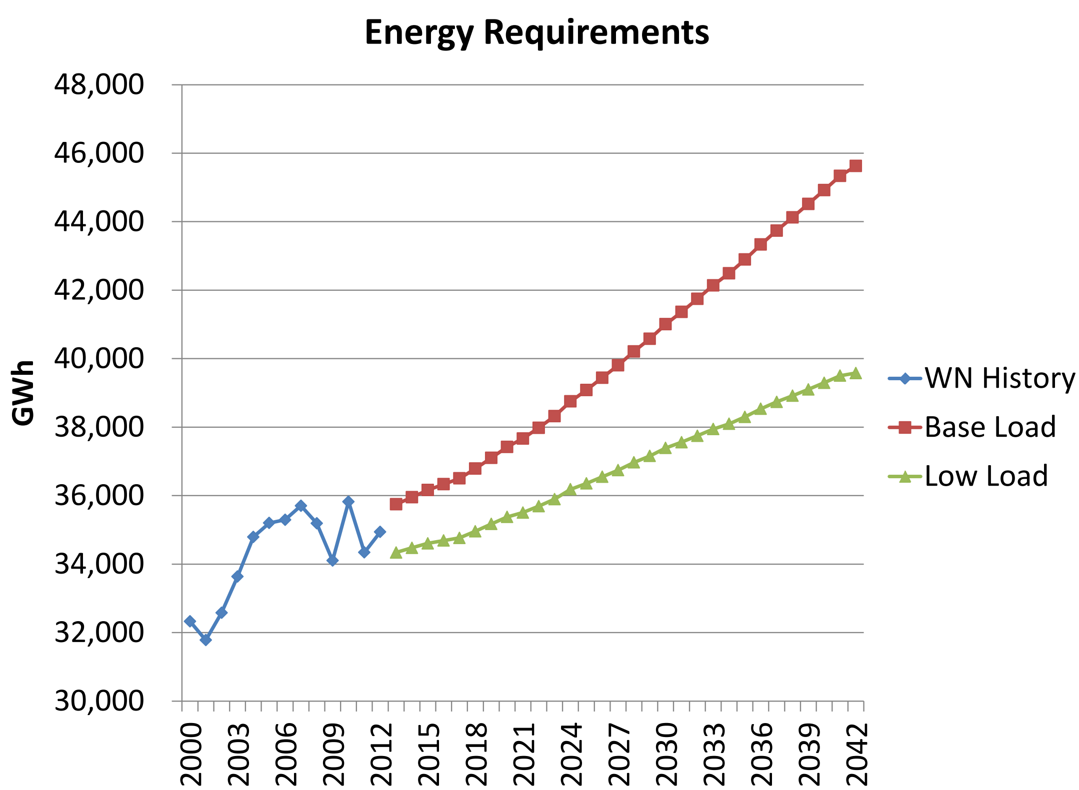

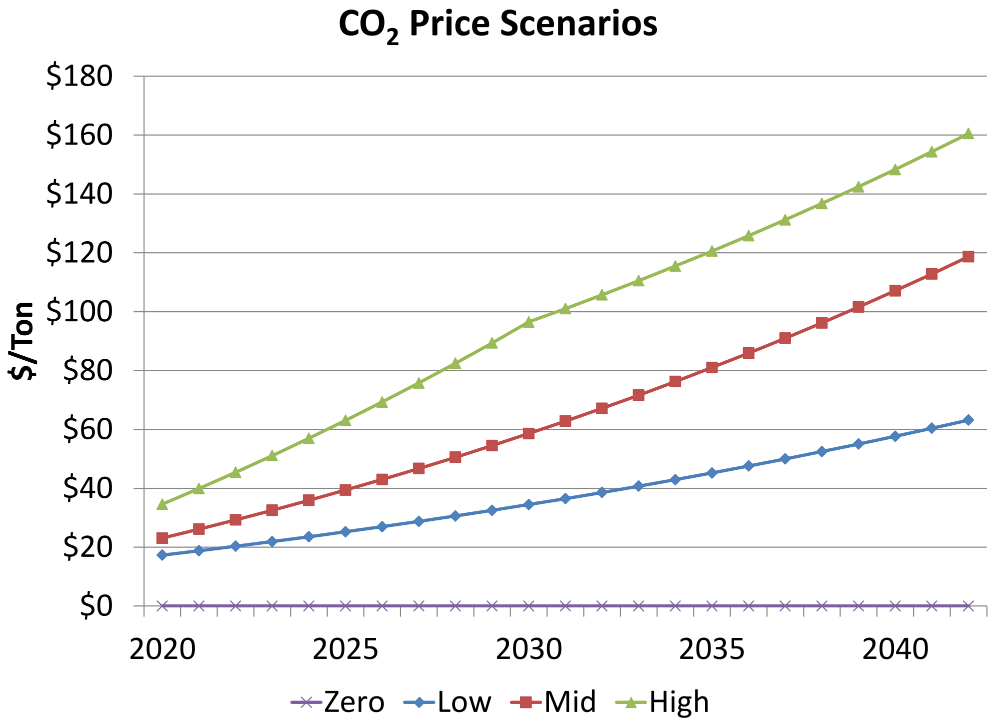

Note: The analysis considered the Zero and Mid CO_2 price scenarios only.

7 Appendix B – Brown 1-2 Retire/Retrofit Analysis Results

	Scenario (Gas/Load/ CO_2)[7]			Case	1st LGR	Production Costs	Capital	Firm Gas Transport	Fixed O&M	Trans Impact[8]	Total Cost
1	MG	BL	0C	Brown 1-2 Retire	'21 SCT	19,485	1,554	381	143	64	21,628
				Brown 1-2 Retrofit	'25 SCT	19,379	1,623	325	246	0	21,573
				Difference		106	(69)	56	(102)	64	55
2			MC	Brown 1-2 Retire	'21 2x1	32,987	1,733	402	154	64	35,340
				Brown 1-2 Retrofit	'25 2x1	33,380	1,714	336	248	0	35,677
				Difference		(393)	19	67	(94)	64	(337)
3		LL	0C	Brown 1-2 Retire	'32 2x1	17,531	959	227	87	64	18,866
				Brown 1-2 Retrofit	'40 SCT	17,460	935	175	196	0	18,766
				Difference		70	23	51	(109)	64	100
4			MC	Brown 1-2 Retire	'32 1x1	30,869	950	209	87	64	32,179
				Brown 1-2 Retrofit	'40 2x1	31,087	1,016	183	198	0	32,485
				Difference		(219)	(66)	27	(111)	64	(305)
5	HG	BL	0C	Brown 1-2 Retire	'21 2x1	20,426	1,715	401	153	64	22,760
				Brown 1-2 Retrofit	'25 2x1	20,210	1,688	333	247	0	22,479
				Difference		216	26	69	(94)	64	281
6			MC	Brown 1-2 Retire	'21 2x1	35,298	1,715	401	153	64	37,631
				Brown 1-2 Retrofit	'25 2x1	35,488	1,688	333	247	0	37,756
				Difference		(190)	26	69	(94)	64	(125)
7		LL	0C	Brown 1-2 Retire	'32 1x1	18,193	950	209	87	64	19,504
				Brown 1-2 Retrofit	'40 1x1	18,021	983	178	197	0	19,380
				Difference		172	(33)	31	(110)	64	124
8			MC	Brown 1-2 Retire	'32 1x1	32,479	950	209	87	64	33,790
				Brown 1-2 Retrofit	'40 2x1	32,586	1,016	183	198	0	33,984
				Difference		(107)	(66)	27	(111)	64	(194)
9	LG	BL	0C	Brown 1-2 Retire	'21 2x1	16,309	1,630	398	151	64	18,553
				Brown 1-2 Retrofit	'25 2x1	16,548	1,649	331	246	0	18,775
				Difference		(239)	(19)	67	(95)	64	(222)
10			MC	Brown 1-2 Retire	'21 2x1	27,841	1,733	402	154	64	30,195
				Brown 1-2 Retrofit	'25 2x1	28,578	1,714	336	248	0	30,876
				Difference		(736)	19	67	(94)	64	(681)
11		LL	0C	Brown 1-2 Retire	'32 SCT	15,330	778	195	83	64	16,450
				Brown 1-2 Retrofit	'40 SCT	15,387	935	175	196	0	16,693
				Difference		(57)	(157)	20	(113)	64	(243)
12			MC	Brown 1-2 Retire	'32 1x1	26,850	950	209	87	64	28,161
				Brown 1-2 Retrofit	'40 2x1	27,244	1,016	183	198	0	28,642
				Difference		(395)	(66)	27	(111)	64	(481)

Brown 1-2 Retirement has Lower PVRR (grey) | Brown 1-2 Baghouse Retrofit has Lower PVRR (yellow)

[7] Gas: Mid (MG), High (HG), Low (LG); Load: Base (BL), Low (LL); CO_2: Zero (0C), Mid (MC).
[8] Further updates to transmission cost estimates may result in changes to these values, but will not affect the recommendation.

Note: The '1st LGR' column in the previous table indicates the LGR that is added after the 2018 CCGT. Production Costs include the production costs for the alternatives being evaluated, the LGRs, and the units in the Companies' existing generation portfolio. Capital, Firm Gas Transport, and Fixed O&M include costs for the alternatives being evaluated and the LGRs. Transmission Impact ("Trans Impact") is the PVRR impact of each alternative on the Companies' 2013 transmission plan. The PVRR values include operating revenue requirements (i.e., Production Costs, Firm Gas Transport, and Fixed O&M revenue requirements) beginning in 2018 and all capital and transmission revenue requirements.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Wallace McMullen and Sierra Club's
Initial Data Requests
Dated November 7, 2014

Case No. 2014-00131

Question No. 1.28

Witness: John N. Voyles

Q1.28 Please refer to the 2014 Resource Assessment's scenarios in which Brown units 1 and 2 are assumed to be retired in 2020.

a. Does the pilot-scale carbon capture and sequestration project at the Brown plant impact the decision whether to retire any of the Brown units? If so, please explain.

b. Does the pilot-scale carbon capture and sequestration project have a parasitic load that has been accounted for in the evaluation of any of the Brown units? If so, please explain

A1.28

a. No, the pilot-scale carbon capture project, funded by the U.S. DOE, does not impact the decision to retire E.W. Brown Units 1 and 2 in 2020. The carbon capture project, which does not include sequestration, is scheduled to be completed by the end of 2016.

b. The parasitic load of the carbon capture pilot project is equivalent to approximately 300kW of steam extraction. This level of steam extraction is *de minimis* compared to the total steam output of E.W. Brown's units. As this pilot project will end in 2016, it was not included in the evaluation of any of the E.W. Brown units.