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 FIRST SET OF DATA REQUESTS OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
DATED MARCH 13, 2014

FILED: MARCH 27, 2014

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

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

(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

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 1

Witness: David S. Sinclair

Q1-1. Please refer to the testimony of David Sinclair page 5 lines 20-23. With respect to the wholesale municipal load served by KU please provide the following:

a. The names of the municipal utilities.

b. For the most recent two years, the monthly energy and capacity (demand) sales by municipal utility.

c. Copies of the wholesale power contracts.

d. The dates each of the municipal power contracts expire.

e. Have any of these municipal utilities given notice of contract termination? If yes, please explain.

f. Have any of these municipal utilities issued Requests For Proposals (RFP) for new wholesale power providers? If yes, then please provide a copy of the RFP.

g. If an RFP has been issued, please provide any response KU has made to the RFP and describe all offers made by KU to retain the load. Please also provide all correspondence, emails or other documents between KU and any of the municipal utilities regarding the termination, renewal or extension of the wholesale power contracts.

h. Assume that the KU municipal load was lost to another wholesale supplier, please describe the effect that would have on the projected reserve margins in this filing and the need for the proposed Green River combined cycle plant.

A1-1.

a. Barbourville Water & Electric
Bardstown Municipal Light & Water
Bardwell City Utilities
Benham Electric System
City of Berea
Corbin City Utilities Commission
Falmouth City Utilities (EDT)
Frankfort Electric & Water Plant Board
Madisonville Municipal Utilities
Nicholasville City Utilities
City of Paris Combined Utilities
Providence Municipal Utilities

b. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

c. The current contracts for each of the municipal customers can be found at:

http://etariff.ferc.gov/TariffBrowser.aspx?tid=799

In September 2013, KU made a filing at FERC to amend the contracts and rate formulas. Those contracts and rate formulas will go into effect subject to refund on April 23, 2014. The parties are currently in settlement discussions regarding these proposed contracts and rate formulas. These contracts can be found at:

http://elibrary.ferc.gov/idmws/file_list.asp?document_id=14148202

d. The contracts do not expire unless terminated by one of the parties.

e. No.

f. The Companies have no knowledge of whether or not any of the municipal utilities have issued an RFP for a new power supplier.

g. See the response to (f) above. See attached for correspondence, emails and other documents between KU and any of the municipal utilities regarding the termination, renewal or extension of the wholesale power contracts. Please note that, pursuant to 18 CFR 385.606, participants to a FERC dispute resolution proceeding may not voluntarily disclose, or through discovery or compulsory process be required to disclose, any information concerning dispute resolution communication. As a result, such information has not been provided here.

h. The table below shows the effect of losing the KU municipal load on the projected reserve margins in this filing. Because the municipal contracts have a 5-year termination notice provision (except for the City of Paris which has a 3-year termination notice), the earliest the contracts could be terminated is 2019. Losing the KU municipal load would likely defer the need for additional generation capacity to 2021 or 2022.

	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
Less: Muni Load					(441)	(444)	(460)	(480)	(499)
Net Peak Load (w/o Munis)	7,040	7,091	7,147	7,214	6,841	6,906	7,212	7,554	7,899
Existing Resources[1]	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 Load	137	137	137	137	137	137	137	137	137
Less: Muni Curtailable Load	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
Total Supply	8,091	8,073	8,073	8,073	8,073	8,073	8,073	8,073	8,073
Reserve Margin (“RM”)	14.9%	13.8%	13.0%	11.9%	18.0%	16.9%	11.9%	6.9%	2.2%
RM Shortfall (17% RM)*	(146)	(224)	(289)	(367)	69	(7)	(365)	(765)	(1,169)
RM Shortfall (15% RM)*	(5)	(83)	(146)	(223)	206	131	(221)	(614)	(1,011)

[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.

CONFIDENTIAL INFORMATION REDACTED

Year 2013			January	February	March	April	May	June	July	August	September	October	November	December
1	[redacted]	Demand kw	18,178	16,987	17,117	13,408	15,948	18,358	19,399	18,415	18,336	14,369	16,370	17,594
	[redacted]	Energy kwh	9,072,000	8,040,000	8,644,000	6,432,000	6,744,000	7,872,000	8,544,000	8,712,000	7,344,000	6,768,000	7,800,000	8,928,000
2	[redacted]	Demand kw	32,475	30,812	29,343	27,889	34,182	36,440	37,656	38,177	38,623	31,210	27,073	32,224
	[redacted]	Energy kwh	17,656,000	15,813,200	16,868,400	15,278,800	16,695,200	18,211,200	18,928,400	20,022,400	17,524,000	15,816,000	14,578,400	16,300,800
3	[redacted]	Demand kw	1,511	1,415	1,325	1,251	1,723	2,080	2,079	2,115	2,016	1,449	1,403	1,548
	[redacted]	Energy kwh	796,800	681,600	705,600	583,200	674,400	854,400	871,200	883,200	746,400	614,400	667,200	837,600
4	[redacted]	Demand kw	2,067	2,114	2,054	1,370	893	955	973	883	867	1,622	2,030	2,049
	[redacted]	Energy kwh	808,800	746,400	782,400	408,000	372,000	398,400	427,200	405,600	340,800	410,400	696,000	799,200
5	[redacted]	Demand kw	27,188	26,409	25,465	19,311	20,553	23,038	24,174	23,017	23,462	18,786	23,719	25,305
	[redacted]	Energy kwh	12,811,946	11,391,478	12,069,244	8,812,683	9,341,896	10,465,640	11,300,182	11,316,023	9,927,974	9,333,865	10,673,364	12,430,492
6	[redacted]	Demand kw	15,287	14,752	14,576	11,519	15,655	17,990	18,649	17,587	17,648	13,213	13,454	14,389
	[redacted]	Energy kwh	7,800,000	6,876,000	7,344,000	5,628,000	6,264,000	7,308,000	7,920,000	8,028,000	6,624,000	5,904,000	6,540,000	7,584,000
7	[redacted]	Demand kw	3,354	3,130	2,906	2,592	3,673	4,167	4,670	4,382	4,439	2,872	2,947	3,146
	[redacted]	Energy kwh	1,651,200	1,616,000	1,676,800	1,353,600	1,500,800	1,737,600	1,948,800	1,929,600	1,574,400	1,417,600	1,542,400	1,782,400
8	[redacted]	Demand kw	123,816	119,885	113,333	97,574	122,842	136,539	140,605	134,837	137,278	110,398	105,577	120,092
	[redacted]	Energy kwh	64,176,000	57,624,000	60,816,000	50,792,000	55,720,000	61,992,000	65,520,000	66,248,000	57,792,000	53,872,000	55,384,000	61,992,000
9	[redacted]	Demand kw	44,625	44,885	42,709	47,994	54,266	61,981	63,646	62,580	62,025	49,648	40,186	44,499
	[redacted]	Energy kwh	26,766,000	23,721,600	25,204,800	23,223,600	25,944,000	29,268,000	30,541,200	31,058,400	27,313,200	24,364,800	22,768,800	25,094,400
10	[redacted]	Demand kw	37,780	37,615	33,210	26,648	30,905	34,918	35,449	34,641	34,837	29,371	31,732	36,054
	[redacted]	Energy kwh	20,237,807	18,213,025	18,813,007	15,118,470	15,845,808	17,756,138	18,382,680	18,512,379	16,559,338	16,127,990	16,768,245	19,268,962
11	[redacted]	Demand kw	13,076	12,763	11,981	9,287	11,044	12,441	13,024	12,108	11,826	9,094	11,605	12,430
	[redacted]	Energy kwh	6,287,159	5,692,857	5,715,846	4,114,429	4,254,284	5,061,731	5,510,815	5,440,554	4,350,982	4,210,554	5,071,802	6,315,258
12	[redacted]	Demand kw	5,560	5,092	4,816	4,360	5,966	7,158	7,215	6,531	6,326	4,684	5,028	5,176
	[redacted]	Energy kwh	3,033,600	2,560,000	2,684,800	2,137,600	2,400,000	2,966,400	2,905,600	2,902,400	2,531,200	2,240,000	2,505,600	2,896,000

Year 2012			January	February	March	April	May	June	July	August	September	October	November	December
1	[redacted]	Demand kw	18,785	19,037	15,962	14,875	17,539	21,053	20,743	19,706	19,380	13,675	16,375	16,306
	[redacted]	Energy kwh	9,576,000	8,544,000	7,320,000	6,672,000	7,968,000	8,352,000	10,056,000	8,928,000	7,176,000	6,744,000	7,824,000	8,376,000
2	[redacted]	Demand kw	30,842	28,698	29,154	30,139	34,445	39,900	40,764	38,452	37,820	26,481	28,285	28,416
	[redacted]	Energy kwh	16,906,800	15,703,600	16,096,800	14,929,200	18,212,000	18,784,800	21,325,600	20,118,400	16,082,800	14,972,000	14,875,200	15,278,400
3	[redacted]	Demand kw	1,531	1,413	1,191	1,192	1,931	2,378	2,401	2,294	1,996	1,086	1,218	1,393
	[redacted]	Energy kwh	746,400	662,400	592,800	588,000	818,400	885,600	1,120,800	957,600	684,000	585,600	631,200	712,800
4	[redacted]	Demand kw	2,359	2,262	1,726	1,358	917	1,073	1,090	994	925	1,356	1,753	1,834
	[redacted]	Energy kwh	808,800	691,200	422,400	391,200	362,400	391,200	492,000	422,400	360,000	468,000	679,200	705,600
5	[redacted]	Demand kw	26,406	25,338	20,382	18,340	21,215	25,922	25,414	23,739	22,298	18,481	22,598	23,574
	[redacted]	Energy kwh	12,641,943	11,357,795	9,592,539	8,854,495	10,107,561	10,614,918	12,758,476	11,288,154	9,545,892	9,087,391	10,411,693	11,150,491
6	[redacted]	Demand kw	14,782	14,669	12,413	13,147	15,509	20,009	20,329	19,398	18,002	11,768	13,012	13,988
	[redacted]	Energy kwh	7,512,000	6,708,000	5,892,000	5,508,000	6,984,000	7,596,000	9,324,000	8,136,000	6,324,000	5,736,000	6,468,000	7,128,000
7	[redacted]	Demand kw	3,133	2,873	2,733	2,514	3,994	4,980	5,000	4,512	4,063	2,660	2,760	2,482
	[redacted]	Energy kwh	1,721,600	1,520,000	1,404,800	1,280,000	1,635,200	1,804,800	2,268,800	1,952,000	1,504,000	1,366,400	1,510,400	1,731,200
8	[redacted]	Demand kw	117,550	111,098	103,191	98,263	121,817	148,159	149,436	137,850	133,577	93,190	104,720	110,712
	[redacted]	Energy kwh	62,216,000	56,560,000	53,984,000	49,672,000	60,592,000	63,616,000	74,536,000	68,488,000	55,888,000	52,640,000	54,600,000	58,296,000
9	[redacted]	Demand kw	45,736	44,248	46,077	53,020	57,498	65,030	69,068	67,339	60,344	43,411	40,871	41,783
	[redacted]	Energy kwh	26,300,400	24,262,800	24,590,400	23,827,200	28,852,800	30,453,600	36,390,000	32,437,200	25,898,400	23,916,000	22,947,600	24,339,600
10	[redacted]	Demand kw	36,276	35,155	30,168	26,479	33,311	38,534	38,005	36,631	36,012	27,915	31,484	34,144
	[redacted]	Energy kwh	19,535,464	17,459,089	15,896,474	14,828,256	17,396,293	18,104,154	20,749,625	19,619,997	16,488,908	15,829,312	16,952,591	18,083,258
11	[redacted]	Demand kw	12,286	11,521	7,281	6,013	11,112	12,856	13,632	13,022	11,271	8,788	10,894	11,388
	[redacted]	Energy kwh	6,170,463	5,277,167	4,341,781	3,862,398	4,536,497	5,119,159	6,270,256	5,558,299	4,223,440	3,987,949	5,078,174	5,654,647
12	[redacted]	Demand kw	5,310	4,968	4,377	5,548	6,567	8,155	8,482	7,904	6,991	4,141	4,658	5,331
	[redacted]	Energy kwh	2,793,600	2,537,600	2,406,400	2,284,800	2,796,800	3,164,800	4,089,600	3,417,600	2,592,000	2,201,600	2,384,000	2,812,800

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March 19, 2013

Paul W. Thompson
Senior Vice President – Energy Services
LG&E and KU
220 West Main Street
Louisville, KY 40202

Re: Return on equity in KU requirements contracts

Dear Mr. Thompson:

I am writing on behalf of the group of municipal requirements customers of Kentucky Utilities Company. We would like to know whether KU would be interested in exploring whether the customers and KU can agree on a reduced rate of return on equity to be included in the formula used to calculate our wholesale power rates.

As I am sure you know, the current ROE is 11.0 percent, but the contracts allow either party to ask FERC to approve a change. With the changes in the cost of money since the contracts were negotiated four years ago, I am told that the current cost of equity is more in the neighborhood of 9.0 percent or lower. The difference amounts to a large amount of additional costs to our utilities and our customers that we believe is no longer justified.

Before launching a new FERC case to address this problem, the customers wanted to approach KU to see if we could find a ROE that both sides could agree to. If KU is interested in exploring this possibility, please let me know within a week or so, and we will promptly arrange for a meeting or conference call to discuss the matter, including with our respective regulatory advisers.

Thank you for your consideration. We look forward to hearing from you. Whether we resolve this by agreement or through regulatory action, we would like the effective date to be no later than July 1, 2013, when the next increase in our formula rates will go into effect. This means we will be placing a high priority on moving this along quickly.

Sincerely yours,

Herbbie Bannister

Herbbie Bannister, P.E.
General Manager

HB/kp

317 West Second Street (P.O. Box 308) Frankfort, Kentucky 40602 Phone (502) 352-4372
Fax (502) 223-3887 www.fpb.cc

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March 28, 2013

David S. Sinclair
Vice President – Energy Supply and Analysis
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Re: Formula rates in KU requirements contracts

Dear Mr. Sinclair:

Thank you for your letter of March 26, 2013, and for your willingness to meet promptly. Unfortunately, the dates you suggested for a meeting next week will not work for the requirements customers. I will be back in touch after the group has the opportunity to review the information provided in your letter.

Sincerely yours,

Herbbie Bannister

Herbbie Bannister, P.E.
General Manager

HB/kp

Equal Opportunity/Affirmative Action Employer

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LG&E KU
PPL companies

David S. Sinclair
Vice President
Energy Supply and Analysis

LG&E and KU Energy LLC
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Louisville, KY 40202
T 502-627-4653
M 502-593-8457
F 502-217-2019
david.sinclair@lge-ku.com

March 26, 2013

Herbbie Bannister
General Manager
Frankfort Plant Board
317 West Second Street
Frankfort, KY 40602

Dear Mr. Bannister:

I am writing in response to your March 19 letter to Mr. Paul Thompson (see attachment). At Kentucky Utilities ("KU") we take very seriously our obligations to provide low-cost, reliable service to all of our customers, including wholesale municipal customers like Frankfort. As part of that effort, last year KU invested almost $300 million in generation capital projects to comply with new U.S. Environmental Protection Agency regulations, expand our capacity to dispose of coal combustion residuals, and build new generation to meet load growth and replace capacity that is being retired. Over the next few years KU will invest an additional $1.2 billion in these types of projects.

In order to attract the capital necessary to make these investments, KU must offer a competitive rate of return for the use of that capital. What is important to investors is the actual return on equity ("ROE") that KU earns on its investment, not the authorized ROE used in the formula rate. While the authorized ROE is 11 percent, the actual ROE earned by KU's investors over the last four years has been significantly less. This is largely due to the fact that the formula uses a 13 month average rate base from the prior calendar year to calculate the demand rate yet these rates are not used to bill wholesale customers until July through June of the following year. Effectively this means that KU is billing wholesale customers based on investments that occurred on average approximately 18 months ago. Given the large amount of money that KU is currently investing to be able to provide you with reliable service and comply with environmental regulations, this "formula lag" has a large, negative impact on our actual ROE.

Under these circumstances, KU does not believe that decreasing the authorized ROE is warranted. However, should you and the other municipal customers want to pursue this matter, please be advised that KU would also want to address other matters such as formula issues, contract terms, and the nature of the service provided to municipal customers. Ultimately, if KU is not going to be adequately compensated for the services it is providing, it has an obligation to its retail customers and shareholders to examine its willingness to continue providing wholesale requirements service in the future.

Should you and the other municipal customers wish to meet on these matters, I would like to suggest either April 4 or April 5 at 10:00 am EDT at our offices in Louisville. In order to make appropriate arrangements, I would appreciate your response by March 29. Also, even though you were "writing on behalf of the group of municipal requirements customers", since there are 12 separate municipal

LG&E KU
PPL companies

contracts I will need by March 29 a written confirmation from each customer (an e-mail to me would be adequate) stating their interest in pursuing discussions on formula and contract issues. We look forward to hearing from you.

Sincerely,

Attachment

Cc: Josh Callihan, Barbourville Water & Electric
joshc@barbourville.com

Lawrence A. Hamilton, Bardstown Municipal Light & Water
lahamilton@bardstowncable.net

Mayor Philip King, Bardwell City Utilities
mayorking1@gmail.com

Danny Quillen, Benham Electric System
Powerboard-deb@hotmail.com

Ed Fortner, City of Berea
efortner@bereaky.gov

Ron Herd, Corbin City Utilities Commission
ron.herd@corbinutilities.com

Terry England, Falmouth City Utilities
englandterry@hotmail.com

Jim Asbury, Madisonville Municipal Utilities
jasbury@madisonvillegov.com

Tom Calkins, Nicholasville City Utilities
Tom_calkins@nicholasville.org

J. Kevin Crump, City of Paris Combined Utilities
kcrump@paris.ky.gov

David May, Providence Municipal Utilities
providencepublicworks@yahoo.com

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March 19, 2013

Paul W. Thompson
Senior Vice President – Energy Services
LG&E and KU
220 West Main Street
Louisville, KY 40202

Re: Return on equity in KU requirements contracts

Dear Mr. Thompson:

I am writing on behalf of the group of municipal requirements customers of Kentucky Utilities Company. We would like to know whether KU would be interested in exploring whether the customers and KU can agree on a reduced rate of return on equity to be included in the formula used to calculate our wholesale power rates.

As I am sure you know, the current ROE is 11.0 percent, but the contracts allow either party to ask FERC to approve a change. With the changes in the cost of money since the contracts were negotiated four years ago, I am told that the current cost of equity is more in the neighborhood of 9.0 percent or lower. The difference amounts to a large amount of additional costs to our utilities and our customers that we believe is no longer justified.

Before launching a new FERC case to address this problem, the customers wanted to approach KU to see if we could find a ROE that both sides could agree to. If KU is interested in exploring this possibility, please let me know within a week or so, and we will promptly arrange for a meeting or conference call to discuss the matter, including with our respective regulatory advisers.

Thank you for your consideration. We look forward to hearing from you. Whether we resolve this by agreement or through regulatory action, we would like the effective date to be no later than July 1, 2013, when the next increase in our formula rates will go into effect. This means we will be placing a high priority on moving this along quickly.

Sincerely yours,

Herbbie Bannister

Herbbie Bannister, P.E.
General Manager

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April 29, 2013

David S. Sinclair
Vice President – Energy Supply and Analysis
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Re: Formula rates in KU requirements contracts

Dear David:

This letter responds further to your letter of March 26, 2013. Since the time of Mr. Bannister's earlier response on March 28, the Kentucky Municipals have had the opportunity to meet and discuss the concerns you raised.

First, let us state on behalf of the group of KU's municipal requirements customers that we fully understand and appreciate that KU needs to be profitable. We agree that it is important for KU to be able to attract capital and that it is entitled to an opportunity to earn a reasonable return on its utility investments. We do not seek to prevent KU from continuing to be a healthy and prosperous company. We understand the importance of KU's being adequately compensated for the services it provides to its wholesale customers.

We have reviewed with interest the concerns raised in your letter. If there are elements of the existing formula rates or contracts, such as the "formula lag," that KU believes should be modified, we are interested in learning more about those elements and are willing to discuss whether there are mutually agreeable changes to address them that could be achieved as part of an overall agreement. As previously expressed, we would also like such an agreement to address our concern that the current rate of return on equity specified in our wholesale rate formula is too high in light of current financial market conditions.

Our suggestion would be that we engage in business-like discussions of our respective interests to explore whether we can find common grounds for an agreement. To that end, we would propose that these matters be added to the agenda for the upcoming KU Operational Meeting on May 7, since that is a time when we are already scheduled to be together.

We have noted your request for written confirmation of which KU wholesale requirements customers are interested in pursuing these matters. We plan to provide that to you in advance of the May 7 meeting.

Sincerely yours,

Herbbie Bannister, P.E.
General Manager
Frankfort Plant Board

Lawrence A. Hamilton, P.E.
Director of Public Works & Engineering
City of Bardstown

Ronald W. Herd, P.E.
General Manager
Corbin City Utilities Commission

Tom Calkins
Utility/Finance Director
Nicholasville City Utilities

Ed Fortner
Utilities Director
City of Berea

HWB/kp

317 West Second Street (P.O. Box 308) Frankfort, Kentucky 40602 Phone (502) 352-4372
Fax (502) 223-3887 www.fpb.cc

Sinclair, David

From: Sinclair, David
Sent: Wednesday, May 01, 2013 11:16 AM
To: 'Bannister, Herbbie'
Cc: tom.trauger@spiegelmcd.com; ron.herd@corbinutilities.com; efortner@bereaky.gov; lahamilton@bardstowncable.net; tom_calkins@nicholasville.org; Beth Cocanougher (Beth.Cocanougher@lge-ku.com); Freibert, Charlie; Brunner, Bob
Subject: RE: ROE / Spring Meeting

Herbbie,

I received your April 29 letter requesting to add a discussion of formula rate and contract issues to the agenda of our upcoming May 7 Operational Meeting. I agree that makes sense. I will have Charlie or Donna send out a revised agenda shortly.

Regards,
David

From: Bannister, Herbbie [mailto:hbannister@fewpb.com]
Sent: Tuesday, April 30, 2013 3:06 PM
To: Sinclair, David
Cc: tom.trauger@spiegelmcd.com; ron.herd@corbinutilities.com; efortner@bereaky.gov; lahamilton@bardstowncable.net; tom_calkins@nicholasville.org
Subject: ROE / Spring Meeting

Mr. Sinclair,

Please find attached a letter regarding the formulated ROE.

Please advise

Herbbie Bannister

Frankfort Plant Board
Herbbie Bannister, P.E.
General Manager
Frankfort Plant Board
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LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 2

Witness: Paul W. Thompson

Q1-2. Please provide any study performed by KU/LG&E or on their behalf within the last three years quantifying the costs versus benefits of joining PJM or MISO. If no such study has been preformed, please explain why not.

A1-2. The Companies' most recent internal analysis was completed in 2012. See attached.

RTO Membership Analysis

1 Executive Summary

A cross-functional team was assembled to conduct a high level analysis of the estimated costs and benefits of LG&E-KU ("LKE" or "the Companies") regional transmission organization (RTO) membership, specifically for Midwest Independent Transmission System Operator (MISO) and PJM Interconnection (PJM). The analysis of joining MISO and PJM covered a ten year study period from 2013 through 2022. The analysis was modeled after a similar study, EKPC RTO Membership Assessment[1], performed by Charles River Associates (CRA) for East Kentucky Power Corporation in their consideration of joining PJM.

- **RTO membership is unfavorable.** LKE's RTO Membership Analysis shows an unfavorable ten-year present value for RTO membership ranging from ($103) M for PJM to ($216) M for MISO.
- **Key driver is "backbone" transmission costs.** Allocation of large transmission expansion projects costs across RTO members is the primary cost driver of RTO membership.

2 Methodology

LKE Transmission Strategy and Planning assembled a cross–functional team for the RTO Membership Analysis.[2] The team was comprised of representatives from Transmission Policy & Tariffs, Federal Regulation & Policy, Regulated Trading and Dispatch, and Economic Analysis. The CRA EKPC RTO Membership Assessment was used as a general guideline for this analysis.

- The methodology for the LKE analysis was consistent with the methodology and testimony from the 2006 MISO exit proceedings.
- The methodology took into consideration changes to the tariff structures and business practices of the RTOs since the exit proceedings.

[1] March 2012 http://psc.ky.gov/pscscf/2012%20cases/2012-00169/20120503_ekpc_application_volume%201.pdf, Exhibit RLL-2
[2] The Compliance Department was apprised of all meetings to ensure maintenance of Standards of Conduct between Transmission function and Trading function employees.

The intent of the analysis was to incorporate updated data and information to assess the costs and benefits of RTO membership at a high level, as opposed to an exhaustive analysis. These results were viewed as a threshold to determine if further in-depth study is warranted.

3 Key Assumptions

This analysis was conducted for a ten year horizon, 2013 through 2022, a period identical to the CRA study conducted for EKPC. The following key simplifying assumptions were incorporated into the analysis:

- LKE would continue to maintain its own capacity to meet a target planning reserve margin established consistently with current processes.
- No changes in locational marginal prices (LMP) due to planned RTO transmission expansions
- No impact from Firm Transmission Rights/Auction Revenue Rights (FTR/ARR) and congestion cost
- No impact from allocation of over collection of marginal losses[3]
- No impact from uplifts or make whole payments other than those identified
- No impact from potential transmission cost sharing within alternative, non-RTO Order 1000 regional planning region

4 Cost / Benefit Components

4.1 Allocation of "Backbone" Transmission Expansion Costs

The key driver of the outcome of this analysis was the allocation of "backbone" transmission expansion costs.

- For PJM, transmission expansion costs of $176 million (present value) represent more than half of the estimated absolute cost of RTO membership (excluding the benefits).
- For MISO these costs are $241 million (present value), approximately 60% of the estimated absolute cost of membership (excluding the benefits).

4.1.1 MISO Multi-Value Projects

[3] Both MISO and PJM collect incremental value of financial losses through the locational marginal price (LMP), which results in over–collection. Both have a process to allocate any over–collection back to the load serving entities.

Under current MISO policy, the cost of new transmission projects that address energy policy and/or provide widespread benefits across the footprint are considered "multi-value projects" (MVP). The cost of MVP are allocated 100% "postage stamp" to load, i.e., all load pays the same rate for MVP irrespective of where its located in the footprint, and are recovered under Schedule 26A of the MISO Tariff. LKE's share of the $5.4 billion in MVP projects currently identified in the Midwest ISO Transmission Expansion Planning (MTEP) process is based on the "indicative annual charges for approved MVP" published on the MISO website[4], applied to LKE loads projected per the 2013 Business Plan. As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period.[5]

4.1.2 PJM Regional Transmission Expansion Planning

Under current PJM policy, the cost of new "backbone" high voltage transmission projects approved under its annual Regional Transmission Expansion Planning (RTEP) process is allocated on a uniform basis to all PJM loads based on the non-coincident annual peak of each PJM transmission zone. These charges are recovered under Schedule 12 of the PJM tariff. "Backbone" facilities comprise "Regional Facilities" that operate above 500 kV and "necessary lower voltage facilities" that operate below 500 kV that must be constructed or strengthened to support new Regional Facilities.[6] As a new member, LKE would most likely be subject to the full cost allocation for expansion without any phase-in period. The allocation to LKE for projects documented in the RTEP within this analysis period has been estimated using PJM's allocation methodology and is a key cost driver for the PJM case.

4.2 Modeled Components

Two components of the analysis, Operating Reserve and Trade Benefits, were estimated by Generation Planning (GP) using the Companies' planning models. Because the models were already developed for other planning purposes, only minimal changes were required to use the models to estimate these components.

4.2.1 Operating Reserve

The reduced operating reserve capacity benefits of joining MISO or PJM were estimated by reducing the Companies' "spinning reserve" requirement from 230 MW to 100 MW, for a present value benefit of $14 M. GP revised the operating reserve input in the

[4] https://www.midwestiso.org/_layouts/MISO/ECM/Redirect.aspx?ID=135589
[5] For discussion of the "unique circumstances" surrounding Entergy joining Midwest ISO that justify Entergy's five year MVP exemption and eight year MVP cost phase-in, see 139 FERC¶ 61,056 at ¶¶ 70,181,213.
[6] CRA Study, p. 12.

Companies' reliability planning software, SERVM, which resulted in a target system planning reserve margin (RM) of 15% (1% lower than the existing target RM of 16%).[7] GP used this new RM to evaluate the impact to the Companies' expansion plan using a spreadsheet model to calculate the expected RM and using Strategist software.

The table below shows the expected RMs with no new capacity after Cane Run 7 in 2015 and the corresponding capacity additions needed with the existing and new target RMs.

	RM w/o New Capacity	**Existing Expansion Plan (16% RM Target)**	**New Expansion Plan (15% RM Target)**
2016	14.7%	165 MW PPA	NA
2017	14.1%	165 MW PPA	NA
2018	12.5%	605 MW CCCT	605 MW CCCT

With the new 15% target RM, the 165 MW Power Purchase Agreements (PPAs) in 2016 and 2017 in the existing expansion plan could be avoided, resulting in an estimated cost savings of $9.6 M each year. However, the absence of the PPAs results in higher expected system production costs of approximately $0.2 M in both 2016 and 2017, as estimated by GP using PROSYM software.

4.2.2 Trade Benefits

The trade benefits of joining MISO or PJM were estimated by GP using PROSYM as lower native load production costs and higher off-system sales (OSS) margins that resulted from the following:

- Reducing the spinning reserve requirement from 230 MW to 100 MW
- Eliminating RTO expenses for OSS and purchases
- Eliminating 3rd party transmission expenses for purchases
- Eliminating LG&E-KU transmission expenses for OSS and purchases
- Eliminating $2 "costless adder" for OSS and purchases

The eliminated LG&E-KU transmission and $2 costless adder expenses were deducted from the total savings because they do not represent actual savings to the Companies. The PJM and MISO analyses used electricity price forecasts specific to each RTO.

[7] With the existing 16% RM target, GP would choose to purchase temporary capacity through a PPA in years with an annual RM between 14% and 15% and would choose permanent capacity in a year with a RM below 14%. With the new 15% RM target, a PPA would be chosen for years with RMs between 13% and 14%; permanent capacity would be chosen below 13%.

- The resulting net trade benefits total between $11 M and $15 M annually over the study period for each RTO
- The present value of trade benefits is approximately $90 M for both PJM and MISO.

4.3 Other Components

4.3.1 Administrative charges

Both MISO and PJM have various tariff schedules to recover the administration cost of operating the markets and providing services to their respective footprints. For MISO, these costs were estimated using $/MWh cost projections contained in the MISO 2011 Budget presentation published on their website[8]. Administrative costs for PJM were estimated based upon the costs noted in the CRA study.

4.3.2 Transmission Revenue

Both MISO and PJM allocate third-party transmission revenues to the transmission owners in their respective footprints. MISO uses a formula based on allocation of plant in service and transmission flows to allocate transmission revenue. This allocation was assumed to be approximately $1 M per year to LKE, estimated based upon prior experience in MISO. The projected allocation to LKE from PJM was estimated using the PJM transmission revenues shown in the CRA study, multiplied by LKE's estimated proportion of PJM's total transmission revenue requirement, which calculated to be approximately 2.7%.

4.3.3 Uplift Costs

Both MISO and PJM have various mechanisms for allocating uplift costs that result from operations of the markets and payments made to others that are not offset by revenues. Typically, for both RTOs, these costs are the result of committing units in real-time that were not committed in the day-ahead market. In MISO these costs are referred to as "revenue sufficiency guarantee" (RSG) costs and, in the PJM market, as "operating and balancing reserve cost". Both RTOs also have other sources of these "revenue insufficient" costs. For MISO, RSG cost was assumed to be a net zero for LKE, but a load ratio share of the historic Revenue Neutrality Uplift cost of $100 million per year was assumed.[9] For this analysis, the PJM allocation of these costs to LKE was assumed to be negligible, which is consistent with the CRA study.

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[8] https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/BOD/2011/20111208/20111208%20BOD%20Item%2006%20%20VI.A%202012%20Budget%20Public%20Final.pdf

[9] Load ratio share roughly estimated based on LKE peak load of 7200 and total MISO peak load of ~107,000 or 6.6%

4.3.4 FERC Charges

Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load, and not just "wholesale" load as LKE is assessed outside of an RTO. For this analysis, the current FERC assessment charges were escalated for inflation and applied to LKE Energy for load as given in the 2013 Business Plan.

4.3.5 Net Zero Components

Two components, congestion cost/ARR/FTR and ancillary services market, have been identified that would be considered of net zero benefit. It is expected that the value of the ARR/FTR may equal or exceed the congestion costs; however, the net cost or benefit will not be known with certainly until such rights are issued. A company may choose to self-supply ancillary services and be no worse off than before joining an RTO. While there could be some potential benefit in the RTO market, there is no means to estimate the value of such benefit.[10]

4.3.6 Eliminated Administration Charges

Membership in either PJM or MISO would result in a re-alignment of internal cost for the provision of certain services. For the purposes of this analysis, it was assumed that LKE would no longer need the current Independent Transmission Operator (ITO) or Reliability Coordinator (RC) services provided by TranServ and TVA, respectively. There also likely would be a reduction in cost in the balancing authority services provided by internal staffing. This reduction would be offset to some degree by increases in internal staffing to manage the day to day operations in the RTO, as well as for back office settlement of the RTO statements and invoices on a daily basis.

4.3.7 De-Pancaking

LKE currently pays "depancaking" cost to certain entities as a result of the 2006 MISO exit.[11] It is assumed that all of these payments would cease if LKE were to join either PJM or MISO.

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[10] See Charles River Associates EKPC RTO Membership Assessment (March 2012)

[11] LKE pays costs for certain entities to keep them from having to pay more for transmission now than when the Companies were in MISO, known as depancaking costs.

5 MISO Summary

												Present Value Rate
												6.75%
Cost		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
	MISO Admin Cost ($M)	-11.3	-11.0	-11.0	-11.4	-11.8	-12.2	-12.6	-13.1	-13.5	-14.1	-85.4
	MISO MVP XM Expansion Cost ($M)	-5.9	-12.1	-20.7	-33.0	-37.9	-43.6	-51.1	-56.8	-55.9	-55.3	-241.3
	LKE Internal Staffing/Equipment Cost ($M)	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-3.9
	MISO Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MISO Misc. Uplift Cost ($M) - Revenue Neutrality Uplift	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-6.6	-46.9
	MISO Ancillary Services Market ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MISO FERC Fees (Incremental of Present) ($M)	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.3	-13.0
	LKE Lost XM Revenue from 3rd Parties	-3.0	-3.1	-3.2	-3.2	-3.3	-3.4	-3.5	-3.6	-3.7	-3.7	-23.6
	Sum of Cost	-28.8	-34.8	-43.6	-56.6	-62.0	-68.3	-76.3	-82.7	-82.6	-82.7	-414.0
Benefits		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
	MISO XM Revenue Allocation ($M)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	7.1
	MISO Trade Benefits (Production Costs) ($M)	11.1	12.3	12.3	11.6	12.1	12.4	13.2	12.7	14.9	15.6	89.7
	MISO Operating Reserve Margin Capacity Benefits ($M)	0.0	0.0	0.0	9.4	9.3	0.0	0.0	0.0	0.0	0.0	13.9
	LKE Elimination of TVA RC Cost ($M)	2	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	15.7
	LKE Elimination of ITO Cost ($M)	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	23.6
	LKE Elimination of De-Pancaking ($M)	6.8	7.1	6.2	6.1	6.2	6.4	6.5	6.7	6.9	7.1	46.8
	LKE Elimination of TEE Group Admin Charge ($M)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
	Sum of Benefits	24.0	25.6	24.8	33.6	34.3	25.6	26.6	26.5	29.0	30.0	197.5
	Net of Cost + Benefits	-4.8	-9.2	-18.8	-23.0	-27.7	-42.7	-49.7	-56.2	-53.6	-52.7	-216.5

6 PJM Summary

Present Value Rate 6.75%

Cost

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
PJM Admin Cost ($M)	-11.4	-11.4	-11.6	-12.0	-12.4	-12.8	-13.2	-13.8	-14.2	-14.8	-89.3
PJM Backbone XM Expansion Cost ($M)	0.0	-12.6	-27.0	-27.0	-27.0	-27.0	-27.0	-40.4	-40.4	-40.4	-176.3
LKE Internal Staffing/Equipment Cost ($M)	-0.5	-0.5	-0.5	-0.5	-0.6	-0.6	-0.6	-0.6	-0.6	-0.6	-3.9
PJM Congestion Cost/ARR/FTR ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM Misc. Uplift Cost ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM Ancillary Services Market ($M)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PJM FERC Fees (Incremental of Present) ($M)	-1.5	-1.6	-1.6	-1.7	-1.8	-1.9	-2.0	-2.1	-2.2	-2.3	-13.0
LKE Lost XM Revenue from 3rd Parties	-3.0	-3.1	-3.2	-3.2	-3.3	-3.4	-3.5	-3.6	-3.7	-3.7	-23.6
Sum of Cost	-16.4	-29.1	-43.9	-44.5	-45.1	-45.7	-46.3	-60.4	-61.1	-61.9	-306.0

Benefits

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	NPV
PJM XM Revenue Allocation ($M)	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.9	1.9	12.0
PJM Trade Benefits (Production Costs) ($M)	12.6	12.9	11.7	10.9	11.3	12.2	13.0	14.2	14.6	15.2	90.2
PJM Reduced Operating Reserve Margin Capacity Benefits ($M)	0.0	0.0	0.0	9.3	9.4	0.0	0.0	0.0	0.0	0.0	13.9
LKE Elimination of TVA RC Cost ($M)	2	2.1	2.1	2.2	2.2	2.3	2.3	2.4	2.4	2.5	15.7
LKE Elimination of ITO Cost ($M)	3.0	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	23.6
LKE Elimination of De-Pancaking ($M)	6.8	7.1	6.2	6.1	6.2	6.4	6.5	6.7	6.9	7.1	46.8
LKE Elimination of TEE Group Admin Charge ($M)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Sum of Benefits	26.0	26.8	24.9	33.4	34.2	26.1	27.2	28.8	29.5	30.5	203.0
Net of Cost + Benefits	9.6	-2.3	-19.0	-11.2	-10.9	-19.6	-19.0	-31.6	-31.6	-31.3	-103.0

7 Additional Considerations and Uncertainties

7.1 NERC Compliance Requirements

Since the companies own and operate certain facilities used in interstate commerce or that have the potential to impact the bulk electric system, the Companies are required to comply with Reliability Standards for planning and operating the bulk electric system, as developed by the North American Electric Reliability Corporation (NERC). Under current operations, LG&E/KU Transmission Owner (TO) are responsible for over 1,200 NERC compliance requirements falling under the Reliability Standards. It is estimated that slightly over 300 of these requirements would be performed by an RTO and no longer an internal function if the companies were to join and RTO. While this reduction is noted qualitatively, the study does not estimate a financial cost/benefit related to compliance.

7.2 Regulatory Environments – MISO, PJM

There has been considerable realignment of RTO memberships since 2006. Examples include the departure from MISO of First Energy and Duke-Ohio/Kentucky. Both entities are now PJM transmission owning members. MISO has retained and, with the joining of Entergy, BREC, and Dairyland Power, gained members who operate in non-contestable load areas, while PJM has solidified membership of transmission owners operating in states that have retail access and unbundled utilities.[12] Given this realignment between MISO and PJM membership, it is likely that more of Kentucky's regulatory paradigm and LKE's traditional regulated utility business model would be accommodated in MISO versus PJM. For example, the entities within MISO that had been advocating for capacity markets are simply not as politically strong as they once may have been. Moreover, membership in PJM would almost certainly pit LKE interests against those of the traditional PPL companies on matters of significance to all concerned.

7.3 Future RTO Market/Program Implementation

The costs/benefits of "markets" or "programs" that each RTO may implement in the future are uncertain and so cannot be reflected in this analysis.

8 Conclusion

The results of this threshold analysis reveal that a more in depth study of the cost and benefits of RTO membership is not warranted at this time. Further, the study results

[12] Ameren-Illinois's continued membership in MISO being a notable exception.

confirm the prudency of LKE continuing with the establishment the Southeast Order 1000 Planning Region.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 3

Witness: David S. Sinclair

Q1-3. With respect to PJM, please provide the following:

a. On a mw basis, how much would the KU/LG&E required reserve margin be reduced as a PJM member with reserves based on the KU/LG&E contribution to PJM's five PLC hours as opposed to the reserves required on a stand-alone basis?

b. For the last three years, please identify the KU/LG&E demand that occurred on each of the PJM five PLC hours. If you do not have this information, please explain why you have not been monitoring this issue for determining possible membership into PJM.

c. On an mw basis, how much would the KU/LG&E reserve share be reduced as a member of PJM as opposed to the reserve sharing agreement with TVA? How many MW of reserves does KU/LG&E have to carry under the TVA load sharing agreement?

d. If KU/LG&E were members of PJM would the market power concerns that caused FERC to conditionally approve the Bluegrass transaction be alleviated? Please explain.

e. Assuming that KU/LG&E were members of PJM, please explain the effect that would have on the need for the proposed Green River combined cycle plant.

A1-3. a. The Companies have no first-hand knowledge of the reserve margin requirements of PJM and have not performed this analysis.

b. The Companies do not have this information and have not investigated PJM membership to this level of detail.

c. The Companies have no precise knowledge of the reserve requirements in PJM. The Companies carry 258 MW as their share of the parties' largest single contingency.

d. 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 results of such analysis depend on a variety of factors including the geographic market studied, assumed market prices, electric generation owned or controlled by market participants, and electric transmission capabilities. While LG&E/KU joining PJM would likely impact each of these factors, it is unclear how these factors would be determined, how LG&E/KU's membership in PJM would impact these factors, and how the impacts would affect the overall market power analysis.

e. The Companies have not performed this analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 4

Witness: David S. Sinclair

Q1-4. Please provide all production cost models, financial models or other computer models in electronic format utilized in this filing.

A1-4. See the response to PSC 1-22.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 5

Witness: David S. Sinclair

Q1-5. Based upon the models used in this filing and assuming the Application is approved, please list by year the expected mwh of off-system sales. By off-system sales, we mean all wholesale energy sales not made to KU's all requirements wholesale customers.

A1-5. See the response to PSC 1-26.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 6

Witness: Paul W. Thompson / David S. Sinclair

Q1-6. Please provide all correspondence, emails or other documents in the possession of either Mr. Thompson or Mr. Sinclair that relates in any way to the decision to construct the Green River combined cycle plant or the 10 MW solar facility at the Brown site.

A1-6. See attached for non-confidential information responsive to this request. All confidential information responsive to this request is being provided under seal pursuant to a Joint Petition for Confidential Protection.

From:	Sinclair, David
To:	Schram, Chuck; Freibert, Charlie; Huff, David; Bellar, Lonnie; Schetzel, Doug; Wilson, Stuart
Subject:	Info for July 3 RFP meeting
Date:	Monday, June 25, 2012 4:45:00 PM

All,

I have scheduled an organizational meeting on July 3 related to the RFP to replace Bluegrass. Below is a stawman schedule and list of likely activities we will need to undertake in the coming months. At this meeting I'd like to reach agreement on the schedule and the list of activities.

Thanks.

Draft Schedule

September 7 – Issue RFP

November 2 - RFP responses due

April 1 – Complete RFP/Self build analysis/3rd party contracts (if any)

May 1 – Begin preparing testimony

July 1 – file ECR for Brown 1&2 (if necessary) and CPCN for new resource(s)

Activities

1. Brown 1&2 retrofit technology review
2. Commercial DSM potential study and potential for DSM filing
3. Self-build option – size, location, date
4. Updated load forecast
5. Transmission issues surrounding Brown site and self-build option
6. Prescreening study of impact of a Bluegrass PPA on BR1&2 retrofit decision (if any)
7. Rate case implications (if any)
8. RFP development

Needham, Meredith

From:	Schram, Chuck
Sent:	Friday, July 06, 2012 4:37 PM
To:	Sinclair, David; Wilson, Stuart; Schetzel, Doug; Freibert, Charlie; Huff, David; Bellar, Lonnie; Brunner, Bob; Hornung, Mike; Conroy, Robert
Subject:	Proposed RFP Schedule Meeting

We will discuss the attached proposed schedule for upcoming RFP/CCN/ECR in next Tuesday's (July 10) meeting:

CCN and ECR Filing Schedule ....

Chuck

Proposed Schedule for 2013 CCN/ECR Filing — Draft July 6, 2012

Date	RFP	ECR/CCN Filing	Transmission Studies	BR1-2 Studies	Self Build Options	DSM Study
Jul 2012			Confirm scope and timing	• Initiate Eng life assessment for BR1-2 • Confirm scope and timing of BR1-2 control evaluation • Confirm with Env Affairs regs affecting BR	• Confirm scope/timing of self build options • Consider solar self-build option and scale	
Aug 2012			Provide self-build inputs to Xmission			
Sep 2012	Sep 7 – issue RFP					
Oct 2012						
Nov 2012	• Nov 2 - responses due • Bid clarification • Screening		Nov 2 - studies related to BR1-2, BR, GR, or other sites for new gen	Nov 2 - BR1-2 controls (MATS and NOx), Eng life assessment	Nov 2 - Technology (include solar), size, configuration, flexibility.	
Dec 2012	• Screening • Short list	Alternative exp plan analysis				
Jan 2013	• Negotiations	Alternative exp plan analysis				Preliminary study output for exp plan analysis
Feb 2013	Negotiations	Alternative exp plan analysis				

Proposed Schedule for 2013 CCN/ECR Filing

Draft July 6, 2012

Date	RFP	ECR/CCN Filing	Transmission Studies	BR1-2 Studies	Self Build Options	DSM Study
Mar 2013	Negotiations	• Complete alternative exp plan analysis • Mar 31 – Sr mgmt approval of exp plan and env compliance plan				
Apr 2013		Finalize supporting docs, including Resource Assessment/Env Compliance Plan				
May 2013		Develop testimony				
Jun 2013		Finalize testimony				
Jul 2013		Jul 1 – ECR/CCN				

Needham, Meredith

From:	Sinclair, David
Sent:	Tuesday, July 10, 2012 5:16 PM
To:	Thompson, Paul
Cc:	Voyles, John
Subject:	Overview of RFP/CCN/ECR process

Paul,

I met today with Chuck, Robert, Mike Hornung, Stuart, Doug and Charlie to review the attached. It provides a high level overview of the various activities we will be performing in the next year to prepare for a likely ECR and CCN filing. Everyone was in agreement with the activities and timing. I'm assuming that you will want John to oversee this process as before. Also, at some point do you want to reconstitute the RFP oversight group that you had last year?

Thanks,
David

CCN and ECR Filing Schedule ....

Proposed Schedule for 2013 CCN/ECR Filing

Draft July 6, 2012

Date	RFP	ECR/CCN Filing	Transmission Studies	BR1-2 Studies	Self Build Options	DSM Study
Jul 2012			Confirm scope and timing	• Initiate Eng life assessment for BR1-2 • Confirm scope and timing of BR1-2 control evaluation • Confirm with Env Affairs regs affecting BR	• Confirm scope/timing of self build options • Consider solar self-build option and scale	
Aug 2012			Provide self-build inputs to Xmission			
Sep 2012	Sep 7 – issue RFP					
Oct 2012						
Nov 2012	• Nov 2 - responses due • Bid clarification • Screening		Nov 2 - studies related to BR1-2, BR, GR, or other sites for new gen	Nov 2 - BR1-2 controls (MATS and NOx), Eng life assessment	Nov 2 - Technology (include solar), size, configuration, flexibility.	
Dec 2012	• Screening • Short list	Alternative exp plan analysis				
Jan 2013	• Negotiations	Alternative exp plan analysis				Preliminary study output for exp plan analysis
Feb 2013	Negotiations	Alternative exp plan analysis				

Proposed Schedule for 2013 CCN/ECR Filing

Draft July 6, 2012

Date	RFP	ECR/CCN Filing	Transmission Studies	BR1-2 Studies	Self Build Options	DSM Study
Mar 2013	Negotiations	• Complete alternative exp plan analysis • Mar 31 – Sr mgmt approval of exp plan and env compliance plan				
Apr 2013		Finalize supporting docs, including Resource Assessment/Env Compliance Plan				
May 2013		Develop testimony				
Jun 2013		Finalize testimony				
Jul 2013		Jul 1 – ECR/CCN				

Needham, Meredith

From: Sebourn, Michael
Sent: Monday, September 30, 2013 11:18 AM
To: Sinclair, David
Cc: Schram, Chuck; Yussman, Eric
Subject: Xcel Solar in Colorado
Attachments: 20130930 Xcel Solar vs Gas in Colorado.docx

David,

The attachment summarizes Xcel Energy's recent proposal in Colorado to include solar PV in their resource plan due to solar's favorable economics.

Key points:

- The plan includes PPAs for simple cycle CTs, wind, and solar.
- The proposed renewables are an economic part of the generation mix (not due to an RPS or projected CO_2 costs) and compare favorably to gas generation.
- Although the capital costs are redacted, the analysis implies solar capital costs of $1,300 - $1,900/kW, well below the $4,000 – 5,000/kW that we previously reviewed. Burns and McDonnell, the provider of our 2014 IRP technology cost inputs, say that prices below $2,500/kW are now achievable.
- Low solar bids for Xcel were driven by lower solar panel costs, economies of scale for larger arrays, and the anticipated decrease in the investment tax credit from 30% to 10% at year-end 2016.
- In addition to Xcel utilizing solar-tracking technology for greater efficiency, higher solar insolation in Colorado drives higher capacity factors vs. similar configurations in Kentucky.

Please let us know if you'd like to discuss.

Mike

____
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Favorable Solar Economics in Colorado

On September 9, 2013, Public Service Company of Colorado ("PSCC"), a subsidiary of Xcel Energy, proposed a plan to develop a resource expansion portfolio composed of natural gas, wind, and solar photovoltaic ("PV") units. PSCC noted that for the first time, solar PV bids were cost-effective vs. gas-fired generation assuming a base gas price forecast and no CO_2 emissions costs.[1]

- **Portfolio of gas, wind, and solar.**
  - PSCC's proposed portfolio consists of 669 MW of gas generation (including a 352 MW coal unit converted to burn gas and two PPAs for simple cycle CTs), 450 MW of wind (two PPAs), and 170 MW of solar PV (two PPAs). Assuming firm capacity contributions from wind of 12.5% and solar of 50-55%, PSCC expects 809 MW of total firm capacity.
  - PSCC considered a variety of combinations of gas, wind, and solar, determining that a mix of these technologies was the least cost plan. PSCC ultimately recommended a slightly higher cost variant of this plan to satisfy qualitative factors such as geographic diversity.
- **Solar compares favorably to gas.**
  - Because PSCC identified a need for mostly peaking capacity vs. energy resources in their RFPs, nearly all bids for gas-fired generation were for simple cycle CTs. Given Colorado's relatively high solar insolation and apparently low bids for solar, the resulting portfolio included a mix of simple cycle CTs and solar.
  - To put the pricing of the lowest cost renewables bids in perspective, PSCC compared the PPA costs for renewables to an estimated cost of avoided generation from existing gas units.[2] While this analysis was not used in developing PSCC's proposed portfolio, it implies that the all-in levelized energy cost for the lowest cost solar bids is $50 - 60/MWh, which is lower than the levelized variable cost of gas generation at $62/MWh.[3]
  - PSCC's gas price forecast is reasonable with a 30-year levelized cost of $6.24/MMBtu compared to LG&E/KU's 2014 Business Plan forecast of $6.14/MMBtu.[4]

[1] For PSCC's "2013 All Source Solicitation 120 Day Report" September 10, 2013 filing, *see* http://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=240772&p_session_id=. For Xcel Energy's news release, *see* http://www.xcelenergy.com/About_Us/Energy_News/News_Releases/Xcel_Energy_proposes_adding_economic_solar,_wind_to_meet_future_customer_energy_demands.

[2] PSCC's "2013 All Source Solicitation 120 Day Report," pp. 30-32.

[3] Because solar generation operates during the day, PSCC compared solar to a combination of simple cycle and combined cycle CTs with an average heat rate of 8.6 MMBtu/MWh, $3/MWh variable O&M, and a gas price volatility mitigation adder of $0.65/MMBtu. Integration costs of $2/MWh are added to solar bids.

[4] For PSCC's modeling assumptions, *see* https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/PSCo2013_UpdatedModelingAssumptions.pdf.

- **Implied solar capital costs are very low.**
  - The solar options included in PSCC's proposed portfolio are PPAs, with all costs and operating information redacted in the filing. However, PSCC notes that the current low cost solar PV bids are priced substantially below solar bids received in previous solicitations due to:
    - sharp decreases in the cost of solar modules,
    - the anticipated decrease in the investment tax credit ("ITC") for solar generation from 30% to a 10% at year-end 2016, effectively making PSCC's current solicitation the last opportunity for solar developers to receive the 30% credit on PSCC projects, thereby motivating developers to provide highly competitive bids,[5] and
    - economies of scale for larger utility-scale solar PV systems.[6]

  - PSCC's implied levelized costs suggest that the capital costs of the lowest cost solar projects are $1,300 – 1,900/kW (before applying the ITC). This is less than the original estimate of $4,000 – 5,000/kW (from LG&E/KU's consultant HDR) for building a 10 MW solar PV array in Kentucky. However, recent information from Burns and McDonnell, the provider of our technology cost inputs for the 2014 IRP, indicates the potential for solar costs below $2,500/kW.

- **High solar capacity factor due to solar tracking and favorable location.**
  - The solar PV systems proposed by PSCC are "1-axis tracking" arrays, meaning that the panels track the sun along a single axis to optimize the angle to the sun. 1-axis tracking increases output by approximately 20%.[7]

  - PSCC staff remarked via email that the proposed solar systems would result in 2.1 MWh of annual energy for every 1 kW of DC capacity for a 24% DC capacity factor. A similar configuration in Kentucky would only produce 1.4 MWh (33% less) at a 16% DC capacity factor due to Kentucky's significantly lower solar insolation.[8]

Next Steps

PSCC's proposal must be reviewed by an independent evaluator for the Colorado Public Utilities Commission. The Commission is scheduled to approve the plan as filed or make amendments to it by Dec. 9, 2013.

---

[5] PSCC's "2013 All Source Solicitation 120 Day Report," p. 29.

[6] PSCC staff noted via email that the solar PV bids with the smallest capacity (~30 MW) cost 15-25% more than the bids for the proposed 50 MW and 120 MW solar PV systems.

[7] Solar output was estimated using the National Renewable Energy Laboratory's PVWatts tool for the 40205 zip code in Kentucky and for Alamosa, CO. *See* http://www.nrel.gov/rredc/pvwatts/.

[8] Estimated using PVWatts for a 1-axis tracking system with a 0 degree array tilt.

Needham, Meredith

From: Schram, Chuck
Sent: Tuesday, October 01, 2013 3:00 PM
To: Sinclair, David
Cc: Wilson, Stuart
Subject: FW: solar

Fyi...Several installations larger than 10 MW.

From: Yussman, Eric
Sent: Tuesday, October 01, 2013 2:47 PM
To: Schram, Chuck
Subject: FW: solar

From: Philip Haddix [mailto:phaddix@solarfound.org]
Sent: Tuesday, October 01, 2013 2:41 PM
To: Yussman, Eric
Cc: Andrea Luecke
Subject: RE: solar

Mr. Yussman,

Thanks for your question. The largest solar installation currently in operation east of the Mississippi River is Florida Power & Light's "Martin Next Generation Solar Energy Center", a 75 MW parabolic trough installation in Martin County, FL since December 2010. The largest *photovoltaic* installation is the 32 MW Long Island Solar Farm, which came online in November 2011.

There are a number of installations planned across the country that will top this. See below for a list of the ones planned for the eastern U.S.

Florida

- National Solar Power currently has a number of large PV solar installations under development for Progress Energy Florida
  - Gadsden Solar Farm (400 MW; announced Sept 2011)
  - Hardee Solar Farm (200 MW; announced Nov 2011)
  - Liberty County Solar Farm (100 MW; announced Jan 2012)

North Carolina

- Strata Solar is developing the Duplin Solar Project, a 100 MW PV solar farm announced in February 2013

New Jersey

- Atlantic Green Power is developing the Upper Pittsgrove Township Solar Farm, an 80 MW PV installation in Salem County, NJ

You can find a list a thorough list of all major solar projects currently operating, under construction, or under development in the U.S. in SEIA's Major Projects List at:
http://www.seia.org/sites/default/files/resources/Major%20Solar%20Projects%20List%2010.1.13.pdf

Hope this helps. Please let me know if you have any other questions.

Best,

Philip Haddix
Manager, Outreach and Policy

THE SOLAR FOUNDATION
Research and Education to Advance Solar Energy

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*Save the Date. **Summer Solstice 2014** will be June 20, 2014 on a downtown Washington, DC rooftop.*
*Read our **Annual Report**.*

Needham, Meredith

From: Schram, Chuck
Sent: Thursday, October 03, 2013 8:56 AM
To: Sinclair, David
Cc: Sebourn, Michael
Subject: FW: Water bird deaths at utility solar facilities

Based on this info from Mike and Eric, the solar/bird issue appears to be more of a desert phenomenon.

Chuck

From: Sebourn, Michael
Sent: Wednesday, October 02, 2013 6:10 PM
To: Schram, Chuck
Cc: Yussman, Eric
Subject: Water bird deaths at utility solar facilities

Chuck,

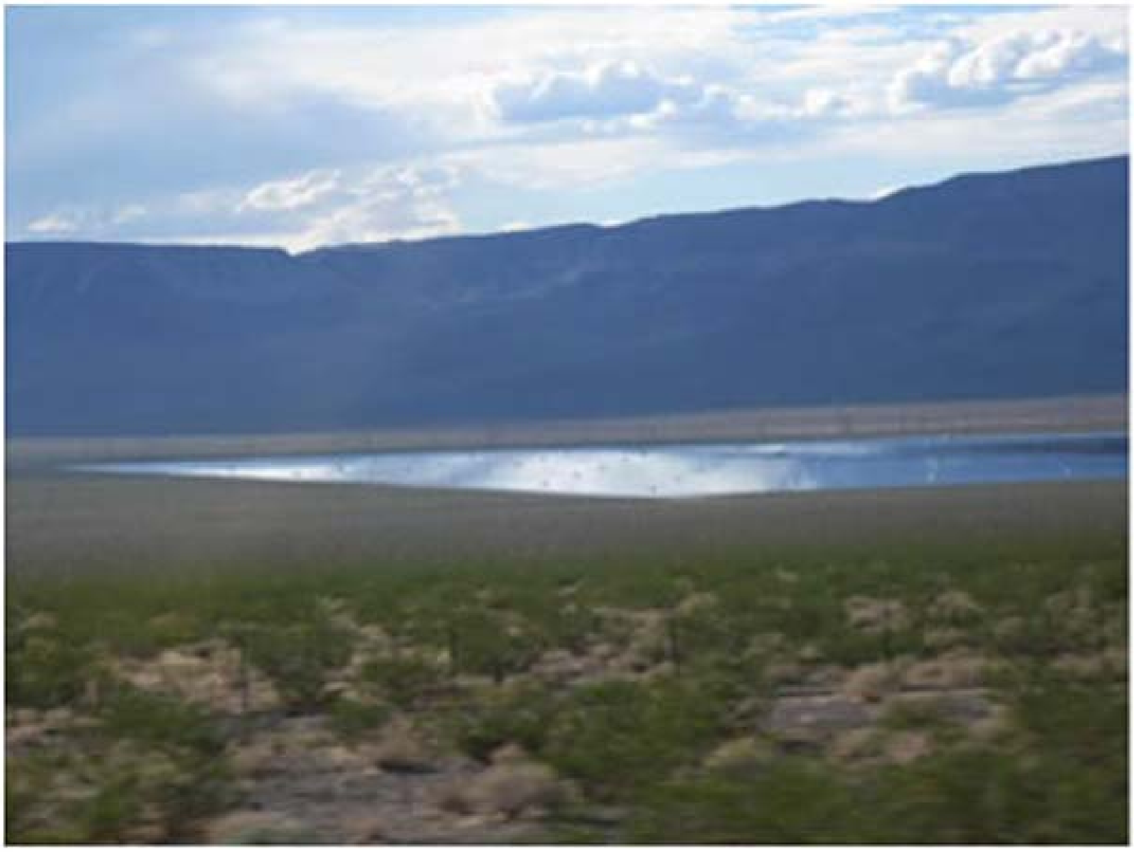
You asked about news reports on bird deaths at solar facilities. In July 2013, there were reports of a high number of water bird (including endangered birds) deaths at two solar facilities currently under construction in Southern California on land managed by the Federal Bureau of Land Management.

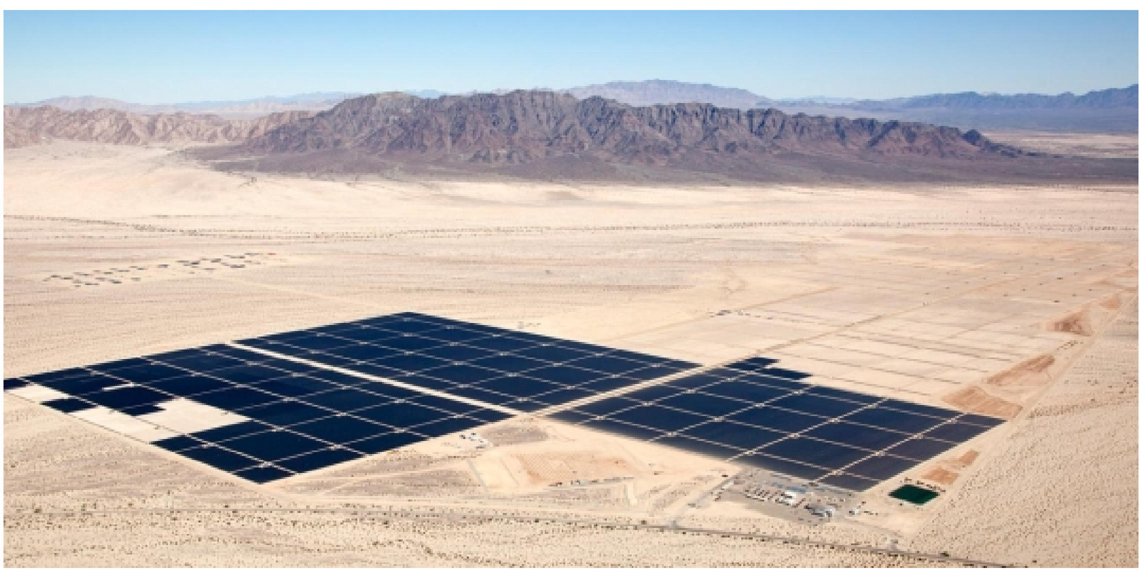
- First Solar's 550 MW (AC) "Desert Sunlight" solar-PV facility; fully operational in 2015 with a PPA planned with So. Cal. Edison and PG&E
- Nextera's 250 MW "Genesis" parabolic trough concentrating solar plant; planned in-service with a PPA with PG&E

Although it hasn't been scientifically confirmed, there is some speculation that reflections from solar facilities' infrastructure, including photovoltaic panels and mirrors, may well be attracting birds in flight across the open desert, who mistake the broad reflective surfaces for water.

I've attached several pictures of solar facilities below that demonstrate the potential for mistaking the reflective solar arrays for water. The first two are of First Solar's "Desert Sunlight" facility. The third is from an unrelated solar facility in Nevada.

Mike





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Needham, Meredith

From:	Wilson, Stuart
Sent:	Thursday, October 25, 2012 5:12 PM
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	RFP Analysis - Project Overview and Schedule
Attachments:	20120828_2012RFPAnalysis_ProjectOverview_0060D02.docx

David,

I've attached the document below for your review prior to our meeting tomorrow at 2:00 PM.

Stuart

October 25, 2012

2012 RFP Analysis

Process

1. Review RFP responses
    a. To ensure a more complete review, responses for a given technology will be reviewed by two people.
    b. For each technology, a standard format will be used to summarize the inputs from each bid. THEN, we'll consider combining the inputs for all technologies in a single worksheet. This should simplify the analysis of bids for each technology.
    c. A meeting will be scheduled to discuss bids and agree on bid-specific inputs and follow-up questions BEFORE a significant amount of analysis begins.
2. Phase/iteration naming convention
    a. A 'phase' includes all work for a deliverable that is presented outside Energy Marketing.
    b. A phase can consist of several 'iterations.'
    c. The write-up will summarize the last iteration in each phase.
    d. Phases will not be assigned more descriptive labels until the write-up (if then). See table below for an example.
3. Documentation
    a. Each iteration folder will contain a subfolder with a complete summary of inputs for that iteration.
        i. Inputs will be clearly labeled so that source and vintage of input is apparent.
        ii. Changes in inputs from the previous iteration will be highlighted.
    b. Each iteration folder will also contain a document summarizing key aspects of the iteration (alternatives considered, changes to input assumptions, etc.).
    c. All analysis files of a given type (e.g., Excel files, PROSYM files, Strategist files, etc.) will be developed with a common set of best practices and formats.
4. Phase 1 screening
    a. The phase 1 screening model will continue to evaluate each response based on its levelized revenue requirement (per MWh). Generally, responses will be grouped by technology and capacity and the responses in each group with the lowest levelized revenue requirement will be considered in subsequent phases of the analysis. Technologies with similar dispatch characteristics (e.g., nuclear, biomass, and waste coal) will be evaluated in one group (by capacity). Consideration will be given to further segmenting the groups by contract term if there are significant differences in contract terms.
    b. For each group, the 'line' determining the number of responses considered in subsequent analysis phases will be drawn at the point where the responses NOT considered are clearly inferior (based on levelized revenue requirement) to the responses considered. Unlike the 2011 analysis, sufficient detail on self-build alternatives is available and will be included in the phase 1 screening analysis. This will simplify the process of determining the number of responses for each group considered in subsequent analysis phases.
    c. Since varying contract start dates can bias the levelized revenue requirement calculation (due to discounting), the Phase 1 screening analysis will assume all contracts begin in the same year.
    d. Depending on the structure of PPAs in each technology group, capital revenue requirements for asset sale alternatives will be computed using either a fixed charge rate or economic carrying charge rate.

October 25, 2012

5. Development of alternatives
    a. Because we cannot consider every combination of RFP responses and self-build options in Strategist (run times are too long), we will continue to develop alternatives 'manually.'
    b. Alternatives consisting of multiple responses/options are 'portfolio' alternatives.
    c. All alternatives will contain (at least) enough capacity to meet the reserve margin shortfall in 2015.
    d. To avoid potential criticisms associated with not evaluating an 'optimal' alternative, initial iterations of the analysis will consider an exhaustive list of alternatives.
    e. Case Developer for Strategist and PROSYM will be used to set up the runs and summarize the results. The inputs to PROSYM and Strategist are contained in a number of input data files. A 'control' file in PROSYM and an '.INP' file in Strategist tell the programs which input files to include in a run. Case Developer automates the process of developing the control and .INP files. The process of creating input files is unchanged and remains in the hands of PROSYM and Strategist users. Particularly for studies involving many runs (50+ runs), Case Developer significantly reduces the potential for error in setting up multiple runs. In addition, Case Developer reduces the time to summarize the results of a run from several minutes to several seconds.
    f. Lessons learned from early iterations will be used to reduce the number of alternatives considered in subsequent iterations/phases.
6. Generations portfolios
    a. Each alternative will be evaluated in the context of a generation portfolio that includes the company's existing SCCTs, BR3, and the Mill Creek, Ghent, and Trimble County coal units.
    b. A retrofitted BR1-2 (with associated capital and fixed O&M) will be considered as a separate alternative in this analysis.
7. Development of long-term capacity resources (LCRs)
    a. LCRs are used to meet reserve margin needs beyond the need that is met by each alternative. LCRs are selected to minimize the extent to which these resources affect the evaluation of alternatives.
    b. Like before, LCRs will be limited to CCCTs and SCCTs. Furthermore (like before), care will be taken to ensure that small differences in the capacity of alternatives do not impact the timing of the 'next' LCR addition.
    c. Consideration will be given to adjusting the heat rates of the LCRs so they do not overlap the range of heat rates for alternatives with same technologies. If this is done in a way that the relative value of LCRs (CCCTs versus SCCTs) is maintained (i.e., the tendency to pick one technology over the other is not changed), the analysis will be (very appropriately) focused on the interaction between the alternatives considered and the company's existing generating portfolio.
8. Development of input assumptions – responsibilities
    a. Input assumptions for self-build options are being developed by Business Development and Project Engineering in conjunction with HDR.
    b. Gas and electricity price assumptions (and scenarios) are being developed by economic analysis.
    c. David Cosby and Project Engineering are updating cost assumptions for BR1-2.
9. Analysis of alternatives in subsequent phases
    a. For a given iteration, the process for analyzing alternatives will remain mostly unchanged from the 2011 RFP analysis.

October 25, 2012

   i. Expansion plans will be developed in Strategist and detailed production costs will be computed using PROSYM.
   ii. Revenue requirements for production costs, capital, and fixed O&M will be summarized in Excel.
   iii. Analysis will utilize same decision criteria (emphasis on 30-year PVRR with an awareness of 10-year PVRR and understanding of risk).

b. Key changes to process/presentation of data.
   i. More than one person will be responsible for developing expansion plans.
   ii. Capital revenue requirements for all alternatives will be summarized in same 'bucket.' Previously, capital revenue requirements for self-build options were included with revenue requirements for LCRs.
   iii. Case Developer will be used to (a) set up Strategist and PROSYM runs and (b) summarize the results.
   iv. Strategist and PROSYM results will be combined with other fixed operating costs (in Excel) in a way that is more seamless, facilitates the process of reviewing the results, and reduces the potential for copy/paste errors.

c. Key uncertainties/scenarios
   i. Market EL/Gas prices
   ii. CO2
   iii. Other environmental?
      1. RPS
      2. Water

10. Schedule (tentative)
    a. November 2 – RFP responses due
    b. November 9 – Meet with Freibert and Schetzel to agree on bid-specific inputs
    c. November 15 – Meet with Sinclair, Freibert, and Schetzel to discuss Phase I screening results and alternatives for further consideration
    d. November 30 – Meet with Sinclair, Freibert, and Schetzel to discuss (preliminary) Phase 2 results
    e. December 7 – Meet with Sinclair, Freibert, and Schetzel to discuss (final) Phase 2 results and presentation to senior officers regarding shortlist
    f. December 14 – Meet with Thompson to discuss shortlist recommendation
    g. January/February/March – Negotiations with shortlisted bidders
    h. April 1 – Complete RFP/Self build analysis/3rd party contracts (if any)
    i. May 1 – Begin preparing testimony
    j. July 1 – file ECR for Brown 1&2 (if necessary) and CPCN for new resource(s)

Needham, Meredith

From: Wilson, Stuart
Sent: Wednesday, November 21, 2012 8:08 PM
To: Bellar, Lonnie
Cc: Sinclair, David; Schram, Chuck
Subject: RFP Summary

Lonnie,

David asked me to send you some summary information regarding our RFP responses…

We received 27 responses to our RFP. In total, the responses refer to 33 unique assets (or asset portfolios) and include 60 unique proposals. The table below contains summary statistics for the assets referenced in the RFP responses.

	Assets	MWs
Total	33	11,338
Coal	9	2,734
Gas	16	7,169
Renewable	6	535
Portfolio	2	900
New	13	4,672
Existing	20	6,666
In-State	12	3,743
Out-of-State	21	7,595

Please let me know if you have any questions.

Stuart

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 7

Witness: David S. Sinclair

Q.1-7. Please provide all economic studies that support the decision to build the 10 MW solar facility at the Brown site. If none exist, please explain why not.

A1-7. See Section 4.6 of Exhibit DSS-1 beginning on page 43. Also see the response to AG 1-137.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 8

Witness: David S. Sinclair

Q1-8. Have KU/LG&E conducted any studies regarding whether any solar or wind renewable resources are available for purchase at a lower cost than the proposed 10 MW solar facility at the Brown site? If not, then please explain.

A1-8. See the response to AG 1-54.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 9

Witness: David S. Sinclair

Q1-9. If KU/LG&E were members of PJM or MISO, would the purchase of wind or solar energy be more affordable? Please explain.

A1-9. The answer to this question is uncertain however it is likely that the sellers of wind and solar energy would seek the market clearing price from their generation regardless of the Companies' membership status in an RTO.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 10

Witness: David S. Sinclair

Q1-10. Please provide all studies regarding the cost of solar or wind Renewable Energy Credits (RECs).

A1-10. See the response to AG 1-166.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to the First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated March 13, 2014

Case No. 2014-00002

Question No. 11

Witness: David S. Sinclair

Q1-11. Please explain why no Request for Proposals (RFP) was done to determine if lower cost solar power is available for purchase.

A1-11. See the response to AG 1-54.