COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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	**)))))))))**	**CASE NO. 2014-00002**

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
AND KENTUCKY UTILITIES COMPANY
TO THE COMMISSION STAFF'S FIRST INFORMATION REQUEST
DATED MARCH 13, 2014

FILED: MARCH 27, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Director, Corporate Tax and Benefit Plan Compliance for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gregory J. Meiman

Gregory J. Meiman

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

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.

Edwin R. Staton

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

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

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

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

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 27th day of March 2014.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 1

Witness: David S. Sinclair

Q-1. Refer to the table on page 4 of the Joint Application.

a. Confirm that the forecasted peak load is projected to grow at an average annual rate of approximately 1.026 percent for the five-year period 2015 through 2020. If this cannot be confirmed, provide the approximate average annual percentage increase, along with the formula used in calculating the average annual percent increase.

b. Confirm that the forecasted peak load is projected to grow at an average annual rate of approximately 0.93 percent for the ten-year period 2015 through 2025. If this cannot be confirmed, provide the approximate average annual percentage increase, along with the formula used in calculating the average annual percentage increase.

c. Confirm that the forecasted peak load is projected to grow at an average annual rate of approximately 0.92 percent for the 15-year period 2015 through 2030. If this cannot be confirmed, provide the approximate average annual percentage increase, along with the formula used in calculating the average annual percent increase.

d. Confirm that the forecasted peak load is projected to grow at an average annual rate of approximately 0.90 percent for the 20-year period 2015 through 2035. If this cannot be confirmed, provide the approximate average annual percentage increase, along with the formula used in calculating the average annual percentage increase.

e. Provide the reasons for the change in the average annual peak load forecast between the first five years of the forecast and the remaining 15 years of the forecast and indicate which customer classes are responsible for the changes.

f. Confirm that the Energy Efficiency/DSM forecasted peak load reduction is projected to grow at an average annual rate of approximately 3.8 percent for the five-year period 2015 through 2020. If this cannot be confirmed, provide the approximate average annual percentage reduction increase, along with the formula used in calculating the average annual percentage increase.

g. Confirm that the Energy Efficiency/DSM forecasted peak load reduction is projected to grow at an average annual rate of approximately 2.1 percent for the 10-year period 2015 through 2025. If this cannot be confirmed, provide the approximate average annual percentage reduction increase, along with the formula used in calculating the average annual percentage increase.

h. Confirm that the Energy Efficiency/DSM forecasted peak load reduction is projected to grow at an average annual rate of approximately 1.5 percent for the 15-year period 2015 through 2030. If this cannot be confirmed, provide the approximate average annual percentage reduction increase, along with the formula used in calculating the average annual percentage increase.

i. Confirm that the Energy Efficiency/DSM forecasted peak load reduction is projected to grow at an average annual rate of approximately 1.2 percent for the 20-year period 2015 through 2035. If this cannot be confirmed, provide the average annual percentage reduction increase, along with the formula used in calculating the average annual percentage increase.

j. Provide the reasons for the change in the Energy Efficiency/DSM average annual peak load reductions forecast between the first five years of the Energy Efficiency/DSM forecast reductions and the remaining 15 years of the Energy Efficiency/DSM forecast reductions, and indicate which customer classes are responsible for the changes.

A-1.

a. Yes, the peak load before DSM grows at a compound annual growth rate ("CAGR") of 1.026 percent between 2015 and 2020.

b. Yes, the peak load before DSM grows at a CAGR of 0.93 percent between 2015 and 2025.

c. Yes, the peak load before DSM grows at a CAGR of 0.92 percent between 2015 and 2030.

d. Yes, the peak load before DSM grows at a CAGR of 0.90 percent between 2015 and 2035.

e. The average annual peak load growth before the impact of the Companies' Energy Efficiency/DSM programs is expected to be slightly lower in the long-term, primarily driven by increasing appliance efficiencies affecting the Residential and Small Commercial classes. As referenced in Mr. Sinclair's testimony on page 6, Residential and Small Commercial sales forecasts are modeled using ITRON's Statistically Adjusted End-use models that incorporate these end-use efficiencies based on the U.S. Energy Information Agency's efficiency inputs.

f. Yes, the forecasted peak load reduction from the Companies' Energy Efficiency/DSM programs grows at a CAGR of 3.8 percent between 2015 and 2020.

g. Yes, the forecasted peak load reduction from the Companies' Energy Efficiency/DSM programs grows at a CAGR of 2.1 percent between 2015 and 2025.

h. Yes, the forecasted peak load reduction from the Companies' Energy Efficiency/DSM programs grows at a CAGR of 1.5 percent between 2015 and 2030.

i. Yes, the forecasted peak load reduction from the Companies' Energy Efficiency/DSM programs grows at a CAGR of 1.2 percent between 2015 and 2035.

j. The changes are attributable to an assumed small incremental annual increase (approximately 4 MWs per year in total) in the last fifteen (15) years for both the Commercial and Residential Load Management Programs. All other programs assume no incremental annual increases in demand reductions over the last 15 years. The customer classes responsible for the changes are residential and commercial.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 2

Witness: David S. Sinclair

Q-2. Refer to page 5, lines 16-18, of the Direct Testimony of Paul W. Thompson ("Thompson Testimony"). Reference is made to the Companies' ability "to add a renewable resource with relatively minor impact on the customer revenue requirements in coming years." Explain how the proposed addition of the E. W. Brown Generating Station ("Brown Station") 10-MW solar photovoltaic facility will benefit the Companies' customers.

A-2. See Mr. Sinclair's testimony at page 27, lines 6-13.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 3

Witness: David S. Sinclair

Q-3. Refer to page 5, line 23 to page 6, line 6, of the Thompson Testimony. Confirm that the Companies' best estimated installed cost for the natural gas combined cycle ("NGCC") facility is $1,000 per kW ($700,000,000 / 700,000 kW) and for the solar photovoltaic facility is $3,600 per kW ($36,000,000 / 10,000 kW).

A-3. The statement is correct.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 4

Witness: David S. Sinclair

Q-4. Explain why the Companies believe that it would not be less costly to install a 710-MW NGCC generating facility at a total cost of $710 million, or an average cost of $1,000 per kW, versus a 700-MW NGCC facility and a 10-MW solar photovoltaic facility at a combined estimated cost of $736 million, or an average cost of $1,037 per kW.

A-4. The suggested comparison is not appropriate. The revenue requirement analysis associated with Brown Solar Facility shown in Section 4.6, Tables 35-37 of Exhibit DSS-1 is based on adding the project to the Companies' existing fleet with the addition of a 670 MW 2x1 NGCC at Green River. As stated in Mr. Sinclair's testimony on page 33, lines 8-12, the exact size of the proposed Green River NGCC has not been determined. There is no reason to believe that the precise capacity rating of Green River NGCC will have a material impact on the revenue requirement analysis related to Brown Solar Facility shown in Tables 35-37 of Exhibit DSS-1.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 5

Witness: John N. Voyles, Jr.

Q-5. Refer to page 6 of the Thompson testimony, lines 12-15, wherein Mr. Thompson states, "Additionally, the Companies have identified land they already own at Brown (it was acquired to provide a supply of cover soil for landfill purposes) which is suitable for solar panel installation after obtaining the cover soil."

a. Provide the cost of the land and the date it was acquired.

b. Provide KU's plans for the land (once the cover soil was removed) before it was decided that the land would be suitable for the solar project.

A-5.

a. KU purchased the land on June 23, 2011 for a cost of $825,000. The tract contains 152.976 acres.

b. KU plans to use this land as buffer for the Brown landfill operation. The parcel will still serve that function with the solar project in place.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 6

Witness: Paul W. Thompson

Q-6. Refer to page 8 of the Thompson Testimony, lines 10-16. Mr. Thompson states that the Companies developed a number of self-build options that were considered in the Request for Proposal ("RFP") process and that the self-build proposal at Green River Generating Station ("Green River") was the "least reasonable cost option." Explain in detail how employees within the Companies who were generating the self-build proposals were separated from employees evaluating the RFP submissions in order to ensure the integrity of the selection process.

A-6. The RFP responses and the Companies' self-build options were evaluated by the Generation Planning Department that reports to Mr. Sinclair who is the officer responsible for developing the recommended resource plan to meet customers' future energy needs. The Companies' self-build options were developed by the Business Development and Project Engineering departments that report to Mr. Voyles based on the requests of the Generation Planning group for various technology options (e.g, 1x1 NGCC, 2x1 NGCC, solar, etc.) to include in their evaluation.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 7

Witnesses: Paul W. Thompson / John N. Voyles, Jr.

Q-7. Refer to page 9 of the Thompson Testimony, lines 12-18, wherein Mr. Thompson states that there are currently 41 employees at Green River and that 45-50 employees are expected to be needed when the proposed Green River NGCC becomes operational. He also states that the solar facility is expected to be staffed by the current employees at the Brown Station.

a. Provide the incremental labor costs that will be incurred when the NGCC becomes operational and state whether these costs are included in the estimated costs for the project.

b. Provide the number of current employees at the Brown Station.

A-7.

a. The operation of Green River 3 and 4 is conducted today with 41 full-time KU employees, supplemented with approximately 19 contracted resources. All alternatives assumed that Green River 3 and 4 would be retired. Individuals will be reassigned or retiring. Therefore the estimated labor cost of $3.3 million from the HDR Study included in the analysis is the incremental labor costs for the Green River NGCC alternative.

b. There are currently 149 full-time KU employees at the Brown Station. In addition, there are 43 contracted employees that support the facility on a full-time basis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 8

Witness: Gregory J. Meiman

Q-8. Refer to the Direct Testimony of Gregory J. Meiman. Explain in detail the eligible tax credits and their impact on the Companies for solar installations which go online prior to 2016. Include in your response the net benefits that will flow through to the customer.

A-8. Section 48(a) of the Internal Revenue Code (IRC) provides a tax credit for a portion of the expenditures the Companies make in placing solar energy property in service. For this purpose, the expenditures for tangible property designed to use solar energy to produce electricity are eligible for the credit. The federal credit is thirty percent of the qualifying cost of the solar energy property, provided it is placed in service prior to 2017.

The solar energy tax credit is an investment tax credit and will have the same accounting and rate treatment as the Companies' previous investment tax credits (including the Qualified Advanced Coal Project Credit investment tax credit received for construction of Trimble County Unit No. 2, LG&E Case No. 2007-00179 and KU Case No. 2007-00178).

The solar panels will be jointly owned by the Companies. Each Company has a long-standing, yet different, irrevocable election under the IRC federal normalization rules for the rate treatment, and consequently the customer, of investment tax credit. The benefit of the credit to the customer is realized through two different methods as described below.

KU, in 1972, elected a rate treatment under the tax code IRC Section 46(f)1, known as Option 1, wherein KU reduced its rate base by the amount of investment tax credit it received. This rate treatment is referred to as the "ratable restoration" method, and affords customers a lower rate base in determining revenue requirements.

That same year, LG&E elected a rate treatment under the IRC Section 46(f)2, known as Option 2, wherein LG&E reduced its cost of service by the amount of the tax credit it amortizes each year. This rate treatment is referred to as the "ratable flow through" method, and affords customers a benefit through a lower cost of service.

The Companies believe that the IRC is clear in that if they do not employ the ratable restoration and ratable flow through methods, respectively, to normalize the credit as previously elected, they would lose the ability to claim the credit.

While IRC Section 46(f) has been repealed, it continues to apply to new investment tax credits through IRC Section 50(d). Thus, the Companies are required to continue to normalize such credits in its traditional fashion.

Also, IRC Section 50(c) requires the tax basis of the solar panels to be reduced by fifty percent of the credit. The loss of depreciable tax basis will result in an unfavorable permanent book versus tax difference over the life of the solar panels equal to the amount of the credit times the applicable tax rate, which we will seek to recover from customers as in the circumstance of Trimble County Unit No. 2 (KU Case No. 2009-00548 and LG&E Case No. 2009-00549).

For accounting purposes the credit received will be recorded to FERC Account 255 – Accumulated Deferred Investment Tax Credit and will be amortized, starting when the solar panels go into service, over the regulatory life of the solar panels. LG&E will amortize the credit to FERC Account 411.4 – Amortization of Investment Tax Credit (an above the line income statement account) and KU will amortize the credit to FERC Account 420 – Amortization of Investment Tax Credit (a below the line income statement account).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 9

Witness: David S. Sinclair

Q-9. Refer to the table below, which consists of Table 1, Peak Demand and Energy Requirements (Before DSM Programs), on page 7 of the Direct Testimony of David S. Sinclair ("Sinclair Testimony") with the lines "I - Annual Percentage Increase" for both Peak Demand and Energy Reduction calculated by Commission Staff.

	2012	2015	2020	2025	2030	2035	2040
Peak Demand (MW)	6,970	7,426	7,815	8,147	8,517	8,891	9,261
Energy (GWh)	35,076	36,748	38,184	39,847	41,768	43,657	45,683
Peak Demand (MW)							
PV - Present Value		6,970	7,426	7,815	8,147	8,517	8,891
FV - Future Value		7,426	7,815	8,147	8,517	8,891	9,261
N - Number of Periods		3	5	5	5	5	5
I -Annual Percentage Increase		2.13%	1.03%	0.84%	0.89%	0.86%	0.82%
Energy (GWh)							
PV - Present Value		35,076	36,748	38,184	39,847	41,768	43,657
FV - Future Value		36,748	38,184	39,847	41,768	43,657	45,683
N - Number of Periods		3	5	5	5	5	5
I – Annual Percentage Increase		1.56%	0.77%	0.86%	0.95%	0.89%	0.91%

Provide the following:

a. The reasons for, and which customer sectors were the cause of, the growth in peak demand at an annual percentage increases of approximately 2.13 percent for the period 2012 through 2015, approximately 1.03 percent for the period 2015 through 2020, approximately 0.84 percent for the period 2020 through 2025, and approximately 0.89 percent for the period 2025 through 2030.

b. The reasons for, and which customer sectors were the cause of, the growth in energy requirements at an annual percentage increase of approximately 1.56 percent for the period 2012 through 2015, approximately 0.77 percent for the period 2015 through 2020, approximately 0.86 percent for the period 2020 through 2025, and approximately 0.95 percent for the period 2025 through 2030.

A-9.

a. The 2012 peak demand and energy requirements values presented in Mr. Sinclair's testimony were incorrect. The table below contains the corrected values for 2012.

	2012	2015	2020	2025	2030	2035	2040
Peak Demand (MW)	7,117	7,426	7,815	8,147	8,517	8,891	9,261
Energy Requirements (GWh)[1]	35,440	36,748	38,184	39,847	41,768	43,657	45,683

After correcting the 2012 data, the CAGR from 2012 to 2015 in peak demand before DSM programs is 1.4 percent which is very consistent with the CAGR of 1.03 percent from 2015 to 2020. The change in peak demand is driven by the same factors that influence the growth in energy requirements discussed in subpart (b).

b. After correcting the 2012 data, the CAGR from 2012 to 2015 in energy requirements is 1.2 percent. The growth rates for energy requirements and peak demand growth across all customer classes are affected by economic growth, changes in use per customer, and customer growth. As referenced in Mr. Sinclair's testimony on pages 7-8, all of the major economic drivers are expected to grow over the next 30 years which leads to growth in energy requirements and peak demand. Peak demand and energy requirements grow at a slightly higher rate from 2012 through 2015 due to the less efficient installed base of appliances in the Residential and Small Commercial classes that are forecasted to slowly be replaced by more efficient end-use technologies. This trend continues throughout the forecast period, thus dampening the growth rate in both peak demand and energy requirements.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 10

Witness: David S. Sinclair

Q-10. Refer to the table below, which consists of Table 2 — 2013 LF — Peak Demand and Energy Reduction from DSM Programs, on page 9 of the Sinclair Testimony with the lines "I — Annual Percentage Increase" for both Peak Demand and Energy Reduction calculated by Commission Staff.

	2012	2015	2020	2025	2030	2035	2040
Peak Demand (MW)	114	386	466	475	484	493	502
Energy (GWh)	139	585	764	764	764	764	764
Peak Demand (MW)							
PV - Present Value		(114)	(386)	(466)	(475)	(484)	(493)
FV - Future Value		386	466	475	484	493	502
N - Number of Periods		3	5	5	5	5	5
I - Annual Percentage Increase		50.16%	3.84%	0.38%	0.38%	0.37%	0.36%
Energy (GWh)							
PV - Present Value		(139)	(585)	(764)	(475)	(484)	(493)
FV - Future Value		585	764	764	764	764	764
N - Number of Periods		3	5	5	5	5	5
I – Annual Percentage Increase		61.43%	5.48%	0.00%	0.00%	0.00%	0.00%

Provide the following:

a. The reasons for, and which customer sectors were the cause of, the growth in peak demand reduction associated with DSM programs at an annual percentage increase of approximately 50.0 percent for the period 2012 through 2015, approximately 3.8 percent for the period 2015 through 2020, and approximately 0.38 percent for each of the five year periods 2020 through 2025 and 2025 through 2030.

b. The reasons for, and which customer sectors were the cause of, the growth in energy requirement reduction associated with DSM Programs at an annual percentage reduction increase of approximately 61.0 percent for the period 2012 through 2015, approximately 5.48 percent for the period 2015 through 2020, and approximately 0.0 percent for the period 2020 through 2025 and 2025 through 2030.

A-10.

a-b.The 2012 demand reduction and energy reduction values presented in Mr. Sinclair's testimony were incorrect. The table below contains the corrected DSM values for 2012.

	2012	2015	2020	2025	2030	2035	2040
Peak Demand (MW)	261	386	466	475	484	493	502
Energy (GWh)	503	585	764	764	764	764	764

After correcting the 2012 data, the CAGR for peak demand reduction from 2012 to 2015 is 13.9 percent.

After correcting for the 2012 data, the CAGR for energy reduction from 2012 to 2015 is 5.2 percent which is comparable to CAGR from 2015 to 2020. Please note the Energy (GWh) in the table reflects cumulative energy reduction values beginning in 2013.

The higher DSM demand and energy for 2012-2015 is related to new and enhanced programs approved in KPSC Case No. 2011-00134, in November 2011 for programs through 2018. Thus, the 3.8% CAGR for 2015-2020 is inclusive of these approved new and enhanced programs. The lower rate for 2020-2040 reflects the flattening of savings after 2018 as discussed at Mr. Sinclair's Testimony page 9 lines 7-18.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 11

Witness: David S. Sinclair

Q-11. Refer to page 9, lines 12-14, of the Sinclair Testimony which state, "Prior to the end of 2018, programs will be revaluated and renewed where appropriate, taking market potentials, building codes, customer expectations, and energy efficient technologies into consideration."

a. State the number of years the Companies have offered DSM programs to their customer bases.

b. During the time frame in which the Companies offered DSM programs to their customer bases, state the number of times the Companies' DSM filings with the Commission resulted in no increase in peak demand reduction and/or energy reduction as a result of the DSM filing.

A-11.

a. LG&E first offered DSM programming in 1994, with KU beginning in 2001.

b. DSM filings typically request approval for seven years of program operation and incorporate increased savings as a result. The current DSM filing (Case No. 2014-00003) covers the last four years of the prior case (Case No. 2011-00134) and no additional demand or energy savings were included in the current case. Rather, program modifications were requested to meet customer demand and still achieve expectations for 2015-2018 as presented in the 2011 DSM case.

The Companies have not had the advantage of an energy efficiency market potential study for previous filings. The recently completed study indicates that at the Companies' current levels of energy savings, the achievable energy efficiency potential will be limited after 2018 based on current energy efficiency technologies and economics.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 12

Witness: David S. Sinclair

Q-12. Refer to the table included in question 10, which consists of Table 2 — 2013 LF — Peak Demand and Energy Reduction from DSM Programs on page 9 of the Sinclair Testimony, with the lines "I — Annual Percentage Increase" for both Peak Demand and Energy Reduction calculated by Commission Staff. Assume an annual average increase of 3.84 percent in peak demand reduction from DSM programs between 2020 through 2040, as the Companies forecasted between 2015 through 2020, along with an annual average increase of 5.48 percent in energy reduction from DSM programs between 2020 through 2040, as the Companies forecasted between 2015 through 2020.

a. Provide a revised Table 3 — 2013 LF — Peak Demand and Energy Requirements (After DSM Programs) as shown on page 10, lines 14-16, of the Sinclair Testimony.

b. How would the revised Table 3 results impact the need for the proposed construction of the 700-MW NGCC and the 10-MW solar photovoltaic facility?

A-12.

a. See below for the revised table.

Revised Table 3

	2012	2015	2020	2025	2030	2035	2040	
Peak Demand (MW)	261	386	466	475	484	493	502	
Energy (GWh)	503	585	764	764	764	764	764	
Peak Deamnd (MW)								
PV-Present Value		(261)	(386)	(466)	(563)	(679)	(820)	
FV-Future Value		386	466	563	679	820	990	Calculated from
Incremental Change				88	195	327	488	Assumed Values
N-Number of Periods		3	5	5	5	5	5	
I-Annual Percentage Increase		13.93%	3.84%	3.84%	3.84%	3.84%	3.84%	Assumed Values
Energy (GWh)								
PV-Present Value		(503)	(585)	(764)	(998)	(1303)	(1701)	
FV-Future Value		585	764	998	1,303	1,701	2,221	Calculated from
Incremental Change				234	539	937	1,457	Assumed Values
N-Number of Periods		3	5	5	5	5	5	
I-Annuall Percentage Increase		5.16%	5.48%	5.48%	5.48%	5.48%	5.48%	Assumed Values
Original Table 3 - DSS								
Peak Deamnd (MW)	6,856	7,040	7,350	7,673	8,034	8,398	8,760	
Energy Requirements (GWh)	34,937	36,162	37,421	39,083	41,004	42,894	44,920	
Revised Table 3								
Peak Demand (MW)		7,040	7,350	7,673	8,034	8,398	8,760	
Hypothetical Additional DSM				88	195	327	488	
Revised Peak		7,040	7,350	7,585	7,839	8,071	8,272	
Energy Requirements (GWh)		36,162	37,421	39,083	41,004	42,894	44,920	
Hypothetical Additional DSM				234	539	937	1,457	
Revised Energy Requirements		36,162	37,421	38,849	40,465	41,957	43,463	

b. Should unknown future DSM programs create the savings suggested in this question, they would have no impact on the proposed construction of the Green River NGCC and Brown Solar Facility for two reasons: (i) the Companies' need for capacity in 2018 is unchanged and (ii) load would still be higher than the Companies' Low load forecast scenario, where the proposed Green River NGCC is still the least-cost alternative (see Table 22 on page 28 of Exhibit DSS-1).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 13

Witness: David S. Sinclair

Q-13. Refer to page 9, Table 2 — 2013 LF — Peak Demand and Energy Reduction from DSM Programs of the Sinclair Testimony. If one were to assume an annual average 3.8 percent reduction in peak demand from DSM programs between 2020 through 2040, as the Companies did between 2015 through 2020, along with the Companies' 2014 Load Forecast ("LF"), what would be the impact on the Reserve Margin line for the 2013 Resource Assessment as shown on Table 6 — Resource Summary Comparison, 2013 on page 19 of the Sinclair Testimony?

A-13. See table below. Compared to the 2013 LF, DSM peak demand reductions are slightly lower in the 2014 LF. Between 2015 and 2020, DSM in the 2014 LF grows at 3.9 percent. In the table below, DSM is escalated at 3.9 percent beyond 2025. Compared to the reserve margin shown in Table 6 on page 19 of the Sinclair Testimony, the reserve margin with these changes is mostly unchanged through 2020. By 2035, the revised reserve margin is 6.6 percent higher.

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2025**	**2030**	**2035**
Peak Load - 2014 LF	7,364	7,450	7,536	7,623	7,663	7,721	8,003	8,285	8,578
DSM*	(336)	(365)	(394)	(423)	(406)	(406)	(490)	(593)	(717)
Net Peak Load	7,028	7,085	7,142	7,199	7,257	7,315	7,513	7,692	7,861
Existing Resources	7,814	7,796	7,796	7,796	7,796	7,796	7,796	7,796	7,796
Firm Purchases (OVEC)	152	152	152	152	152	152	152	152	152
Curtailable Demands	137	137	137	137	137	137	137	137	137
Total Supply	8,103	8,085	8,085	8,085	8,085	8,085	8,085	8,085	8,085
Reserve Margin - Revised	15.3%	14.1%	13.2%	12.3%	11.4%	10.5%	7.6%	5.1%	2.8%
Reserve Margin - Table 6 in Sinclair Testimony	15.1%	14.0%	13.1%	12.1%	11.0%	10.0%	5.4%	0.6%	-3.7%
Difference	0.2%	0.1%	0.1%	0.2%	0.4%	0.5%	2.2%	4.5%	6.6%

*Hypothetical DSM for years beyond 2020.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 14

Witness: David S. Sinclair

Q-14. Refer to page 13, Table 4 — 2014 LF compared to the 2013 LF — Peak Demand and Energy Requirements (After DSM Programs) of the Sinclair Testimony.

a. Confirm that the change in the 2013 LF and the 2014 LF in peak demand for 2040 is a reduction of approximately 3.2 percent ((284)/8,760).

b. Confirm that the change in the 2013 LF and the 2014 LF in energy requirements for 2040 is a reduction of approximately 5.8 percent [(2,586)/44,920)].

c. If one were to assume an annual average 3.8 percent reduction in peak demand from DSM programs between 2020 through 2035, as the Companies did between 2015 through 2020, along with the Companies' 2014 LF, what would the Reserve Margin line show on page 4 of the Joint Application?

A-14.

a. The change in peak demand in 2040 between the 2014 LF and the 2013 LF is 3.2 percent.

b. The change in energy requirements in 2040 between the 2014 LF and the 2013 LF is 5.8%.

c. See the response to Question No. 13.

The 2014 LF uses a lower amount of peak DSM compared to the 2013 LF. A comparison of the peak DSM amounts between the 2013 LF, 2014 LF, and the most recent DSM filing is shown in the table below.

Demand Side Management Demand Reductions (MW)

	2015	2020	2025	2030	2035	2040
1) Peak DSM in (2014-2018) DSM Filing	388	500				
2) Peak DSM in 2013 LF	386	466	475	484	493	502
3) Peak DSM in 2014 LF	336	406	406	406	406	406

Please note the following:

- The 2014 LF peak DSM amounts are lower compared to the 2013 LF because customers are installing higher efficiency AC units and thus the amount of peak energy reduction achieved per load control device has assumed to decrease. The lower peak DSM amounts reflected in the 2014 LF reflect this change.
- The 2014 DSM filing and previous cases present year-end reductions while the load forecasts use mid-year conventions to correspond to summer peak load conditions. Thus, if comparing the two filings one would notice a difference based upon mid-year versus year-end conventions.
- Consequently, the difference shown between the Peak DSM in the 2014 DSM Filing and the Peak DSM in 2013 LF is due to mid-year convention, the change from 2013 LF to 2014 LF is due to the reduction in load achieved per load control switch, and putting the load reduction amounts on a consistent weather basis to the load forecast.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 15

Witness: David S. Sinclair

Q-15. Refer to page 17 of the Sinclair Testimony. Explain why the Federal Energy Regulatory Commission's ("FERC") conditional approval of the Companies' request to purchase the Bluegrass Generation facilities rendered that transaction not economical.

A-15. See FERC's May 4, 2012 Order in Docket No. EC12-29-000 at pp. 15 and 22. (http://www.ferc.gov/EventCalendar/Files/20120504160345-EC12-29-000.pdf).

On June 18, 2012, the Companies sent a letter to the Executive Director of the Commission, advising of the Companies' intent to terminate the purchase agreement with Bluegrass Generation. A copy of that letter is attached. In addition, an Informal Conference was held on June 27, 2012. A copy of the presentation provided at the Informal Conference is attached.

LG&E KU
PPL companies

LG&E and KU Energy LLC
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Lonnie E. Bellar
Vice President
T 502-627-4830
F 502-217-2109
lonnie.bellar@lge-ku.com

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

RECEIVED
JUN 18 2012
PUBLIC SERVICE
COMMISSION

June 18, 2012

RE: ***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. 2011-00375

Dear Mr. DeRouen:

On May 8, 2012, our counsel sent a letter to you enclosing a May 4, 2012 Federal Energy Regulatory Commission ("FERC") order concerning Louisville Gas and Electric Company and Kentucky Utilities Company's proposed acquisition of the Bluegrass Generation Company's combustion turbines in Lagrange, Kentucky. (The proposed acquisition is part of what the Kentucky Public Service Commission approved in its May 3, 2012 final order in Case No. 2011-00375.) Our counsel's letter noted that the Companies were going to review the FERC order and apprise you of any developments.

I am writing to you to inform the Commission that the Companies have carefully reviewed the FERC order and have decided not to proceed with the Bluegrass acquisition because of the significant uncertainty the FERC order creates. This decision does not create a near term capacity shortfall for the Companies since the proposed acquisition, while anticipated to have closed in 2012, was to support future needs.

The order conditions approval of the acquisition on the Companies' submitting by July 3, 2012, a proposed market-power mitigation proposal, which FERC would then have to review and accept or reject, which could necessitate additional possible mitigation measures of unknown cost and duration. The order creates a second layer of significant uncertainty by requiring the Companies to make a second compliance filing no later than December 31, 2016, to re-examine market-power issues related to the Bluegrass units, which could result in requiring additional mitigation measures, again of unknown cost and duration.

In addition to the uncertainties the FERC order creates concerning the ultimate cost of obtaining final approval for the acquisition, the order markedly extends the regulatory process necessary to obtain truly final approval. Also, and importantly, mitigation would mean that the ratepayers might not have access to the Bluegrass units when and if needed for an unknown period of time.

Circumstances may yet eventuate to make purchasing the units or entering into another kind of arrangement with Bluegrass Generation economical for our customers. But at present, it is prudent for the Companies and their customers to terminate the current purchase agreement with Bluegrass Generation and to consider further how best to meet our customers' future needs.

We would be glad to discuss this with you and your staff if you would like additional information on how the Companies arrived at this decision.

Sincerely,

Lonnie E. Bellar

cc: Parties of Record

PPL companies

Update to Bluegrass Purchase
Case No. 2011-00375

Informal Conference
Kentucky Public Service Commission
June 27, 2012






Background

- *Bluegrass generating units were a least cost resource in 2011 Resource Assessment*
  - *Pricing justified purchase in 2012 to serve 2016 capacity needs*
  - *Beginning in 2012 units would have:*
    - *Displaced higher-cost power*
    - *Served contingent power needs as necessary*
    - *Been a low-cost solution to meet future environmental requirements*
- *Federal Power Act Sec. 203 application with Federal Energy Regulatory Commission ("FERC")*
  - *Required market concentration analysis of Companies' generating capacity within Balancing Authority Area ("BAA")*
  - *FERC's formulas showed screen failures resulting from the Companies' control of generating capacity in excess of amount needed to serve load*
  - *Companies argued that screen failures were not material because:*
    - *FERC's requirement for Companies to sell power within their BAA at cost-based rates would mitigate any market power issues*
    - *Bluegrass capacity is not significant compared to overall capacity in the BAA*
    - *Virtually all energy from Bluegrass has historically been sold to Companies, thus no market impact*
  - *Companies' arguments were not contested (no interventions in proceeding)*

FERC Order

- *Section 203 Order issued on May 4, 2012*
  - *FERC conditionally approved the acquisition*
  - *Mitigation of apparent horizontal market power concentration required prior to closing*
  - *Subsequent FERC filing in 2016 required to show that no screen failures exist*
- *Procedural options considered*
  - *Request a hearing or a rehearing*
  - *After rehearing, file an appeal*
- *Procedural options not pursued*
  - *Mitigation not tolled pending rehearing requests*
  - *An order could take a year or longer*
  - *While mitigation in place, ratepayer supply is uncertain and could lead to duplication*
  - *Low likelihood of success*

FERC Order (continued)

- *Mitigation options considered*
  - *Transfer operational control to a third party*
  - *Sell energy from Bluegrass*
  - *Build transmission*
- *Mitigation options not pursued*
  - *Uncertain availability of a third-party marketer or market*
  - *No assurance that Bluegrass power would be available in extreme emergencies*
  - *Uncertain duration for mitigation raised concerns about when additional capacity would be required*
  - *Mitigation costs would add to the cost of the Bluegrass acquisition*
  - *Because mitigation must be in place prior to closing, a June 2012 closing was not possible*
- *Discussion with FERC Staff*

Decision

- *Due to the timing, cost and risk concerns associated with procedural options and mitigation options, Companies determined they would terminate the contract to acquire the Bluegrass units and pursue alternative plan.*

- *Termination notice issued to LS Power on 6/18/2012.*

Next Steps

- *Analysis of how to satisfy future capacity needs will include:*
  - *RFP to survey market*
    - *Possible proposal involving Bluegrass units*
    - *Purchase Power Agreement*
    - *Asset Purchase*
  - *Self-build option(s)*
  - *Evaluation of environmental controls for Brown 1 and 2*
  - *Updated load forecast*
  - *Consideration of upcoming DSM potential study*
  - *Evaluation of transmission requirements for all options*

MEETING TRACKING SIGN-IN SHEET
#549
DATE/TIME CONFERENCE ROOM
June 27, 2012 at 2:00 PM
CR # 1
NAME OF REQUESTOR/SUBJECT OF MEETING
Louisville Gas and Electric and Kentucky Utilities
FERC Order and Bluegrass Acquisition

NAME	AGENCY/COMPANY
Chris Balmer	LG&E/KU
Doug Schetzel	LGE/KU
CHUCK SCHRAM	LG&E/KU
Lindsey Ingram	SKO/LG&E/KU
Joe Childers	Sierra Club
Mike Kurtz	KIUC
Lonnie Bellar	LG&E KU
RICHARD RAFF	PSC-LEGAL
AARON GREENWELL	PSC
Beth Cocanougher	LGE/KU
Allyson Sturgeon	LGE/KU
Larry Cook	OAG
Quang D. Nguyen	PSC
John Rogness	PSC
Errol K Wagner	PSC
David B. Raff	PSC-Legal
Daryl Newby	PSC - FA
Jim Wood	PSC Legal

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 16

Witness: David S. Sinclair

Q-16. Refer to page 17 of the Sinclair Testimony. Table 5 — LG&E/KU Resource Summary (MW Summer 2013 LF) displays the Companies' forecasted reserve margin. Recalculate and provide the forecasted reserve margin table assuming the proposed 710 MW of resource capacity is approved as requested.

A-16. See table below. 90% of Brown Solar's capacity is assumed to be available to meet the summer peak demand.

Resource Summary with Green River NGCC and Brown Solar (Summer)

	2015	2016	2017	2018	2019	2020	2025	2030	2035
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	8,147	8,517	8,891
Energy Efficiency/DSM	(386)	(418)	(450)	(482)	(464)	(466)	(475)	(484)	(493)
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,673	8,034	8,398
Existing Resources[1]	7,814	7,796	7,796	7,796	7,796	7,796	7,796	7,796	7,796
Green River NGCC and Brown Solar		9	9	709	709	709	709	709	709
Firm Purchases (OVEC)	152	152	152	152	152	152	152	152	152
Curtailable Load	137	137	137	137	137	137	137	137	137
Total Supply	8,103	8,094	8,094	8,794	8,794	8,794	8,794	8,794	8,794
Reserve Margin ("RM")	15.1%	14.1%	13.2%	21.9%	20.8%	19.6%	14.6%	9.5%	4.7%
RM Shortfall (17% RM)	(134)	(203)	(268)	354	275	195	(183)	(605)	(1,032)
RM Shortfall (15% RM)	7	(62)	(125)	498	420	342	(29)	(445)	(864)

[1] 'Existing Resources' reflects the retirement of Tyrone Unit 3, Green River Units 3 and 4, and Cane Run Units 4, 5, and 6 as well as the addition of Cane Run Unit 7.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 17

Witness: David S. Sinclair

Q-17. Refer to page 22 of the Sinclair Testimony. In discussing the process to select the best resources to meet customer needs over the next 30 years, the term "economically robust under a range of possible conditions" is utilized. Define the meaning of the phrase "economically robust under a range of possible conditions."

A-17. As Mr. Sinclair states on page 22, lines 4-7, "After careful consideration, the Companies identified three key risk elements as most critical for testing the robustness of possible resources: (i) load growth, (ii) natural gas prices, and (iii) potential CO_2 regulations." The future cannot be known with certainty so a generating resource whose economics compare favorably to other resources under a number of these risk elements would be more "economically robust" than a resource that may be somewhat lower cost under a very limited set of elements and very expensive under other elements.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 18

Witness: David S. Sinclair

Q-18. Refer to page 22 of the Sinclair Testimony, lines 19-21, which state ". . . having excess capacity and energy is often viewed as more costly than adding additional capacity should load turn out to be greater." Explain why having excess capacity and energy is often viewed as being more costly than adding capacity to meet greater than anticipated load.

A-18. Very often, regulated utility assets must be considered "used and useful" in order for those costs to be included in rates. Utility regulatory commissions throughout the nation have been reluctant to allow "excess capacity" costs to be included in rates for the reason that the capacity is not considered "used and useful" and thus, would unnecessarily increase customers' costs. Adding more capacity at a later date should load growth turn out to be greater than forecasted would, by definition, result in capacity that would be "used and useful" to meet customers' energy needs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 19

Witness: David S. Sinclair

Q-19. Refer to page 27 of the Sinclair Testimony. It is stated that the estimated cost of building the solar project at the Brown Station in September 2013 was $2,400/kW which includes an available existing company site, effectively removing the land cost from the overall project cost. On page 28 of the Sinclair Testimony, the December 2013 cost estimate escalates to $3,600/kW. Explain in detail why the cost estimate in December 2013 was 33 percent higher than the cost estimate in September 2013.

A-19. Section 4.6 of Exhibit DSS-1 provides a description of the development of the cost estimate. See the table below. The change in the cost estimate is explained primarily by an increase in the assumed installed cost of solar panels. Owner and site development costs as well as contingency costs are also higher in the December cost estimate. Contingency costs are 10 percent of the installed cost of solar panels in the September cost estimate; in the December cost estimate, contingency costs are 15 percent of the installed cost of solar panels.

Solar PV Cost Estimate	**September Cost**	**December Cost**	**Cost Difference**
Installed Cost of Solar Panels	20,000,000	29,000,000	9,000,000
Owner/Site Development Cost	1,770,000	2,420,000	650,000
Contingency	2,000,000	4,350,000	2,350,000
Total Project Cost	23,770,000	35,770,000	12,000,000
Total Cost $/kW (AC)	$2,377/kW	$3,577/kW	$1,200/kW

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 20

Witness: David S. Sinclair

Q-20. Refer to page 34, lines 7-9, of the Sinclair Testimony, which state, "If the Companies continue to achieve annual savings at the planned rate, achievable discretionary electric efficiency potential will be exhausted in 2020."

a. Provide a definition of the phrase "achievable discretionary electric energy efficiency potential."

b. Is it the Companies' testimony that all mobile homes connected to their distribution system will no longer have resistance heating systems operational in the mobile homes after 2020?

c. Is it the Companies' testimony that all residential customers connected to their distribution system will have only Energy Star appliances installed in their homes after 2020?

A-20.

a. The Cadmus Group market potential study evaluated electric efficiency by first looking at total Technical Potential which assumes all electric efficiency measures would be deployed to every residential and commercial customer. They then calculated Economic Potential by comparing the cost of each of these measures to the Companies' avoided cost of capacity and energy. Lastly, they calculated achievable potential based on their primary research looking at customer acceptance. From this, achievable discretionary electric energy efficiency potential relates to the achievable potential left to customer choice as there are no mandates to force customers to deploy or adopt energy efficiency efforts.

b. No. This statement would only be true in the evaluation of Technical Potential. The Companies' DSM programs are voluntary for customer participation and are not designed to cover the full cost of deploying various efficiency measures. As such, customers who own mobile homes may not choose to retrofit their home for a multitude of reasons including economics. Thus not all resistance heating systems will be eliminated by/or after 2020.

c. No. This statement would only be true in the evaluation of Technical Potential. The Companies' DSM programs are voluntary for customer participation and are not designed to cover the full cost of deploying various efficiency measures. As such, customers who purchase appliances may not choose to purchase Energy Star appliances for a multitude of reasons including economics. Thus not all customers will install Energy Star appliances by/or after 2020.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 21

Witness: David S. Sinclair

Q-21. Refer to page 35 of the Sinclair Testimony, lines 6-8, wherein Mr. Sinclair states that, to address capacity and energy needs in 2016 and 2017, the Companies are pursing negotiations for a short term purchase power agreement ("PPA"). State whether the Companies intend to make a selection for this PPA from the responses to its September 2012 RFP, or if the Companies intend to issue a new RFP.

A-21. At this time, the Companies are exploring all options, including alternatives from parties that provided responses to the Companies' September 2012 RFP. No decision has been made regarding issuing a new RFP.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 22

Witness: David S. Sinclair

Q-22. Refer to Exhibit DSS-1 of the Sinclair Testimony. Provide the initial analysis of the bids received in response to the RFP, as well all analyses performed for each phase of the Resource Analysis, in electronic format.

A-22. 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. The root directory on the hard drive contains three folders:

- 01_Correspondence: This folder contains RFP responses and other correspondence with the bidders.

- 02_Analysis: This folder contains all analysis files supporting Exhibit DSS-1. The analysis for the resource assessment was completed in phases (and some phases include multiple iterations). The phase/iteration naming convention was modified for the resource assessment document to simplify the presentation of the results. The following table maps sections of the resource assessment document to the electronic file folder(s) that contain the associated analysis files.

Phase/Iteration – Resource Assessment Document	**Phase/Iteration – Analysis Folder**
Key Inputs and Uncertainties (Section 4.1)	02_Analysis\ModelInputs
Phase 1 Screening Analysis (Section 4.3)	02_Analysis\Phase1
Phase 2, Iteration 1 – Analysis of Two-Year PPAs (Section 4.4.2)	02_Analysis\Phase2\Iteration1
Phase 2, Iteration 2 – Analysis of Long-Term Proposals (Section 4.4.3)	02_Analysis\Phase2\Iteration2
Phase 3, Iteration 1 – Enhancements (Section 4.5.1)	02_Analysis\Phase2\Iteration3
Phase 3, Iteration 2 – Deferral Considerations (Section 4.5.2)	02_Analysis\Phase3\Iteration1 02_Analysis\Phase3\Iteration2
Phase 4 – Solar Considerations (Section 4.6)	02_Analysis\Phase3\Iteration3

- 03_Deliverables: This folder contains the 2013 Resource Assessment document.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 23

Witness: David S. Sinclair

Q-23. Refer to page 3, Section 2 of Exhibit DSS-1. Explain in detail what is meant by FERC's finding of significant screen failures in the horizontal market power analysis of the Bluegrass Generation decision.

A-23. FERC requires applications for approval under Section 203 of the Federal Power Act to contain, among other things, a "Competitive Analysis Screen" that looks at the impact of the proposed transaction on the concentration in the market for electric generation, as measured by a quantitative measure of market concentration. The Competitive Analysis Screen requires that such impact be measured under a variety of season and time periods, and under two measures of how much generating capacity entities in the market place control. An analysis is said to fail a screen if market concentration increases by more than certain levels established by FERC. In its order on the Companies' application under FPA Section 203 to acquire the Bluegrass Facility, FERC stated "The Commission finds that the Proposed Transaction results in significant screen failures in the horizontal market power analysis." *Bluegrass Generation Co.*, Docket No. EC12-29-000, 139 FERC ¶ 61,094 at P 1 (2012).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 24

Witness: David S. Sinclair

Q-24. Refer to page 7 of Exhibit DSS-1. It is stated in the paragraph above Table 3, "The DSM programs in Table 3 are the most competitive programs that will not be included in the DSM filing." Explain why the programs in Table 3 were not included in the Companies' most recent Demand-Side Management ("DSM") filing.

A-24. Of all the programs considered in Table 3, only the last 2 (Commercial New Construction and Automated Demand Response) were included in the DSM filing. For those programs in Table 3 that were not included in the DSM filing, they either scored poorly on the demand-side California tests and/or had an unfavorable impact on the revenue requirements in the production cost analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 25

Witness: David S. Sinclair

Q-25. Refer to page 9 of Exhibit DSS-1, Section 4.1.1 Load Forecast, which states, "According to the Energy Information Administration's ("EIA") Annual Energy Outlook ("AEO") issued in 2013, annual electricity consumption on a national level is expected to grow at an average rate, from 2010 to 2040, of 0.7%, 0.8% and 0.6% for the Residential, Commercial and Industrial sectors, respectively."

a. Would the Companies agree that if the national annual electricity consumption were consumed equally among all three electric sectors, Residential, Commercial and Industrial, one would expect the annual electricity consumption on a national level to grow at an average rate between 2010 to 2040 of approximately 0.7 percent, using the information from the EIA AEO above [(.007 X .3333) + (.008 X .333) + .006 X .3334)]?

b. Refer to Table 6 — Native Load Scenarios on page 10 of Exhibit DSS-1. What is the average annual increase percentage forecasted for the 29 years between 2013 and 2042 for the 2013 LF column?

c. Explain why the average annual increase used on Table 6, column "2013 LF" is approximately 5 percent greater than the EIA's AEO highest sector's forecast for the similar time period.

d. Provide the Companies' 2009 load forecasts, for both energy requirements and peak demand, for each year 2010 through 2039.

e. Provide the Companies' actual energy requirement and peak demand for each year 2010 through 2013.

f. Provide the percentage difference between the Companies' 2009 load forecast for years 2010 through 2013 and the Companies' actual energy requirements and peak demand for the same years, along with the reasons for the differences and the customer sector(s) causing the difference.

A-25.

a. The Companies agree that the EIA AEO's average annual growth rate from 2010 to 2040 would be approximately 0.7 percent when equally weighting residential, commercial and industrial sector growth.

b. The CAGR from 2013 to 2042 for the 2013 LF is 0.84 percent.

c. The Companies assume that the "5 percent" difference in growth rates cited in the question is calculated by dividing 0.84 percent from subpart (b) by 0.80 percent for the U.S. commercial sector as forecasted by the EIA and cited in this question. If so, the Companies do not believe that it is appropriate in this context to compare growth rates on a percent change basis. The table below compares the CAGR with various starting years through 2040 for the Companies' energy requirements (as shown in Exhibit DSS-4) with the EIA's forecast of residential and commercial sales over the same periods. This shows that the growth rates are not materially different, regardless of which time period is selected. Furthermore, the CAGR from 2011 through 2040 of the Companies' forecasted energy requirements is the same 0.9 percent as EIA's forecast for total US electricity demand (see Mr. Sinclair's testimony, footnote 11 on page 10) for the same time period.

	2010-40	2011-40	2012-40	2013-40
Companies' Energy Requirements	0.80%	0.91%	0.90%	0.85%
US Residential Sales	0.67%	0.75%	0.87%	0.98%
US Commercial Sales	0.78%	0.83%	0.84%	0.92%

d. See the tables below for the 2010 LF (prepared in 2009) energy requirements, peak demands and sales by class after DSM. Note that energy requirements are provided only on a total basis, not by class.

Year	2010 LF - Energy Requirements (GWh)	2010 LF - Peak Demand (MW)	2010 LF - Residential Sales (GWh)	2010 LF - Commercial Sales (GWh)	2010 LF - Industrial Sales (GWh)	2010 LF - Public Authority Sales (GWh)
2010	33,907	6,685	10,965	8,280	7,817	4,911
2011	34,890	6,794	10,988	8,531	8,307	5,075
2012	35,954	6,856	11,088	8,753	8,819	5,243
2013	36,741	6,871	11,197	8,941	9,144	5,361
2014	37,307	6,972	11,321	9,050	9,367	5,435
2015	37,902	6,996	11,484	9,220	9,534	5,508
2016	38,429	7,126	11,661	9,377	9,658	5,559
2017	38,848	7,141	11,748	9,518	9,786	5,606
2018	39,392	7,280	11,906	9,681	9,933	5,660
2019	39,976	7,316	12,081	9,859	10,065	5,720
2020	40,544	7,433	12,262	10,040	10,190	5,776
2021	40,980	7,536	12,357	10,198	10,305	5,820
2022	41,545	7,670	12,526	10,384	10,424	5,881
2023	42,077	7,723	12,703	10,543	10,541	5,928
2024	42,733	7,865	12,962	10,736	10,653	5,995
2025	43,294	8,002	13,132	10,921	10,769	6,055
2026	43,867	8,082	13,355	11,076	10,880	6,103
2027	44,444	8,166	13,575	11,242	10,993	6,155
2028	45,122	8,251	13,836	11,432	11,113	6,221
2029	45,673	8,416	14,041	11,590	11,223	6,273
2030	46,245	8,488	14,286	11,730	11,333	6,317
2031	46,745	8,614	14,474	11,868	11,443	6,360
2032	47,297	8,676	14,686	12,014	11,561	6,407
2033	47,846	8,793	14,855	12,176	11,686	6,462
2034	48,380	8,868	15,032	12,323	11,814	6,509
2035	48,919	8,994	15,200	12,485	11,946	6,563
2036	49,520	9,092	15,454	12,626	12,081	6,606
2037	50,090	9,194	15,614	12,797	12,228	6,662
2038	50,634	9,303	15,777	12,947	12,375	6,718
2039	50,613	9,393	15,901	13,120	12,484	6,770

e-f. See table below for 2010 LF (prepared in 2009) energy requirements and peak demands after DSM compared to actuals for the years 2010 to 2013.

Year	2010 LF - Energy Requirements	2010 LF - Peak Demand	Actual Peak Demand (MW)	Actual Energy Requirements (GWh)	% Peak Difference	% Energy Difference
2010	33,907	6,685	7,175	36,636	7.34%	8.05%
2011	34,890	6,794	6,756	34,755	-0.56%	-0.39%
2012	35,954	6,856	6,856	34,728	0.00%	-3.41%
2013	36,741	6,871	6,434	35,042	-6.35%	-4.63%

In the normal course of business, the Companies produce weather-normalized estimates for sales by class. These values were grossed up for losses to approximate energy requirements. The Companies have not performed an analysis of the "other" variances, but note that the economic recovery has been slower than forecasted which has particularly impacted residential and commercial sales, as well as wholesale municipal sales (which are largely residential and commercial in nature). The impact of the slower growth in 2012 and 2013 is reflected in the 2013 LF and 2014 LF. See table below.

		Weather					
(GWh)	Energy Req Total Variance	Res	Com	Ind	Public Authority	Muni	Total
2010	2,730	(947)	(212)	(47)	(40)	(60)	(1,306)
2011	(135)	(100)	(39)	(18)	(6)	(12)	(175)
2012	(1,226)	140	(16)	(20)	(1)	(11)	93
2013	(1,699)	(125)	(6)	(2)	(3)	(0)	(136)
		Other					
	(GWh)	Res	Com	Ind	Public Authority	Muni	Total
	2010	9	(54)	1,349	94	26	1,424
	2011	(300)	(593)	844	(161)	(100)	(310)
	2012	(429)	(946)	788	(331)	(215)	(1,133)
	2013	(562)	(1,221)	646	(455)	(244)	(1,835)

	Total Sales (MWh)					
	2010 LF	Actual	Weather Normalized Actual			
2010	31,973,446	34,276,482	33,054,302			
2011	32,900,339	32,803,411	32,638,676			
2012	33,902,469	32,793,964	32,882,066			
2013	34,642,758	32,968,392	32,840,630			
	Residential Sales (MWh)			Commercial Sales (MWh)		
	2010 LF	Actual	Weather Normalized Actual	2010 LF	Actual	Weather Normalized Actual
2010	10,964,947	11,773,508	10,887,176	8,280,233	8,363,425	8,164,893
2011	10,988,025	10,809,543	10,715,501	8,530,883	8,015,370	7,978,920
2012	11,087,869	10,567,106	10,699,182	8,752,741	7,887,022	7,872,307
2013	11,196,740	10,761,493	10,644,077	8,941,086	7,779,180	7,773,307
	Industrial Sales (MWh)			Public Authority Sales (MWh)		
	2010 LF	Actual	Weather Normalized Actual	2010 LF	Actual	Weather Normalized Actual
2010	7,816,919	9,061,203	9,017,504	4,911,347	5,078,346	4,984,730
2011	8,306,709	9,128,329	9,111,428	5,074,722	4,850,169	4,832,827
2012	8,818,967	9,594,342	9,575,683	5,242,892	4,745,494	4,734,894
2013	9,144,137	9,733,611	9,731,690	5,360,796	4,694,108	4,691,556

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 26

Witness: David S. Sinclair

Q-26. Refer to Section 4.1.1. on page 11 of Exhibit DSS-1. Explain why the Companies did not consider off-system sales in evaluating mitigating short-term costs associated with excess capacity.

A-26. See Exhibit DSS-1 at page 14. 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 speculation 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 the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 27

Witness: David S. Sinclair

Q-27. Refer to Section 4.5.1 on page 32 of Exhibit DSS-1. The last sentence of the section states, "At this price level, justification for solar projects is difficult." State whether there are implicit ratepayer benefits which justify the cost. Explain in detail.

A-27. All resource options considered in the Resource Assessment were evaluated using economic factors that could be translated into revenue requirements. No "implicit ratepayer benefits," were included.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 28

Witness: John N. Voyles, Jr.

Q-28. State whether Kentucky is geographically situated for a solar facility based upon the solar power resource available expressed in kWh/m2/day.

a. What average daily output do the Companies project for the Brown Station Solar Facility?

b. State whether the Brown Station solar output projections will vary monthly/seasonally.

c. Since concentrating solar power (CSP) generation can be coupled with fossil-fired boiler capacity to provide base load and cover periods of peak demand, were any CSP technology options considered as an alternative to using photovoltaic solar technology at the Brown generating station facility?

A-28. The map shown at the link below shows central Kentucky receives approximately 4.3 kWh/m^2/day. This is slightly below average for the continental United States. http://www.nrel.gov/gis/images/map_pv_national_hi-res_200.jpg

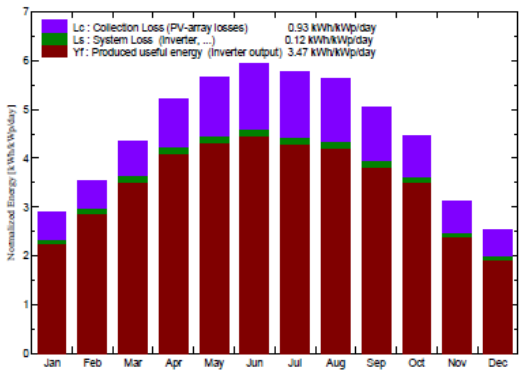
a. Based on the PVSyst software model used by HDR in the Siting Study Review, the Companies expect the Brown Solar Facility to produce 15,216 MWh per year for an average output of 41.7 MWh per day.

b. Yes, the output will vary daily, monthly and seasonally. In the Siting Study Review performed by HDR for the Brown facility, the PVSyst modeling software produced the following average monthly energy production chart for the site.

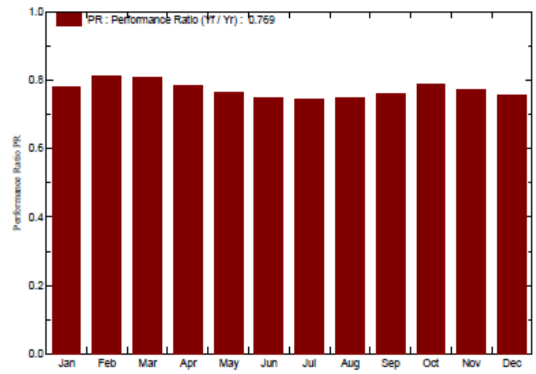
Main simulation results

System Production	**Produced Energy**	**15215678 kWh/year**	Specific prod.	1268 kWh/kWp/year
	Performance Ratio PR	76.9 %		

Normalized productions (per installed kWp): Nominal power 11999 kWp



Performance Ratio PR



c. No, the price of PV solar has dropped substantially in recent years and is now significantly cheaper to install than CSP. Many projects originally conceived as CSP were converted to PV before construction. Therefore CSP was not considered for the Brown Solar Facility.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 29

Witness: John N. Voyles, Jr.

Q-29. Refer to page 56 of Exhibit DSS-1. Section 6.4.1.2 states that the costs of decommissioning Green River units 3 and 4 are not included in the cost estimate.

a. Provide the date that Green River units 3 and 4 will be retired.

b. Provide the costs of decommissioning Green River units 3 and 4.

c. Describe the physical process of decommissioning Green River units 3 and 4. Include in your response whether the units will be removed from the site.

d. State whether some or all of the steps to decommission Green River units 3 and 4 would be required prior to starting construction of the proposed Green River NGCC project.

e. This section also states, "Major market shifts, such as an increased demand for natural gas or labor shortage due to environmental compliance projects, could cause the cost estimate to be exceeded." Explain why an increase in the demand for natural gas could cause construction costs to increase.

A-29. Decommissioning costs are not a part of the project cost estimates and have been estimated separately for the current Green River station.

a. Based on the compliance requirements and date in the MATS regulations, Green River units 3 and 4 cannot be operated after April of 2015 without additional emission controls. The regulations do provide for extensions of 1 or 2 years from that date, if granted by the permitting authority. At this time, the Companies have not sought extension of the compliance date, but are analyzing that option. Regardless, the Green River coal units will be retired before Green River NGCC is commissioned and any extended operation of the Green River coal units will not materially impact the cost of Green River NGCC.

b. The decommissioning costs are currently estimated at $1.7 million.

c. The current decommission plan will leave the existing plant structure in place, but will include a number of steps performed to ensure the plant is safe and environmentally secure. The decommissioning plans include:

- Secure plant buildings
- Heat trace water lines to offices
- Remove floating docks
- Cap stacks
- Close sewage treatment plant
- Fill in coal grizzly hopper
- Fill in or seal FGD reaction tank and recycle pit
- Seal penetrations on river side wall (circulating water duct banks, etc.)
- Drain and remove oil from existing equipment and storage tanks
- Remove chemicals from site
- Drain/remove Freon
- Drain water from all systems
- Drain oil from decommissioned transformers
- Mercury device mitigation

d. The decommissioning process is not required prior to starting construction of the proposed Green River NGCC project.

e. The word “plants” was omitted from the referenced statement. The statement should read as follows, “Major market shifts, such as an increased demand for natural gas ***plants*** or labor shortage due to environmental compliance projects, could cause the cost estimate to be exceeded." An increased demand for natural gas would not be expected to have a material impact on construction costs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 30

Witness: John N. Voyles, Jr.

Q-30. Provide a detailed cost breakdown and construction timeline for the proposed Green River NGCC project.

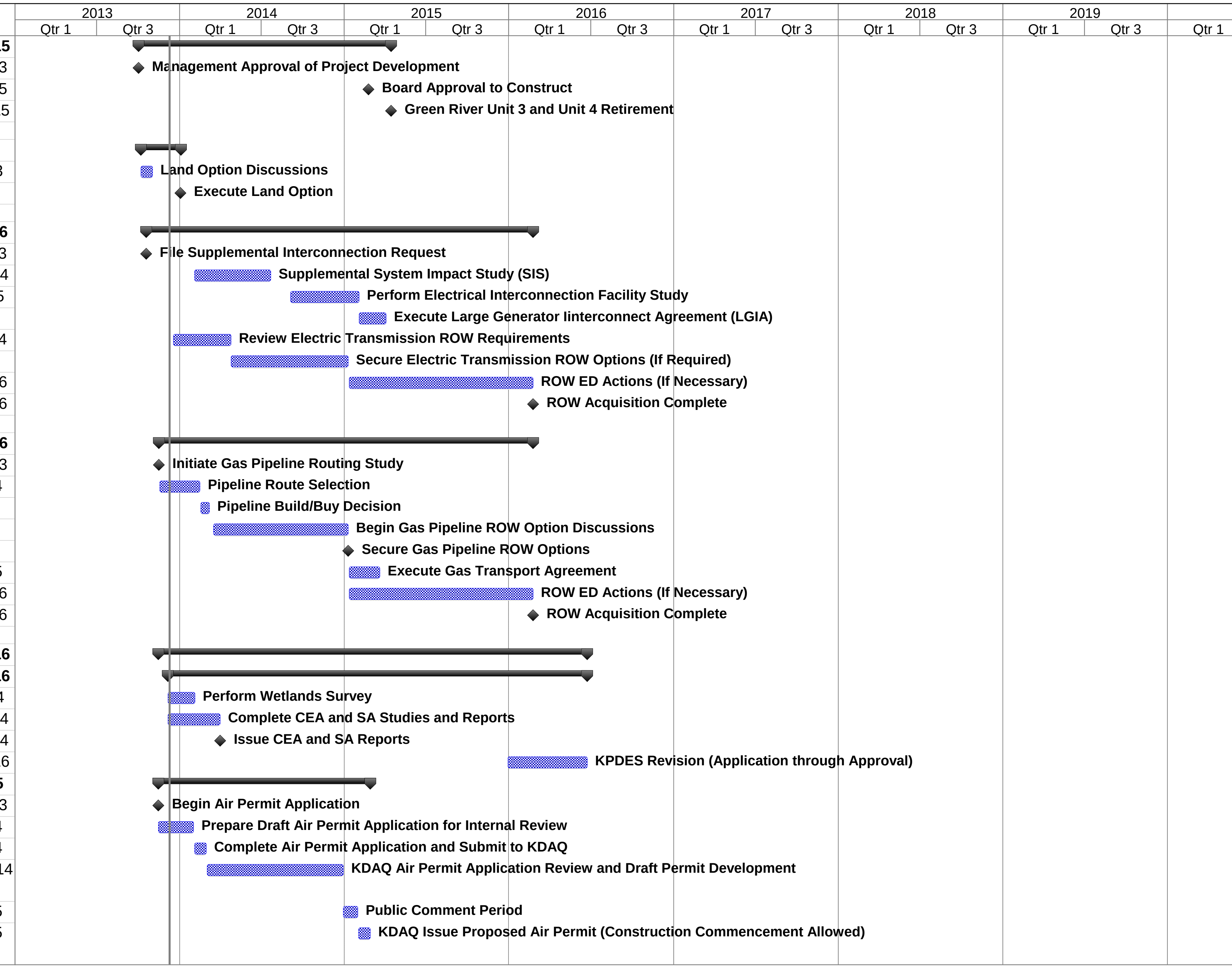
A-30. The following Green River NGCC Project Estimate was used in the Resource Assessment based on a 670 MW unit.

	$(million)
Total Direct Cost	$364.4
Construction Indirect & Services	$43.9
Total Construction Cost	$408.3
Project Engineering (Eng.,PM, CM & Procurement)	$24.5
EPC Contractor's Insurance & Misc.	$4.6
Escalation	$24.0
EPC Contractor's Contingency, Profit & Overhead	$49.6
Expected EPC Cost	$511.0
Owners' Indirect Cost	$84.8
Owners' Contingency	$51.1
Long Term Maintenance Agreement	$3.5
Total Project Cost	**$650.4**

The expected Green River NGCC project schedule is attached.

Green River 5 NGCC Project
Development Schedule
2018 COD

ID	Task Name	Duration	Start	Finish
1	**Management Approvals**	**389 days**	**Tue 10/1/13**	**Wed 4/15/15**
2	Management Approval of Project Development	0 days	Tue 10/1/13	Tue 10/1/13
3	Board Approval to Construct	0 days	Tue 2/24/15	Tue 2/24/15
4	Green River Unit 3 and Unit 4 Retirement	0 days	Wed 4/15/15	Wed 4/15/15
5				
6	**Property Acquisition**	**61 days**	**Mon 10/7/13**	**Fri 1/3/14**
7	Land Option Discussions	20 days	Mon 10/7/13	Fri 11/1/13
8	Execute Land Option	1 day	Fri 1/3/14	Fri 1/3/14
9				
10	**Electrical Interconnection**	**594 days**	**Fri 10/18/13**	**Tue 2/23/16**
11	File Supplemental Interconnection Request	0 days	Fri 10/18/13	Fri 10/18/13
12	Supplemental System Impact Study (SIS)	119 days	Mon 2/3/14	Mon 7/21/14
13	Perform Electrical Interconnection Facility Study	103 days	Thu 9/4/14	Mon 2/2/15
14	Execute Large Generator Iinterconnect Agreement (LGIA)	44 days	Tue 2/3/15	Fri 4/3/15
15	Review Electric Transmission ROW Requirements	90 days	Wed 12/18/13	Thu 4/24/14
16	Secure Electric Transmission ROW Options (If Required)	179 days	Fri 4/25/14	Fri 1/9/15
17	ROW ED Actions (If Necessary)	285 days	Mon 1/12/15	Tue 2/23/16
18	ROW Acquisition Complete	0 days	Tue 2/23/16	Tue 2/23/16
19				
20	**Natural Gas Pipeline**	**574 days**	**Fri 11/15/13**	**Tue 2/23/16**
21	Initiate Gas Pipeline Routing Study	0 days	Fri 11/15/13	Fri 11/15/13
22	Pipeline Route Selection	61 days	Mon 11/18/13	Fri 2/14/14
23	Pipeline Build/Buy Decision	15 days	Mon 2/17/14	Fri 3/7/14
24	Begin Gas Pipeline ROW Option Discussions	208 days	Mon 3/17/14	Fri 1/9/15
25	Secure Gas Pipeline ROW Options	0 days	Fri 1/9/15	Fri 1/9/15
26	Execute Gas Transport Agreement	50 days	Mon 1/12/15	Fri 3/20/15
27	ROW ED Actions (If Necessary)	285 days	Mon 1/12/15	Tue 2/23/16
28	ROW Acquisition Complete	0 days	Tue 2/23/16	Tue 2/23/16
29				
30	**Environmental**	**661 days**	**Fri 11/15/13**	**Wed 6/22/16**
31	**Site Studies and Permits (Land and Water)**	**648 days**	**Fri 12/6/13**	**Wed 6/22/16**
32	Perform Wetlands Survey	40 days	Fri 12/6/13	Mon 2/3/14
33	Complete CEA and SA Studies and Reports	80 days	Fri 12/6/13	Mon 3/31/14
34	Issue CEA and SA Reports	0 days	Mon 3/31/14	Mon 3/31/14
35	KPDES Revision (Application through Approval)	125 days	Wed 12/30/15	Wed 6/22/16
36	**Air Permit**	**325 days**	**Fri 11/15/13**	**Fri 2/27/15**
37	Begin Air Permit Application	0 days	Fri 11/15/13	Fri 11/15/13
38	Prepare Draft Air Permit Application for Internal Review	52 days	Fri 11/15/13	Fri 1/31/14
39	Complete Air Permit Application and Submit to KDAQ	20 days	Mon 2/3/14	Fri 2/28/14
40	KDAQ Air Permit Application Review and Draft Permit Development	210 days	Mon 3/3/14	Mon 12/29/14
41	Public Comment Period	23 days	Tue 12/30/14	Fri 1/30/15
42	KDAQ Issue Proposed Air Permit (Construction Commencement Allowed)	20 days	Mon 2/2/15	Fri 2/27/15

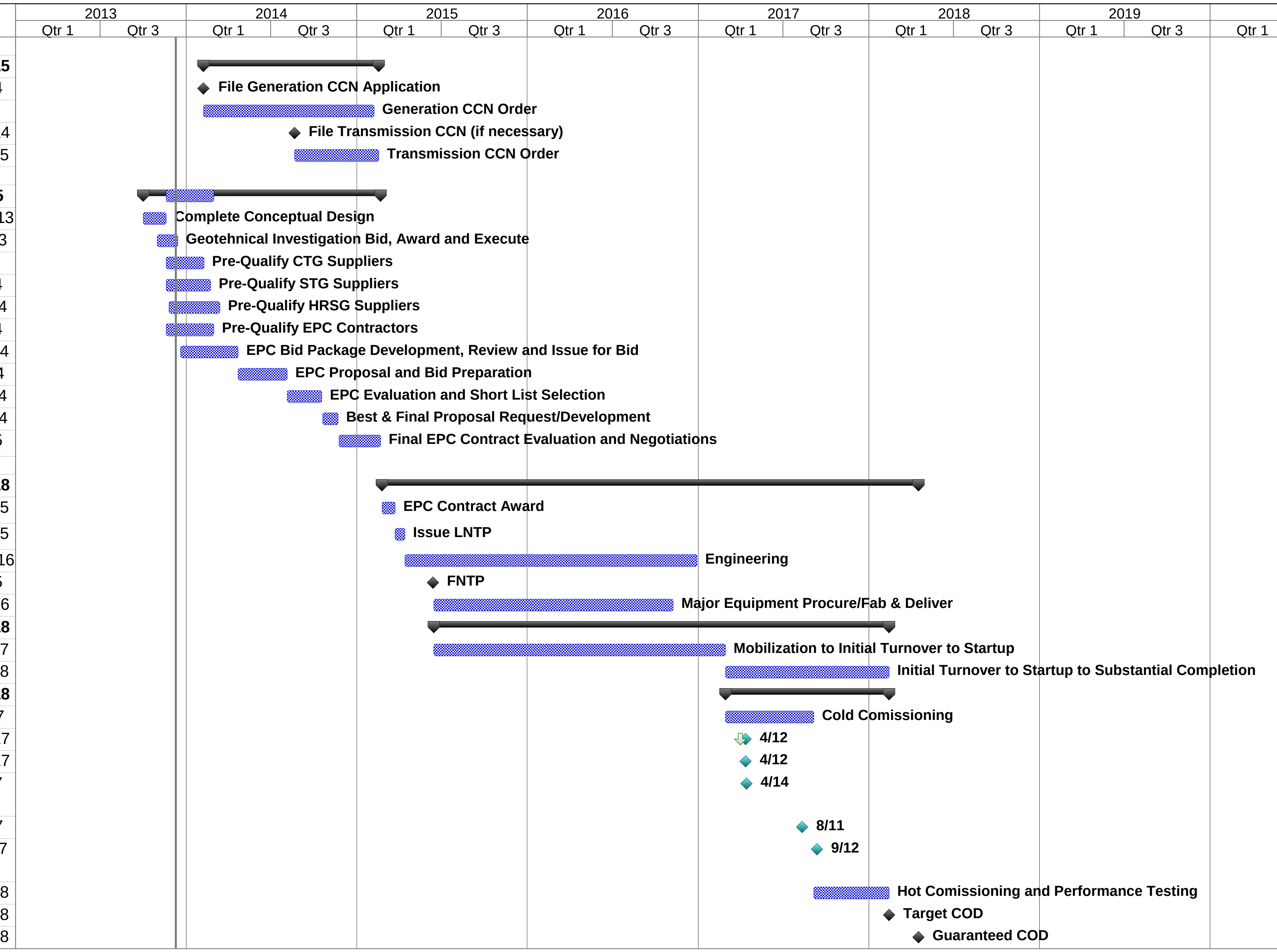


Green River NGCC Development Schedule
Date: Tue 12/10/13

Task	External Tasks	Inactive Summary	Start-only
Split	External Milestone	Manual Task	Finish-only
Milestone	Inactive Task	Duration-only	Progress
Summary	Inactive Task	Manual Summary Rollup	Deadline
Project Summary	Inactive Milestone	Manual Summary	

Green River 5 NGCC Project
Development Schedule
2018 COD

ID	Task Name	Duration	Start	Finish
43				
44	**Regulatory**	**260 days**	**Thu 2/6/14**	**Mon 2/16/15**
45	File Generation CCN Application	0 days	Thu 2/6/14	Thu 2/6/14
46	Generation CCN Order	254 days	Fri 2/7/14	Fri 2/6/15
47	File Transmission CCN (if necessary)	0 days	Wed 8/20/14	Wed 8/20/14
48	Transmission CCN Order	123 days	Thu 8/21/14	Mon 2/16/15
49				
50	**Project Engineering**	**353 days**	**Tue 10/1/13**	**Fri 2/20/15**
51	Complete Conceptual Design	35 days	Tue 10/1/13	Mon 11/18/13
52	Geotehnical Investigation Bid, Award and Execute	30 days	Thu 10/31/13	Fri 12/13/13
53	Pre-Qualify CTG Suppliers	55 days	Tue 11/19/13	Fri 2/7/14
54	Pre-Qualify STG Suppliers	65 days	Tue 11/19/13	Fri 2/21/14
55	Pre-Qualify HRSG Suppliers	75 days	Mon 11/25/13	Thu 3/13/14
56	Pre-Qualify EPC Contractors	70 days	Tue 11/19/13	Fri 2/28/14
57	EPC Bid Package Development, Review and Issue for Bid	85 days	Fri 12/20/13	Mon 4/21/14
58	EPC Proposal and Bid Preparation	73 days	Tue 4/22/14	Mon 8/4/14
59	EPC Evaluation and Short List Selection	53 days	Tue 8/5/14	Fri 10/17/14
60	Best & Final Proposal Request/Development	25 days	Mon 10/20/14	Fri 11/21/14
61	Final EPC Contract Evaluation and Negotiations	61 days	Mon 11/24/14	Fri 2/20/15
62				
63	**EPC Contract Execution**	**813 days**	**Tue 2/24/15**	**Mon 4/16/18**
64	EPC Contract Award	20 days	Tue 2/24/15	Mon 3/23/15
65	Issue LNTP	15 days	Tue 3/24/15	Mon 4/13/15
66	Engineering	440 days	Tue 4/14/15	Wed 12/28/16
67	FNTP	0 days	Fri 6/12/15	Fri 6/12/15
68	Major Equipment Procure/Fab & Deliver	360 days	Mon 6/15/15	Mon 11/7/16
69	**Construction**	**690 days**	**Mon 6/15/15**	**Mon 2/12/18**
70	Mobilization to Initial Turnover to Startup	440 days	Mon 6/15/15	Mon 2/27/17
71	Initial Turnover to Startup to Substantial Completion	250 days	Tue 2/28/17	Mon 2/12/18
72	**Startup and Commisioning**	**250 days**	**Tue 2/28/17**	**Mon 2/12/18**
73	Cold Comissioning	135 days	Tue 2/28/17	Mon 9/4/17
74	Back Feed Power Available (EPC Contract Milestone)	0 days	Wed 4/12/17	Wed 4/12/17
75	Raw Water Available (EPC Contract Milestone)	0 days	Wed 4/12/17	Wed 4/12/17
76	Operations Staff Available For Training (EPC Contract Milestone)	0 days	Fri 4/14/17	Fri 4/14/17
77	Fuel Available (EPC Contract Milestone)	0 days	Fri 8/11/17	Fri 8/11/17
78	Full Electrical Export Capability Available (EPC Contract Milestone)	0 days	Tue 9/12/17	Tue 9/12/17
79	Hot Comissioning and Performance Testing	115 days	Tue 9/5/17	Mon 2/12/18
80	Target COD	0 days	Mon 2/12/18	Mon 2/12/18
81	Guaranteed COD	0 days	Mon 4/16/18	Mon 4/16/18



Green River NGCC Development Schedule
Date: Tue 12/10/13

Task | Split | Milestone | Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | Progress | Deadline

Attachment to Response to PSC-1 Question No. 30
Page 2 of 2
Voyles

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 31

Witness: John N. Voyles, Jr.

Q-31. Provide a detailed cost breakdown and construction timeline for the proposed Brown Station solar project.

A-31. The cost estimate for the Brown Solar Facility is shown below.

Table 1 Capital Cost and Cost of Generation Summary	
Description	Standard Efficiency
EPC Direct Cost	
Site Preparation	$3,000,000 (see Note 1)
Panel Modules & Support	$15,000,000
500 kW Inverters	$3,000,000
Electrical Distribution System	$5,000,000
Electrical Interconnect	$500,000
Engineering, Permitting, Geotech	$2,500,000
EPC Cost	$29,000,000
Owner Cost	
Project Development	$650,000
Electrical Interconnect	$450,000
Construction Power	$50,000
Owners Project Management	$500,000
Owners Engineer	$170,000
Owners Legal Counsel	$250,000
Land	$0
Electric Transmission Service	$50,000
Site Security	$50,000
Spare Parts	$100,000
AFUDC (KU Ownership Portion)	$150,000
Contingency (15% of EPC)	$4,350,000
Owner Cost	$6,770,000
Total Project Cost	$35,770,000

Table 1 Capital Cost and Cost of Generation Summary	
Description	Standard Efficiency
Total Cost $/kW (AC)	$3577/kW
Notes: 1. EPC Site Preparation cost based on conceptual level design utilizing available USGS topographic survey and boring logs resulting in an estimate accuracy level of -$1,500,000/+$5,000,000. Final design to be based on one (1) foot contour field topographic survey and geotechnical investigation.	

Shortly after approval the Companies will issue the Full Notice to Proceed ("FNTP") to the constructor. The solar PV facility's project schedule from FNTP to commercial operation has been estimated at 18 months.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 32

Witness: Edwin R. Staton

Q-32. Confirm that no costs to operate the proposed Brown Station solar facility would be recoverable through the fuel adjustment clause of the Companies. If this cannot be confirmed, explain.

A-32. Given that there are no fuel costs associated with operating a solar facility, the Companies would not anticipate any operating costs included in the fuel adjustment clause.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 33

Witness: John N. Voyles, Jr.

Q-33. Refer to page 5 of the Direct Testimony of John N. Voyles, Jr. ("Voyles Testimony"), lines 11-15, wherein Mr. Voyles states that 120 acres will need to be purchased for siting setback requirements for the proposed Green River NGCC project. Provide the cost of the additional acreage and state whether the cost has been included in the estimated cost of the project.

A-33. Negotiations are ongoing to acquire the 120 acres from a private land owner. The anticipated cost of the property was not included in the project cost as a separate line item. The cost of the land, which is immaterial relative to the overall cost of the project, will be covered from contingency funds which were included in the cost of the project.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 34

Witness: David S. Sinclair

Q-34. Refer to page 11, lines 8-10, of the Voyles Testimony which state, "The Green River NGCC is expected to generate approximately 4,900 GWh per year beginning in 2018, resulting in an annual total fixed and non-fuel operating cost of approximately $14.5 million." Using a 700-MW NGCC generating facility, provide the following:

a. The expected annual generating capacity factor.

b. The calculations supporting the annual total fixed and non-fuel operating cost of approximately $14.5 million.

A-34.

a. See attached.

b. The annual fixed and non-fuel operating cost of approximately $14.5 million is based on a 670 MW unit (see Mr. Sinclair's Testimony at page 33, lines 8 -12). The fixed operating and maintenance cost for the Green River NGCC is approximately $7.80/kW-year or $5.2 million per year in 2018 dollars ($7.80/kW-year * 670 MW * 1000 kW/MW = $5.2 million). In the Mid gas, Base load scenario, the non-fuel operating cost for the unit is approximately $9.1 million. The sum of fixed and non-fuel operating costs were rounded to the nearest half million for Mr. Voyles' testimony.

   The annual fixed O&M cost of $5.2 million ($7.80/kW-year * 670 MW * 1000 kW/MW) was determined utilizing the HDR study and is comprised of the following components:

Parts	$1.2
Annual Fixed LTSA Fee	$0.2
Heat Recovery Steam Generator	$0.2
Steam Turbine & Balance of Plant	$0.1
Labor	$3.3
Misc Expenses	$0.1
Total	$5.2

Note: The total does not equal the sum of the components due to rounding. In addition to this cost, a rotor replacement is assumed every 16 years at a cost of $27.1 million.

Non-fuel operating costs consist of the following components (values are listed in 2018 dollars):

- Variable O&M: $0.37/MWh.
- Long-Term Service Agreement: Greater of $937/operating hour or $25,902/start.

Annual Capacity Factor for 2018 NGCC Unit (%)

Year	Scenario											
	Base Gas Base Load Zero Carbon	Base Gas Base Load Medium Carbon	Low Gas Base Load Zero Carbon	Low Gas Base Load Medium Carbon	High Gas Base Load Zero Carbon	High Gas Base Load Medium Carbon	Base Gas Low Load Zero Carbon	Base Gas Low Load Medium Carbon	Low Gas Low Load Zero Carbon	Low Gas Low Load Medium Carbon	High Gas Low Load Zero Carbon	High Gas Low Load Medium Carbon
2013	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2014	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2015	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2016	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2017	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2018	85%	85%	95%	95%	56%	56%	83%	83%	95%	95%	45%	45%
2019	83%	83%	95%	95%	53%	53%	79%	79%	94%	94%	42%	42%
2020	74%	95%	95%	95%	44%	93%	64%	94%	95%	95%	33%	92%
2021	70%	95%	95%	95%	39%	93%	58%	94%	95%	95%	29%	92%
2022	57%	94%	95%	95%	32%	93%	45%	94%	95%	95%	23%	91%
2023	55%	95%	95%	95%	31%	92%	45%	94%	95%	95%	22%	92%
2024	54%	95%	95%	95%	27%	93%	42%	94%	95%	95%	19%	92%
2025	56%	94%	94%	95%	20%	90%	43%	95%	95%	95%	21%	92%
2026	57%	93%	93%	95%	16%	89%	42%	95%	95%	95%	21%	93%
2027	49%	93%	93%	95%	15%	89%	37%	94%	94%	95%	19%	92%
2028	46%	94%	94%	95%	18%	91%	43%	95%	95%	95%	23%	93%
2029	29%	94%	94%	95%	16%	91%	38%	95%	95%	95%	19%	93%
2030	31%	94%	94%	95%	17%	92%	36%	95%	95%	95%	21%	93%
2031	28%	94%	94%	95%	19%	93%	34%	95%	95%	95%	22%	94%
2032	31%	94%	94%	95%	22%	93%	34%	95%	95%	95%	24%	94%
2033	35%	93%	93%	94%	18%	92%	37%	95%	95%	95%	27%	94%
2034	30%	91%	92%	94%	10%	91%	34%	95%	95%	95%	23%	94%
2035	33%	92%	92%	94%	12%	91%	36%	95%	95%	95%	24%	94%
2036	24%	92%	92%	94%	11%	92%	35%	95%	95%	95%	23%	94%
2037	19%	93%	92%	94%	13%	92%	35%	95%	95%	95%	23%	94%
2038	21%	93%	93%	95%	15%	92%	37%	95%	95%	95%	27%	94%
2039	19%	93%	92%	94%	14%	92%	33%	95%	95%	95%	24%	94%
2040	20%	93%	92%	95%	15%	90%	36%	94%	94%	95%	25%	93%
2041	21%	91%	93%	93%	15%	91%	35%	94%	94%	95%	23%	93%
2042	24%	88%	93%	92%	16%	90%	39%	94%	95%	95%	25%	92%

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the Commission Staff's First Information Request
Dated March 13, 2014

Case No. 2014-00002

Question No. 35

Witness: David S. Sinclair

Q-35. Refer to page 14, lines 18-2,1 of the Voyles Testimony which state that "conceptual fixed and variable operating and maintenance costs for the proposed Brown Station Solar Facility are assumed to be $12.50/kW-year and $0.80/MWh, respectively." Provide the calculations supporting the following:

a. The annual capacity factor for the proposed Brown Station 10-MW solar facility.

b. The annual total operating cost of approximately $140,000.

A-35.

a. The Brown Solar Facility is forecasted to generate approximately 15,216 MWh per year. This equates to an annual capacity factor of approximately 17%, based on the 10 MW AC rating. The PVsyst solar modeling software, which is a widely utilized industry generation estimation tool, was used to model the output of the Brown facility. PVsyst applies hourly historic meteorological data to estimate the production of a PV system based on specific OEM module performance at site conditions.

b. The annual total operating cost of approximately $140,000 is calculated as follows: $12.50/kW-year * 10 MW * 1,000 kW/MW + $0.80/MWh * 15,216 MWh.

The annual total operating cost of approximately $140,000 is comprised of the following component breakdown:

Property Tax	$35,000
Insurance	$40,000
Ground Maintenance	$50,000
Equipment Maintenance	$15,000
Total	$140,000