From: Brunner, Bob
To: Sinclair, David
Subject: FW: Questions for Shortlisted RFP Respondents
Date: Friday, January 04, 2013 2:43:06 PM
Attachments: 20121219_RFPQuestions_AEP_0060D02.docx
ATT00001.htm
ATT00002.htm
20121219_RFPQuestions_BigRivers_0060.docx
ATT00003.htm
20121219_RFPQuestions_ERORA_0060.docx.docx
ATT00004.htm
20121219_RFPQuestions_Khanjee_0060.docx
ATT00005.htm
20121219_RFPquestions_LSPower_0060.docx
ATT00006.htm
20121219_RFPQuestions_Ameren_0060.docx

David,
Attached are the questions sent to the counterparties.
Bob

From: Freibert, Charlie
Sent: Thursday, January 03, 2013 10:28 AM
To: Brunner, Bob
Subject: Fwd: Questions for Shortlisted RFP Respondents

Bob
Here are the questions. You were copied on 12/20/12. I sent on 12/21/12 to the 6 on the short list. I will send you the updated ameren questions next.

Leaving at noon for Lexington airport. I will be Driving the horse but also fishing! Diana said I desired the get away - actually she insisted.

Charlie

Sent from my iPhone

Begin forwarded message:

> **From:** "Wilson, Stuart" [redacted]
> **Date:** December 20, 2012, 1:16:25 PM EST
> **To:** "Freibert, Charlie" [redacted], "Depaull, Tom" [redacted], "Oelker, Linn" [redacted]>, "Brunner, Bob" [redacted], "Schetzel, Doug" [redacted], "Schram, Chuck" [redacted]
> **Cc:** "Farhat, Monica" [redacted], "Karavayev, Louanne" [redacted], "Leitner, George" [redacted], "Ryan, Samuel" [redacted], "Wang, Chung-Hsiao" [redacted]
> **Subject: Questions for Shortlisted RFP Respondents**
>
> Please see attached…

Stuart

12/21/2012

Big Rivers

1. Review your company's organization.
2. Review your company's financial standing and applicable project financing.
3. Confirm operating parameters

Operating Parameters - Big Rivers - PPA	
Start Date	Negotiable
Term (Years)	up to 15 years
Summer Capacity (MW)	417
Winter Capacity (MW)	417
Minimum Capacity (MW)	300
Heat Rate @baseload (Btu/kWh)	10,450
Ramp up (MW/min)	3
Min run time (hrs)	24
Min down time (hrs)	24
Forced Outage Rate	4%

4. Confirm Financial Terms

Financial Terms - Big Rivers - PPA	
Quote Year	2015
Capacity Charge ($/MW-yr)	$138,000
Capacity Price Esc (%)	1
Variable O&M ($/MWh)	$2.7
VO&M Esc	CPI-U
Fuel Price ($/mmBtu)*	2.4
Start Cost ($/Start)	6,000
Start Fuel (gallons)	25,000
Environmental Surcharge**	5.54%

*2015 Estimated Coal Price
**Environmental surcharge is applied to capacity charge, total energy charge and total start charge

5. Discuss transmission assumptions

Assumptions - Big Rivers - PPA	
Transmission Losses	2.5%
MISO Transmission Cost ($/MW-yr)	$36,056

6. Additional Questions
   a. Seller states that they welcome discussions regarding how to structure the deal to minimize transmission costs to buyer. How might transmission costs be reduced?

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b. What type of fuel is being used at the Wilson station? Can you provide a delivered fuel price forecast?
c. Please provide a seasonal heat rate curve (at least two points; summer and winter).
d. How is the environmental surcharge calculated? Is the environmental surcharge applicable to the Big Rivers fleet or just the Wilson station?
e. What additional environmental controls will be needed at the Wilson station? For what portion of these costs will the buyer be responsible?
f. How would you propose to compensate buyer for not meeting availability guarantees?
g. How would you propose structuring an asset sale proposal?

12/21/2012

ERORA

1. Review your company's organization.
2. Review your company's financial standing and applicable project financing.
3. Confirm unit operating parameters. Provide missing parameters where necessary.

ERORA 2x1 CCCT	
Summer Capacity Unfired (MW)	535
Summer Duct - Fired Capacity (MW)	165
Winter Capacity – Total (MW)	700
Minimum Capacity 1X1 CCCT (MW) – Summer	156
Minimum Capacity 2X1 CCCT (MW) – Summer	336
Minimum Capacity 1X1 CCCT (MW) – Winter	178
Minimum Capacity 2X1 CCCT (MW) – Winter	375
Unfired Heat Rate @ baseload (Btu/kWh)	6,705
Duct fired Heat Rate (Btu/kWh)	8,546
Min Load Heat Rate (Btu/kWh)	7,566
Output in 10 min (MW)	0
Ramp up (MW/min)	55
Start-up time to min Cap (hrs)	2
Min run time (hrs)	4
Min down time (hrs)	24
Guaranteed Annual/Summer Availability	90% / 95%
Forced Outage Rate	5%

4. Describe risk mitigation measures related to your offer.
   a. Elaborate on your ability to meet a COD of June 1, 2017?
   b. What is the status of the changes to your air permit? Describe the air permit and any related operating limitations.
   c. What is the status of the right-of-way required for the transmission interconnection?
   d. Have you confirmed that the ANR pipeline has sufficient capacity to provide gas transportation services for this facility?
   e. Please confirm that the seller is responsible for any upgrade costs required for additional capacity on the ANR pipeline. Please confirm that these upgrades can be completed before the unit goes into service.
   f. What investment-grade credit support will be provided by the owners under the PPA?

5. Confirm the following contract terms.

ERORA 2x1 CCCT- PPA	
Start Date	6/1/2017
Term (Years)	10 or 20
Capacity Price ($/MW-yr)	64,800
Capacity Quote Year	2016

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Tolling Charge ($/kW-mo)	5.40
Tolling Charge Escalation/yr	2.0%
Fixed O&M ($/mo)	380,000
Fixed O&M Escalation	BLS Employment Cost Index
Variable O&M ($/MWh)	1.70
Variable O&M Escalation	PPI
O&M escalation	BLS Employment Cost Index
Levelized Monthly Maintenance Charge (LMMC)	Greater of $10,000/CT start or $340/turbine fired hour
LMMC Escalation	50% PPI/50% BLS Employment Cost Index

ERORA 2x1 CCCT- Sale	
Start Date	6/1/2017
Purchase Price ($)	765,000,000
Capacity Quote Year	2016

6. Additional Questions
   a. According to chart labeled '2X1 7FA.05 Combined Cycle Operational Curves at Summer Peak Conditions' in Attachment 1 of the proposal, the Summer Peak Net Plant Output is 603 MW at a Summer Peak Net Plant Heat Rate of 6,705 btu/kWh. On pages 3 and 4 of the proposal, the guaranteed heat rate of 6,705 btu/kWh is applicable for the first 535 MW. Why are these output levels different?
   b. Please confirm that the quantity of natural gas required to deliver 535 MW to the Daviess County substation is the product of 6,705 btu/kWh and 535,000 kWh. Please confirm that neither value needs to be adjusted for losses.
   c. Why are CT starts limited to 120 per year? Please confirm that this limit applies to each CT. How would you structure a proposal with a higher number of CT starts?
   d. Are the interconnection plans for this facility still consistent with the facility study completed in August 2011 (LGE-GIS-2007-004)? Will the unit be considered in the MISO footprint?
   e. What is the allocation of electric transmission costs (to the Companies' system, Big River's system, and other systems) for direct interconnection and system upgrades?
   f. What is the risk allocation if system upgrade costs are different when restudy occurs?
   g. Where would the plant output be measured? How would losses between the plant site and the Daviess County substation be measured? How and where would generation delivered to the LG&E/KU system be measured?
   h. What incremental value to the buyer is provided by the fact that the project will also be interconnected to the MISO at CP Node BREC.REID1?

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Khanjee

1. Review your company's organization. Describe your involvement in Prairie State.
2. Review your company's financial standing and applicable project financing.
3. Confirm unit operating parameters. Provide missing parameters where necessary.

Khanjee 2x1 CCCT in KY	
Summer Capacity (MW)	700
Summer Capacity- adj for losses (MW)	700
Summer Duct - Fired Capacity (MW)	40
Winter Capacity (MW)	700
Winter Capacity- adj for losses (MW)	700
Winter Duct - Fired Capacity (MW)	40
Minimum Capacity (MW)	145
Minimum Capacity in 1x1 Configuration	
Minimum Capacity in 2x1 Configuration	
Unfired Heat Rate @baseload (Btu/kWh)	6,800
Duct fired Heat Rate (Btu/kWh)	9,877
Min Load Heat Rate (Btu/kWh)	7,566
Output per CT in 10 min (MW)	240
Ramp rate – CTs/Steam (MW/min)	17 / 10
Start-up time to min Cap Normal/Emerg (hrs)	0.22 / 0.08
Start-up time to max Cap Normal/Emerg (hrs)	0.47 / 0.20
Min run time (hrs)	1*
Min down time (hrs)	6
Guaranteed Annual Availability	93%
Forced Outage Rate	2.5%

*Note Start charge of $25,000 per start applies only if run time is less than 30 hours

4. Describe risk mitigation measures related to your offer.
   a. Where specifically is the site located and how certainly is it available for purchase? What permitting risks exist for the site? Is the site appropriately zoned? How does it comply with the siting board requirements? What is the proximity to any non-attainment zones? Demonstrate that you have the capability to permit and construct a new CCCT facility by June 2017.
   b. Please confirm that seller will be responsible for gas and electric interconnect costs.
   c. Describe your status and schedule for the electrical interconnection process.
   d. What type of gas transportation service is factored into the cost of the proposal?
   e. Have you confirmed that the Texas Gas pipeline has sufficient capacity to provide gas transportation services for this facility?
   f. Please confirm that the seller is responsible for any upgrade costs required for additional winter capacity on the Texas Gas pipeline. Please confirm that these upgrades can be completed before the unit goes into service.
   g. How do you plan to manage credit risks associated with this proposal? Please elaborate on contracts you have with long-term natural gas suppliers.

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h. What do you anticipate for a future change in law provision?

5. Confirm the following contract terms for the Fixed Price option in KY.

Khanjee 2x1 CCCT in KY – Fixed Price & Tolling	
Start Date	1/1/2015
Term (Years)	22
Capacity Price ($/MW-yr)	See Capacity Price table below
Energy Price for Fixed Price ($/MWh)	See Energy Price table below
Variable O&M for Tolling ($/MWh)	See Variable O&M table below
Start-up Cost	$25,000/turbine start if run time < 30 hrs

Khanjee 2x1 CCCT in KY – Fixed Price & Tolling Capacity Price ($/MW-yr)	
2015	55,000
2016	55,000
2017	100,800
2018	102,912
2019	105,068
2020	107,269
2021	109,516
2022	111,811
2023	114,153
2024	116,545
2025	118,986
2026	121,479
2027	124,024
2028	126,622
2029	129,275
2030	131,983
2031	134,748
2032	137,571
2033	140,453
2034	143,396
2035	146,400
2036	149,467

Khanjee 2x1 CCCT in KY – Fixed Price Energy Price ($/MWh)	
2015	45.00
2016	45.00
2017	30.63
2018	31.73

2019	33.04
2020	34.48
2021	36.40
2022	37.49
2023	38.60
2024	39.76
2025	40.94
2026	42.17
2027	43.42
2028	44.72
2029	46.05
2030	47.43
2031	48.84
2032	50.30
2033	51.80
2034	53.35
2035	54.94
2036	56.58

Khanjee 2x1 CCCT in KY – Tolling Variable O&M ($/MWh)	
2015	4.50
2016	4.50
2017	0.55
2018	0.56
2019	0.57
2020	0.58
2021	0.60
2022	0.61
2023	0.62
2024	0.63
2025	0.64
2026	0.66
2027	0.67
2028	0.68
2029	0.70
2030	0.71
2031	0.73
2032	0.74
2033	0.76
2034	0.77
2035	0.79
2036	0.80

6. Additional Questions
   a. How much notice is required to bring the unit on-line?

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b. How would you propose structuring a 20-year PPA beginning in 2017 for the CCCT capacity and energy?

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LS Power

1. Review your company's organization.
2. Review your company's financial standing and applicable project financing.
3. Confirm unit operating parameters. Provide missing parameters where necessary.

SCCT	
Summer Capacity Unfired (MW)	165
Winter Capacity Unfired (MW)	192
Minimum Capacity Summer/Winter (MW)	116/134
Guaranteed Heat Rate @ baseload (Btu/kWh)	10,900
Min Load Heat Rate (Btu/kWh)	
Output in 10 min (MW)	0
Ramp up (MW/min)	13
Start-up time to min Cap (min)	27
Min run time (hrs)	2
Min down time (hrs)	2
Forced Outage Rate – Summer	3%
Guaranteed Availability (Summer)	97%
Guaranteed Availability (Winter)	93%

4. Confirm the following contract terms.

20 Year PPA of Bluegrass Simple Cycle (2015 Start)	
Start Date	1/1/2015
Term (Years)	20
Capacity Price ($/MW-yr)	30,000(2015-2019)/33,000(2020-2029)/36,000(2030-2034)
Capacity Escalation/yr	N/A
Capacity Discount under tolling ($/MW-yr)	0
Fixed O&M ($/MW-yr)	7,800
VO&M ($/MWh)	0.50
Water Cost	300 gallons/min * $3.35/kgal
O&M escalation	2.5%
Start-up Cost	$8,500/turbine start
Base Year for O&M Costs	2013
Start-up Cost Escalation	2.5%
Option to Purchase ($)	115 million (12/31/2017) or 105 million (12/31/2019)

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5 Year PPA of Bluegrass Simple Cycle (2015 Start)	
Start Date	1/1/2015
Term (Years)	5
Capacity Price ($/MW-yr)	37,200
Capacity Escalation/yr	N/A
Capacity Discount under tolling ($/MW-yr)	0
Fixed O&M ($/MW-yr)	7,800
VO&M ($/MWh)	0.50
Water Cost	300 gallons/min * $3.35/kgal
O&M escalation	2.5%
Start-up Cost	$8,500/turbine start
Base Year for O&M Costs	2013
Start-up Cost Escalation	2.5%

5. Additional Questions
   a. What fuel arrangements do you currently have in place?
   b. Please confirm that the $0.50 / MWh VO&M charge does not include water costs.
   c. Please elaborate on the station's water consumption.
   d. What are the timing and cost of the next major maintenance events?
   e. How would you propose structuring a 5-year PPA with options to buy the assets?
   f. How would you propose structuring transactions to begin 6/1/2015 (instead of 1/1/2015)?
   g. How would you propose structuring a PPA for summer peaking capacity (only)?
   h. When does the PILOT agreement with Oldham County expire?
   i. If the buyer exercises the option to purchase the assets, please confirm that the buyer has no obligation under the PILOT agreement with Oldham County.
   j. Are the dates associated with your option purchases expected closing dates or dates for providing notice of purchase?

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Ameren

1. Review your company's organization.
2. Review your company's financial standing and credit support.
3. Confirm operating parameters.

Operating Parameters - Ameren - PPA	
Start Date	January 1, 2015
Term (Years)	5 years
Capacity (MW)	Negotiable
Summer Capacity (each unit, MW)	167
Minimum Capacity (each unit, MW)	47
Heat Rate @baseload (Btu/kWh)	10,586
Heat Rate @min (Btu/kWh)	12,258
Ramp up (MW/min)	4
Summer Forced Outage Rate	3%
Non-Summer Forced Outage Rate	6%

4. Confirm Financial Terms

Financial Terms - Ameren – PPA	
Base Year for Costs	2015
Capacity Charge ($/MW-yr)	$137,496
Capacity Charge Esc (%)	0
Variable O&M ($/MWh)*	See table below
Fuel Price ($/ton)	(OTC Broker Index for PRB 8,800 btu/lbm + $0.25/ton + transport)/17.6
Start Cost ($/Start)	1,430 mmBtu * Gas Index + 3*no load hourly cost + 43
Non-fuel start cost escalation	2%
SO_2 Adjustment** ($/ton)	See formula below

*VO&M Schedule

Year	2015	2016	2017	2018	2019
$/MWh	2.61	2.69	2.73	2.78	2.84

**SO_2 adjustment is calculated using $\frac{(C-S)*A*ADI}{1000000}$

A Actual Btu of delivered coal
C OTC Broker Index nominal Sulfur Dioxide Value
S Actual SO_2 content of the coal delivered (expect 0.5lbs/mmBtu)
ADI Based on Argus Air Daily Index
SO_2 adjustment is multiplied by 2.86 to account for CAIR.

5. Discuss transmission assumptions

Assumptions - Ameren – PPA	
Transmission losses from delivery point	No losses
Transmission Transportation Cost ($/MW-yr)	None

6. Additional Questions
   a. Based on the Dec 20th announcement of Ameren's exit from merchant business, is this offer still valid?
      i. Will the Joppa plant be able to operate given its emission profile and the outlook for Ameren's other related plants?
   b. What is the 'no load hourly cost' used to compute start cost?
   c. Please provide an example of the $ Per Ton SO2 Adjustment calculation. Is the expected value of this adjustment zero?
   d. What is the current forecast for the OTC Broker Index for PRB – 8,800 btu/lbm?
   e. Please discuss fuel cost and fuel transportation cost risks.
   f. Please elaborate on the definition of the System as well as the scheduling and dispatch provisions of the proposal. How does the seller envision dispatching the EEI units for this transaction?
   g. What additional environmental controls will be needed at the EEI plant? Please confirm that the seller is responsible for the cost of these controls.
   h. Under what circumstances can the units operate beyond 2019?
   i. How would you propose structuring transactions for different capacities and/or terms? Specifically
      i. 167 MW for 3 years
      ii. 501 MW for 5 years

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AEP

1. Review your company's organization.
2. Review your company's financial standing and applicable project financing.
3. Confirm operating parameters

Operating Parameters - AEP - PPA	
Start Date	Flexible
Term (Years)	Flexible
Summer Capacity (MW)	Up to 700
Winter Capacity (MW)	Up to 700
Minimum Capacity (MW)	0

4. Confirm Financial Terms

Financial Terms - AEP - PPA	
Base Year for Quote	2015
Capacity Charge ($/MW-day)	$402.8
Capacity Price Esc (%)	0
Variable O&M ($/MWh)	$0.55
VO&M Esc (%)	2

Energy Price ($/MWh)					
2015	2016	2017	2018	2019	2020
38.70	40.08	41.79	43.67	45.65	48.35

5. Discuss Assumptions

Assumptions - AEP – PPA	
Forced outage rate (%)	5

6. Additional Questions
   a. Please confirm that the buyer has control over the way the units are dispatched.
   b. Please confirm that the fixed energy prices are nominal values.
   c. How would you propose structuring transactions that begin 6/1/2015?
   d. How would you propose structuring a 2-year PPA for 350 MW (beginning 6/1/2015)?
   e. Please elaborate on the way the buyer's share of the portfolio will be dispatched? How is generation scheduled?

From: Wilson, Stuart
To: Sinclair, David
Cc: Schram, Chuck; Sebourn, Michael
Subject: RFP Analysis Timeline
Date: Wednesday, January 09, 2013 3:10:33 PM
Attachments: 20130108_2012RFPAnalysisTimeline_0060.docx

David,

I've updated our RFP analysis timeline per your conversation with Chuck. If we get updated coal and natural gas prices tomorrow (which is the plan), we should be able to begin reviewing the 'no purchases' results by next Tuesday. Then, after we receive updated market electricity prices (middle of next week), the computers can be updating the runs with 'limited' purchases (for future reference).

Stuart

2012 RFP Analysis Timeline

1. Week of 1/7
    a. Complete iteration #4; update process document
        i. Document Brown 1-2 considerations (including capital that can be spent with 2030 retirement).
        ii. Consider continuation of LS Power PPA at end of 5-year term.
    b. 1/10 – Meet w/ Ameren
    c. 1/10 – Receive updated fuel/NG prices; begin updating 'no purchases' model runs
    d. 1/11 – Meet w/ ERORA and Big Rivers
2. Week of 1/14
    a. Quantify option value associated with short-term PPA (and deferring long-term decision).
    b. Follow-up with Energy Efficiency re: DSM proposals.
    c. As needed, update Ameren, ERORA, LS Power, and Big Rivers inputs; evaluate new alternatives.
    d. 1/14 – Meet w/ LS Power
    e. 1/15 – Complete update of 'no purchases' model runs; update process document
    f. 1/16 – Receive updated market electricity prices; begin updating model runs with limited purchases.
    g. 1/17 – Meet w/ AEP
3. Week of 1/21
    a. As needed, update AEP and Khanjee inputs; evaluate new alternatives.
    b. Develop slides/outline for 1/29 officer presentation.
    c. 1/21 – Complete update of model runs with limited purchases.
    d. 1/22 – Meet w/ Khanjee
    e. 1/25 – Meet to discuss slides/outline for 1/29 officer presentation.
4. Week of 1/28
    a. As necessary, evaluate final iteration of alternatives for Phase 2.
    b. 1/29 – Meet w/ officers
5. Week of 2/4
    a. Finalize Phase 2 analysis; prepare for negotiations.
6. Balance of February & March – Negotiations with shortlisted bidders
7. April 1 – Complete RFP/Self build analysis/3rd party contracts (if any)
8. May 1 – Begin preparing testimony
9. July 1 – file ECR for Brown 1&2 (if necessary) and CPCN for new resource(s)

From: Wilson, Stuart
To: Sinclair, David
Cc: Schram, Chuck
Subject: FW: RM Shortfall Chart
Date: Monday, January 21, 2013 5:32:26 PM
Attachments: 20130121_LAK_RMShortfallChart_0060.xlsx

David,

Per your request, here's the Excel file upon which the reserve margin shortfall table is based.

Stuart

From: Karavayev, Louanne
Sent: Monday, January 21, 2013 5:24 PM
To: Wilson, Stuart
Subject: RM Shortfall Chart

Stuart,

Please see attached for the worksheet I used to create the reserve margin shortfall chart in PowerPoint. The chart is at the bottom of the sheet. Let me know if you have any questions. Thanks,

Lou Anne Karavayev
LG&E and KU
Generation Planning
p [redacted]
f
e [redacted]

Data Adjusted from 2013 BP LCRCM
1/21/2013

		2015	2016	2017	2018	2019
	Base Load (MW)					
	Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746
	Energy Efficiency/DSM	-386	-418	-450	-482	-464
	Net Peak Load	7,040	7,091	7,147	7,214	7,282
	Low Load (MW)					
	Forecasted Peak Load	7,120	7,185	7,255	7,336	7,366
	Energy Efficiency/DSM	-386	-418	-450	-482	-464
	Net Peak Load	6,734	6,767	6,805	6,854	6,902
	Supply With BR1-2 (MW)					
	Existing Resources	7,814	7,802	7,819	7,781	7,800
	Firm Purchases (OVEC)	152	152	152	152	152
	Curtailable Demand	137	137	137	137	137
	Total Supply	8,103	8,091	8,108	8,070	8,089
	Supply Without BR1-2 (MW)					
	Existing Resources	7,542	7,533	7,550	7,512	7,531
	Firm Purchases (OVEC)	152	152	152	152	152
	Curtailable Demand	137	137	137	137	137
	Total Supply	7,831	7,822	7,839	7,801	7,820
15%	**RM Shortfall (15% RM)**					
	With BR1-2, Base Load	-7	64	111	226	285
	With BR1-2, Low Load	-359	-309	-282	-188	-152
	Without BR1-2, Base Load	265	333	380	495	554
	Without BR1-2, Low Load	-87	-40	-13	81	117
-261	**Incremental DSM**	-125	-157	-189	-221	-203

15% Reserve Margin Shortfall (MW)	***2015***	***2016***	***2017***	***2018***	***2019***
With Brown 1-2					
Base Load	*(7)*	*64*	*111*	*226*	*285*
Low Load	*(359)*	*(309)*	*(282)*	*(188)*	*(152)*
Without Brown 1-2					
Base Load	*265*	*333*	*380*	*495*	*554*
Low Load	*(87)*	*(40)*	*(13)*	*81*	*117*
Incremental DSM	*125*	*157*	*189*	*221*	*203*

2020	2021
7,816	7,885
-466	-467
7,350	7,418
7,414	7,458
-466	-467
6,948	6,991
7,801	7,801
152	152
137	137
8,091	8,091
7,532	7,532
152	152
137	137
7,822	7,822
362	440
-100	-51
631	709
169	218
-205	-206

2020	***2021***
362	*440*
(100)	*(51)*
631	*709*
169	*218*
205	*206*

From:	Wilson, Stuart
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	Presentation Materials
Date:	Monday, January 21, 2013 4:59:53 PM
Attachments:	20130121_LAK_RMShortfallChart_0060.pptx

David,

I've attached the reserve margin chart. Also, I spoke with Doug regarding potential advantages of Brown as a self-build site… The HDR estimates we have weren't developed for a specific site (so they're somewhat 'greenfield' in nature). When he removes redundant costs (in the HDR estimates) for land, water treatment, fire water pumps, raw water intake equipment, and gas lines, Doug expects the HDR estimate to decrease by $30-35 million (and be more competitive than ERORA's bid).

Stuart

15% Reserve Margin Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021
With Brown 1-2							
Base Load	(7)	64	111	226	285	362	440
Low Load	(359)	(309)	(282)	(188)	(152)	(100)	(51)
Without Brown 1-2							
Base Load	265	333	380	495	554	631	709
Low Load	(87)	(40)	(13)	81	117	169	218
Incremental DSM	125	157	189	221	203	205	206

LG&E KU
PPL companies

From:	Wilson, Stuart
To:	Schram, Chuck; Sinclair, David
Subject:	RE: Slides for Tuesday Meeting
Date:	Monday, January 28, 2013 10:12:51 AM
Attachments:	20130129_RFP Status Final 1-29-13_0060.pptx

Here's the updated presentation with this change and the change from Greg.

Stuart

From: Schram, Chuck
Sent: Monday, January 28, 2013 9:55 AM
To: Sinclair, David
Cc: Wilson, Stuart
Subject: Slides for Tuesday Meeting

David,
In reviewing the slides again, I have one minor suggestion if you haven't sent to participants:

Slide 2 first bullet:
Change from:

- Capacity needs caused by existing retirement plans and load growth beginning in 2015

To:

- Capacity needs beginning in 2015 caused by existing retirement plans and load growth

Chuck






PPL companies

Meeting Future Capacity Needs in a World of Uncertainty

January 29, 2013

Key uncertainties related to future resources

- *Capacity needs beginning in 2015 caused by existing retirement plans and load growth*
- *Downside load growth risk driven by continuing national and global economic challenges (new load forecast by June)*
- *Future natural gas prices*
- *Potential environmental regulations on CO2 and fracking*
- *Availability of CCGT resources: self-build and 3rd party alternatives might not be doable by 2017*
- *Future of Brown 1&2 – existing and future regulations and future coal/gas price spread*

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Capacity could be needed as early as 2015 but could be as late as 2022

Reserve Margin Over/(Under) 15% (MW)	2015	2016	2017	2018	2019	2020	2021
With Brown 1-2							
Base Load Forecast	7	(64)	(111)	(226)	(285)	(362)	(440)
Low Load Forecast	359	309	282	188	152	100	51
Without Brown 1-2							
Base Load Forecast	(265)	(333)	(380)	(495)	(554)	(631)	(709)
Low Load Forecast	87	40	13	(81)	(117)	(169)	(218)
Incremental DSM above 2012 level (reflected in the data above)	*125*	*157*	*189*	*221*	*203*	*205*	*206*

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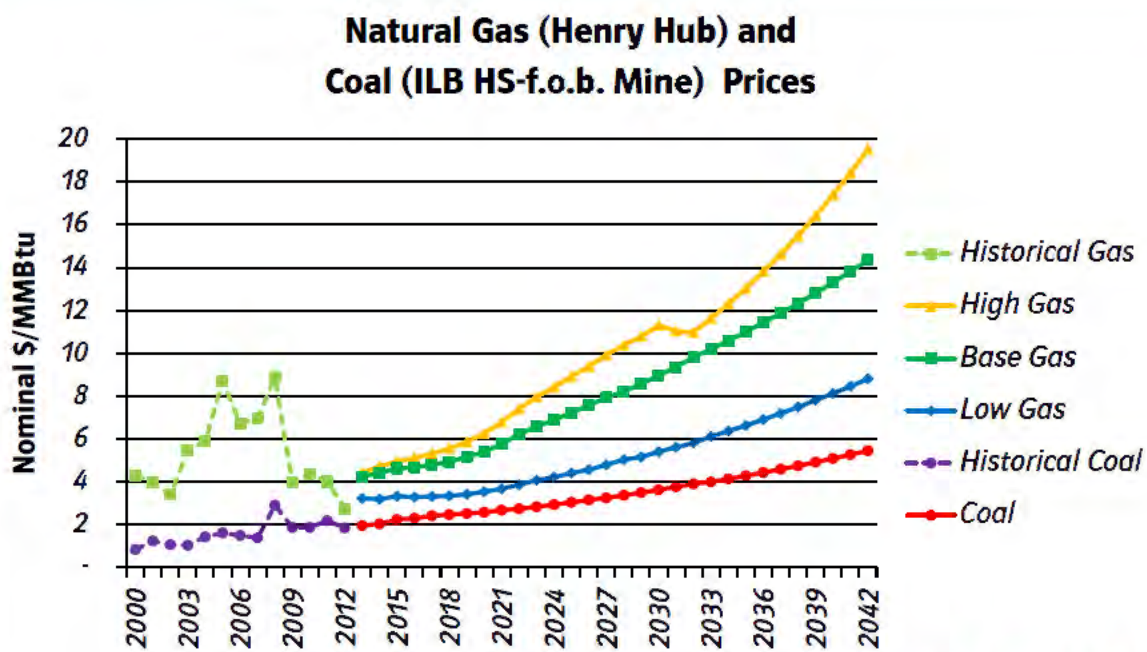
Wide range of possible future gas prices



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Alternative strategies to address capacity need

- *Key Question – Do we need to commit to a long-term resource now?*
  - *The Companies have a history of long-term commitments*
  - *Options could be valuable given major uncertainties*
  - *Most long-term solutions are not available until 2017 at the earliest so short-term capacity could still be needed*
- *Alternatives:*
  - *Short term approach enables better information on key uncertainties*
  - *Long-term approach that works best given possible outcomes for key uncertainties*

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Short-term v. Long-term strategies

Approach	Pros	Cons	Risks
Short-term	• *Better information on Key Uncertainties* • *Could be lower cost in short-term* • *Could be easier regulatory process* • *Potentially capture future technology improvements*	• *Could pay a premium in the long-run* • *Justification of transmission upgrades absent LT system benefits*	• *Pass on viable LT resource* • *Could create ability for future regulatory second guessing* • *Key Uncertainties remain largely unresolved*
Long-term	• *Consistent with past practice* • *Lock-in future capacity costs & technology*	• *Give up some future resource flexibility to address Key Uncertainties* • *Forego technology improvements*	• *Key uncertainties are resolved adverse to resource choice* • *Regulatory second guessing*

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Alternatives to address short-term needs

- *LS Power (495 MW)*
  - *Can defer capacity need until at least 2019 at relatively low cost*
  - *Keeps these units economically viable and creates future optionality (asset purchase, future PPA)*
- *Ameren (334-501 MW)*
  - *Sourced from Joppa*
  - *Based on current environmental compliance plan, Joppa may not be viable beyond 2019*
- *Purchase firm transmission and source energy from the market*
  - *Probably do not want do this for more than 200 MW (~ 2% of reserve margin)*
- *Retrofit Brown 1&2 (272 MW) with FGD additive technology (Nalco)*

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Alternatives to address long-term needs

- *LS Power (495 MW) – PPA w/ or w/o purchase option*
  - *Available in 2015*
  - *FERC approval of purchase remains uncertain*
  - *Long-term v. multiple short-term PPAs*
- *ERORA (700 MW greenfield CCGT) – PPA or Purchase*
- *Khanjee (700 MW greenfield CCGT) – PPA*
- *Big Rivers (417 MW from Wilson) – PPA or Purchase*
  - *Available in 2015*
- *Self-build (600-700 MW CCGT)*
  - *Still evaluating site specific costs at Brown and Green River*
- *Retrofit Brown 1&2 (272 MW)*
  - *Baghouse v. FGD additive (Nalco)*

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Future of Brown 1&2 remains in doubt

- *How long will units operate even with proposed upgrades?*
- *Increasing risk of CO_2 regulations on existing units*
- *Future Gas/Coal spread that will support baghouse retrofit*
- *Baghouse progress payments in 2013 ($12.4 million)*
- *Major capital planned in 2013-14 (~$14 million)*
- *Nalco test results*
- *What has changed since December 2011 KPSC settlement?*
  - *Baghouse capital costs decreased by $34 million (from $228 to $194)*
  - *Baghouse operating costs decreased by $13/MWH (from $15 to $2)*
  - *Long-term view of gas prices is lower by ~$3/mmBtu (~$21/MWh for CCGT)*
  - *Increasing risk of CO2 regulations*
  - *SCR installation risk is about the same*
- *Economic justification of baghouses may be closer than in 2011*

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Baghouse progress payments begin to mount

Baghouse Cumulative Progress Payments
$(000)

2013	BR1	BR2	Total
Apr	430	485	915
May	859	971	1,830
Jun	1,633	1,845	3,478
Jul	1,633	1,845	3,478
Aug	3,695	4,175	7,870
Sep	5,242	5,923	11,165
Oct	5,242	5,923	11,165
Nov	5,242	5,923	11,165
Dec	5,843	6,603	12,446

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Value varies with Key Uncertainties

	Gas	BG	BG	BG	BG	HG	HG	HG	HG	LG	LG	LG	LG
	Load	BL	BL	LL	LL	BL	BL	LL	LL	BL	BL	LL	LL
	Carbon	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC
Alternative	*Next CCGT*												
1 - PPA (2015-16) & CCGT (2017)	2021												
2 - Coal PPA (2015-19)	2019												
3 - BR1-2 Baghouse Retrofit	2018												
4 - 2015 Asset Purchase (SCCT)	2019												
5 - BR1-2 Baghouse Retrofit (Retire 2030)	2018												

Gas: Base/Mid (BG), High (HG), Low (LG)   Load: Base (BL), Low (LL)   Carbon: Zero (0C), Mid (MC)

<-Better/Worse->

- *Alt #1 – Prefer CCGT in low-gas and mid-carbon scenarios*
- *Alt #2 – Short-term PPA viable in most scenarios; prefer coal to SCCT*
- *Alt #3 – Prefer BR1-2 retrofit in zero carbon and mid-high gas price scenarios*
- *Alt #4 – Prefer SCCT purchase in zero carbon and mid gas price scenario*
- *Alt #5 – BR1-2 retrofit not favorable if units don't operate through 2042*

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Path Forward

- *February*
  - *Finalize bids from ERORA, LS Power, and Ameren*
  - *Provide detailed due diligence questions to Khanjee and Big Rivers*
  - *Finalize self-build costs*

- *March*
  - *Make decision on Brown 1&2 baghouse retrofit*
  - *Assess potential of Nalco process for Brown 1&2*
  - *Finalize financial and risk analysis*
  - *Recommend alternative(s) for future capacity*

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Appendix

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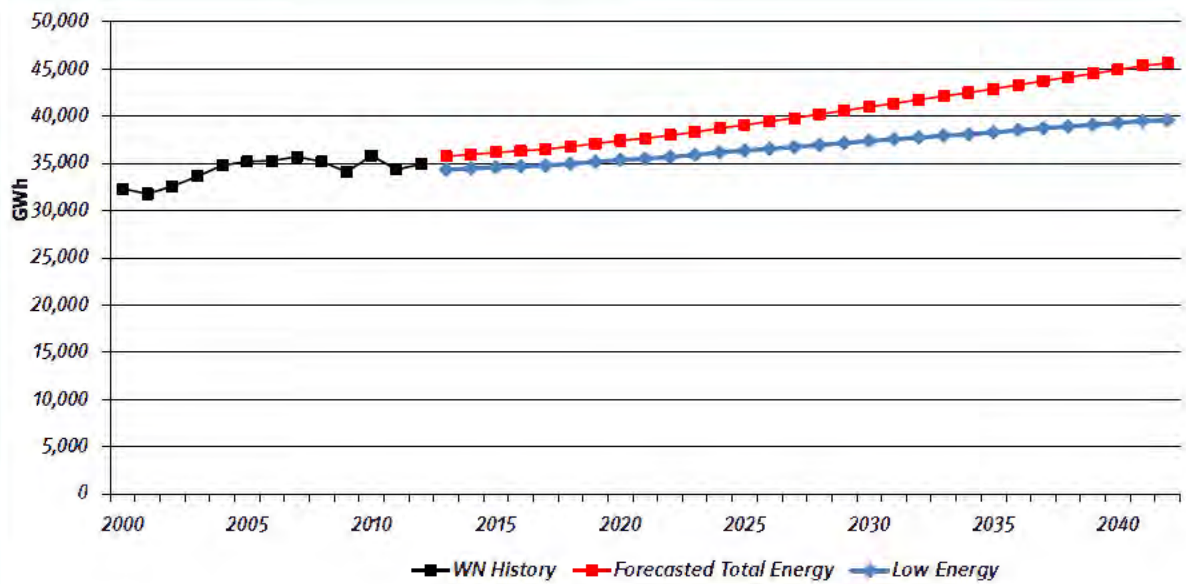
Combined Company Energy Requirements



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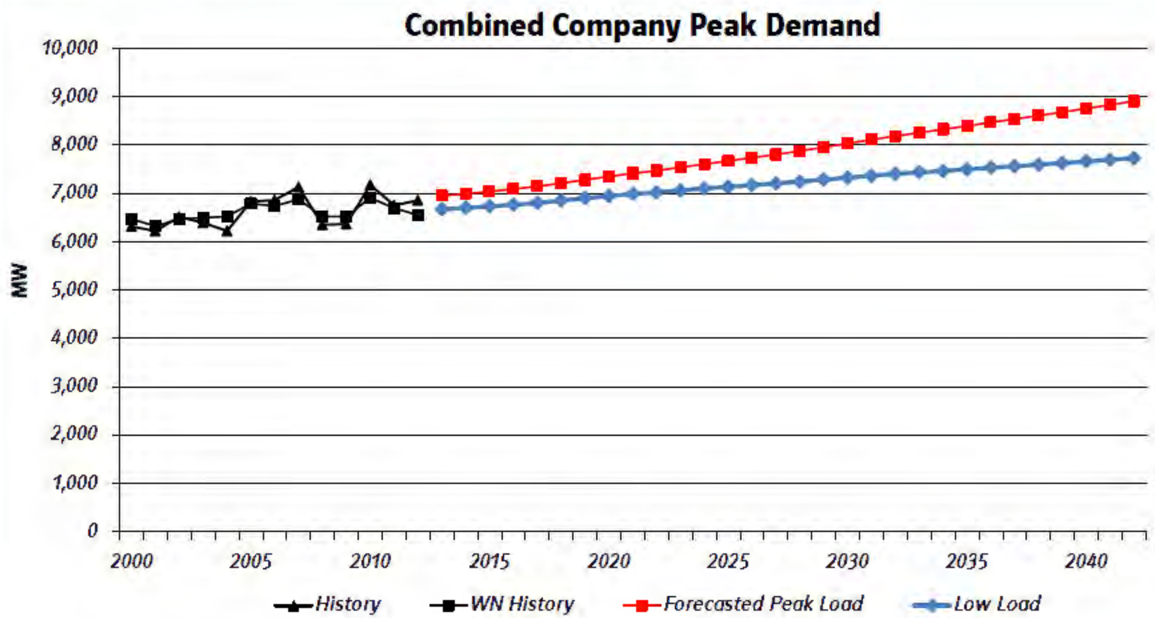
Peak Demands



* Historical peaks not adjusted for curtailments.

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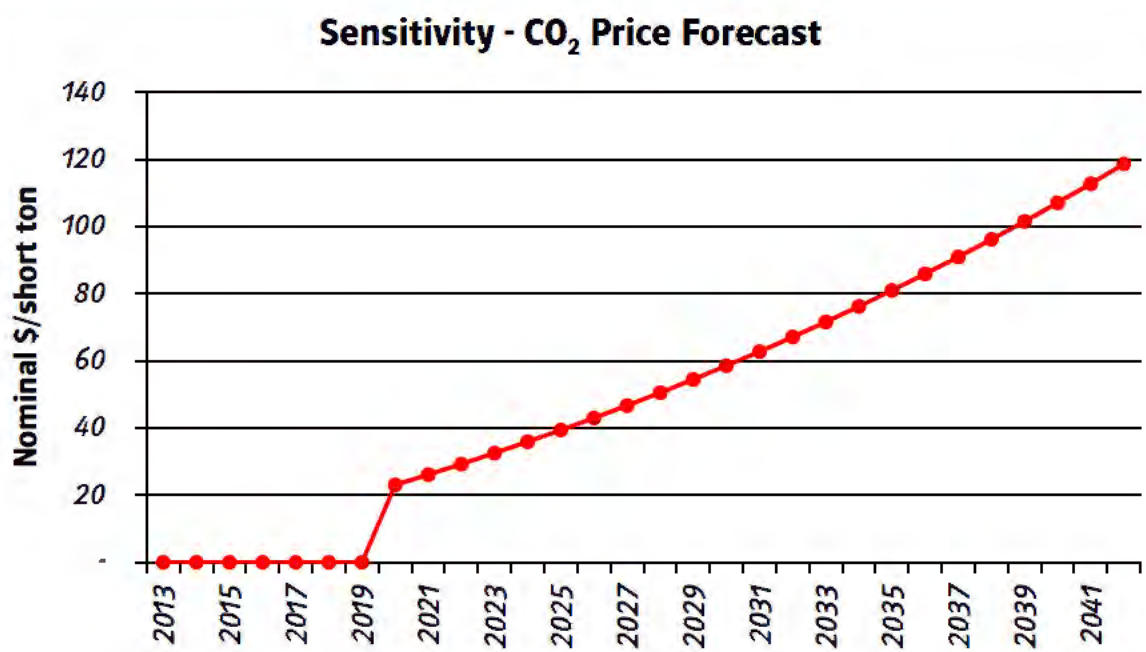
CO_2 price sensitivity starting in 2020



LG&E KU
PPL companies

From:	Schram, Chuck
To:	Thompson, Paul; Bowling, Ralph; Voyles, John; Sinclair, David; Brunner, Bob; Balmer, Chris; Freibert, Charlie; Wilson, Stuart; Schetzel, Doug; Jessee, Tom
Subject:	RFP Update Material
Date:	Friday, February 15, 2013 5:33:37 PM
Attachments:	20130215_RFP Status 2-18-13.pptx

All,
Please see the attached material for discussion in Monday’s RFP Update meeting.

Chuck

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Wilson, Stuart
Cc:	Brunner, Bob; Freibert, Charlie
Subject:	FW: Proposal For the Sale or Lease of Big Rivers Wilson Plan
Date:	Friday, March 01, 2013 11:36:34 AM
Attachments:	Wilson Sale or Lease Proposal 2-28-13.doc

FYI: BREC's response.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]
email: [redacted]

From: Bob Berry [redacted]
Sent: Friday, March 01, 2013 10:44 AM
To: Freibert, Charlie
Cc: Lindsay Barron
Subject: Proposal For the Sale or Lease of Big Rivers Wilson Plan

Charlie, Please find attached the proposal for Big Rivers to sale or lease the Wilson plant to LG&E / KU. If you have any questions please contact me.

Regards
Bob Berry
Chief Operating Officer
Big Rivers Electric

February 28, 2013

Charles A. Freibert, Jr.
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202

RE: Proposal to Sell Wilson Station

Dear Charlie,

As discussed, as a result of the termination notice of our largest customer, Big Rivers currently has available capacity which it is willing to sell or lease. As you know, the Wilson Station facility is a 417MW pulverized coal fired generating station located in Centertown, KY which was commercialized in 1986. It has adequate real estate for additional plant developments and is located in the heart of the Western Kentucky coal fields.

Big Rivers proposes to sell LG&E and KU Energy LLC our Wilson facility at a price of $500,000,000.

Big Rivers would also be willing to lease the facility to LG&E and KU Energy LLC for a term not to exceed 9 years, 11 months for $39,700,000 annually.

This Offer is preliminary and is intended to set forth certain basic terms and to serve as a basis for further discussion and negotiations between the Parties with respect to the potential Agreement described herein. This Offer does not contain all matters upon which agreement must be reached in order for the transaction to be completed. The matters set forth herein are not intended to and do not constitute a binding agreement of the Parties nor do they establish any obligation of the Parties with respect to the Agreement, and this Offer may not be relied upon by a Party as the basis for a contract by estoppel or otherwise. A binding agreement will arise only upon the negotiation, execution and delivery of mutually satisfactory definitive agreements and the satisfaction of the conditions set forth therein, including completion of due diligence and the approval of such agreements by the respective governing body(ies) (include KY PSC and USDA-RUS), management and board of each Party, which approval shall be in the sole subjective discretion of the respective governing body(ies), management and board.

If you have any questions, please feel free to contact me at [redacted]. I look forward to further discussions with you on this topic.

Sincerely,

Robert W Berry

Robert W. Berry
Chief Operating Officer
Big Rivers Electric Corporation

From:	Wilson, Stuart
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	Spreadsheet
Date:	Wednesday, March 06, 2013 4:37:53 PM
Attachments:	20130305_BigRiversLevelizedCostComparison_0060.xlsx

David,

I've attached the spreadsheet you requested.

Stuart

2.4% Capital Escalation Rate
2.0% O&M Escalation Rate
6.75% Discount Rate
2025 Year Wilson is Retired

2015 $	Units	CCCT	Big Rivers
Capital Cost	$M	590	276
Max Capacity	MW	670	417
Capital Cost	$/kW	881	662
Capacity Factor	%	80%	80%
Heat Rate	Btu/kWh	6,900	10,450
Variable O&M	$/MWh	1.60	2.70
Fixed O&M	$/MW-yr	11,160	68,597
Firm Gas Transport	$/MW-yr	21,924	0
Generation	MWh	4,695,360	2,922,336
Fixed Charge Rate	%	10%	15%
Levelized Cost			
Fuel	$/MWh	38.89	30.75
VOM	$/MWh	1.74	2.93
Firm Gas	$/MWh	3.39	0.00
FOM	$/MWh	1.59	10.60
Capital	$/MWh	12.99	14.32
Total	$/MWh	58.60	58.60
Levelized Fuel Cost	$/MMBtu	5.64	2.94

	$/MMBtu		Generation MWh		Fuel $000		VOM $000		Firm Gas $000		FOM $000		Capital $000		Total $000	
	CCCT	Big Rivers	CCCT	Big Rivers	CCCT	Big Rivers	CCCT	Big Rivers	CCCT	Big Rivers	CCCT	Big Rivers	CCCT	Big Rivers	CCCT	Big Rivers
2012	2.9781	3.0397														
2013	4.4630	2.5131														
2014	4.6406	2.5599														
2015	4.8600	2.5532	4,695,360	2,922,336	157,456	77,971	7,523	7,890	14,689	0	7,477	28,605	61,009	41,844	248,154	156,310
2016	4.9123	2.6405	4,695,360	2,922,336	159,148	80,637	7,673	8,048	14,983	0	7,477	29,177	61,009	41,844	250,290	159,705
2017	5.0377	2.7908	4,695,360	2,922,336	163,210	85,225	7,827	8,209	15,283	0	7,477	29,760	61,009	41,844	254,805	165,038
2018	5.1839	2.8749	4,695,360	2,922,336	167,949	87,795	7,983	8,373	15,588	0	7,477	30,356	61,009	41,844	260,007	168,367
2019	5.4243	2.9379	4,695,360	2,922,336	175,736	89,719	8,143	8,541	15,900	0	7,477	30,963	61,009	41,844	268,265	171,066
2020	5.6646	3.0007	4,695,360	2,922,336	183,522	91,637	8,306	8,712	16,218	0	7,477	31,582	61,009	41,844	276,532	173,774
2021	6.0617	3.1399	4,695,360	2,922,336	196,386	95,888	8,472	8,886	16,542	0	7,477	32,214	61,009	41,844	289,886	178,831
2022	6.5319	3.2175	4,695,360	2,922,336	211,620	98,257	8,642	9,063	16,873	0	7,477	32,858	61,009	41,844	305,621	182,022
2023	6.9080	3.3255	4,695,360	2,922,336	223,806	101,555	8,814	9,245	17,211	0	7,477	33,515	61,009	41,844	318,317	186,159
2024	7.2215	3.4639	4,695,360	2,922,336	233,962	105,782	8,991	9,430	17,555	0	7,477	34,185	61,009	41,844	328,994	191,241
2025	7.5872	3.6020	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	7.9321	3.7551	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	8.3187	3.8772	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	8.6217	4.0297	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	8.9874	4.1973	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	9.3844	4.3645	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2031	9.8024	4.5467	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	10.2831	4.7286	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	10.6802	4.8487	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	11.0926	5.0335	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	11.5210	5.2252	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	11.9660	5.4239	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	12.4283	5.6298	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	12.9084	5.8434	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	13.4072	6.0647	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	13.9252	6.2942	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2041	14.4634	6.5320	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2042	15.0224	6.7786	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Big Rivers Capital Cost $M 500

			$M	$000							
	Book Life	FCR	Levelized	NPVRR	2012	2013	2014	2015	2016	2017	2018
Big Rivers	10	15%	76	575	0	0	0	96,283	90,492	85,104	80,058
Big Rivers	50	8%	41	623	0	0	0	59,435	57,418	55,506	53,691
CCCT	40			722	0	0	15,690	54,368	58,786	72,609	77,146
		10%	64	722	0	0	0	0	0	63,972	63,972

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
75,260	70,462	65,663	60,865	56,067	51,269	0	0	0	0	0	0	0
51,965	50,322	48,756	47,260	45,776	44,293	42,809	41,325	39,841	38,357	36,873	35,389	33,905
74,398	71,780	69,281	66,894	64,609	62,419	60,245	58,070	55,896	53,721	51,547	49,372	47,198
63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
0	0	0	0	0	0	0	0	0	0	0	0	0
32,421	30,937	29,454	28,401	27,779	27,157	26,535	25,913	25,291	24,669	24,047	23,425	22,803
45,024	42,849	40,675	38,500	36,326	34,728	33,708	32,688	31,668	30,647	29,627	28,607	27,587
63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972

2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
0	0	0	0	0	0	0	0	0	0	0	0	0
22,181	21,560	20,938	20,316	19,694	19,072	18,450	17,828	17,206	16,584	15,962	15,340	14,718
26,566	25,546	24,526	23,506	22,485	21,465	20,445	19,425	18,404	17,384	16,364	15,344	3,812
63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	63,972	

2058	2059	2060	2061
0	0	0	0
14,097	13,475	12,853	12,231
0	0	0	0

From:	Freibert, Charlie
To:	Schram, Chuck; Wilson, Stuart; Brunner, Bob; Sinclair, David
Subject:	Fwd: Revised Pricing for Cash Creek Generation, LLC Proposals to LGE/KU RFP
Date:	Friday, April 26, 2013 11:55:56 AM
Attachments:	Revised CCG Pricing for LGE-KU RFP Proposals.pdf ATT00001.htm

---

FYI

Sent from my iPhone

Begin forwarded message:

> **From:** "Mike McInnis"[redacted]
> **To:** "Freibert, Charlie"[redacted]
> **Cc:** [redacted]
> **Subject: Revised Pricing for Cash Creek Generation, LLC Proposals to LGE/KU RFP**
>
> Dear Charlie:
> Recent changes in market conditions have enabled Cash Creek Generation, LLC ("CCG") to materially improve pricing for both its base and alternative proposals, in response to LGE/KU's Request for Proposals to Sell Capacity and Energy. The attached letter documents the following proposal price reductions:
>
> · Base Proposal: The capacity charge is reduced from \$5.40/kW-month to \$5.05/kW-month.
> · Alternative Proposal: The capacity charge is reduced from \$6.12/kW-month to \$5.55/kW-month.
>
> CCG is very pleased to offer these price reductions to LGE/KU. Should you have any questions, feel free to give me a call at [redacted].
> Best regards,
> Mike McInnis
> Manager
> Cash Creek Generation, LLC

From: Schram, Chuck
To: Sinclair, David
Cc: Wilson, Stuart
Subject: FW: High Cap Factor Turbines
Date: Monday, April 29, 2013 12:54:56 PM
Attachments: NGCC Capacity Factor Summary Rev A.DOC

David, fyi.
Chuck

From: Straight, Scott
Sent: Monday, April 29, 2013 8:26 AM
To: Schram, Chuck
Subject: FW: High Cap Factor Turbines

Chuck, here is the HDR report from February. I will forward other info as it comes in today. As we discussed on the phone this morning, there isn't any special information on "high capacity factor" turbines as the gas fired turbines on the market today are designed for high capacity factor.

Scott

INTRODUCTION

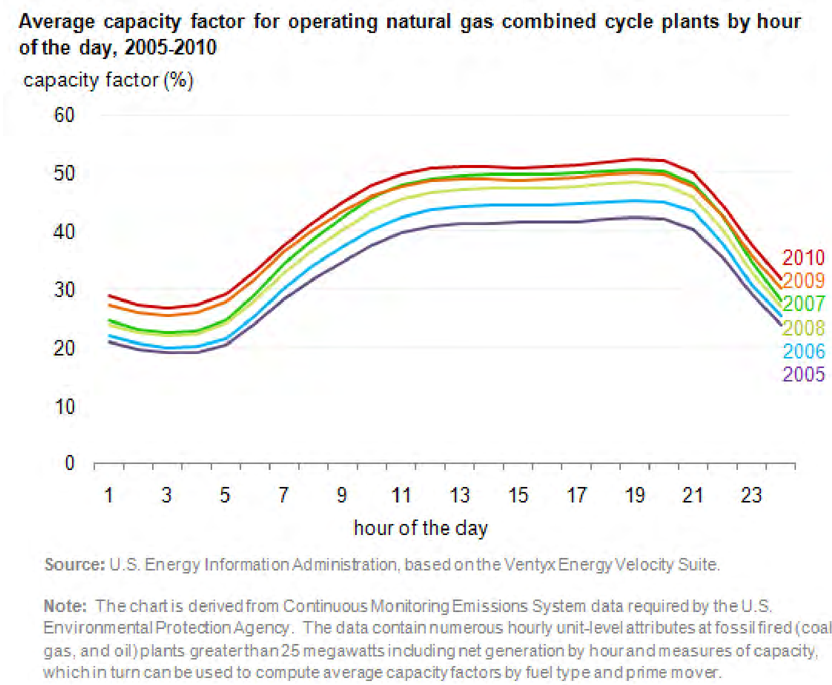
In response to plant dispatch experienced in the period 2003 to 2009, the major focus of combined cycle plant design in the past several years has been operating flexibility including daily cycling, fast start and load following. The attention to cycling has been in response to fleet wide maintenance issues resulting from actual dispatch consisting of daily cycling vs. an original plant design intended for baseload operation. A number of EPRI programs were initiated to develop plant designs supporting plant cycling. The current industry design criteria incorporates flexibility of operation supporting both cycling and baseload modes of operation.

This supplementary evaluation associated with the New Generation Options Study is an assessment of the proposed combined cycle technology to support high capacity factor baseload dispatch. The capacity factor evaluation documents current reported US industry and OEM provided international capacity factor statistical data. The 2018 Generation Options Study included incorporation of LTSA budgetary pricing for each technology option and configuration based on an intermediate dispatch of 4200 operating hours/250 starts per year and also included an LTSA sensitivity analysis for dispatch at 8000 annual operating hours.

INDUSTRY EXPERIENCE AT HIGH CAPACITY FACTOR

The 2011 average US combined cycle facility capacity factor was approximately 50% which is expected to increase significantly in the upcoming years due to market fuel cost (gas and coal). The historical US NGCC average capacity factor reported by EIA is provided below in Figure 1.

Figure 1 Average US NGCC Capacity Factor



A number of US NGCC plants have experienced high capacity factor as indicated below in Figure 2. These plants include a high number of cogeneration applications serving process steam.

Figure 2 2010 Top 20 NGCC Capacity Factor Plants

Table 7:Top 20 Gas-fired Combined-cycle by Capacity Factor (2010)

Rank	Owner/Operator	Plant	State	Capacity MW	Generation GWh	Capacity Factor	Fuel Consumption*	Heat Rate mmBtu/MWhr	2010 Rank
1	General Electric	Cardinal Cogen	CA	42	413	112.4%	4,420,051	10.71	
2	Manulife Financial	Michigan Power	MI	128	1,100	98.1%	9,636,123	8.76	
3	UBS	Nevada Cogen	NV	85	723	97.1%	5,287,288	7.31	
4	UBS	Black Mtn. Cogen	NV	85	715	96.0%	4,728,241	6.62	
5	Southern Co.	Washington Cty Cogen	AL	100	829	94.6%	8,830,368	10.66	
6	Carson Holdings	Carson Cogen	CA	49	403	93.4%	3,559,569	8.83	
7	Rock-Tenn Co.	Jefferson Smurfit	CA	26	210	92.3%	1,202,061	5.72	
8	Olympus Power LLC	Brooklyn Navy Yard Cogen	NY	250	2,006	91.6%	13,559,431	6.76	17
9	Southern Co.	Barry	AL	962	7,700	91.4%	54,051,193	7.02	7
10	Southern Co.	Lansing Smith	FL	481	3,836	91.0%	27,295,501	7.12	
11	Olympus Power LLC	OLS Energy Chino	CA	29	229	90.3%	1,631,164	7.11	
12	Olympus Power LLC	OLS Energy Camarillo	CA	28	224	90.3%	1,754,563	7.84	
13	Foster Wheeler AG	Foster Wheeler Martinez	CA	104	809	89.3%	6,690,308	8.27	
14	New York Power Authority	Richard M Flynn	NY	136	1,061	89.0%	8,403,343	7.92	
15	Energy Capital Partners	Milford	CT	507	3,921	88.3%	29,058,327	7.41	
16	EOG LLC	Rupert Cogen	ID	10	80	88.1%	511,591	6.37	
17	Sabine Energy LP	Sabine	TX	87	657	86.0%	3,393,507	5.17	
18	Calpine	Pine Bluff	AR	192	1,433	85.2%	7,264,125	5.07	
19	Shell	March Point Cogen	WA	146	1,091	85.2%	6,646,674	6.09	2
20	Atlantic Power Corp.	North Island	CA	42	308	84.7%	2,083,991	6.77	
				Total	Total	Total	Total	Average	
		Top 20 Generating		3,489	27,750	91.7%	200,007,419	7.38	
		EPA Reporting		205,063	783,333	43.6%	5,803,084,119	7.41	

*mmBtu

Table 2 reflects the Siemens provided reference list of units operating at capacity factor greater than 80%. Siemens indicated many of these facilities have operated at similar capacity factor for the past five years. A similar report was requested from General Electric which will be provided at a later date. The GE fleet experience is anticipated to be similar to Siemens. The Alstom GT24 fleet capacity factor from 2007 to 2012 was 68.2% reflecting higher values outside of the United States.

Table 1
Siemens Global 2012
Combustion Turbine Capacity Factors
Capacity Factor > 80%

Owner	Plant	CT Machine	CF (%)
Petrobras Energia S.A.	Genelba	V94.3A(1)	98.24%
Petrobras Energia S.A.	Genelba	V94.3A(1)	93.28%
Petrobras Energia S.A.	Genelba	KN-50HZ	98.39%
First Gas Power Corporation	Santa Rita	V84.3A(2)	97.39%
First Gas Power Corporation	Santa Rita	V84.3A(2)	86.01%
First Gas Power Corporation	Santa Rita	HE-60HZ	96.86%
First Gas Power Corporation	Santa Rita	HE-60HZ	84.98%
First Gas Power Corporation	Santa Rita	V84.3A(2)	89.39%

Table 1
Siemens Global 2012
Combustion Turbine Capacity Factors
Capacity Factor > 80%

Owner	Plant	CT Machine	CF (%)
First Gas Power Corporation	Santa Rita	HE-60HZ	88.92%
First Gas Power Corporation	Santa Rita	V84.3A(2)	96.82%
First Gas Power Corporation	Santa Rita	HE-60HZ	96.51%
Midelec	Midelec	V64.3	89.03%
First Gas Power Corporation	San Lorenzo	V84.3A(2)	96.42%
First Gas Power Corporation	San Lorenzo	HE-60HZ	96.07%
First Gas Power Corporation	San Lorenzo	V84.3A(2)	96.27%
First Gas Power Corporation	San Lorenzo	HE-60HZ	95.91%
EET (Energie Electric de Thaddart)	Tahaddart	V94.3A(2)	97.83%
EET (Energie Electric de Thaddart)	Tahaddart	SST5-3000	96.46%
SIEMENS	Rudeshur	SGT5-4000F(2)	87.82%
SIEMENS	Rudeshur	SGT5-4000F(2)	81.55%
SIEMENS	Rudeshur	SGT5-4000F(2)	87.83%
TERMOELECTRICA MANUEL BELGRANO	Manuel Belgrano	SGT5-4000F(4)	90.59%
TERMOELECTRICA MANUEL BELGRANO	Manuel Belgrano	SGT5-4000F(4)	95.39%
Termoelectrica Jose de San Martin S.A.	San Martin	SGT5-4000F(4)	93.80%
Caithness Long Island, LLC	Caithness Long Island Energy Center	SGT6-5000F(3)	86.89%
Caithness Long Island, LLC	Caithness Long Island Energy Center	SST-900RH	86.13%
TERMOELECTRICA MANUEL BELGRANO	Manuel Belgrano	SST5-5000	96.07%
Termoelectrica Jose de San Martin S.A.	San Martin	SST5-5000	89.70%

Note: Material Listed is Siemens Confidential.

A mid-western combined cycle plant's experience with increased dispatch is documented in a Combined Cycle Journal article available at http://www.ccj-online.com/nipsco-sugar-creek-generating-station/ .

LTSA IMPACTS

The Combustion Turbine OEMs typically provide LTSA costs for specific dispatch conditions with variable costs calculated based on both starts and operating hours for intermediate dispatch and hours only for baseload applications. For the 2018 New Generation Options Study, LTSA quotations for both the 4200 and 8000 hour operating conditions were provided by OEMs for evaluation. A summary of the LTSA differences for intermediate and baseload dispatch is provided below based on a 2-on-1 F class configuration.

The table below compares the GE and Siemens maintenance intervals.

Table 2
GE and Siemens
LTSA Service Interval Summary

Inspection Type	Siemens Interval	GE Interval
Combustor Inspection	16,600 Hours 1200 Starts	N/A
Hot Gas Path Inspection	33,200 Hours 1200 Starts	24,000 Hours 900 Starts
Major Inspection	66,400 Hours 2400 Starts	48,000 Hours 1800 Starts

The GE proposed LTSA fees for two combustion turbine units based on the 4200 hour/250 start cycling load profile are as follows;

- Initiation Fee: $11,000,000
- Annual Fixed Fee: $240,000
- Annual Factored Fired Hour (FFH) Fee: $455.97/FFH both CT

The GE proposed LTSA fees for one combustion turbine units based on the 8000 hour/20 start baseload load profile are as follows;

- Initiation Fee: $11,000,000
- Annual Fixed Fee: $240,000
- Annual Factored Fired Hour (FFH) Fee: $248.58/FFH both CT

The Siemens proposed LTSA fees for each F class combustion turbine unit are as follows;

- Program Initiation Fee: $1,500,000 per CT
- Annual Fixed Fee: $100,000 per CT
- Annual Variable Fee: ($11,500/start/CT) **or** $416/Equivalent Base Hours/CT based on the number of Equivalent Hours (EBH) or Equivalent Starts (ES), as determined below.

  Where: X = Ratio of cumulative EBH accrued to cumulative ES

  When X is ≤ 27.7 (less than or equal to 27.7 EBH per ES) for all values of X, then the Variable Fee will be charged per ES.

  When X is > 27.7 (more than 27.7 EBH per ES) for all values of X, then the Variable Fee will be charged per EBH.

The MHI G Class and Siemens H Class machine LTSA costs reflect similar structure with slight economic advantage for baseload operation. The advanced technology G and H class machines are typically applied to baseload applications, although features permitting cycling have been incorporated into the design (air cooling vs. steam cooling).

SUMMARY AND CONCLUIONS

The industry includes a limited number of combined cycle plants with long term operating history at capacity factors above 80% in the United States. This group is anticipated to increase in size dramatically in the near term as a result of fuel costs. The number of installations operating at high capacity factor has been driven by economic dispatch rather than technical limitations of the combustion turbine technology or other NGCC equipment. Operation of a combined cycle plant at high capacity factor presents maintenance challenges to meet target forced outage rates, and plant design features addressing redundancy may be determined to be economically justified at higher capacity factors, but the technology is capable of this application. A highly cycled dispatch is typically considered a more difficult operating regime for the combustion turbine and other key components including the HRSG and steam turbine reflected in the increased LTSA costs for the combustion turbine and the HRSG cycling/fast start feature capital cost.

From: Schram, Chuck
To: Wilson, Stuart; Sinclair, David
Subject: RE: RFP Presentation for Monday''s Mtg
Date: Friday, May 10, 2013 4:06:04 PM
Attachments: 20130513_RFPAnalysisUpdate_0060D03.pptx

Changed slide 3 to "640+ MW" for the GR self-build.

Chuck

From: Wilson, Stuart
Sent: Friday, May 10, 2013 2:06 PM
To: Sinclair, David; Schram, Chuck
Subject: RE: RFP Presentation for Monday's Mtg

Sorry. Doing too many things at once…

From: Sinclair, David
Sent: Friday, May 10, 2013 1:29 PM
To: Wilson, Stuart; Schram, Chuck
Subject: RE: RFP Presentation for Monday's Mtg

You need to include my prior edits as well. Thanks

From: Wilson, Stuart
Sent: Friday, May 10, 2013 1:29 PM
To: Sinclair, David; Schram, Chuck
Subject: RE: RFP Presentation for Monday's Mtg

With both updates…

From: Sinclair, David
Sent: Friday, May 10, 2013 1:25 PM
To: Wilson, Stuart; Schram, Chuck
Subject: RE: RFP Presentation for Monday's Mtg

Does the ERORA PPA value include networking upgrades? If not, we should footnote that as well.

From: Wilson, Stuart
Sent: Friday, May 10, 2013 1:22 PM
To: Sinclair, David; Schram, Chuck
Subject: RFP Presentation for Monday's Mtg

David/Chuck,

I’ve added a table of results to slide 3.

Stuart

PPL companies

RFP Analysis Update

May 13, 2013






Continued operation of Brown 1-2 defers the short-term need for capacity

Reserve Margin Over/(Under) 15% (MW)	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*
With Brown 1-2							
2013 BP Load Forecast	7	(64)	(111)	(226)	(285)	(362)	(440)

- *NALCO injection for Brown 1-2 is a viable MATS compliance alternative.*

LG&E KU
PPL companies

Self-build CCGT is most competitive long-term option

- *Self-Build CCGT (640+ MW) at Green River – Configuration (2x1, etc.) to be determined.*
- *LS Power (495 MW; SCCT) – PPA with asset purchase option not competitive in mid carbon scenarios.*
- *Big Rivers (417 MW; Coal) – PPA and asset purchase not competitive under any scenario.*
- *Khanjee (700 MW, CCGT) – PPA and associated project development evaluated to be too uncertain and risky.*
- *ERORA Asset Purchase (789 MW; CCGT) – Not competitive compared to self-build options.*
- *ERORA PPA (700 MW; CCGT)*
  - *PPA results in need to increase share of equity financing to offset higher amount of imputed debt on balance sheet.*
  - *Cost of incremental equity financing and XM network costs make PPA not a least-cost option.*

LG&E KU
PPL companies

2018 CCGT at Green River is least-cost long-term option

PVRR ($M)

	Average PVRR over 12 Gas Price/Load/CO2 Price Scenarios*	Difference from Best Alternative
Green River CCGT (2018)	*26,469*	*0*
Brown CCGT (2018)	*26,472*	*4*
LS Power PPA w/ Asset Purchase (2020)	*26,590*	*121*
*ERORA PPA (2018)***	*26,612*	*143*
Big Rivers Asset Purchase (2015)	*26,890*	*421*

**Values exclude production costs prior to 2018.*

***ERORA PPA does not include XM networking costs.*

LG&E KU
PPL companies

Next Steps

- *Finalize analysis of optimal plant size*
- *Inform short-listed parties that they were not selected*
- *Develop "Resource Assessment" document*

PPL companies

From:	Wilson, Stuart
To:	Blake, Kent
Cc:	Sinclair, David; Schram, Chuck
Subject:	RFP Analysis Update
Date:	Tuesday, May 14, 2013 3:35:12 PM
Attachments:	20130513_RFPAnalysisUpdate_0060.docx

Kent,

I've attached an updated version of the document we presented to Paul and others a couple weeks ago regarding the RFP analysis. It contains the additional layer of information you requested. Please let us know if you have any questions.

Thanks.

Stuart

RFP Analysis Update

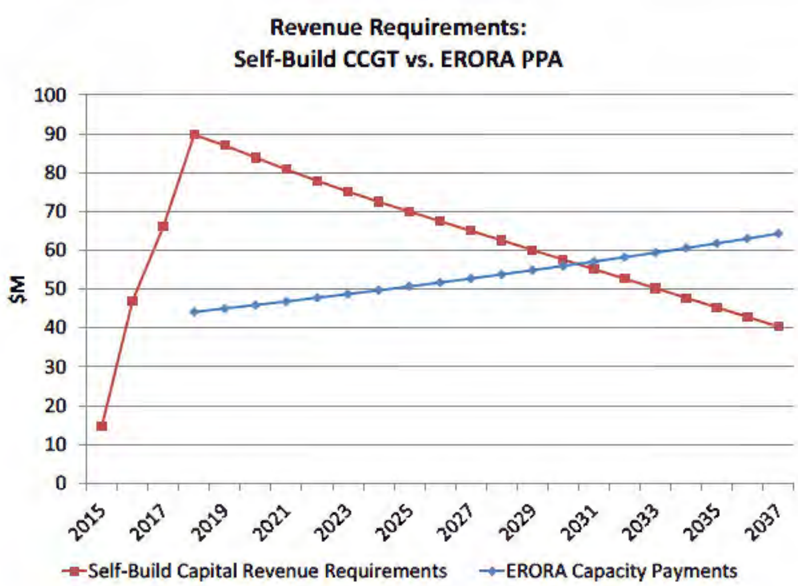
1. When we last discussed (1/29/2013)…
    a. CCGT options were favorable in most gas price/load/carbon scenarios.
    b. ERORA PPA and self-build CCGT were among the top CCGT options.

2. Today, this is still the case, but ERORA PPA is more competitive than before.
    a. XM system upgrade costs are lower for the Cash Creek site than for either Brown or Green River.
        i. ~$50 million lower than Brown
        ii. ~$80 million lower than Green River
        iii. Note: ERORA unit connected to XM system via single 26-mile radial line.
    b. ERORA lowered its PPA capacity payment from $5.40/kW-month to $5.05/kW-month ($30 million favorable PVRR impact).

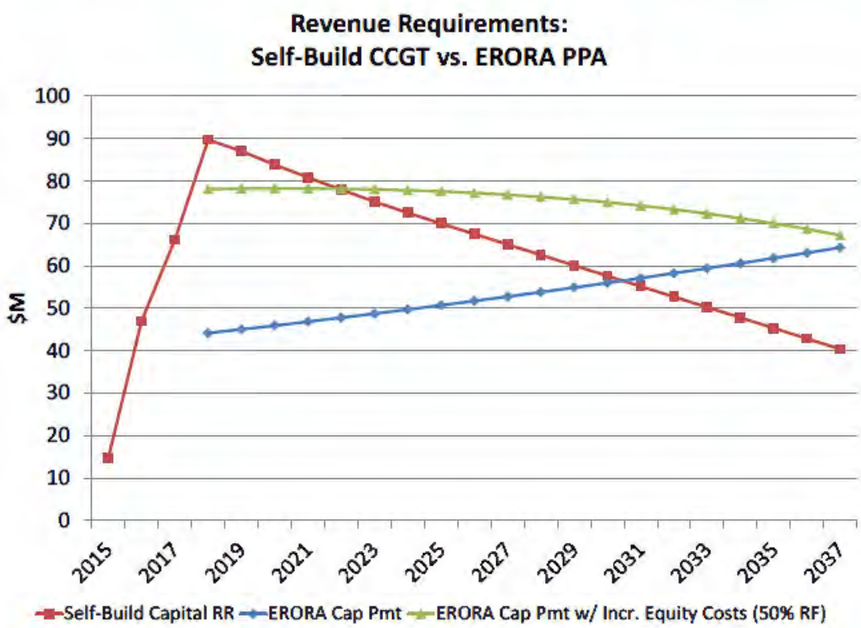
3. Before considering XM networking costs and cost of imputed debt associated with PPA, self-build CCGT is more costly than ERORA PPA.

Cost Item	Average PVRR Difference over 12 Gas Price/Load/Carbon Scenarios ($M) (Self-Build CCGT vs. ERORA PPA)*
Firm Gas Transportation	-1
Fixed O&M	20
Production Costs	-124
XM Capital	80
Unit Capital/Capacity Charge	87
Total	63

*Negative values indicate that self-build CCGT is favorable to ERORA PPA.



4. Cost of imputed debt…
    a. Rating agencies impute debt for utilities' PPAs.
    b. To maintain target capital structure, utilities must increase equity share of capital structure to offset imputed debt.
    c. Incremental cost of equity financing more than offsets favorability of ERORA PPA.



	Average PVRR Difference over 12 Gas Price/Load/Carbon Scenarios ($M) (Self-Build CCGT vs. ERORA PPA)*
w/o Cost of Imputed Debt	63
w/ Cost of Imputed Debt (50% Risk Factor)	-143
w/ Cost of Imputed Debt (25% Risk Factor)	-40

*Negative values indicate that self-build CCGT is favorable to ERORA PPA.

5. XM networking costs
    a. ERORA proposal includes cost of interconnection (via a single 26-mile radial line) to XM system.
    b. All other units in LG&E/KU system are 'networked' via multiple outlets.
    c. XM group is developing range of costs for networking ERORA unit.

6. LS Power PPA w/ option to purchase assets is favorable in zero carbon cases ASSUMING Companies can complete transaction to purchase assets following the inception of the PPA.
   a. If Companies cannot purchase assets, long-term PPA not competitive.
   b. No LS Power alternative is competitive in mid-carbon scenarios.

PVRR Difference (Self-Build CCGT vs. LS Power Alternative, $2013 M)*

LS Power Alternative	Average Difference over Six Zero Carbon Scenarios	Average Difference over Six Mid Carbon Scenarios	Average Difference over All Scenarios
20-year PPA w/ 2020 Asset Purchase	151	-417	-133
20-year PPA	-41	-450	-246

*Negative values indicate that self-build CCGT is favorable to LS Power alternative.

7. Siting considerations for self-build CCGT (Green River vs. Brown)…
   a. Costs of CCGT and XM are higher at Green River (compared to Brown).
      i. Cost of CCGT is $10 million (nominal) higher at Green River if BR1-2 continue to operate.
         1. If BR1-2 are retired, cost of CCGT is $30 million (nominal) higher at Green River.
      ii. Cost of XM is $30 million (NPV) higher at Green River.
   b. Gas interconnection cost is higher at Green River but firm gas transportation costs are lower.
   c. If company can 'net out' during permitting for new CCGT, we assume new CCGT will not be subject to annual start limit.

8. Comparison of self-build options (PVRR, $2013 M)

Alternative*	Year of 2nd CCGT in Mid Load Case	Mid Gas, Mid Load, Zero Carbon	Average over Six Zero Carbon Scenarios	Average over Six Mid Carbon Scenarios	Average over All Scenarios
1 - BR1-2 (Rt w/ BR 2x1), GR 2x1 (Jan '18), BR 2x1	2025	21,949	19,796	33,118	26,457
2 - BR1-2 (Rt w/ BR 2x1), GR 2x1 (Jan '18), BR 2x1	2021	22,103	19,918	32,957	26,437
3 - BR1-2, BR 2x1 SL (Jan '18), GR 2X1 SL	2025	21,815	19,766	33,179	26,472
4 - BR1-2, GR 2x1 (Jan '18), BR 2x1 SL	2025	21,781	19,729	33,208	26,469
Alternative		**Difference from Best Case**			
1 - BR1-2 (Rt w/ BR 2x1), GR 2x1 (Jan '18), BR 2x1	2025	169	67	161	20
2 - BR1-2 (Rt w/ BR 2x1), GR 2x1 (Jan '18), BR 2x1	2021	322	189	0	0
3 - BR1-2, BR 2x1 SL (Jan '18), GR 2X1 SL	2025	35	37	222	35
4 - BR1-2, GR 2x1 (Jan '18), BR 2x1 SL	2025	0	0	251	31

*Units with 'SL' in unit name are subject to annual 'start limit.'

   a. Given uncertainty regarding carbon regulations, recommend building CCGT at Green River. Recommendation retains option to implement alternative 2 if carbon regulations are promulgated.

9. Short-term capacity considerations...
    a. Expect BR1-2 NALCO to be viable option.
    b. Based on reserve margin shortfall in 2015-17, not compelled to enter into short-term PPA at this time.

10. Next steps…
    a. Evaluate various amount of duct firing capacity to determine optimal CCGT design.
    b. Further examine potential reliability and XM cost savings associated with building 1x1 CCGTs.
        i. Initial review of 1x1 configuration is costly.

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Cc:	Freibert, Charlie
Subject:	Clarity. RE: Proposal to Sale or Lease Coleman Generating Station
Date:	Thursday, May 23, 2013 9:36:45 AM

All,

I just talked w Bob Berry. BREC is offering Coleman and Wilson. They would be happy to sell or lease to LKE either one or both.

Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]
email: [redacted]

From: Freibert, Charlie
Sent: Thursday, May 23, 2013 6:57 AM
To: Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Subject: Fwd: Proposal to Sale or Lease Coleman Generating Station

FYI

Sent from my iPhone

Begin forwarded message:

> **From:** Bob Berry [redacted]
> **Date:** May 22, 2013, 10:55:18 PM EDT
> **To:** "Freibert, Charlie [redacted]
> **Cc:** Lindsay Barron [redacted]
> **Subject: Proposal to Sale or Lease Coleman Generating Station**
>
> Charlie, As a follow up to our previous discussion regarding the potential sale or lease of our Wilson generating plant, Big Rivers would like to extend an offer to sale or lease

the Coleman generating plant. Please find attached a proposal to sale or lease the Coleman generating plant. Please contact me if you have any questions.

Regards,
Bob Berry
Chief Operating Officer
Big Rivers Electric

From: Freibert, Charlie
To: Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Subject: Fwd: Proposal to Sale or Lease Coleman Generating Station
Date: Thursday, May 23, 2013 6:57:17 AM
Attachments: Sale or Lease of Coleman Letter to LG&E.pdf
ATT00001.htm

FYI

Sent from my iPhone

Begin forwarded message:

> **From:** Bob Berry [redacted]
> **Date:** May 22, 2013, 10:55:18 PM EDT
> **To:** "Freibert, Charlie [redacted]
> **Cc:** Lindsay Barron [redacted]
> **Subject: Proposal to Sale or Lease Coleman Generating Station**
>
> Charlie, As a follow up to our previous discussion regarding the potential sale or lease of our Wilson generating plant, Big Rivers would like to extend an offer to sale or lease the Coleman generating plant. Please find attached a proposal to sale or lease the Coleman generating plant. Please contact me if you have any questions.
>
> Regards,
> Bob Berry
> Chief Operating Officer
> Big Rivers Electric
>
> ---
>
>

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Cc:	Freibert, Charlie
Subject:	FW: Data Request. RE: Proposal to Sale or Lease Coleman Generating Station
Date:	Friday, May 24, 2013 12:20:44 PM
Attachments:	20130524_BR_RequestforColemanData_0060.docx

FYI

Below is the email I sent to BREC. I left Bob Berry a message. Lindsay and I just talked. Lindsay stated BREC has never done a toll agreement but she will research and respond to our data request by 5/31/13. I encouraged both Bob and Lindsay to get us a response even sooner if possible.

Lindsay stated that BREC was sorry for the late additional offer but BREC made the Coleman offer to another party and thought they should make the same offer to us.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Freibert, Charlie
Sent: Friday, May 24, 2013 12:10 PM
To: 'Bob Berry'
Cc: Lindsay Barron; Freibert, Charlie
Subject: Data Request. RE: Proposal to Sale or Lease Coleman Generating Station

Hi Bob,

LG&E/KU requires additional information to fully evaluate the Big Rivers' offer of May 22 to sell or lease the Coleman station. Given the late timing of your offer, LG&E/KU will require a response to our request no later than 5 PM on May 31 to fully consider and evaluate the Coleman proposal.

Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement?

Please see the attachment for our standard RFP data form, which includes a complete list of questions and data requirements for your Coleman proposal. It is imperative that you respond by May 31, 2013 so we can fully evaluate your proposal.

Thank you.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Bob Berry [redacted]
Sent: Wednesday, May 22, 2013 10:55 PM
To: Freibert, Charlie
Cc: Lindsay Barron
Subject: Proposal to Sale or Lease Coleman Generating Station

Charlie, As a follow up to our previous discussion regarding the potential sale or lease of our Wilson generating plant, Big Rivers would like to extend an offer to sale or lease the Coleman generating plant. Please find attached a proposal to sale or lease the Coleman generating plant. Please contact me if you have any questions.

Regards,
Bob Berry
Chief Operating Officer
Big Rivers Electric

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller ____

Product and Generation Characteristics:
Proposal Description____
____
____
____
Generation Source Description ____
Transmission Interconnection Point of the Source ___________________________________
Point of interconnection to the grid ____
Fuel Price (if applicable) ______________________
Start Date and Term of Contract ____
Summer Firm Capacity Amount ________ MW
Summer Maximum Dispatch Capacity Amount (if applicable) ________MW
Summer Minimum Dispatch Capacity Amount (if applicable) ________ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) ________Btu/kwh
Winter Firm Capacity Amount ________ MW
Winter Maximum Dispatch Capacity Amount (if applicable) ________MW
Winter Minimum Dispatch Capacity Amount (if applicable) ________MW
Output in 10 minutes ________MW
Ramp capability ________MW/minute
Start-up time to minimum capability _____________________________________
Start-up time to maximum capability _____________________________________
Minimum run time _____________________________
Minimum down time ___________________________
Constraints on production time (if applicable) _______________________________
Forced Outage Rate _________________%
Guaranteed Availability ____
Planned Outage Schedule ____

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)
1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term
a. Variable O&M ___________ ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

Additional Questions

1. Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement? Please detail the terms of such an offer.

2. What is the Coleman Station's maintenance and capital expenditure plan for the nine year, eleven month period referenced in your offer letter?
3. What is the Coleman Station's forecast for fixed and non-fuel variable O&M costs for the nine year, eleven month period referenced in your offer letter?
4. What are the Coleman Station's mercury, NOx, and SO2 emissions rates? Please provide available emission testing results for mercury.
5. What additional environmental controls will be needed at the Coleman station to comply with the EPA's Mercury and Air Toxics Standard?

From:	Freibert, Charlie
To:	Schram, Chuck
Cc:	Sinclair, David; Brunner, Bob; Wilson, Stuart
Subject:	Fwd: Data Request. RE: Proposal to Sale or Lease Coleman Generating Station
Date:	Monday, May 27, 2013 3:58:09 PM

Chuck
FYI. The others received it earlier. I had a typo on your name. I cc'd them again.
Thanks
Charlie

Sent from my iPhone

Begin forwarded message:

> **From:** Bob Berry [redacted]
> **Date:** May 25, 2013, 7:18:42 PM EDT
> **To:** "Freibert, Charlie" [redacted]
> **Cc:** Lindsay Barron [redacted]
> **Subject: RE: Data Request. RE: Proposal to Sale or Lease Coleman Generating Station**
>
> Charlie, We received your email and yes Big Rivers would be willing to offer a tolling arrangement for any combination of the Coleman units. We will respond to your data request before 5 p.m. on May 31.
>
> Bob
>
> ---
>
> **From:** Freibert, Charlie [redacted]
> **Sent:** Friday, May 24, 2013 11:10 AM
> **To:** Bob Berry
> **Cc:** Lindsay Barron; Freibert, Charlie
> **Subject:** Data Request. RE: Proposal to Sale or Lease Coleman Generating Station
>
> Hi Bob,
>
> LG&E/KU requires additional information to fully evaluate the Big Rivers' offer of May 22 to sell or lease the Coleman station. Given the late timing of your offer, LG&E/KU will require a response to our request no later than 5 PM on May 31 to fully consider and evaluate the Coleman proposal.
>
> Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement?

Please see the attachment for our standard RFP data form, which includes a complete list of questions and data requirements for your Coleman proposal. It is imperative that you respond by May 31, 2013 so we can fully evaluate your proposal.

Thank you.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Bob Berry [redacted]
Sent: Wednesday, May 22, 2013 10:55 PM
To: Freibert, Charlie
Cc: Lindsay Barron
Subject: Proposal to Sale or Lease Coleman Generating Station

Charlie, As a follow up to our previous discussion regarding the potential sale or lease of our Wilson generating plant, Big Rivers would like to extend an offer to sale or lease the Coleman generating plant. Please find attached a proposal to sale or lease the Coleman generating plant. Please contact me if you have any questions.

Regards,
Bob Berry
Chief Operating Officer
Big Rivers Electric

From: Freibert, Charlie
To: Sinclair, David; Brunner, Bob; Schram, Chuck; Wilson, Stuart
Cc: Freibert, Charlie
Subject: FW: Coleman Information
Date: Wednesday, June 05, 2013 5:32:45 PM

My response to BREC.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Freibert, Charlie
Sent: Wednesday, June 05, 2013 5:32 PM
To: 'Lindsay Barron'
Cc: Bob Berry; Freibert, Charlie
Subject: RE: Coleman Information

Hi Lindsay,

I just got out of meetings. Sorry I could not answer your calls.

Thank you for the additional information about the Coleman plant/generators. We requested information and a tolling proposal no later than COB, 5pm EDT, Friday, 5/31/13. Your information received today at 2:45pm EDT is clearly late and does not contain a tolling proposal. The LKE RFP process has progressed since 5/31/13. LKE will attempt to use the information you provided if possible in our RFP process.

Thanks again.

Charlie Freibert
Director Marketing

LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Lindsay Barron [redacted]
Sent: Wednesday, June 05, 2013 2:44 PM
To: Freibert, Charlie
Cc: Bob Berry
Subject: Coleman Information

Charlie,

Please accept the attached information for your analyses of our offer to Sell or Lease Coleman Station. Please note, we are also willing to consider a tolling arrangement and would like LKE to propose a preferred arrangement to us.

I genuinely apologize for the delay.

If you have any further questions or need any additional information, please let Bob or me know.

Thanks so much!

Lindsay☺

Lindsay N. Barron, CPA
Vice President Energy Services
Big Rivers Electric Corporation
PO Box 24
Henderson, KY 42419
[redacted]

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Subject:	Fwd: Coleman Information
Date:	Wednesday, June 05, 2013 6:30:25 PM

BREC's reply. I talked with Lindsey a few minutes ago. She repeated this message. I repeated that the process has progressed. She asked if we will provide tolling concepts to discuss. I replied that providing concepts and proposals was not part of our process.

Charlie

Sent from my iPhone

Begin forwarded message:

From: Lindsay Barron [redacted]
Date: June 5, 2013, 5:57:58 PM EDT
To: "'Freibert, Charlie'" [redacted]
Cc: Bob Berry [redacted]
Subject: RE: Coleman Information

Charlie,

I genuinely apologize for being late. We were very sensitive to the need to respond in a timely manner and actually had the information completed on Thursday of last week. Amid the plethora of activities here at Big Rivers, I failed to forward the information.

As far as the tolling agreement is concerned, Big Rivers has never actually participated in a tolling agreement and we felt it would be appropriate to solicit your feedback as to a preferred arrangement. As we've discussed before, we are committed to working with you to find a mutually beneficial solution for both our Members and your ratepayers and shareholders.

Again, I personally apologize for the 3 business day delay.

Thanks!

Lindsay

From: Freibert, Charlie [redacted]
Sent: Wednesday, June 05, 2013 4:32 PM
To: Lindsay Barron
Cc: Bob Berry; Freibert, Charlie
Subject: RE: Coleman Information

Hi Lindsay,

I just got out of meetings. Sorry I could not answer your calls.

Thank you for the additional information about the Coleman plant/generators. We requested information and a tolling proposal no later than COB, 5pm EDT, Friday, 5/31/13. Your information received today at 2:45pm EDT is clearly late and does not contain a tolling proposal. The LKE RFP process has progressed since 5/31/13. LKE will attempt to use the information you provided if possible in our RFP process.

Thanks again.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Lindsay Barron [mailto:Lindsay.Barron@bigrivers.com]
Sent: Wednesday, June 05, 2013 2:44 PM
To: Freibert, Charlie
Cc: Bob Berry
Subject: Coleman Information

Charlie,

Please accept the attached information for your analyses of our offer to Sell or Lease Coleman Station. Please note, we are also willing to consider a tolling arrangement and would like LKE to propose a preferred arrangement to us.

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If you have any further questions or need any additional information, please let Bob or me know.

Thanks so much!

Lindsay☺

Lindsay N. Barron, CPA
Vice President Energy Services
Big Rivers Electric Corporation
PO Box 24
Henderson, KY 42419
[redacted]

From: Freibert, Charlie
To: Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Cc: Freibert, Charlie
Subject: FW: Coleman Information
Date: Wednesday, June 05, 2013 3:49:43 PM
Attachments: Coleman - 2013 Budget Net Heat Rate Curves.pdf
Coleman 1.pdf
Coleman 2.pdf
Coleman 3.pdf

FYI.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Lindsay Barron [mailto:Lindsay.Barron@bigrivers.com]
Sent: Wednesday, June 05, 2013 2:44 PM
To: Freibert, Charlie
Cc: Bob Berry
Subject: Coleman Information

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If you have any further questions or need any additional information, please let Bob or me know.

Thanks so much!

Lindsay☺

Lindsay N. Barron, CPA
Vice President Energy Services

Big Rivers Electric Corporation
PO Box 24
Henderson, KY 42419
[redacted]

5/24/2013

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller __Big Rivers Electric Corporation____

Product and Generation Characteristics:
Proposal Description: Proposal to Buy or Lease **Coleman Station Unit 1** – Coleman Station ___ has a common FGD for all three units. Data below has the common FGD auxiliary power and costs split evenly between all three units Big Rivers is also willing to consider a proposal from LKE for a tolling agreement. ____
Generation Source Description _Pulverized Coal Fired Generating Unit
Transmission Interconnection Point of the Source _Multiple_
Point of interconnection to the grid __BREC.Cole1 MISO Node_
Fuel Price (if applicable) _2013 Budget - $2.346, 2012 Actual - $2.309, 2011 Actual - $2.201 ($/MMBtu)
Start Date and Term of Contract __Negotiable_
Summer Firm Capacity Amount __146___ MW
Summer Maximum Dispatch Capacity Amount (if applicable) __146__MW
Summer Minimum Dispatch Capacity Amount (if applicable) __70__ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) see attached curve Btu/kwh
Winter Firm Capacity Amount ___146__ MW
Winter Maximum Dispatch Capacity Amount (if applicable) __146___MW
Winter Minimum Dispatch Capacity Amount (if applicable) ___70___MW
Output in 10 minutes __N/A__MW
Ramp capability ___1___MW/minute
Start-up time to minimum capability _Hot Start – 8 hours, Cold Start – 15 hours_
Start-up time to maximum capability _Hot Start – 14 hours, Cold Start – 21 hours_
Minimum run time _24 hours__
Minimum down time _24 hours__
Constraints on production time (if applicable) __N/A__
Forced Outage Rate _2013 Budget – 5.0%, 2012 Actual – 8.2%, 2011 Actual – 5.6%
Guaranteed Availability __negotiable______________________
Planned Outage Schedule _3 year planned outage cycle (9 yr turbine O/H); Next planned outage scheduled – 9/14/13 to 10/12/13 (672 hours); Next turbine overhaul scheduled – Spring 2019_

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term

a. Variable O&M _2013 Budget - $1.396 , 2012 Actual - $1.065, 2011 Actual - $0.944 ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

5/24/2013

Additional Questions

1. Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement? Please detail the terms of such an offer. Big Rivers is willing to consider any arrangement desired by LGE. Please advise of your preferred tolling arrangement. We feel we can come to terms that are mutually agreeable for both parties, and are open to a plethora of options.

2. What is the Coleman Station's maintenance and capital expenditure plan for the nine year, eleven month period referenced in your offer letter?

   Coleman Station Capital: 2013 - $10,579,000, 2014 - $17,235,459, 2015 - $17,946,000, 2016 - $10,609,000
   Prices do not include any MATS compliance or any new environmental compliance. Please see question 3 for maintenance expenditure plan. After 2016, prices are escalated by an inflation rate.

3. What is the Coleman Station's forecast for fixed and non-fuel variable O&M costs for the nine year, eleven month period referenced in your offer letter?

   Coleman Station Fixed O&M (includes labor): 2013 - $26,448,216, 2014 - $29,447,926, 2015 - $27,690,817, 2016 – $28,891,156
   Non-Fuel Variable O&M – 2013 - $1.396/MWH, 2014 - $1.434/MWH, 2015 (pre MATS) - $1.474/MWH, 2015 (post MATS) – $1.927/MWH, 2016 - $1.970/MWH.
   Prices do not include any new environmental compliance (besides MATS). After 2016, prices are escalated by an inflation rate.

4. What are the Coleman Station's mercury, NOx, and SO2 emissions rates? Please provide available emission testing results for mercury.

   Mercury – 3.52 lbs / T Btu (from 2011 S&L testing); Additional testing in progress
   NOx – 0.33 lbs / MMBtu
   SO2 – 0.20 lbs / MMBtu

5. What additional environmental controls will be needed at the Coleman station to comply with the EPA's Mercury and Air Toxics Standard?

   Install activated carbon and dry sorbent injection systems on all three units. Plan to install mercury continuous emission monitor systems (CEMS) for control testing and utilize sorbent tubes for compliance testing.

Coleman Unit 1 Net Heat Rate Curve - 2013 Budget (BTU/kWH)					
46 MW	67 MW	88 MW	109 MW	130 MW	151 MW
12,816	12,118	11,577	11,194	10,967	10,898

Coleman Unit 2 Net Heat Rate Curve - 2013 Budget (BTU/kWH)					
46 MW	67 MW	88 MW	109 MW	130 MW	151 MW
12,816	12,118	11,577	11,194	10,967	10,898

Coleman Unit 3 Net Heat Rate Curve - 2013 Budget (BTU/kWH)					
56 MW	75.8 MW	95.6 MW	115.4 MW	135.2 MW	155 MW
12,629	11,970	11,468	11,124	10,937	10,907

5/24/2013

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller __Big Rivers Electric Corporation____

Product and Generation Characteristics:
Proposal Description: Proposal to Buy or Lease **Coleman Station Unit 2** – Coleman Station ___ has a common FGD for all three units. Data below has the common FGD auxiliary power and costs split evenly between all three units. Big Rivers is also willing to consider a proposal from LKE for a tolling agreement. ____
Generation Source Description _Pulverized Coal Fired Generating Unit
Transmission Interconnection Point of the Source _Multiple_
Point of interconnection to the grid __BREC.Cole1 MISO Node_
Fuel Price (if applicable) _2013 Budget - $2.346, 2012 Actual - $2.309, 2011 Actual - $2.201 ($/MMBtu)
Start Date and Term of Contract __Negotiable_
Summer Firm Capacity Amount __146___ MW
Summer Maximum Dispatch Capacity Amount (if applicable) __146__MW
Summer Minimum Dispatch Capacity Amount (if applicable) __70__ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) see attached curve Btu/kwh
Winter Firm Capacity Amount ___146__ MW
Winter Maximum Dispatch Capacity Amount (if applicable) __146___MW
Winter Minimum Dispatch Capacity Amount (if applicable) ___70___MW
Output in 10 minutes _N/A__MW
Ramp capability ___1___MW/minute
Start-up time to minimum capability _Hot Start – 8 hours, Cold Start – 15 hours_
Start-up time to maximum capability _Hot Start – 14 hours, Cold Start – 21 hours_
Minimum run time _24 hours__
Minimum down time _24 hours__
Constraints on production time (if applicable) __N/A__
Forced Outage Rate _2013 Budget – 5.0%, 2012 Actual – 1.4%, 2011 Actual – 4.1%
Guaranteed Availability __negotiable_______________________
Planned Outage Schedule _3 year planned outage cycle (9 yr turbine O/H); Next planned outage scheduled – 5/2/15 to 5/27/15 (600 hours); Next turbine overhaul scheduled – Fall 2018_

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term

a. Variable O&M _2013 Budget - $1.396 , 2012 Actual - $1.065, 2011 Actual - $0.944 ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

5/24/2013

Additional Questions

1. Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement? Please detail the terms of such an offer. Big Rivers is willing to consider any arrangement desired by LGE. Please advise of your preferred tolling arrangement. We feel we can come to terms that are mutually agreeable for both parties, and are open to a plethora of options.

2. What is the Coleman Station's maintenance and capital expenditure plan for the nine year, eleven month period referenced in your offer letter?

   Coleman Station Capital: 2013 - $10,579,000, 2014 - $17,235,459, 2015 - $17,946,000, 2016 - $10,609,000
   Prices do not include any MATS compliance or any new environmental compliance. Please see question 3 for maintenance expenditure plan. After 2016, prices are escalated by an inflation rate.

3. What is the Coleman Station's forecast for fixed and non-fuel variable O&M costs for the nine year, eleven month period referenced in your offer letter?

   Coleman Station Fixed O&M (includes labor): 2013 - $26,448,216, 2014 - $29,447,926, 2015 - $27,690,817, 2016 – $28,891,156
   Non-Fuel Variable O&M – 2013 - $1.396/MWH, 2014 - $1.434/MWH, 2015 (pre MATS) - $1.474/MWH, 2015 (post MATS) – $1.927/MWH, 2016 - $1.970/MWH.
   Prices do not include any new environmental compliance (besides MATS). After 2016, prices are escalated by an inflation rate.

4. What are the Coleman Station's mercury, NOx, and SO2 emissions rates? Please provide available emission testing results for mercury.

   Mercury – 3.52 lbs / T Btu (from 2011 S&L testing); Additional testing in progress
   NOx – 0.33 lbs / MMBtu
   SO2 – 0.20 lbs / MMBtu

5. What additional environmental controls will be needed at the Coleman station to comply with the EPA's Mercury and Air Toxics Standard?

   Install activated carbon and dry sorbent injection systems on all three units. Plan to install mercury continuous emission monitor systems (CEMS) for control testing and utilize sorbent tubes for compliance testing.

5/24/2013

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller __Big Rivers Electric Corporation____

Product and Generation Characteristics:
Proposal Description: Proposal to Buy or Lease **Coleman Station Unit 3** – Coleman Station ___ has a common FGD for all three units. Data below has the common FGD auxiliary power and costs split evenly between all three units. Big Rivers is also willing to consider a proposal from LKE for a tolling agreement.____

Generation Source Description _Pulverized Coal Fired Generating Unit
Transmission Interconnection Point of the Source _Multiple_
Point of interconnection to the grid __BREC.Cole1 MISO Node_
Fuel Price (if applicable) _2013 Budget - $2.346, 2012 Actual - $2.309, 2011 Actual - $2.201 ($/MMBtu)
Start Date and Term of Contract __Negotiable_
Summer Firm Capacity Amount __151___ MW
Summer Maximum Dispatch Capacity Amount (if applicable) __151__MW
Summer Minimum Dispatch Capacity Amount (if applicable) __60__ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) see attached curve Btu/kwh
Winter Firm Capacity Amount ___151__ MW
Winter Maximum Dispatch Capacity Amount (if applicable) __151___MW
Winter Minimum Dispatch Capacity Amount (if applicable) ___60___MW
Output in 10 minutes __N/A__MW
Ramp capability ___1___MW/minute
Start-up time to minimum capability _Hot Start – 8 hours, Cold Start – 11 hours_
Start-up time to maximum capability _Hot Start – 14 hours, Cold Start – 17 hours_
Minimum run time _24 hours__
Minimum down time _24 hours__
Constraints on production time (if applicable) __N/A__
Forced Outage Rate _2013 Budget – 6.0%, 2012 Actual – 1.0%, 2011 Actual – 6.7%
Guaranteed Availability __negotiable_______________________
Planned Outage Schedule _3 year planned outage cycle (9 yr turbine O/H); Next planned outage scheduled (turbine overhaul) – 4/5/14 to 5/26/14 (1,224 hours)_

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price ________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term

a. Variable O&M _2013 Budget - $1.396 , 2012 Actual - $1.065, 2011 Actual - $0.944 ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

5/24/2013

Additional Questions

1. Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement? Please detail the terms of such an offer. Big Rivers is willing to consider any arrangement desired by LGE. Please advise of your preferred tolling arrangement. We feel we can come to terms that are mutually agreeable for both parties, and are open to a plethora of options.

2. What is the Coleman Station's maintenance and capital expenditure plan for the nine year, eleven month period referenced in your offer letter?

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   Coleman Station Fixed O&M (includes labor): 2013 - $26,448,216, 2014 - $29,447,926, 2015 - $27,690,817, 2016 – $28,891,156
   Non-Fuel Variable O&M – 2013 - $1.396/MWH, 2014 - $1.434/MWH, 2015 (pre MATS) - $1.474/MWH, 2015 (post MATS) – $1.927/MWH, 2016 - $1.970/MWH.
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4. What are the Coleman Station's mercury, NOx, and SO2 emissions rates? Please provide available emission testing results for mercury.

   Mercury – 3.52 lbs / T Btu (from 2011 S&L testing); Additional testing in progress
   NOx – 0.33 lbs / MMBtu
   SO2 – 0.20 lbs / MMBtu

5. What additional environmental controls will be needed at the Coleman station to comply with the EPA's Mercury and Air Toxics Standard?

   Install activated carbon and dry sorbent injection systems on all three units. Plan to install mercury continuous emission monitor systems (CEMS) for control testing and utilize sorbent tubes for compliance testing.

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Subject:	Fwd: Coleman Tolling Agreement
Date:	Thursday, June 06, 2013 7:31:00 AM
Attachments:	Coleman 1.pdf ATT00001.htm Coleman 2.pdf ATT00002.htm Coleman 3.pdf ATT00003.htm Coleman Tolling agreement.pdf ATT00004.htm

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FYI

Sent from my iPhone

Begin forwarded message:

> **From:** Lindsay Barron [redacted]
> **Date:** June 5, 2013, 10:38:56 PM EDT
> **To:** "Freibert, Charlie" [redacted]
> **Cc:** Bob Berry [redacted]
> **Subject: Coleman Tolling Agreement**
>
> Charlie,
>
> Based on our conversation today, it became clear to me that you were looking for a specific tolling proposal from us. We did not realize that was your requirement; we thought you were asking if we would consider one. In our earlier response to you, it was my intention to allow you to share your preference, however based on our phone conversation, please find attached our proposed Tolling Agreement for the Coleman Station. We would entertain a toll agreement on 1 or more of the units.
>
> We welcome any questions you may have on the attached proposal. As we've said before, we are committed to working with you to find a mutually beneficial arrangement that can support providing safe, reliable, low-cost power to consumers throughout the Commonwealth.
>
> Thanks Charlie!
>
> Lindsay
>
> *Lindsay N. Barron, CPA*
> *Vice President Energy Services*
> *Big Rivers Electric Corporation*
> *PO Box 24*
> *Henderson, KY 42419*
> [redacted]
>
>

5/24/2013

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller __Big Rivers Electric Corporation____

Product and Generation Characteristics:
Proposal Description: Proposal to Buy or Lease **Coleman Station Unit 1** – Coleman Station ___ has a common FGD for all three units. Data below has the common FGD auxiliary power and costs split evenly between all three units Big Rivers is also willing to consider a proposal from LKE for a tolling agreement. ____
Generation Source Description _Pulverized Coal Fired Generating Unit
Transmission Interconnection Point of the Source _Multiple_
Point of interconnection to the grid __BREC.Cole1 MISO Node_
Fuel Price (if applicable) _2013 Budget - $2.346, 2012 Actual - $2.309, 2011 Actual - $2.201 ($/MMBtu)
Start Date and Term of Contract __Negotiable_
Summer Firm Capacity Amount __146___ MW
Summer Maximum Dispatch Capacity Amount (if applicable) __146__MW
Summer Minimum Dispatch Capacity Amount (if applicable) __70__ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) see attached curve Btu/kwh
Winter Firm Capacity Amount ___146__ MW
Winter Maximum Dispatch Capacity Amount (if applicable) __146___MW
Winter Minimum Dispatch Capacity Amount (if applicable) ___70___MW
Output in 10 minutes _N/A__MW
Ramp capability ___1___MW/minute
Start-up time to minimum capability _Hot Start – 8 hours, Cold Start – 15 hours_
Start-up time to maximum capability _Hot Start – 14 hours, Cold Start – 21 hours_
Minimum run time _24 hours__
Minimum down time _24 hours__
Constraints on production time (if applicable) __N/A__
Forced Outage Rate _2013 Budget – 5.0%, 2012 Actual – 8.2%, 2011 Actual – 5.6%
Guaranteed Availability __negotiable______________________
Planned Outage Schedule _3 year planned outage cycle (9 yr turbine O/H); Next planned outage scheduled – 9/14/13 to 10/12/13 (672 hours); Next turbine overhaul scheduled – Spring 2019_

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)
1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term
a. Variable O&M _2013 Budget - $1.396 , 2012 Actual - $1.065, 2011 Actual - $0.944 ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

5/24/2013

Additional Questions

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5/24/2013

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller __Big Rivers Electric Corporation____

Product and Generation Characteristics:
Proposal Description: Proposal to Buy or Lease **Coleman Station Unit 2** – Coleman Station ___ has a common FGD for all three units. Data below has the common FGD auxiliary power and costs split evenly between all three units. Big Rivers is also willing to consider a proposal from LKE for a tolling agreement. ____
Generation Source Description _Pulverized Coal Fired Generating Unit
Transmission Interconnection Point of the Source _Multiple_
Point of interconnection to the grid __BREC.Cole1 MISO Node_
Fuel Price (if applicable) _2013 Budget - $2.346, 2012 Actual - $2.309, 2011 Actual - $2.201 ($/MMBtu)
Start Date and Term of Contract __Negotiable_
Summer Firm Capacity Amount __146___ MW
Summer Maximum Dispatch Capacity Amount (if applicable) __146__MW
Summer Minimum Dispatch Capacity Amount (if applicable) __70__ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) see attached curve Btu/kwh
Winter Firm Capacity Amount ___146__ MW
Winter Maximum Dispatch Capacity Amount (if applicable) __146___MW
Winter Minimum Dispatch Capacity Amount (if applicable) ___70___MW
Output in 10 minutes _N/A__MW
Ramp capability ___1___MW/minute
Start-up time to minimum capability _Hot Start – 8 hours, Cold Start – 15 hours_
Start-up time to maximum capability _Hot Start – 14 hours, Cold Start – 21 hours_
Minimum run time _24 hours__
Minimum down time _24 hours__
Constraints on production time (if applicable) __N/A__
Forced Outage Rate _2013 Budget – 5.0%, 2012 Actual – 1.4%, 2011 Actual – 4.1%
Guaranteed Availability __negotiable_______________________
Planned Outage Schedule _3 year planned outage cycle (9 yr turbine O/H); Next planned outage scheduled – 5/2/15 to 5/27/15 (600 hours); Next turbine overhaul scheduled – Fall 2018_

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term

a. Variable O&M _2013 Budget - $1.396 , 2012 Actual - $1.065, 2011 Actual - $0.944 ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

5/24/2013

Additional Questions

1. Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement? Please detail the terms of such an offer. Big Rivers is willing to consider any arrangement desired by LGE. Please advise of your preferred tolling arrangement. We feel we can come to terms that are mutually agreeable for both parties, and are open to a plethora of options.

2. What is the Coleman Station's maintenance and capital expenditure plan for the nine year, eleven month period referenced in your offer letter?

   Coleman Station Capital: 2013 - $10,579,000, 2014 - $17,235,459, 2015 - $17,946,000, 2016 - $10,609,000
   Prices do not include any MATS compliance or any new environmental compliance. Please see question 3 for maintenance expenditure plan. After 2016, prices are escalated by an inflation rate.

3. What is the Coleman Station's forecast for fixed and non-fuel variable O&M costs for the nine year, eleven month period referenced in your offer letter?

   Coleman Station Fixed O&M (includes labor): 2013 - $26,448,216, 2014 - $29,447,926, 2015 - $27,690,817, 2016 – $28,891,156
   Non-Fuel Variable O&M – 2013 - $1.396/MWH, 2014 - $1.434/MWH, 2015 (pre MATS) - $1.474/MWH, 2015 (post MATS) – $1.927/MWH, 2016 - $1.970/MWH.
   Prices do not include any new environmental compliance (besides MATS). After 2016, prices are escalated by an inflation rate.

4. What are the Coleman Station's mercury, NOx, and SO2 emissions rates? Please provide available emission testing results for mercury.

   Mercury – 3.52 lbs / T Btu (from 2011 S&L testing); Additional testing in progress
   NOx – 0.33 lbs / MMBtu
   SO2 – 0.20 lbs / MMBtu

5. What additional environmental controls will be needed at the Coleman station to comply with the EPA's Mercury and Air Toxics Standard?

   Install activated carbon and dry sorbent injection systems on all three units. Plan to install mercury continuous emission monitor systems (CEMS) for control testing and utilize sorbent tubes for compliance testing.

5/24/2013

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller __Big Rivers Electric Corporation____

Product and Generation Characteristics:
Proposal Description: Proposal to Buy or Lease **Coleman Station Unit 3** – Coleman Station ___ has a common FGD for all three units. Data below has the common FGD auxiliary power and costs split evenly between all three units. Big Rivers is also willing to consider a proposal from LKE for a tolling agreement.____

Generation Source Description _Pulverized Coal Fired Generating Unit
Transmission Interconnection Point of the Source _Multiple_
Point of interconnection to the grid __BREC.Cole1 MISO Node_
Fuel Price (if applicable) _2013 Budget - $2.346, 2012 Actual - $2.309, 2011 Actual - $2.201 ($/MMBtu)
Start Date and Term of Contract __Negotiable_
Summer Firm Capacity Amount __151___ MW
Summer Maximum Dispatch Capacity Amount (if applicable) __151__MW
Summer Minimum Dispatch Capacity Amount (if applicable) __60__ MW
Guaranteed Heat Rate (or heat rate curve) (if applicable) see attached curve Btu/kwh
Winter Firm Capacity Amount ___151__ MW
Winter Maximum Dispatch Capacity Amount (if applicable) __151___MW
Winter Minimum Dispatch Capacity Amount (if applicable) ___60___MW
Output in 10 minutes _N/A__MW
Ramp capability ___1___MW/minute
Start-up time to minimum capability _Hot Start – 8 hours, Cold Start – 11 hours_
Start-up time to maximum capability _Hot Start – 14 hours, Cold Start – 17 hours_
Minimum run time _24 hours__
Minimum down time _24 hours__
Constraints on production time (if applicable) __N/A__
Forced Outage Rate _2013 Budget – 6.0%, 2012 Actual – 1.0%, 2011 Actual – 6.7%
Guaranteed Availability __negotiable_______________________
Planned Outage Schedule _3 year planned outage cycle (9 yr turbine O/H); Next planned outage scheduled (turbine overhaul) – 4/5/14 to 5/26/14 (1,224 hours)_

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year _________________
Energy Pricing (Provide energy pricing in one of the following formats)

1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term

a. Variable O&M _2013 Budget - $1.396 , 2012 Actual - $1.065, 2011 Actual - $0.944 ($/MWh)
b. Guaranteed Heat Rate _______ (Btu/kwh)
c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

5/24/2013

Additional Questions

1. Would Big Rivers be willing to offer a tolling arrangement for one, two, or three of the Coleman units instead of a lease arrangement? Please detail the terms of such an offer. Big Rivers is willing to consider any arrangement desired by LGE. Please advise of your preferred tolling arrangement. We feel we can come to terms that are mutually agreeable for both parties, and are open to a plethora of options.

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   NOx – 0.33 lbs / MMBtu
   SO2 – 0.20 lbs / MMBtu

5. What additional environmental controls will be needed at the Coleman station to comply with the EPA's Mercury and Air Toxics Standard?

   Install activated carbon and dry sorbent injection systems on all three units. Plan to install mercury continuous emission monitor systems (CEMS) for control testing and utilize sorbent tubes for compliance testing.

Big Rivers ELECTRIC CORPORATION

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Date:	June 5, 2013
Seller:	Big Rivers Electric Corporation ("Seller")
Buyer:	LG&E and KU Energy LLC ("Buyer")
Product:	Capacity ("Capacity"), associated unit contingent energy ("Energy") and ancillary services ("Ancillary Services") from Seller's Coleman Station generation facility located in Hancock County, Kentucky ("Facility").
Facility:	The Facility contains three pulverized coal fired units (146MW, 146MW, 151MW) located near Hawesville, KY.
	The MISO CP Node is BREC.COLE1, BREC.COLE2, BREC.COLE3
Unit Specifications:	See attached sheets with unit specific information.
Scheduling:	Buyer must provide energy schedule by 8 am (CPT) the business day prior to operating day. Buyer may schedule quantities varying hourly between the min and max, subject to unit limitations. Seller will consider Buyer's request to establish real-time control of generation.
Contract Term:	Up to 15 Years, start date negotiable
Contract Quantity:	Up to 443 MW, fixed quantity (maximum delivery and billing determinant for Capacity Price)
Capacity Price:	2015-2018 $7.50/kW-month
	2019-End of term $11.50/kW-month, escalating annually at 1% thereafter
Capacity Charge:	The Capacity Price times the Contract Quantity x 1000 for any month during the Term
Energy Charge:	Variable O&M Charge: $1.396/MWh, escalating annually with CPI-U
	Fuel to be supplied by Buyer
Start Charge:	Assume $6,000 per start for initial indicative pricing, escalating annually with CPI-U plus
	Start Fuel: Assume 1,500 mmBTU natural gas per start
Environmental Charges:	Tied to Big Rivers Monthly Environmental Surcharge. Will be calculated as (Total Capacity Charge + Total Energy Charge + Total Start Charge) * Monthly Environmental Surcharge Percentage (4.93974% in April 2013)
Fuel:	Buyer will provide coal to the Facility.
Delivery Point:	Negotiable

Big Rivers ELECTRIC CORPORATION

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Transmission:	Facility is connected to MISO at transmission level voltage. This quote includes the cost of MISO network transmission; however, payment of any congestion costs and/or additional transmission needed to reach preferred delivery point of Buyers' transmission system will need to be added. Because of Seller and Buyer's close proximity, Seller welcomes discussion about the most advantageous structure of deal to minimize transmission costs to Buyer.
Availability:	Seller is willing to negotiate availability guarantees and remedies for non-performance.
Indicative Scheduled Outages:	See attached sheets with unit specific information. Seller will provide future scheduled outages to Buyer in a timely fashion.
Additional Information:	If any additional information is required, please contact Lindsay Barron, Vice President of Energy Services, 270.993.1594 or Lindsay.Barron@bigrivers.com.

Where escalation of prices is stated, the escalator shall be the CPI-U defined as the Consumer Price Index for all Urban Consumers as published by the U.S. Department of Labor Bureau of Labor Statistics.

Any final agreement shall be subject to the negotiation of mutually acceptable credit terms and conditions.

This Term Sheet is preliminary and is intended to set forth certain basic terms and to serve as a basis for further discussion and negotiations between the Parties with respect to the potential Agreement described herein. This Term Sheet does not contain all matters upon which agreement must be reached in order for the transaction to be completed. The matters set forth herein are not intended to and do not constitute a binding agreement of the Parties nor do they establish any obligation of the Parties with respect to the Agreement, and this Term Sheet may not be relied upon by a Party as the basis for a contract by estoppel or otherwise. A binding agreement will arise only upon the negotiation, execution and delivery of mutually satisfactory definitive agreements and the satisfaction of the conditions set forth therein, including completion of due diligence and the approval of such agreements by the respective governing body(ies), management and board of each Party, which approval shall be in the sole subjective discretion of the respective governing body(ies), management and board.

From: Freibert, Charlie
To: Sinclair, David; Wilson, Stuart
Cc: Freibert, Charlie; Brunner, Bob; Schram, Chuck
Subject: FW: Info Request. RE: Coleman Tolling Agreement
Date: Monday, June 10, 2013 4:39:03 PM
Importance: High

FYI - Request sent to BREC.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Freibert, Charlie
Sent: Monday, June 10, 2013 4:38 PM
To: 'Lindsay Barron'
Cc: 'Bob Berry'; Freibert, Charlie; Brunner, Bob; Schram, Chuck
Subject: Info Request. RE: Coleman Tolling Agreement
Importance: High

Hi Lindsay,

I know your schedule is very busy but I need the following information asap for us to complete our review of your offer.

Coleman tolling proposal:

1. Please provide:
   a. An estimate of the Monthly Environmental Surcharge Percentage over the life of the proposed tolling agreement.
   OR
   b. Eliminate the Environmental Surcharge; instead, provide a capacity price and variable O&M charge that is inclusive of environmental charges.

2. LG&E/KU will supply the fuel in the tolling proposal. Given this, how will the Total Energy Charge component be calculated if the Environmental Surcharge is used? Please provide an example of the calculation of the Energy Charge component.

Coleman asset sale proposal:

1. What is the current arrangement and future plan for the disposal of coal combustion byproducts at Coleman Station?
   a. How much ash pond or landfill space (in volumetric terms) is available?
   b. What additional disposal related costs (capital and O&M) are expected?
2. Please provide an estimate of MATS compliance capital for the Coleman units.

We need this information in writing (an email is fine) by no later than 5:00pm EDT Wednesday, 6/12/13. Please copy Bob and Chuck on the CC line in your response to me since I will be on vacation starting this Wednesday till next Tuesday. If you decide to send by email, we will immediately confirm reciept by sending an email back to you.

Thank you.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Lindsay Barron [redacted]
Sent: Wednesday, June 05, 2013 10:39 PM
To: Freibert, Charlie
Cc: Bob Berry
Subject: Coleman Tolling Agreement

Charlie,

Based on our conversation today, it became clear to me that you were looking for a specific tolling proposal from us. We did not realize that was your requirement; we thought you were asking if we would consider one. In our earlier response to you, it was my intention to allow you to share your preference, however based on our phone conversation, please find attached our proposed Tolling Agreement for the Coleman Station. We would entertain a toll agreement on 1 or more of the units.

We welcome any questions you may have on the attached proposal. As we've said before, we are committed to working with you to find a mutually beneficial arrangement that can support providing safe, reliable, low-cost power to consumers throughout the Commonwealth.

Thanks Charlie!

Lindsay

Lindsay N. Barron, CPA
Vice President Energy Services
Big Rivers Electric Corporation
PO Box 24
Henderson, KY 42419
[redacted]

From: Schram, Chuck
To: Freibert, Charlie
Cc: Sinclair, David; Wilson, Stuart; Brunner, Bob
Subject: BREC Questions
Date: Monday, June 10, 2013 12:59:43 AM

Charlie, below are questions for BREC. I am out on vacation this week, but will be in touch.
Thanks,
Chuck

Coleman tolling proposal:

1. Please provide:
    a. An estimate of the Monthly Environmental Surcharge Percentage over the life of the proposed tolling agreement.

    OR

    b. Eliminate the Environmental Surcharge; instead, provide a capacity price and variable O&M charge that is inclusive of environmental charges.

2. LG&E/KU will supply the fuel in the tolling proposal. Given this, how will the Total Energy Charge component be calculated if the Environmental Surcharge is used? Please provide an example of the calculation of the Energy Charge component.

Coleman asset sale proposal:

1. What is the current arrangement and future plan for the disposal of coal combustion byproducts at Coleman Station?
    a. How much ash pond or landfill space (in volumetric terms) is available?
    b. What additional disposal related costs (capital and O&M) are expected?
2. Please provide an estimate of MATS compliance capital for the Coleman units.

From:	Brunner, Bob
To:	Sinclair, David; Cocanougher, Beth
Subject:	FW: LS Power"s RFP Proposal
Date:	Wednesday, June 12, 2013 4:54:51 PM
Attachments:	Bluegrass - LGE KU Term Sheets 2 yr.docx Bluegrass - LGE KU Term Sheets 4 yr.docx

Fyi...attached is the email sent to LS Power this afternoon.

From: Brunner, Bob
Sent: Wednesday, June 12, 2013 4:48 PM
To: [redacted]
Cc: Freibert, Charlie; Brunner, Bob
Subject: LS Power's RFP Proposal

Dear Mr. Kim,

We are in the process of wrapping up our analysis of the RFP proposals to determine the next steps in advancing towards the reasonably least cost solution to the Companies' future capacity needs. Attached are two possible deal structures that we would be interested in exploring. It would be helpful if you could let us know by Tuesday, 6/18/13, if you are interested in negotiating with us to develop an agreement under the terms outlined in either of the attached documents. Please note that the attached documents are for discussion purposes only, and are not offers or bids, and are subject to the restrictions in the Confidentiality Agreement between the parties.

If you have any questions, please give me a call at [redacted].

Best Regards,
Bob Brunner

From:	Farhat, Monica
To:	Wilson, Stuart; Sinclair, David
Cc:	Schram, Chuck; Hurst, Brian; Wang, Chung-Hsiao; Ryan, Samuel
Subject:	RE: RFP Material
Date:	Friday, June 14, 2013 2:21:28 PM
Attachments:	20130604_CaseNames&NPVRR_Base&LowLoad_0060D04.xlsx 20130604_CaseNames&NPVRR_AllCases_0060D05.xlsx

David,

I am attaching the two documents that Stuart mentioned in his previous email:

1. Updated NPVRR and ranks of the two iterations in Phase 4 for all three gas forecast, two carbon scenarios, and for base and low load.

2. Worksheet with all cases , all NPVRR values, and all rankings on one 11X16 piece of paper.

The top two alternatives have not changed: LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18), LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20).

Please let us know if you have any questions.

Monica

-----Original Message-----
From: Wilson, Stuart
Sent: Friday, June 14, 2013 9:53 AM
To: Sinclair, David
Cc: Schram, Chuck; Farhat, Monica; Hurst, Brian; Wang, Chung-Hsiao; Ryan, Samuel
Subject: RFP Material

David,

Later today, we're going to send you the following:

1. Updated version of material we distributed last Friday. One note... Phase 4 consists of two iterations. When we added the high load scenario to iteration 1, the number of cases in iteration 1 became too large. As a result, we removed the 1x1 CCGT cases from iteration 1 and added a single 1x1 CCGT case to iteration 2 (in combination with the best short-term alternative from iteration 1). I think this approach makes more sense from a process perspective. So, the updated material will contain all the relevant cases, but fewer 1x1 cases.
2. Worksheet with all cases (including the high load cases), all NPVRR values, and all rankings. I think all this will fit nicely on one 11X16 piece of paper.

Please let us know if you have any questions.

Stuart

-----Original Message-----
From: Schram, Chuck
Sent: Friday, June 14, 2013 8:56 AM
To: Wilson, Stuart
Subject: RFP Mtl

Thanks Stuart. After we talk we should let David know that this is coming:

1. Updated pkt that we distributed for last Friday's meeting.

2. A worksheet with all cases and NPVRR data.
3. A worksheet like #2 but with rankings instead of NPVRR values.

Sent from my iPhone

Rank	Alternative	*NPVRR ($000) in 2013 $* Average NPVRR All Cases	Versus Least Cost Option
1	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	31,425,872	0
2	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	31,436,185	10,313
3	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	31,443,532	17,660
4	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	31,446,521	20,649
5	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,458,001	32,129
6	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	31,461,412	35,540
7	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	31,464,961	39,089
8	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,477,935	52,064
9	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	31,478,253	52,381
10	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,479,501	53,629
11	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	31,483,507	57,635
12	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	31,493,277	67,405
13	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	31,494,596	68,724
14	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	31,495,211	69,339
15	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	31,495,331	69,459
16	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	31,496,569	70,698
17	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,500,727	74,855
18	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,517,783	91,912
19	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	31,519,623	93,751
20	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	31,520,354	94,482
21	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT	31,578,006	152,134
22	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	31,590,372	164,500
23	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,615,870	189,998
24	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	31,621,182	195,310
25	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	31,645,457	219,585
26	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	31,947,057	521,185
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	32,144,975	719,103

NPVRR ($000) in 2013 $

Rank	Alternative	Carbon Probability	Average NPVRR All Cases	Versus Least Cost Option
1	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	20%	27,405,217	0
2	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT	20%	27,405,218	0
3	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	20%	27,425,728	20,511
4	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	20%	27,431,821	26,604
5	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	20%	27,439,168	33,951
6	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	20%	27,453,637	48,420
7	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	20%	27,457,048	51,831
8	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	20%	27,460,597	55,379
9	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	20%	27,462,852	57,635
10	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	20%	27,471,760	66,543
11	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	20%	27,473,572	68,354
12	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	20%	27,473,889	68,672
13	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	20%	27,474,677	69,459
14	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	20%	27,475,347	70,130
15	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	20%	27,475,777	70,560
16	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	20%	27,488,913	83,696
17	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	20%	27,490,232	85,015
18	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	20%	27,490,847	85,630
19	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	20%	27,496,573	91,356
20	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	20%	27,498,830	93,613
21	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	20%	27,513,420	108,202
22	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	20%	27,515,990	110,772
23	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	20%	27,556,472	151,255
24	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	20%	27,597,155	191,938
25	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	20%	27,611,671	206,454
26	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	20%	27,650,287	245,070
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	20%	27,873,466	468,249

Rank	Alternative	NPVRR ($000) in 2013 $ Medium Gas Base Load Zero Carbon	Versus Least Cost Option
1	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	26,652,664	0
2	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	26,714,411	61,747
3	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	26,774,999	122,335
4	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	26,838,605	185,941
5	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	26,857,533	204,869
6	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	26,861,363	208,699
7	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	26,871,197	218,533
8	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	26,877,094	224,430
9	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26,879,755	227,091
10	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26,891,369	238,705
11	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	26,893,031	240,367
12	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26,893,443	240,779
13	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	26,894,536	241,872
14	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	26,902,065	249,401
15	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	26,906,279	253,615
16	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	26,908,959	256,295
17	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	26,911,111	258,447
18	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	26,916,914	264,250
19	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	26,920,163	267,499
20	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,923,053	270,389
21	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	26,931,113	278,449
22	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,932,490	279,826
23	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	26,943,496	290,832
24	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	26,956,448	303,784
25	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	27,028,373	375,709
26	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	27,030,216	377,552
27	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	27,105,694	453,030

Rank	Alternative	*NPVRR ($000) in 2013 $* Average NPVRR Zero Carbon	Versus Least Cost Option
1	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,557,696	0
2	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,623,618	65,922
3	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	24,661,512	103,816
4	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	24,681,928	124,233
5	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,699,232	141,536
6	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	24,706,580	148,884
7	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	24,718,159	160,463
8	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	24,719,147	161,451
9	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,721,048	163,353
10	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,724,459	166,763
11	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,728,008	170,312
12	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	24,730,971	173,275
13	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	24,731,977	174,282
14	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,740,983	183,287
15	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,741,301	183,605
16	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,742,901	185,205
17	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	24,755,030	197,335
18	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,756,325	198,629
19	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	24,757,643	199,947
20	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,758,258	200,562
21	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,764,127	206,431
22	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,780,831	223,135
23	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	24,783,401	225,705
24	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	24,803,728	246,032
25	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	24,851,149	293,453
26	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,879,195	321,499
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	24,958,577	400,881

Rank	Alternative	*NPVRR ($000) in 2013 $* Average NPVRR Medium Carbon	Versus Least Cost Option
1	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	38,173,138	0
2	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	38,180,485	7,347
3	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	38,190,232	17,095
4	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,194,954	21,816
5	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	38,198,364	25,227
6	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	38,201,913	28,776
7	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	38,211,113	37,975
8	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,214,888	41,751
9	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,215,206	42,068
10	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,216,102	42,964
11	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	38,230,230	57,093
12	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,231,548	58,411
13	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,232,164	59,026
14	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,237,328	64,190
15	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	38,247,868	74,730
16	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,254,736	81,599
17	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	38,257,306	84,169
18	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	38,259,691	86,554
19	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	38,261,162	88,024
20	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	38,284,215	111,077
21	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,352,546	179,408
22	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	38,377,016	203,879
23	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	38,391,214	218,077
24	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,598,315	425,178
25	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,667,297	494,160
26	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	39,175,956	1,002,818
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	39,331,372	1,158,235

NPVRR ($000) in 2013 $ 6/14/2013

Alternative	Base Gas Base Load Zero Carbon	Base Gas Base Load Medium Carbon	Base Gas High Load Zero Carbon	Base Gas High Load Medium Carbon	Base Gas Low Load Zero Carbon	Base Gas Low Load Medium Carbon	High Gas Base Load Zero Carbon	High Gas Base Load Medium Carbon	High Gas High Load Zero Carbon	High Gas High Load Medium Carbon	High Gas Low Load Zero Carbon	High Gas Low Load Medium Carbon
LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	26,838,605	40,803,754	30,321,918	44,413,609	23,720,500	37,359,735	27,879,999	42,949,569	31,750,011	47,319,332	24,384,766	38,912,098
LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	26,857,533	40,770,969	30,373,683	44,409,837	23,736,739	37,319,232	27,940,696	42,905,083	31,847,817	47,316,022	24,455,325	38,860,377
LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	26,861,363	40,823,904	30,337,731	44,429,786	23,741,504	37,381,061	27,900,243	42,969,877	31,774,266	47,340,231	24,405,036	38,932,682
LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	26,871,197	40,784,633	30,394,082	44,430,235	23,755,179	37,337,672	27,962,011	42,926,398	31,875,680	47,343,886	24,481,250	38,886,301
LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26,879,755	40,793,192	30,395,335	44,431,488	23,758,540	37,341,032	27,963,271	42,927,658	31,869,984	47,338,189	24,476,852	38,881,903
Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	26,877,094	40,790,531	30,395,051	44,431,204	23,763,912	37,346,405	27,945,762	42,910,150	31,855,712	47,323,917	24,469,383	38,874,433
LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	26,893,031	40,806,468	30,415,345	44,451,499	23,776,592	37,359,085	27,984,198	42,948,585	31,897,460	47,365,665	24,502,389	38,907,439
Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	26,894,536	40,859,685	30,374,741	44,466,433	23,778,259	37,417,494	27,931,902	43,001,472	31,798,926	47,368,247	24,439,071	38,966,404
Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26,893,443	40,806,880	30,406,362	44,442,515	23,782,686	37,365,179	27,956,690	42,921,078	31,862,353	47,330,558	24,482,953	38,888,003
Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	26,902,065	40,815,501	30,423,514	44,459,667	23,790,778	37,373,271	27,984,323	42,948,711	31,896,734	47,364,939	24,508,251	38,913,301
Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26,891,369	40,805,605	30,411,824	44,444,277	23,784,612	37,367,048	27,955,646	42,918,904	31,861,000	47,328,356	24,483,013	38,888,470
Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	26,908,959	40,871,500	30,378,061	44,470,116	23,794,083	37,433,640	27,938,146	43,007,780	31,805,278	47,371,243	24,449,111	38,976,757
Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	26,906,279	40,871,428	30,387,293	44,478,984	23,790,728	37,429,963	27,944,266	43,013,836	31,812,542	47,381,863	24,451,347	38,978,679
Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	26,916,914	40,830,350	30,433,325	44,469,478	23,808,052	37,390,545	27,993,752	42,958,140	31,901,875	47,370,081	24,520,321	38,925,372
Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	26,911,111	40,824,547	30,428,230	44,464,383	23,797,105	37,379,597	27,982,698	42,947,085	31,891,975	47,360,180	24,503,948	38,908,998
Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	26,920,163	40,833,599	30,440,593	44,476,747	23,807,779	37,390,272	28,003,365	42,967,752	31,915,783	47,383,988	24,526,178	38,931,229
LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,923,053	40,837,289	30,441,591	44,474,044	23,801,927	37,384,363	28,009,456	42,972,713	31,915,188	47,382,543	24,519,598	38,925,055
Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	26,931,113	40,893,654	30,402,920	44,494,975	23,816,368	37,455,925	27,963,229	43,032,863	31,831,663	47,397,628	24,472,402	39,000,048
Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,932,490	40,845,926	30,447,263	44,483,416	23,821,483	37,403,976	28,001,699	42,966,086	31,906,795	47,375,001	24,525,004	38,930,055
Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	26,943,496	40,856,933	30,461,581	44,497,735	23,834,113	37,416,606	28,024,321	42,988,708	31,932,558	47,400,763	24,549,190	38,954,240
LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	27,105,694	40,938,842	30,409,929	44,572,982	23,782,150	37,569,130	28,061,723	43,091,425	31,935,568	47,531,029	24,399,425	39,004,194
LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	26,956,448	41,034,581	30,446,098	44,624,804	23,848,591	37,590,116	28,099,042	43,096,496	31,942,822	47,513,140	24,659,864	39,071,411
Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	27,030,216	40,943,071	30,546,426	44,585,080	23,919,685	37,501,886	28,088,960	43,055,309	31,991,381	47,467,169	24,619,127	39,024,174
LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	26,652,664	41,236,307	30,124,896	45,358,428	23,484,016	37,876,682	27,668,041	43,052,955	31,473,889	47,358,622	24,106,625	39,029,703
LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	26,714,411	41,302,255	30,190,972	45,409,768	23,551,627	37,944,209	27,735,220	43,121,363	31,536,399	47,422,599	24,171,767	39,094,561
Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	26,774,999	41,618,285	30,195,286	45,169,039	23,647,002	38,347,801	27,625,395	43,385,717	31,489,967	47,794,962	23,994,868	39,353,418
Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	27,028,373	41,778,387	30,418,474	45,352,216	23,894,621	38,454,924	27,856,967	43,541,338	31,750,765	47,973,229	24,277,524	39,501,703

Alternative	Base Gas Base Load Zero Carbon	Base Gas Base Load Medium Carbon	Base Gas High Load Zero Carbon	Base Gas High Load Medium Carbon	Base Gas Low Load Zero Carbon	Base Gas Low Load Medium Carbon	High Gas Base Load Zero Carbon	High Gas Base Load Medium Carbon	High Gas High Load Zero Carbon	High Gas High Load Medium Carbon	High Gas Low Load Zero Carbon	High Gas Low Load Medium Carbon
LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	4	5	4	2	4	6	5	10	4	2	5	9
LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	5	1	6	1	5	1	9	1	11	1	11	1
LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	6	10	5	3	6	11	6	14	6	7	7	15
LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	7	2	10	4	7	2	14	5	16	8	15	4
LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	9	4	12	6	8	3	16	6	15	6	14	3
Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	8	3	11	5	9	4	11	2	12	3	12	2
LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	11	7	17	9	10	5	18	8	19	12	18	7
Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	13	17	7	12	11	17	7	17	7	13	8	17
Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	12	8	14	7	13	7	13	4	14	5	16	5
Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	14	9	19	10	16	9	19	9	18	11	20	10

Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	10	6	16	8	14	8	12	3	13	4	17	6
Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	16	19	8	14	17	19	8	18	8	15	9	18
Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	15	18	9	17	15	18	10	19	9	17	10	19
Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	18	12	21	13	21	14	20	11	20	14	22	12
Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	17	11	20	11	18	10	17	7	17	10	19	8
Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	19	13	22	16	20	13	22	13	23	19	24	14
LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	20	14	23	15	19	12	23	15	22	18	21	11
Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	21	20	13	19	22	20	15	20	10	20	13	20
Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	22	15	25	18	23	15	21	12	21	16	23	13
Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	23	16	26	20	24	16	24	16	24	21	25	16
LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	27	21	15	21	12	22	25	23	25	25	6	21
LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	24	23	24	23	25	23	27	24	26	24	27	24
Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26	22	27	22	27	21	26	22	27	23	26	22
LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	1	24	1	26	1	24	2	21	1	9	2	23
LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	2	25	2	27	2	25	3	25	3	22	3	25
Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	3	26	3	24	3	26	1	26	2	26	1	26
Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	25	27	18	25	26	27	4	27	5	27	4	27

Low Gas Base Load Zero Carbon	Low Gas Base Load Medium Carbon	Low Gas High Load Zero Carbon	Low Gas High Load Medium Carbon	Low Gas Low Load Zero Carbon	Low Gas Low Load Medium Carbon	Average NPVRR Zero Carbon	Average NPVRR Medium Carbon	Average NPVRR All Cases	Versus Least Cost Option
23,745,251	35,795,355	26,163,530	38,225,321	21,399,948	33,320,882	26,244,948	39,899,962	33,072,455	0
23,777,292	35,833,816	26,187,801	38,240,854	21,427,807	33,349,348	26,289,410	39,889,504	33,089,457	17,003
23,762,983	35,818,371	26,177,115	38,228,390	21,420,441	33,340,781	26,264,520	39,918,343	33,091,431	18,977
23,757,582	35,814,106	26,175,988	38,229,042	21,412,258	33,333,799	26,298,359	39,898,452	33,098,406	25,951
23,798,907	35,855,430	26,207,223	38,260,276	21,448,965	33,370,506	26,310,981	39,911,075	33,111,028	38,574
23,818,644	35,875,167	26,232,758	38,285,811	21,471,959	33,393,500	26,314,475	39,914,569	33,114,522	42,067
23,778,809	35,835,333	26,195,022	38,248,076	21,433,028	33,354,569	26,319,542	39,919,635	33,119,589	47,134
23,808,061	35,858,165	26,224,679	38,286,470	21,463,051	33,383,985	26,301,470	39,956,484	33,128,977	56,522
23,837,287	35,893,810	26,250,589	38,303,642	21,492,837	33,414,378	26,329,467	39,929,560	33,129,514	57,059
23,803,145	35,859,668	26,221,990	38,275,042	21,459,242	33,380,783	26,332,227	39,932,320	33,132,274	59,819
23,843,562	35,896,858	26,264,068	38,321,331	21,499,203	33,419,725	26,332,700	39,932,286	33,132,493	60,038
23,820,710	35,876,097	26,234,941	38,286,215	21,480,855	33,401,195	26,312,238	39,966,060	33,139,149	66,695
23,819,079	35,869,183	26,236,369	38,298,160	21,474,126	33,395,059	26,313,559	39,968,573	33,141,066	68,611
23,820,288	35,876,811	26,238,321	38,291,374	21,478,620	33,400,162	26,345,719	39,945,813	33,145,766	73,311
23,849,655	35,906,178	26,262,264	38,315,317	21,501,342	33,422,884	26,347,592	39,947,685	33,147,639	75,184
23,818,749	35,875,273	26,235,954	38,289,007	21,473,315	33,394,857	26,349,098	39,949,192	33,149,145	76,690
23,840,328	35,893,624	26,257,255	38,314,518	21,490,399	33,410,921	26,355,422	39,955,008	33,155,215	82,760
23,843,900	35,899,288	26,259,001	38,310,276	21,503,170	33,423,510	26,335,974	39,989,796	33,162,885	90,431
23,875,281	35,931,804	26,288,625	38,341,678	21,529,027	33,450,569	26,369,741	39,969,835	33,169,788	97,333
23,846,330	35,902,854	26,264,270	38,317,323	21,502,955	33,424,497	26,373,202	39,973,295	33,173,249	100,794
23,919,986	35,940,334	26,298,173	38,339,184	21,553,387	33,718,172	26,385,115	40,078,366	33,231,740	159,286
23,937,332	36,033,635	26,342,505	38,438,608	21,605,615	33,521,047	26,426,480	40,102,649	33,264,564	192,110
23,980,715	36,032,234	26,398,663	38,462,585	21,636,465	33,558,599	26,467,960	40,070,012	33,268,986	196,531
23,852,362	36,394,824	26,180,449	39,419,611	21,582,467	33,999,421	26,125,045	40,414,061	33,269,553	197,099
23,918,902	36,461,134	26,246,683	39,489,934	21,649,778	34,080,260	26,190,640	40,480,676	33,335,658	263,203
24,269,482	37,219,502	26,661,685	39,481,997	21,997,207	35,131,011	26,295,099	40,833,526	33,564,312	491,858
24,481,889	37,445,512	26,887,980	39,693,149	22,212,087	35,266,369	26,534,298	41,000,759	33,767,528	695,074

Low Gas Base Load Zero Carbon	Low Gas Base Load Medium Carbon	Low Gas High Load Zero Carbon	Low Gas High Load Medium Carbon	Low Gas Low Load Zero Carbon	Low Gas Low Load Medium Carbon	Average NPVRR Zero Carbon	Average NPVRR Medium Carbon	Average NPVRR All Cases
1	1	1	1	1	1	3	3	1
4	4	5	4	4	4	5	1	2
3	3	3	2	3	3	4	6	3
2	2	2	3	2	2	7	2	4
6	6	7	6	6	6	9	4	5
9	10	10	8	9	9	12	5	6
5	5	6	5	5	5	13	7	7
8	7	9	10	8	8	8	15	8
14	15	16	14	15	15	14	8	9
7	8	8	7	7	7	15	10	10

16	16	20	19	16	16	16	9	11
13	12	11	9	13	13	10	16	12
11	9	13	13	11	11	11	17	13
12	13	14	12	12	12	18	11	14
19	19	19	17	17	17	19	12	15
10	11	12	11	10	10	20	13	16
15	14	17	16	14	14	21	14	17
17	17	18	15	19	18	17	20	18
21	20	22	21	20	20	22	18	19
18	18	21	18	18	19	23	19	20
23	21	23	20	21	23	24	22	21
24	23	24	22	23	21	25	23	22
25	22	25	23	24	22	26	21	23
20	24	4	24	22	24	1	24	24
22	25	15	26	25	25	2	25	25
26	26	26	25	26	26	6	26	26
27	27	27	27	27	27	27	27	27

From:	Freibert, Charlie
To:	Sinclair, David; Cocanougher, Beth; Brunner, Bob
Cc:	Freibert, Charlie
Subject:	FW: AEM"s RFP Proposal
Date:	Tuesday, June 18, 2013 6:34:26 PM
Attachments:	RFPAEM061813.doc

FYI

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Freibert, Charlie
Sent: Tuesday, June 18, 2013 6:34 PM
To: Dennis Beutler [redacted]
Cc: Freibert, Charlie
Subject: AEM's RFP Proposal

Hi Dennis,

We are in the process of wrapping up our analysis of the RFP proposals to determine the next steps in advancing towards the reasonably least cost solution to the Companies' future capacity needs. Attached is a deal structure that we would be interested in exploring. It would be helpful if you could let us know by Friday 6/21/13, if you are interested in negotiating with us to develop an agreement under the terms outlined in the attached documents. Please note that the attached document is for discussion purposes only, and is not an offer or a bid, and is subject to the restrictions in the Confidentiality Agreement between the parties.

If you have any questions, please give me a call.

Best Regards,

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From:	Freibert, Charlie
To:	Sinclair, David; Brunner, Bob; Schram, Chuck
Cc:	Freibert, Charlie
Subject:	AEM"s response
Date:	Tuesday, June 25, 2013 5:30:25 PM
Attachments:	LGEBeutlerProposalTollCoal(34)June25,2013.doc

Attached is the AEM response to our deal structure. Summary:

1. AEM accepted our exclusive rights to the first MWs of production
2. AEM put the start charge back in – 1430mmBtu*Gas Index;
3. AEM did not accept our capacity charges. AEM did shape the charges over the months but only provided a 8.3% decrease from the original capacity charges.
4. AEM addressed scheduling and ramping by forcing a minimum of 8 hours must take when scheduling 167MWs or 334MWs.
5. AEM added a new contingency "b)", that AEM or Dynegy must be able to retain the variance to the Illinois Multi-Pollutant Standard, that is, the variance to burn coal at Joppa with no additional pollution controls until 12/31/19.

We can discuss next steps later.
Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

This document outlines a proposed transaction between Ameren Energy Marketing Company and the companies of Louisville Gas and Electric and Kentucky Utilities for the sale of capacity and energy under the terms and conditions of a yet to be drafted Electric Service Agreement.

The terms of the transaction are as follows:

Date: June 25, 2013

Seller: Ameren Energy Marketing Company

Buyer: Louisville Gas and Electric Company and Kentucky Utilities Company

Term: January 1, 2016 through December 31, 2019

Product:

A. 1/1/2016 – 12/31/2017 - 167MW - System Firm capacity and System Firm energy

B. 1/1/2018 – 12/31/2019 - 334MW – System Firm capacity and System Firm energy

Buyer shall have exclusive rights to the first MWs of production from the System.

For purposes of this proposal, System shall be defined as the coal-fired units 1-6, totaling approximately, 1,002MW located at the Electric Energy Inc. plant near Joppa, Illinois (EEI). The System Firm capacity is owned or controlled by Seller for the length of the Term and shall not be sold to any other party. Seller shall deliver System Firm energy, when available, from one or more of the coal-fired units 1-6 located at EEI (Designated Network Resource). Seller retains the right to deliver energy from any of the System units.

Provided Buyer submits Day-Ahead Schedules in accordance with this proposal, Seller's failure to deliver shall only be excused: (i) by Buyer's failure to perform; (ii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on the System; (iii) to the extent the control area or reliability coordinator within which the System operates declares an emergency condition, as determined in the control area's or the reliability coordinator's reasonable judgment; (iv) by the interruption or curtailment of transmission to the Delivery Point; (v) by Force Majeure.

In the event of a Major Equipment Failure or like situation that prevents Seller from meeting its obligations, Seller is allowed to redefine the System. Such new definition of the System shall be limited to units located at EEI and shall also be contingent on Buyer being able to secure the transmission required to support the newly defined Designated Network Resource.

Technology:

Boilers: The boilers were designed as a natural circulation, balanced draft, sub-critical, radiant, reheat design type and are rated at 1.2MM lbs/hr with steam conditions of 1800 psig and 1055 degrees F. The burners are Low NOx Concentric Firing with Separated Over-fire Air on units 1, 3, 4, 5, and 6. Fuel is processed in type 673 Raymond Bowl Mills.

Turbines: The turbines are tandem compound, 3600 rpm, rated at 181MW gross. Each turbine is an F2 design with single HP, IP/LP and single double flow LP. Excitation is provided by an external motor generator set with a spare exciter that can be hot swapped with any of the units. Each unit is equipped with three single phase generator step up transformers and one auxiliary transformer.

Guaranteed Heat Rate (GHR): 10,501 BTU/KWh

Start Charge (SC): SC = (1,430 mmBtu * Gas Index)

Buyer shall only be charged for the actual System unit starts required to support Buyer's Day-Ahead Schedule.
For the purpose of clarity, Buyer is not responsible for a SC if the System units are already on-line regardless of the Day-Ahead Schedule.

Gas Index: Platt's Gas Daily / Daily Price Survey Midpoint / MichCon City-gate

Capacity Charge (MCC): Buyer shall pay to Seller a Monthly Capacity Payment (MCP) based upon the Monthly Capacity Charges (MCC) identified in the table below.

January	February	March	April	May	June
$11.94/KW-month	$11.94/KW-month	$9.24/KW-month	$9.24/KW-month	$9.24/KW-month	$10.10/KW-month
July	August	September	October	November	December
$11.94/KW-month	$11.94/KW-month	$11.94/KW-month	$9.24/KW-month	$9.24/KW-month	$10.10/KW-month

The monthly delivery factor shall be mega-watt hours delivered (MWD) divided by mega-watt hours scheduled (MDF).

MWD / MWS = MDF

In the event Buyer schedules zero (0) megawatt-hours in any month of the Term, then the MDF shall equal one (1).

The monthly capacity payment (MCP) shall be calculated as follows:
If the MDF is greater than or equal to .96 then: MCP = MCC * 1000 * Product capacity
If the MDF is less than .96 then: MCP = MDF * MCC * 1000 * Product capacity

Energy Charge and: MWh delivered * (((Coal Index + Transportation Charge) / 17.60) * (GHR/1,000)) + (VO&M * MWh delivered) + (SC * number of actual starts required to support Buyer's Day-Ahead Schedule)

Coal Index: Final Monthly Average Price will be fixed on a monthly basis utilizing the OTC Broker Index for PRB – 8,800 Btu/lbm final monthly average price ("Index Price") obtained from Platts Coal Trader (or its successor), plus $0.25 per ton. The index price settles on the 25th date of the month prior to the contract delivery month and is published on or after the 26th day of the month prior to delivery. In addition, there will be a per ton SO_2 adjustment to be calculated as follows:

Targeted Sulfur Dioxide Value – 0.50 lbs. SO_2 per million Btu.
Adjustment Period for the sulfur dioxide value adjustment shall be monthly.

Actual SO_2 shall be used in the Sulfur Dioxide Value Adjustment formula below to determine a per ton adjustment to account for the variation:

$$\text{\$ Per Ton } SO_2 \text{ Adjustment} = \frac{(C - S) \times A \times ADI}{1{,}000{,}000}$$

Where: A = Actual Btu of the Coal delivered in the relevant adjustment period

C = 0.80 lbs. SO_2/mmBtu (OTC Broker Index nominal Sulfur Dioxide Value).

S = Actual SO_2 content of the Coal delivered in the relevant adjustment period (expect to achieve 0.5).

ADI = Argus Air Daily Index: the monthly value of the Argus Air Daily SO_2 Allowance Index (as published in Argus Coal Daily, or its successor) arithmetically averaged over the relevant Adjustment Period (expressed as $/allowance SO_2).

* **Note:** For deliveries received through 2014, the SO2 Adjustment shall be multiplied by two (2) to account for changes implemented on January 1, 2010 in the Clean Air Interstate Rules (CAIR) where two (2) SO2 allowances are required for every one ton of SO2 emitted. For deliveries received after 2014, the SO2 adjustment shall be multiplied by 2.86 to account for changes implemented on January 1, 2010 in the CAIR, where 2.86 SO2 allowances are required for every ton of SO2 emitted. The above provisions for the multipliers shall not be applicable if CAIR rules or any other rule of regulation in effect at the time of deliveries effectively changes the number of SO2 allowances required for every ton of SO2 emitted. After executing this Agreement, in the event the SO2 price index published in Argus Air Daily is changed, or the CAIR rules are modified to change the number of SO2 allowances required for every ton of SO2 emitted, both parties agree to negotiate, in good faith, a new index and/or multiplier that reflects the intent of the current CAIR rules.

Transportation Charge (TC): The Transportation Charge shall be the actual, total cost of transport required to deliver coal to the System.

The current coal transportation contract expires on December 31, 2017

Variable Operations And Maintenance (VO&M) Charge: The VO&M charge shall be in accordance with Table B below.

Table B

Year	2016	2017	2018	2019
$/MWh	$2.69	$2.73	$2.78	$2.84

Delivery Point: EEI/LGE interface or its successor

Transmission: Seller is responsible for all charges associated with delivery of energy to the Delivery Point. Buyer is responsible for all charges associated with delivery of energy at and from the Delivery Point.

Scheduling Requirements: Each Friday of the Term or the last Business Day prior if Friday is a NERC holiday, no later than 15:00 Eastern Standard Time, Buyer shall submit an energy forecast to Seller specifying the amounts of energy that Buyer anticipates it will purchase the following week (Weekly Forecast).

Additionally, Buyer shall submit an energy schedule to Seller, in whole megawatts, in an agreed upon format no later than one hundred twenty (120) minutes prior to the day-ahead deadlines imposed by the Midcontinent Independent System Operator, Inc. (MISO), specifying for each hour of the applicable day, the amounts of energy Buyer will purchase from Seller (Day-Ahead Schedule).

For Product A: Buyer is allowed to schedule 0MW or 167MW. Buyer is not allowed to schedule any other quantity in the Day-Ahead Schedule. In the event Buyer schedules 167MW in any hour of the Day-Ahead Schedule, then Buyer must schedule 167MW for a continuous eight (8) hour period (First Continuous Period Requirement). After meeting the First Continuous Period Requirement, Buyer is allowed to reduce the quantities of the Day-Ahead Schedule to 0MW. In the event Buyer reduces the quantities in the Day-Ahead Schedule to 0MW, then Buyer is no longer allowed to schedule any other quantities for the remainder of the Day-Ahead Schedule.

For Product B: Buyer is allowed to schedule 0MW or 167MW or 334MW. Buyer is not allowed to schedule any other quantity in the Day-Ahead Schedule. In the event Buyer schedules 167MW in any hour of the Day-Ahead Schedule, then Buyer must meet the First Continuous Period Requirement. Additionally, Buyer is allowed to schedule 334MW. In the event Buyer schedules 334MW in any hour of the Day-Ahead Schedule, Buyer must schedule 334MW for a continuous eight (8) hour period (Second Continuous Period Requirement). After meeting the First Continuous Period Requirement and/or the Second Continuous Period Requirement, as applicable, Buyer is allowed to reduce the quantities of the Day-Ahead Schedule to 0MW. In the event Buyer reduces the quantities in the Day-Ahead Schedule to 0MW, then Buyer is no longer allowed to schedule any other quantities for the remainder of the Day-Ahead Schedule.

Environmental: Seller is responsible for obtaining all necessary Permits and providing all credits and allowances necessary to comply with permit requirements for the Term.

System O & M: Seller, in its sole discretion, shall manage all aspects of System operations and maintenance in accordance with good utility practices and the concept of optimizing the market position of the System.

Operating Committee: An operating committee shall be established by the Parties as a means of securing effective cooperation and interchange of information and of providing consultation on a prompt and orderly basis between the Parties in connection with the Electric Service Agreement.

Confidentiality: All terms and conditions described in this proposal are considered proprietary and confidential information that shall only be disclosed to Seller and Buyer, their respective affiliates, representatives and duly appointed agents, unless disclosure is otherwise required by any laws, rules or regulations. The terms and conditions herein shall not be disclosed to third parties without the written consent of Buyer and Seller.

Contingencies And Acceptance:

THE PARTIES UNDERSTAND AND AGREE THAT UNTIL A DEFINITIVE AGREEMENT HAS BEEN EXECUTED AND DELIVERED, NO CONTRACT, OR AGREEMENT PROVIDING FOR A TRANSACTION AMONG THE PARTIES SHALL BE DEEMED TO EXIST AMONG THE PARTIES AND NO PARTY WILL BE UNDER ANY LEGAL OBLIGATION OF ANY KIND WHATSOEVER WITH RESPECT TO THIS PROPOSAL BY VIRTUE OF THIS OR ANY WRITTEN OR ORAL EXPRESSION THEREOF. THIS PROPOSAL NEITHER OBLIGATES A PARTY TO DEAL EXCLUSIVELY WITH THE OTHER PARTY NOR PREVENTS A PARTY OR ANY OF ITS AFFILIATES FROM COMPETING WITH ANOTHER PARTY OR ANY OF ITS AFFILIATES.

THIS PROPOSAL IS CONTINGENT UPON:

a) BOTH BUYER AND SELLER RECEIVING ALL REQUISITE APPROVALS, INCLUDING SELLER'S APPROVAL FROM THE AMEREN RISK MANAGEMENT STEERING COMMITTEE;

AND

b) SELLER, OR SELLER'S SUCCESSOR, BEING ABLE TO RETAIN VARIANCE RELIEF FROM ILLINOIS' MULTI-POLLUTANT STANDARD GRANTED BY THE ILLINOIS POLLUTION CONTROL BOARD;

AND

c) THE PARTIES NEGOTIATING AN ACCEPTABLE PURCHASE POWER AGREEMENT, INCLUDING APPROPRIATE CREDIT DOCUMENTS AND ALL NECESSARY REPRESENTATIONS AND COVENANTS TO CONFIRM THE STATUS OF THE PURCHASE POWER AGREEMENT AS A NON-FINANCIAL COMMODITY FORWARD CONTRACT, EXCLUDED FROM THE DEFINITION OF "SWAP" UNDER THE COMMODITY FUTURES TRADING COMMISSION REGULATIONS AND INTERPRETATIONS;

AND

d) TRANSMISSION AVAILABILITY

AND

e) REGULATORY APPROVAL

Name:____________________________________

Title:____________________________________

From:	Brunner, Bob
To:	Sinclair, David
Subject:	FW: AEM 1/16/13 offer
Date:	Wednesday, June 26, 2013 9:52:53 AM
Attachments:	LGEBeutlerProposalTollCoal(29)January16,2013.doc

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From: Freibert, Charlie
Sent: Wednesday, June 26, 2013 9:50 AM
To: Brunner, Bob
Cc: Freibert, Charlie
Subject: AEM 1/16/13 offer

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

This document outlines a proposed transaction between Ameren Energy Marketing Company and the companies of Louisville Gas and Electric and Kentucky Utilities for the sale of capacity and energy under the terms and conditions of a yet to be drafted Electric Service Agreement.

The terms of the transaction are as follows:

Date: January 16, 2013

Seller: Ameren Energy Marketing Company

Buyer: Louisville Gas and Electric Company and Kentucky Utilities Company

Term: January 1, 2015 through December 31, 2019

Product: 334MW - System Firm capacity and System Firm energy / quantities are negotiable.

For purposes of this proposal, System shall be defined as thirty-three percent (33%) of the coal-fired units 1-6, totaling approximately, 1,002MW located at the Electric Energy Inc. plant near Joppa, Illinois (EEI). The System Firm capacity is owned or controlled by Seller for the length of the Term and shall not be sold to any other party. Seller shall deliver System Firm energy, when available, from one or more of the coal-fired units 1-6 located at EEI (Designated Network Resource). For purposes of clarity, Seller retains the right to deliver energy from any of the units identified in the System.

Provided Buyer submits Day-Ahead Schedules in accordance with this proposal, Seller's failure to deliver shall only be excused: (i) by Buyer's failure to perform; (ii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on the System; (iii) to the extent the control area or reliability coordinator within which the System operates declares an emergency condition, as determined in the control area's or the reliability coordinator's reasonable judgment; or (iv) by the interruption or curtailment of transmission to the Delivery Point; (v) by Force Majeure; (vi) because of unit de-rates and/or unit forced outages.

In the event of a Major Equipment Failure or like situation that prevents Seller from meeting its obligations, Seller is allowed to redefine the System. Such new definition of the System shall be limited to units located at EEI and shall also be contingent on Buyer being able to secure the transmission required to support the newly defined Designated Network Resource.

At Buyer's expense, Seller is willing to allow the installation of communications links required to provide Buyer with automatic generation control; such automatic generation control shall be within predetermined limits defined by Operational Requirements (AGC). In the event Buyer elects to install AGC, then the Parties understand and agree that a more detailed discussion is warranted regarding Operational Requirements, including, but not limited to, System dispatch, ancillary services, and delivery point.

Technology: Boilers: The boilers were designed as a natural circulation, balanced draft, sub-critical, radiant, reheat design type and are rated at 1.2MM lbs/hr with steam conditions of 1800 psig and 1055 degrees F. The burners are Low NOx Concentric Firing with Separated Over-fire Air on units 1, 3, 4, 5, and 6. Fuel is processed in type 673 Raymond Bowl Mills.

Turbines: The turbines are tandem compound, 3600 rpm, rated at 181MW gross. Each turbine is an F2 design with single HP, IP/LP and single double flow LP. Excitation is provided by an external motor generator set with a spare exciter that can be hot swapped with any of the units. Each unit is equipped with three single phase generator step up transformers and one auxiliary transformer.

Guaranteed Heat Rate (GHR): For the purpose of calculating the Energy Charge, Seller shall utilize heat rates in accordance with Table A below.

Table A

Net MW	Net Plant Heat Rate Btu/kWh	Net MW	Net Plant Heat Rate Btu/kWh	Net MW	Net Plant Heat Rate Btu/kWh	Net MW	Net Plant Heat Rate Btu/kWh
47-56	12,364	57-66	12,013	67-76	11,696	77-86	11,416
87-96	11,171	97-106	10,962	107-116	10,789	117-126	10,652
127-136	10,550	137-146	10,485	147-156	10,458	157-167	10,501
168-177	11,241	178-187	11,127	188-197	11,022	198-207	10,925
208-217	10,838	218-227	10,759	228-237	10,689	238-247	10,629
248-257	10,577	258-267	10,534	268-277	10,500	278-287	10,476
288-297	10,460	298-307	10,454	308-317	10,463	318-327	10,486
328-334	10,501						

Start Charge (SC): SC = (1,430 mmBtu * Gas Index)
Buyer shall only be charged for unit starts required to support Buyer's Day-Ahead Schedule.

Gas Index: Platt's Gas Daily / Daily Price Survey Midpoint / MichCon City-gate

Capacity Charge and Payment: The monthly capacity charge shall be: $11,458.00 / MW – month (MCC)

The monthly delivery factor shall be mega-watt hours delivered (MWD) divided by mega-watt hours scheduled. (MDF)

MWD / MWS = MDF

The monthly capacity payment (MCP) shall be calculated as follows:

If the MDF is greater than or equal to .96 then:	MCP = MCC
If the MDF is greater than or equal to .70 and less than .96 then:	MCP = (MDF + .04) * MCC
If the MDF is less than .70 then:	MCP = MDF * MCC

Energy Charge and Payment: MWh delivered * (((Coal Index + Transportation Charge) / 17.60) * (GHR)) + (VO&M * MWh delivered) + (SC * number of successful starts required to support Buyer's Day-Ahead Schedule)

Coal Index: Final Monthly Average Price will be fixed on a monthly basis utilizing the OTC Broker Index for PRB – 8,800 Btu/lbm final monthly average price ("Index Price") obtained from Platts Coal Trader (or its successor), plus $0.25 per ton. The index price settles on the 25th date of the month prior to the contract delivery month and is published on or after the 26th day of the month prior to delivery. In addition, there will be a per ton SO_2 adjustment to be calculated as follows:

Targeted Sulfur Dioxide Value – 0.50 lbs. SO_2 per million Btu.
Adjustment Period for the sulfur dioxide value adjustment shall be monthly.

Actual SO_2 shall be used in the Sulfur Dioxide Value Adjustment formula below to determine a per ton adjustment to account for the variation:

$$\$ \text{ Per Ton } SO_2 \text{ Adjustment} = \frac{(C - S) \times A \times ADI}{1{,}000{,}000}$$

Where: A = Actual Btu of the Coal delivered in the relevant adjustment period

C = 0.80 lbs. SO_2/mmBtu's (OTC Broker Index nominal Sulfur Dioxide Value).

S = Actual SO_2 content of the Coal delivered in the relevant adjustment period (expect to achieve 0.5).

ADI = Argus Air Daily Index: the monthly value of the Argus Air Daily SO_2 Allowance Index (as published in Argus Coal Daily, or its successor) arithmetically averaged over the relevant Adjustment Period (expressed as $/allowance SO_2).

* **Note:** For deliveries received through 2014, the SO2 Adjustment shall be multiplied by two (2) to account for changes implemented on January 1, 2010 in the Clean Air Interstate Rules (CAIR) where two (2) SO2 allowances are required for every one ton of SO2 emitted. For deliveries received after 2014, the SO2 adjustment shall be multiplied by 2.86 to account for changes implemented on January 1, 2010 in the CAIR, where 2.86 SO2 allowances are required for every ton of SO2 emitted. The above provisions for the multipliers shall not be applicable if CAIR rules or any other rule of regulation in effect at the time of deliveries effectively changes the number of SO2 allowances required for every ton of SO2 emitted. After executing this Agreement, in the event the SO2 price index published in Argus Air Daily is changed, or the CAIR rules are modified to change the number of SO2 allowances required for every ton of SO2 emitted, both parties agree to negotiate, in good faith, a new index and/or multiplier that reflects the intent of the current CAIR rules.

Seller is willing to purchase coal in the quantities and term as directed by Buyer (Coal Purchase). Seller retains the absolute right to select the type and quality of the Coal Purchase. Buyer assumes all responsibility for the costs of such Coal Purchase.

Transportation

Charge (TC): The Transportation Charge shall be the actual, total cost of transport required to deliver coal to the Unit.

The current coal transportation contract expires on December 31, 2017

Variable Operations And Maintenance (VO&M) Charge: The VO&M charge shall be in accordance with Table B below.

Table B

Year	2015	2016	2017	2018	2019
$/MWh	$2.61	$2.69	$2.73	$2.78	$2.84

Delivery Point: EEI/LGE interface or its successor

Transmission: Seller is responsible for all charges associated with delivery of energy to the Delivery Point. Buyer is responsible for all charges associated with delivery of energy at and from the Delivery Point.

Scheduling and Dispatch: Each Friday of the Term or the last Business Day prior if Friday is a NERC holiday, no later than 09:00 Eastern Standard Time, Buyer shall submit an energy forecast to Seller specifying the amounts of energy that Buyer anticipates it will purchase the following week (Weekly Forecast).

Additionally, Buyer shall submit an energy schedule to Seller, in whole mega-watts, in an agreed upon format, specifying for each hour of the applicable day, the amounts of energy Buyer will purchase from Seller, no later than 09:00 Eastern Standard Time the last Business Day prior to the delivery day (Day-Ahead Schedule).

The minimum quantity for any hour of the Weekly Forecast and/or the Day-Ahead Schedule shall be 47MW. In the event, Buyer exceeds 155MW during any hour of the Weekly Forecast and/or the Day-Ahead Schedule, then the minimum quantity for all of the remaining hours of the Weekly Forecast and/or the Day-Ahead Schedule shall be 91MW. In the event Buyer exceeds 325MW during any hour of the Weekly Forecast and/or the Day-Ahead Schedule, then the minimum quantity for all of the remaining hours of the Weekly Forecast and/or the Day-Ahead Schedule shall be 139MW. The maximum quantity for any hour of the Weekly Forecast and/or the Day-Ahead Schedule shall be 334MW. Unless otherwise agreed to by Seller, Buyer shall not increase or decrease the quantity of energy Buyer schedules from one hour to the next hour in an amount greater than 60MW.

Environmental: Seller is responsible for obtaining all necessary Permits and providing all credits and allowances necessary to comply with permit requirements for the Term.

System O & M: Seller, in its sole discretion, shall manage all aspects of System operations and maintenance in accordance with good utility practices and the concept of optimizing the market position of the System.

Operating Committee: An operating committee shall be established by the Parties as a means of securing effective cooperation and interchange of information and of providing consultation on a prompt and orderly basis between the Parties in connection with the Electric Service Agreement.

Confidentiality: All terms and conditions described in this proposal are considered proprietary and confidential information that shall only be disclosed to Seller and Buyer, their respective affiliates, representatives and duly appointed agents, unless disclosure is otherwise required by any laws, rules or regulations. The terms and conditions herein shall not be disclosed to third parties without the written consent of Buyer and Seller.

Contingencies And Acceptance: **THE PARTIES UNDERSTAND AND AGREE THAT UNTIL A DEFINITIVE AGREEMENT HAS BEEN EXECUTED AND DELIVERED, NO CONTRACT, OR AGREEMENT PROVIDING FOR A TRANSACTION AMONG THE PARTIES SHALL BE DEEMED TO EXIST AMONG THE PARTIES AND NO PARTY WILL BE UNDER ANY LEGAL OBLIGATION OF ANY KIND WHATSOEVER WITH RESPECT TO THIS PROPOSAL BY VIRTUE OF THIS OR ANY WRITTEN OR ORAL EXPRESSION THEREOF. THIS PROPOSAL NEITHER OBLIGATES A PARTY TO DEAL EXCLUSIVELY WITH THE OTHER PARTY NOR PREVENTS A PARTY OR ANY OF ITS AFFILIATES FROM COMPETING WITH ANOTHER PARTY OR ANY OF ITS AFFILIATES.**

THIS PROPOSAL IS CONTINGENT UPON BOTH BUYER AND SELLER RECEIVING ALL REQUISITE APPROVALS, INCLUDING SELLER'S APPROVAL FROM THE AMEREN RISK MANAGEMENT STEERING COMMITTEE.

Name:______________________________________

Title:______________________________________

From: Wilson, Stuart
To: Sinclair, David
Cc: Schram, Chuck
Subject: External RFP Response Details
Date: Wednesday, June 26, 2013 9:13:51 AM
Attachments: 20121206_ExternalRFPSummaryStats_0060.xlsx

David,

I've attached details regarding the external RFP responses. Also, the DSM programs are as follows:

1. Lighting
2. Thermostat Rebates
3. Windows & Doors
4. Manufactured Homes
5. Behavioral Thermostat Pilot
6. Commercial New Construction
7. Automated Demand Response (ADR)

With the exception of ADR, the demand reduction for all programs is less than 5 MW. The demand reduction for ADR is ultimately 15-20 MWs. Commercial New Construction was the most competitive option.

Stuart

Copied from Phase 1 Screening model (D09). Note change to 22A. WORD table is at bottom of this sheet.

Response	Counterparty	Class	Technology	Description	Asset Location	Fuel Considerations	Escalators	XM Interconnect Point (TIP)	Contract Start Date	Term or Book Life (Years)	Capacity @ TIP	XM Losses	Delivered Capacity	Base Year for Quote	Unique Asset	Fuel Type	New/Existing	In/Out	Capacity @ TIP
1A	ERORA	CCCT (2X1)_10	CCCT (2x1), GE	10 yr PPA,	Henderson, KY	ANR	BLS Employ	Davies Cty	1/1/2016	10.0	700	0%	700	2016	1	Gas	New	In-State	700
1B	ERORA	CCCT (2X1)_20	CCCT (2x1), GE	20 yr PPA,	Henderson, KY	ANR	BLS Employ	Davies Cty	1/1/2016	20.0	700	0%	700	2016	0				0
1C	ERORA	CCCT (2X1)_Own	CCCT (2x1), GE	Asset Sale,	Henderson, KY	ANR	BLS Employ	Davies Cty	1/1/2016	40.0	700	0%	700	2016	0				0
2	AEP	Coal_10	Portfolio	11 yr PPA,	PJM			AEP Gen Hu	1/1/2015	11.0	700	0%	700	2015	1	Portfolio	Existing	Out-of-Stat	700
3	TPF Generation	SCCT_Own	SCCT	Asset Sale,	Bristol, VA	East Tennessee Pipelin		CONSTELL	TBD	16.0	245	0%	245	2015	1	Gas	Existing	Out-of-Stat	245
4A	Big Rivers	Coal_5	Coal	1-15 yr PPA	Centertown, KY		CPI-U	BREC.WILS	TBD	5.0	417	2.5%	407	2015	1	Coal	Existing	In-State	417
4B	Big Rivers	Coal_10	Coal	1-15 yr PPA	Centertown, KY		CPI-U	BREC.WILS	TBD	10.0	417	2.5%	407	2015	0				0
5A	Quantum Choctaw Power	CCCT (2X1)_20	CCCT (2x1), Siemens	20-35 yr PF	Ackerson, MS	Texas Eastern XM Pipe		Ackerson, I	1/1/2015	20.0	701	3%	680	2013	1	Gas	Existing	Out-of-Stat	701
5B	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	Asset Sale,	Ackerson, MS	Texas Eastern XM Pipe		Ackerson, I	1/1/2015	32.0	701	3%	680	2015	0				0
5C	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	20-35 yr PF	Ackerson, MS	Texas Eastern XM Pipe		Ackerson, I	1/1/2015	32.0	701	3%	680	2013	0				0
5D	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 7	Ackerson, MS	Texas Eastern XM Pipe		Ackerson, I	1/1/2015	5.0	701	3%	680	2013	0				0
5E	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 7	Ackerson, MS	Texas Eastern XM Pipe		Ackerson, I	1/1/2016	5.0	701	3%	680	2013	0				0
5F	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 7	Ackerson, MS	Texas Eastern XM Pipe		Ackerson, I	1/1/2014	6.0	701	3%	680	2013	0				0
6A	Calpine	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, D	Decatur, AL	Tennesse G	GDP-IPD	Trinity/Lim	1/1/2015	5.0	500	3%	485	2015	1	Gas	Existing	Out-of-Stat	500
6B	Calpine	CCCT (1X1)_5	CCCT (1x1), Siemens	5 yr PPA, D	Decatur, AL	Tennesse G	GDP-IPD	Trinity/Lim	1/1/2015	5.0	250	3%	243	2015	1	Gas	Existing	Out-of-Stat	250
7A	Ameren	Coal_5	Coal	5 yr PPA, 6	Joppa, IL	OTC Broker Index for P		EEI/LGE Int	1/1/2015	5.0	668	0%	668	2015	1	Coal	Existing	Out-of-Stat	668
7B	Ameren	Coal_10	Coal	10 yr PPA,	Joppa, IL			EEI/LGE Int	1/1/2015	10.0	668	0%	668	2015	0				0
7C	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA,	Joppa, IL			EEI/LGE Int	1/1/2015	10.0	668	0%	668	2015	0				0
7D	Ameren	Coal_10	Portfolio (Coal and NG)	10 yr PPA,	Joppa, IL			EEI/LGE Int	1/1/2015	10.0	700	0%	700	2015	0				0
7E	Ameren	Coal_10	Portfolio (NG) w/ Coal-to-NG Conv.	10 yr PPA,	Joppa, IL			EEI/LGE Int	1/1/2015	10.0	700	0%	700	2015	0				0
7F	Ameren	SCCT_5	SCCT	5 yr PPA, 5	Joppa, IL	Platt's Gas Daily / Daily		EEI/LGE Int	1/1/2015	5.0	222	0%	222	2015	1	Gas	Existing	Out-of-Stat	222
7G	Ameren	Coal_5	Coal	5 yr PPA, 3	Joppa, IL	OTC Broker Index for P		EEI/LGE Int	1/1/2015	5.0	334	0%	334	2015	0				0
7H	Ameren	Coal_10	Coal	10 yr PPA,	Joppa, IL			EEI/LGE Int	1/1/2015	10.0	334	0%	334	2015	0				0
7I	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA,	Joppa, IL			EEI/LGE Int	1/1/2015	10.0	334	0%	334	2015	0				0
7J	Ameren	Coal_5	Coal	5 yr PPA, 5	Joppa, IL	OTC Broker Index for P		EEI/LGE Int	1/1/2015	5.0	501	0%	501	2015	0				0
8	Paducah Power Systems	SCCT_5	SCCT	5 yr PPA, 2	Paducah, KY	TGT Zone 1		LGEE-PPS1	1/1/2015	5.0	26	0%	26	2015	1	Gas	Existing	In-State	26
9A	Agile	SCCT_Own	NG-Fired Recip Engine	Asset Sale,	Muhlenburg Cnty, KY		CPI	KU Sub in M	6/1/2016	30.0	112.9	0%	113	2016	1	Gas	New	In-State	112.9
9B	Agile	SCCT_20	NG-Fired Recip Engine	20 yr Tollin	Muhlenburg Cnty, KY		CPI	KU Sub in M	6/1/2016	20.0	112.9	0%	113	2016	0				0
10	KMPA	RTC	Coal, Base Load	5 yr PPA, 2	Paducah, KY			AMIL, MISC	1/1/2015	5.0	25	0%	25	2015	1	Coal	Existing	In-State	25
11A	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA,	Murdock, IL	Panhandle Eastern Pip		Murdock, I	1/1/2015	22.0	746	3%	727	2016	1	Gas	New	Out-of-Stat	746
11B	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL	Panhandle Eastern Pip		Murdock, I	1/1/2015	22.0	746	3%	727	2016	0				0
11C	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL	Panhandle Eastern Pip		Murdock, I	1/1/2015	22.0	746	3%	727	2016	0				0
11D	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA,	LGE/KU Service Territory	LGE Gas; TGT		Kentucky	1/1/2015	22.0	746	0%	746	2016	1	Gas	New	In-State	746
11E	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	LGE/KU Service Territory	LGE Gas; TGT		Kentucky	1/1/2015	22.0	746	0%	746	2016	0				0
11F	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	LGE/KU Service Territory	LGE Gas; TGT		Kentucky	1/1/2015	22.0	746	0%	746	2016	0				0
12	Exelon Generation Company	RTC	Firm Physical Energy	10 yr PPA,	Indiana			Indiana Hu	1/1/2015	10.0	200	3%	195	2015	1	Portfolio	Existing	Out-of-Stat	200
13	CPV Smyth Generation Co.	CCCT (2X1)_20	CCCT (2X1), Alstom	20 yr PPA,	Smyth Cnty, VA	East Tenne	CPI, CPI-U (	Smyth Cou	6/1/2017	20.0	630	0%	630	2017	1	Gas	Existing	Out-of-Stat	630
14A	Duke	Coal_Own	OVEC	Asset Sale i	Piketon, OH			OVEC Busb	1/1/2015	20.0	203	0%	203	2015	1	Coal	Existing	Out-of-Stat	203
14B	Duke	Coal_Own	OVEC	Asset Sale i	Piketon, OH			OVEC Busb	1/1/2013	20.0	203	0%	203	2013	0				0
15	Wellhead Energy Systems	SCCT_Own	NG-Fired Recip Engine	Asset Sale,	LGE/KU Service Territory	LGE Gas; TGT		LGE/KU Sys	1/1/2016	20.0	100	0%	100	2013	1	Gas	New	In-State	100
16A	Power4Georgians	RTC	Supercritical Coal	24 yr PPA,	Washington Cnty, GA			Georgia ITS	1/1/2019	24.0	850	6%	802	2019	1	Coal	New	Out-of-Stat	850
16B	Power4Georgians	RTC	Supercritical Coal	24 yr Tollin	Washington Cnty, GA			Georgia ITS	1/1/2019	24.0	850	6%	802	2019	0				0
16C	Power4Georgians	RTC	Supercritical Coal	Asset Sale,	Washington Cnty, GA			Georgia ITS	1/1/2019	60.0	850	6%	802	2019	0				0
17	Solar Energy Solutions	Solar_Own	Solar (PV Array)	Asset Sale,	LGE/KU Service Territory			LGE/KU Sys	1/1/2016	20.0	1	0%	1	2015	1	Renewable	New	In-State	1
18A	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW				MISO/LGE	1/1/2015	15.0	99	0%	99	2015	1	Renewable	Existing	Out-of-Stat	99
18B	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW				MISO/LGE	1/1/2016	15.0	151	0%	151	2016	1	Renewable	Existing	Out-of-Stat	151.2
18C	EDP Renewables	Wind	Wind (As Available)	20 yr PPA,	LGE/KU Service Territory			LGE/KU Sys	1/1/2016	20.0	100	0%	100	2016	1	Renewable	New	In-State	100
19A	LS Power	SCCT_20	SCCT	20 yr PPA s	Oldham Cnty, KY	LGE Gas; TGT		LGE Buckne	1/1/2015	20.0	495	0%	495	2013	1	Gas	Existing	In-State	495
19B	LS Power	SCCT_Own	SCCT	3 yr PPA st	Oldham Cnty, KY	LGE Gas; TGT		LGE Buckne	1/1/2015	20.0	495	0%	495	2013	0				0
19C	LS Power	SCCT_Own	SCCT	5 yr PPA st	Oldham Cnty, KY	LGE Gas; TGT		LGE Buckne	1/1/2015	20.0	495	0%	495	2013	0				0
19D	LS Power	SCCT_20	SCCT	20 yr PPA s	Oldham Cnty, KY	LGE Gas; TGT		LGE Buckne	1/1/2014	20.0	495	0%	495	2013	0				0
19E	LS Power	SCCT_Own	SCCT	5-mon PPA	Oldham Cnty, KY	LGE Gas; TGT		LGE Buckne	1/1/2014	20.0	495	0%	495	2014	0				0
19F	LS Power	SCCT_5	SCCT	5 yr PPA st	Oldham Cnty, KY	LGE Gas; TGT		LGE Buckne	1/1/2015	5.0	495	0%	495	2013	0				0
20	Sky Global, Elk Ridge Energy Center	CCCT (1X1)_10	CCCT (1X1), GE	10-20 yr PF	Pineville, KY	HH Spot or PPI		KU's Pinevi	1/1/2016	10.0	250	0%	250	2016	1	Gas	New	In-State	250
21	Wellington	RTC	Waste Coal w/ CFBC	20 yr PPA, 112 MW				PJM West	9/1/2016	20.0	112	0%	112	2012	1	Coal	New	Out-of-Stat	112
22A	Southern Company Services	SCCT_5	SCCT	5 yr PPA, 7	Demopolis, AL	Gas Transportation - S		Demopolis,	1/1/2015	5.0	675	6%	71	2015	1	Gas	Existing	Out-of-Stat	675
22B	Southern Company Services	SCCT_5	SCCT	5 yr PPA (S	Demopolis, AL	Gas Transportation - S		Demopolis,	1/1/2015	5.0	75	6%	71	2015	0				0
22C	Southern Company Services	Coal_10	Coal	15 yr PPA,	Juliette, GA	High SO2 coal to GA??		Unit GSU -	1/1/2016	15.0	159	6%	150	2016	1	Coal	Existing	Out-of-Stat	159
23	Santee Cooper	Coal_10	Coal	7.8 yr PPA, Georgetown, SC				Georgetow	4/1/2017	8.0	250	0%	250	2012	1	Coal	Existing	Out-of-Stat	250
24A	Nextera	Coal_5	Coal	6 yr PPA, 30 MW				Into LG&E/	1/1/2015	6.0	30	0%	30	2015	0				0
24B	Nextera	Coal_10	Coal	10 yr PPA, 50 MW				Into LG&E/	1/1/2015	10.0	50	0%	50	2015	1	Coal	Existing	Out-of-Stat	50
25	South Point Biomass	RTC	Biomass	20 yr PPA,	Lawrence, OH			AEP/Bellef	5/1/2015	20.0	165	0%	165	2015	1	Renewable	New	Out-of-Stat	165
26	North American BioFuels	RTC	Landfill Gas	20 yr PPA, 19 MW				WI and PA	1/1/2014	20.0	19	0%	19	2013	1	Renewable	New	Out-of-Stat	19
27A	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA,	E.W. Brown	LGE Gas; T	CPI	Existing LG	6/1/2017	20.0	770	0%	770	2012	1	Gas	New	In-State	770

27B	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA,	E.W. Brown	LGE Gas; T(	CPI	Site TBD	6/1/2017	20.0	770	0%	770	2012	0				0
41A	Union Power Partners	CCCT (2X1)_Own	CCCT (2X1), GE	Asset Sale (	El Dorado, AK	TGT, Regency Gas		Entergy AK	1/1/2015	28.0	500	3%	485	2015	1	Gas	Existing	Out-of-Stat	500
41B	Union Power Partners	CCCT (2X1)_10	CCCT (2X1), GE	20 Yr PPA	El Dorado, AK	TGT, Regency Gas		Entergy AK	1/1/2015	10.0	500	3%	485	2015	0				0
42	Energy Development, Inc	RTC	Landfill Gas	20 yr PPA, 14.4 MW				Kentucky	1/1/2015	20.0	14	0%	14	2015	1	Renewable	New	In-State	14.4

	Unique Assets	MW
Total	35	11,853
Coal	9	2,734
Gas	17	7,669
Renewable	7	550
Portfolio	2	900
New	14	4,686
Existing	21	7,166
In-State	13	3,757
Out-of-Stat	22	8,095

From:	Flood, Glenn
To:	Wilson, Stuart
Cc:	Hurst, Brian; Farhat, Monica; Sinclair, David; Schram, Chuck; Brunner, Bob; Schrader, Duane
Subject:	RE: BG transport on TGT
Date:	Thursday, June 27, 2013 12:45:08 PM

Stewart,
The cost to add WNS at BG using rates similar to those at TC and CR is $1.6M per CT, per season. This leaves the total cost of adding BG at $2.9M

Keep in mind however that the numbers below assume we are only adding STF at max rate. When we introduce purchasing WNS without purchasing SNS we may get a higher WNS rate than we have for CR and TC.

Thanks,
Glenn

From: Wilson, Stuart
Sent: Thursday, June 27, 2013 12:05 PM
To: Flood, Glenn
Cc: Hurst, Brian; Farhat, Monica; Sinclair, David; Schram, Chuck; Brunner, Bob; Schrader, Duane
Subject: Re: BG transport on TGT

So it sounds like it's either 1.3 or 2.6 million (per CT), depending on whether we purchase service for the winter, correct? Also, are these values in today's dollars or $2016?

Thanks.

Stuart

On Jun 27, 2013, at 11:37 AM, "Flood, Glenn" [redacted] wrote:

> All,
> I reported previously that the annual cost of purchasing Texas Gas Summer No Notice Service (SNS) and Winter No Notice Service (WNS) for **each** Bluegrass (BG) CT is expected to be $3.7M per/yr. This is based on a 10.8 heat rate at 165 MW and discount rates equivalent to our current rates at TC and CR. These discount rates are approximately 68% of max rates.
>
> After discussion we have determined that it is possible to lower the $3.7 million cost per CT without giving up much flexibility in unit availability. The $3.7M assumed that WNS was required for BG in the winter season. It is now our understanding that this WNS is not required. The savings from not purchasing WNS for BG is $1.6M per CT, per season.
>
> Additional savings can also be accomplished in the summer season by moving enough of our Trimble SNS to BG to provide the no notice service for the CT(s) at BG. To fill the

gap left at TC we could purchase Summer STF at a lower rate ($.2042) than the SNS ($.33). The savings from this strategy is $768K per CT, per season.

The total cost then for providing the additional Texas Gas firm transport for adding BG is then $1.3M per CT, per season.

NOTES:

- This strategy assumes we renew our TC SNS and WNS beyond 2017 at current rates.
- There may be some issues with Texas Gas on LG&E/KU scheduling gas for our unit and LS Power scheduling gas for the remaining units.

Thanks,
Glenn Flood

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Cc:	Freibert, Charlie
Subject:	AEM response on the MPS waiver
Date:	Friday, June 28, 2013 3:56:43 PM
Attachments:	LGEBeutlerMPSSummary(2)June28,2013.docx Ameren Energy ResourcesEEI receives relief from Illinois Pollution Control Board for environmental compliance of SO2 levels.msg

All,

Attached is AEM's response. I was expecting more details. Illinois Power Holding (IPH) must be a subsidiary of Dynegy. I also understand that AER is retaining ownership of Meredosia and Hutsonville Energy Centers which in my mind impacts a new waiver being granted to IPH/Dynegy.

Due to the lack of detail I have attached Tom DePaull's email from 9/25/12 on the IPCB order impact on Joppa. His email has the order attached.

AEM will not remove the condition of receiving the waiver. They stated -
Charlie, at this time we are not able to waive the contingency in the proposal.

Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

In May of 2012, Ameren Energy Resources Company LLC (AER) filed a petition with the Illinois Pollution Control Board (IPCB) seeking flexibility in meeting certain emissions standards established by the Illinois Multi-Pollutant Standards (MPS).

In September of 2012, the IPCB granted AER a variance to extend compliance dates through December 31, 2019 in meeting certain emissions standards established by the IPCB. The order requires AER to comply with a schedule of deadlines for completion of various aspects of the installation and completion of a scrubber project at the Newton Energy Center. The order also requires AER to refrain from operating the Meredosia and Hutsonville Energy Centers through December 31, 2020; however, this restriction does not impact AER's ability to make the Meredosia Energy Center available for any parties that may be interested in repowering one of its units to create a oxy-fuel combustion coal-fired energy center designed for permanent carbon dioxide capture and storage (Variance).

In March of 2013, Ameren Corporation entered into a transaction agreement with Illinois Power Holdings (IPH) to divest the coal assets of AER.

In April of 2013, AER and IPH filed an application for approval to transfer the Variance to IPH.

In June of 2013, the IPCB denied, purely on procedural grounds, AER's and IPH's motion to transfer variance relief from the MPS from AER to IPH. The IPCB indicated that IPH is free to file a new request for variance relief.

By mid-July of 2013, IPH plans to file a variance petition with the IPCB seeking flexibility in meeting certain emissions standards imposed on the coal assets of AER (Petition).

AER and IPH believe the IPCB will respond quickly if they believe the filing of the Petition is premature and that in order to seek such relief the petitioner must be the current owner of the assets. .

The IPCB has 120 days to deny the Petition otherwise it is automatically approved.

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Wilson, Stuart
Cc:	Freibert, Charlie
Subject:	AEM response on the MPS waiver
Date:	Friday, June 28, 2013 3:56:43 PM
Attachments:	LGEBeutlerMPSSummary(2)June28,2013.docx Ameren Energy ResourcesEEI receives relief from Illinois Pollution Control Board for environmental compliance of SO2 levels.msg

All,

Attached is AEM's response. I was expecting more details. Illinois Power Holding (IPH) must be a subsidiary of Dynegy. I also understand that AER is retaining ownership of Meredosia and Hutsonville Energy Centers which in my mind impacts a new waiver being granted to IPH/Dynegy.

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AEM will not remove the condition of receiving the waiver. They stated - Charlie, at this time we are not able to waive the contingency in the proposal.

Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Wilson, Stuart
Cc:	Brunner, Bob; Freibert, Charlie
Subject:	FW: Bluegrass
Date:	Friday, July 05, 2013 3:49:55 PM
Attachments:	Bluegrass - LGE_KU TS 4 yr (Option A)(LSP)(July 3, 2013).docx Bluegrass - LGE_KU TS 4 yr (Option B)(LSP)(July 3, 2013).docx

FYI – pricing without the buy option and with the buy option.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Ernest Kim [redacted]
Sent: Friday, July 05, 2013 3:08 PM
To: Freibert, Charlie; Thompson, Paul; Brunner, Bob
Cc: Mark Strength; David Nanus
Subject: RE: Bluegrass

Charlie,

Hope you had a safe and enjoyable holiday. Please find attached 2 alternate responses to LG&E 4 year proposal. We appreciate your feedback to date and patience.

Please feel free to reach out with any questions as you review these options. We look forward to continuing our discussions.

Best Regards,

Ernest Kim
LS Power Equity Advisors, LLC
1700 Broadway, 35th Floor
New York, NY 10019
[redacted]

From: Freibert, Charlie [redacted]
Sent: Wednesday, July 03, 2013 4:49 PM
To: David Nanus; Thompson, Paul
Cc: Ernest Kim; Mark Strength
Subject: RE: Bluegrass

Thanks Dave for the update.

You and the team have a great 4th too!

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: David Nanus [redacted]
Sent: Wednesday, July 03, 2013 4:45 PM
To: Thompson, Paul; Freibert, Charlie
Cc: Ernest Kim; Mark Strength
Subject: Bluegrass

Paul and Charlie

We hope to get response to you by end of day today but cld slip to Friday.

Have a great Independence Day.

Dave

Sent with Good (www.good.com)

PROPOSAL FOR 4 YEAR PPA OF BLUEGRASS IN SIMPLE CYCLE	
Start Date and Term:	January 1, 2016 through December 31, 2019 (4 years)
Delivery Point:	Facility interconnection at the LG&E Buckner (345kV) substation
Product:	PPA with embedded contract right for Buyer to provide fuel for the Facility in exchange for adjustment to Monthly Energy Payment
Generation Source:	Bluegrass Generating Facility (La Grange, Kentucky) Combustion Turbines: Specific units to be mutually agreed upon
Capacity Amount:	1/1/2016 - 12/31/2017 1 unit = 165 MW Summer, 192 MW Winter 1/1/2018 - 12/31/2019 2 units = 330 MW Summer, 384 MW Winter
Capacity Price:	Buyer shall pay Seller Monthly Capacity Payments as follows based on Summer Capacity: January $2.~~75~~65/KW-mo. February $2.~~75~~65/KW-mo. March $2.~~40~~30/KW-mo. April $2.~~40~~30/KW-mo. May $2.~~75~~65/KW-mo. June $~~3.0~~2.90/KW-mo. July $~~3.0~~2.90/KW-mo. August $~~3.0~~2.90/KW-mo. September $~~3.0~~2.90/KW-mo. October $~~2.4~~2.30/KW-mo. November $~~2.4~~2.30/KW-mo. December $~~2.6~~2.50/KW-mo.
Fixed O&M Fee:	Buyer shall pay Seller a Monthly Fixed O&M Payment as follows based on Summer Capacity: ■ $0.70/kW-mo (escalating at 2.5% annually starting in 2017)

Production (Energy) Cost:	Buyer shall pay Seller a Monthly Energy Payment for any energy delivered: **Monthly Energy Payment** = (Delivered Energy x VOM) + Fuel Price + Start-up **Delivered Energy** – means energy, in whole MWh, delivered in response to a schedule properly submitted by Buyer in accordance with the Scheduling section of this Proposal **VOM** – means $0.5375/MWh (escalating at 2.5% annually starting in 2017) **Start-up** – means $~~6,00~~8,500 per combustion turbine start (escalating at 2.5% annually starting in 2017) **Fuel Price** – means the total actual cost of natural gas purchased and incurred by Seller, acting in a prudent manner according to industry standard purchasing practices, necessary to generate Delivered Energy scheduled by Buyer, subject to the Heat Rate Guaranty. Actual hourly Fuel Price in $/MMBtu and volume will be included in each monthly invoice. If the Buyer exercises its contract right to supply fuel to the Facility, and only for that period, the Fuel Price component will be excluded from the Monthly Energy Payment calculation. **Heat Rate Guaranty –** the Fuel Price for energy delivered to Facility will not exceed 10,900 Btu/kWh for baseload operations. If Buyer decides to exercise its contract right to purchase and supply the fuel necessary to generate Delivered Energy (see "Alternative Gas Arrangements"), then there will be a reduction in the Monthly Energy Payment for any gas purchased above 10,900 Btu/kWh for baseload operations.

~~**Option to Purchase:**~~	~~Buyer shall have option to purchase Facility as provided below.~~ ▪ ~~Close by December 31, 2017 - $110 million~~ ▪ ~~Close by December 31, 2019 - $100 million~~ ▪ ~~Subject to regulatory approvals~~ ***Please refer to note at bottom of term sheet for purchase option discussion.***
Fuel Purchases:	Seller will use all commercially reasonable efforts to procure fuel utilizing non-firm transportation service provided by Texas Gas Transmission. If Seller receives notice of any fuel unavailability, Seller will notify Buyer promptly by phone of the volume and timing of such unavailability.
Alternative Gas Arrangements:	Buyer may decide at any point and for any period of time during the PPA to toll, whereby Buyer would provide fuel to the Facility for scheduled energy.
Scheduling:	Buyer shall have the right to schedule energy delivery of any amount between 70% and 100% of each Unit. Buyer shall provide at least ~~1~~ 2 hours notice to facilitate dispatch of the contract quantity (or as otherwise mutually agreed to with Seller). Buyer schedules shall be in accordance with Facility and Unit operating constraints. Seller will accommodate a notice request that is shorter than the Notice Period if operationally possible. The scheduling parameters are as follows: Minimum Run-Time: 2 hours Minimum Down Time: 2 hours
Ancillary Services:	Buyer shall be entitled to any ancillary services available from the Unit(s) associated with the Contract Capacity.
AGC:	At Buyer's expense, Buyer may connect to and transmit a real-time signal to the Capacity Resource so that Buyer can remotely control scheduled energy.
Exclusive rights:	During the Term, Buyer shall have exclusive rights to all electrical output of the Unit(s) in any form including the right to declare the units as designated network resources (DNRs). Seller will not operate the contracted ~~Facility or~~ Units during the Term except to deliver energy scheduled by Buyer pursuant to this Agreement; provided, however, Seller will be permitted to run the contracted ~~Facility or~~ Units to the extent it is directed to do so by the transmission provider or regulatory authorities.

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Planned Outages:	Actual overhaul duration and frequency will be based on prudent industry practice and manufacturer recommendations. Seller shall provide a Planned Outage Schedule prior to the beginning of each calendar year. The following scheduled maintenance outages shall be allowed subject to revisions per manufacturers' recommendations: 7 days in spring (March – April); 7 days in fall (October – November); 14 additional days in year of combustor inspection per unit; 21 additional days in year of hot gas path inspection per unit; and 21 additional days in year of major inspection per unit. (The additional days allowed during the year for the combustor inspection/the hot gas path inspection/the major inspection shall be taken at one time and shall be scheduled in March, April, October and November) All other outages (planned or unplanned) shall be included the Performance calculation.
Guaranteed Availability:	Target availability shall equal 97% Summer and Winter (June-Sept and Dec-Feb), 93% Shoulder (other months). Capacity Price adjustment of 1% for each 1% actual availability is greater than or less than the target availability on a 12 month rolling average basis, excluding planned and maintenance outages. Seller shall also have the right to provide replacement power from an alternate unit located at Bluegrass.~~Capacity Price paid to Seller for a given month shall be adjusted by the ratio of MWhrs delivered in that month divided by the MWhrs scheduled in that month. If this ratio is greater than 1 then the ratio shall equal 1. If no MWhrs are scheduled, then the ratio is also 1.~~
Conditions Precedent:	Contingent on 1. Parties negotiating acceptable agreements including appropriate credit documents and all necessary representations and covenants to confirm the status of the PPA as a non-financial commodity forward contract, excluded from the definition of "swap" under CFTC regulations and interpretations. 2. Availability of transmission 3. Regulatory Approval
Governing Law	New York law, as to federal agency regulated issues and Kentucky law as to state law issues.

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Change in Law:	Buyer shall be responsible for any new tax, charges or fees imposed or levied by any Governmental Authority (including carbon or emission regulation to the extent applicable) relating to the energy produced by the facility. ~~, excluding a~~Any tax, charges or fees or costs related to equipment reconfiguration, modification or replacement shall be paid by Buyer pro rata based on the number of years remaining on this Agreement and expected useful life of such equipment reconfiguration, modification or replacement.

****Seller is willing to discuss purchase option of the Facility in context of longer-term off-take agreement.***

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CONFIDENTIAL - Not an offer or bid.
For discussion purposes only

Bluegrass Generation Company, LLC
LG&E and KU Energy - 2012 RFP

PROPOSAL FOR 4 YEAR PPA OF BLUEGRASS IN SIMPLE CYCLE	
Start Date and Term:	January 1, 2016 through December 31, 2019 (4 years)
Delivery Point:	Facility interconnection at the LG&E Buckner (345kV) substation
Product:	PPA with embedded contract right for Buyer to provide fuel for the Facility in exchange for adjustment to Monthly Energy Payment
Generation Source:	Bluegrass Generating Facility (La Grange, Kentucky) Combustion Turbines: Specific units to be mutually agreed upon
Capacity Amount:	1/1/2016 - 12/31/2017 ~~1~~ 2 units = ~~165~~ 330 MW Summer, ~~192~~ 384 MW Winter 1/1/2018 - 12/31/2019 ~~2~~3 units = ~~330~~ 495 MW Summer, ~~384~~ 576 MW Winter
Capacity Price:	Buyer shall pay Seller Monthly Capacity Payments as follows based on Summer Capacity: January $2.~~75~~80/KW-mo. February $2.~~75~~80/KW-mo. March $2.~~40~~45/KW-mo. April $2.~~40~~45/KW-mo. May $2.~~75~~80/KW-mo. June $3.~~00~~05/KW-mo. July $3.~~00~~05/KW-mo. August $3.~~00~~05/KW-mo. September $3.~~00~~05/KW-mo. October $2.~~40~~45/KW-mo. November $2.~~40~~45/KW-mo. December $2.~~60~~65/KW-mo.
Fixed O&M Fee:	Buyer shall pay Seller a Monthly Fixed O&M Payment as follows based on Summer Capacity: ■ $0.70/kW-mo (escalating at 2.5% annually starting in 2017)

Production (Energy) Cost:

Buyer shall pay Seller a Monthly Energy Payment for any energy delivered:

Monthly Energy Payment = (Delivered Energy x VOM) + Fuel Price + Start-up

Delivered Energy – means energy, in whole MWh, delivered in response to a schedule properly submitted by Buyer in accordance with the Scheduling section of this Proposal

VOM – means $0.5375/MWh (escalating at 2.5% annually starting in 2017)

Start-up – means $~~6,00~~8,500 per combustion turbine start (escalating at 2.5% annually starting in 2017)

Fuel Price – means the total actual cost of natural gas purchased and incurred by Seller, acting in a prudent manner according to industry standard purchasing practices, necessary to generate Delivered Energy scheduled by Buyer, subject to the Heat Rate Guaranty.

Actual hourly Fuel Price in $/MMBtu and volume will be included in each monthly invoice.

If the Buyer exercises its contract right to supply fuel to the Facility, and only for that period, the Fuel Price component will be excluded from the Monthly Energy Payment calculation.

Heat Rate Guaranty – the Fuel Price for energy delivered to Facility will not exceed 10,900 Btu/kWh for baseload operations.

If Buyer decides to exercise its contract right to purchase and supply the fuel necessary to generate Delivered Energy (see "Alternative Gas Arrangements"), then there will be a reduction in the Monthly Energy Payment for any gas purchased above 10,900 Btu/kWh for baseload operations.

Option to Purchase:	Buyer shall have option to purchase Facility as provided below. ■ Close by December 31, 2017 - $~~110~~ 115 million ■ Close by December 31, 2019 - $~~100~~ 105 million ■ Subject to regulatory approvals
Fuel Purchases:	Seller will use all commercially reasonable efforts to procure fuel utilizing non-firm transportation service provided by Texas Gas Transmission. If Seller receives notice of any fuel unavailability, Seller will notify Buyer promptly by phone of the volume and timing of such unavailability.
Alternative Gas Arrangements:	Buyer may decide at any point and for any period of time during the PPA to toll, whereby Buyer would provide fuel to the Facility for scheduled energy.
Scheduling:	Buyer shall have the right to schedule energy delivery of any amount between 70% and 100% of each Unit. Buyer shall provide at least ~~1~~ 2 hours notice to facilitate dispatch of the contract quantity (or as otherwise mutually agreed to with Seller). Buyer schedules shall be in accordance with Facility and Unit operating constraints. Seller will accommodate a notice request that is shorter than the Notice Period if operationally possible. The scheduling parameters are as follows: Minimum Run-Time: 2 hours Minimum Down Time: 2 hours
Ancillary Services:	Buyer shall be entitled to any ancillary services available from the Unit(s) associated with the Contract Capacity.
AGC:	At Buyer's expense, Buyer may connect to and transmit a real-time signal to the Capacity Resource so that Buyer can remotely control scheduled energy.
Exclusive rights:	During the Term, Buyer shall have exclusive rights to all electrical output of the Unit(s) in any form including the right to declare the units as designated network resources (DNRs). Seller will not operate the contracted ~~Facility or~~ Units during the Term except to deliver energy scheduled by Buyer pursuant to this Agreement; provided, however, Seller will be permitted to run the contracted ~~Facility or~~ Units to the extent it is directed to do so by the transmission provider or regulatory authorities.

Planned Outages:	Actual overhaul duration and frequency will be based on prudent industry practice and manufacturer recommendations. Seller shall provide a Planned Outage Schedule prior to the beginning of each calendar year. The following scheduled maintenance outages shall be allowed subject to revisions per manufacturers' recommendations: 7 days in spring (March – April); 7 days in fall (October – November); 14 additional days in year of combustor inspection per unit; 21 additional days in year of hot gas path inspection per unit; and 21 additional days in year of major inspection per unit. (The additional days allowed during the year for the combustor inspection/the hot gas path inspection/the major inspection shall be taken at one time and shall be scheduled in March, April, October and November) All other outages (planned or unplanned) shall be included the Performance calculation.
Guaranteed Availability:	Target availability shall equal 97% Summer and Winter (June-Sept and Dec-Feb), 93% Shoulder (other months). Capacity Price adjustment of 1% for each 1% actual availability is greater than or less than the target availability on a 12 month rolling average basis, excluding planned and maintenance outages. Seller shall also have the right to provide replacement power from an alternate unit located at Bluegrass.~~Capacity Price paid to Seller for a given month shall be adjusted by the ratio of MWhrs delivered in that month divided by the MWhrs scheduled in that month. If this ratio is greater than 1 then the ratio shall equal 1. If no MWhrs are scheduled, then the ratio is also 1.~~
Conditions Precedent:	Contingent on 1. Parties negotiating acceptable agreements including appropriate credit documents and all necessary representations and covenants to confirm the status of the PPA as a non-financial commodity forward contract, excluded from the definition of "swap" under CFTC regulations and interpretations. 2. Availability of transmission 3. Regulatory Approval
Governing Law	New York law, as to federal agency regulated issues and Kentucky law as to state law issues.

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Change in Law:	Buyer shall be responsible for any new tax, charges or fees imposed or levied by any Governmental Authority (including carbon or emission regulation to the extent applicable) relating to the energy produced by the facility. ~~, excluding a~~Any tax, charges or fees or costs related to equipment reconfiguration, modification or replacement shall be paid by Buyer pro rata based on the number of years remaining on this Agreement and expected useful life of such equipment reconfiguration, modification or replacement.

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From: Freibert, Charlie
To: Sinclair, David; Brunner, Bob; Schram, Chuck
Cc: Freibert, Charlie
Subject: FW: Question
Date: Monday, July 08, 2013 1:24:42 PM

See AEM's response below on the MPS waiver relative to a definitive PPA.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Beutler, Dennis R[redacted]
Sent: Monday, July 08, 2013 1:13 PM
To: Freibert, Charlie
Cc: Schukar, Shawn E; Millard, Joseph E; Seidler, Eric V; Steiner, Mike J; Stewart, Sheri L
Subject: RE: Question

Hello Charlie,

Thanks for the conversation last week / very much appreciated.

AEM is willing to sign a definitive agreement that includes the following:

- If IPH does not receive variance relief from the Illinois multi-pollutant standard, then, at IPH's discretion, the definitive agreement can be terminated
- If the pending sale of AER's coal assets to IPH does not close, then the definitive agreement shall continue
- AEM commits to keeping supporting agreements in place through the end of the definitive agreement sufficient to meet its capacity supply obligations under the definitive agreement

Charlie, we are available for additional discussion and are glad to give you a call. If it is not too burdensome, please respond to this note so we are certain you have received it.

Best,

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....
Ameren Energy Marketing Company
1500 Eastport Plaza Drive
Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

From: Freibert, Charlie [redacted]
Sent: Monday, July 01, 2013 3:35 PM
To: Beutler, Dennis R
Cc: Freibert, Charlie
Subject: Question

Hi Dennis,

Thank you for the write-up on MPS on 6/28/13. In the AEM counter proposal on 6/25/13 the following was stated:

THIS PROPOSAL IS CONTINGENT UPON: SELLER, OR SELLER'S SUCCESSOR, BEING ABLE TO RETAIN VARIANCE RELIEF FROM ILLINOIS' MULTI-POLLUTANT STANDARD GRANTED BY THE ILLINOIS POLLUTION CONTROL BOARD;

For KU to properly evaluate the AEM response, please explain what will happen to a Definitive Agreement if the waiver is not granted to IPH/Dynegy.

Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202

From:	Wilson, Stuart
To:	Sinclair, David; Brunner, Bob; Freibert, Charlie
Cc:	Schram, Chuck
Subject:	RE: XM Questions
Date:	Monday, July 15, 2013 5:29:35 PM

David/Bob/Charlie,

The following does NOT contain transmission information that cannot be shared with marketing function employees…

After our meeting on Friday, I posed several questions to the XM group. Those questions (along with their responses) are listed below. In our meeting on Friday, we mentioned the fact that – if the $35 million project is not completed – a transaction between EKPC and LS Power will result in operating guidelines that effectively limit the way we can dispatch our units. XM acknowledged this fact and agreed that it was a common complaint with the process.

Stuart

1. Compared to a 'base' case where we build at Brown in 2018 (and never mind the $35 million project for now), do the Ameren and LS Power deferral cases create the need for any XM projects that are not already in the 'base' case? No. My sense is that the deferral cases just change the timing of projects already in the base case. Correct.
2. If we're not required to complete the $35 million project, but we ask for it… Who pays for this project? Does LG&E/KU pay for it all or is the cost shared by other XM customers? LG&E/KU pays for it.
    a. If we're required to complete the $35 million project (or any other project for that matter), who pays for the project? Sorry, I think we talked about this before… The vast majority of costs will be shared by all transmission customers and recovered through transmission rates.
        i. Since the project is only needed through 2020, is there a different process for sharing the costs of the project? No. In this case, the fact that the project is only needed through 2020 explains why the project is NOT required.
3. What causes the problems related to the Trimble Co. – Clifty line to go away in 2020+? The problem goes away as a result of assumptions (in the transmission model) that change over time not related to specific XM projects.
    a. Are there other projects that could be accelerated to make the $35 million project go away? No.

Thanks.

Stuart

From:	Freibert, Charlie
To:	Sinclair, David
Subject:	FW: Question
Date:	Tuesday, July 23, 2013 11:39:23 AM

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Freibert, Charlie
Sent: Monday, July 08, 2013 1:25 PM
To: Sinclair, David; Brunner, Bob; Schram, Chuck
Cc: Freibert, Charlie
Subject: FW: Question

See AEM's response below on the MPS waiver relative to a definitive PPA.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

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Sent: Monday, July 08, 2013 1:13 PM
To: Freibert, Charlie

Cc: Schukar, Shawn E; Millard, Joseph E; Seidler, Eric V; Steiner, Mike J; Stewart, Sheri L
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Charlie, we are available for additional discussion and are glad to give you a call. If it is not too burdensome, please respond to this note so we are certain you have received it.

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DENNIS BEUTLER
Wholesale Sales
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Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

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Cc: Freibert, Charlie
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For KU to properly evaluate the AEM response, please explain what will happen to a Definitive Agreement if the waiver is not granted to IPH/Dynegy.

Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From:	Schram, Chuck
To:	Freibert, Charlie; Brunner, Bob
Cc:	Sinclair, David
Subject:	Capacity Charge Update
Date:	Monday, July 29, 2013 3:04:25 PM
Attachments:	20130726_P5I1_AmerenEnergyAdderSummary_0060D05.docx

Updated document for capacity charge associated with $4 adder.

Energy Adder[1]

Adder ($/MWh)	Prod Cost Increase NPVRR ($2013, $000s)	Ameren Energy Change vs. Zero Adder (2016-2019) (GWh)	%
3	18,517	-6	-0.1
4	24,697	-18	-0.2
5	30,878	-38	-0.4
7	43,060	-139	-2
8	49,008	-362	-4
9	54,212	-1,814	-21
10	57,347	-3,164	-37

Ameren Energy (GWh)

	Adder ($/MWh)							
	0	3	4	5	7	8	9	10
2016	1,409	1,407	1,405	1,400	1,357	1,281	1,008	637
2017	1,406	1,406	1,403	1,400	1,389	1,371	1,176	898
2018	2,810	2,808	2,803	2,795	2,766	2,693	2,139	1,783
2019	2,811	2,810	2,807	2,803	2,786	2,730	2,300	1,956

$3 Adder Production Cost Delta vs. $0 Adder (Nominal $000)

	Prod Cost Delta
2016	4,226
2017	4,217
2018	8,442
2019	8,444
Total	25,329

Ameren Proposal Capacity Charge to Offset Adder ($/kW-mo)

Adder ($/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
0	11.94	11.94	9.24	9.24	9.24	10.10	11.94	11.94	11.94	9.24	9.24	10.1	10.51
3	9.55	9.55	7.39	7.39	7.39	8.08	9.55	9.55	9.55	7.39	7.39	8.08	8.40
4	8.75	8.75	6.77	6.77	6.77	7.40	8.75	8.75	8.75	6.77	6.77	7.40	7.70

[1] Based on average of 6 cases (three gas prices, 2 load scenarios)

Decrease in Capacity Charge Cost vs. Current Offer (Nominal $000)

	Cap Charge Delta
2016	-4,221
2017	-4,221
2018	-8,443
2019	-8,443
Total	-25,329

From:	Schram, Chuck
To:	Sinclair, David
Cc:	Freibert, Charlie; Brunner, Bob
Subject:	Energy Adder - Additional Table
Date:	Monday, July 29, 2013 12:58:48 PM
Attachments:	20130726_P5I1_AmerenEnergyAdderSummary_0060D04.docx

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David,
We added a table with Ameren energy by year.

Chuck

Energy Adder[1]

Adder ($/MWh)	Prod Cost Increase NPVRR ($2013, $000s)	Ameren Energy Change vs. Zero Adder (2016-2019)	
		(GWh)	%
3	18,517	-6	-0.1
4	24,697	-18	-0.2
5	30,878	-38	-0.4
7	43,060	-139	-2
8	49,008	-362	-4
9	54,212	-1,814	-21
10	57,347	-3,164	-37

Ameren Energy by Year (GWh)

	Adder ($/MWh)							
	0	3	4	5	7	8	9	10
2016	1,409	1,407	1,405	1,400	1,357	1,281	1,008	637
2017	1,406	1,406	1,403	1,400	1,389	1,371	1,176	898
2018	2,810	2,808	2,803	2,795	2,766	2,693	2,139	1,783
2019	2,811	2,810	2,807	2,803	2,786	2,730	2,300	1,956

$3 Adder Production Cost Delta vs. $0 Adder (Nominal $000)

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2016	4,226
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Total	25,329

Ameren Proposal Capacity Charge to Offset Adder ($/kW-mo)

Adder ($/MWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	11.94	11.94	9.24	9.24	9.24	10.1	11.94	11.94	11.94	9.24	9.24	10.1
3	9.55	9.55	7.39	7.39	7.39	8.08	9.55	9.55	9.55	7.39	7.39	8.08

[1] Based on average of 6 cases (three gas prices, 2 load scenarios)

Decrease in Capacity Charge Cost vs. Current Offer (Nominal $000)

	Cap Charge Delta
2016	-4,221
2017	-4,221
2018	-8,443
2019	-8,443
Total	-25,329

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob
Cc:	Freibert, Charlie
Subject:	Internal review of new AEP proposal and email
Date:	Tuesday, July 30, 2013 12:04:14 PM
Attachments:	RFPAEM072913.doc

David, Chuck and Bob,

Monica has check the math for the new proposed demand charges per month after the $4/MWH adder over the 4 year term based off of AEM's latest proposal on 6/25/13. I have rounded the demands to the nearest $.05 and slightly adjusted to keep the same NPV over 4 years less ~$5K.

Attached is the redlined LKE proposal in response. Below is my proposed cover email to AEM to accompany the attached proposal.

"Hi Dennis,

Attached is a new LG&E/KU proposal in response to the latest proposal from AEM. You will note that the pricing structure has changed but not the ultimate value from the 4 year term in your latest proposal. These pricing structure changes address reliability and credit concerns.

I will call you to discuss our proposal. We request a response to this proposal in the next 3 business days.

Thanks.

Charlie"

Let me know if you have any edits or if we need to discuss.

Once everyone is Ok I will send to AEM, hopefully this afternoon.

Thanks.

Charlie Freibert
Director Marketing

LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

Louisville Gas and Electric and Kentucky Utilities proposed terms for the sale of capacity and energy yet to be drafted in Electric Service Agreement.

The terms of the transaction are as follows:

Date: July 24, 2013

Seller: Ameren Energy Marketing Company

Buyer: Louisville Gas and Electric Company and Kentucky Utilities Company

Term: January 1, 2016 through December 31, 2019

Product: A. 1/1/2016 – 12/31/2017 - 167MW - System Firm capacity and System Firm energy

B. 1/1/2018 – 12/31/2019 - 334MW – System Firm capacity and System Firm energy

Buyer shall have exclusive rights to the first MWs of production from the System.

For purposes of this proposal, System shall be defined as the coal-fired units 1-6, totaling approximately, 1,002MW located at the Electric Energy Inc. plant near Joppa, Illinois (EEI). The System Firm capacity is owned or controlled by Seller for the length of the Term and shall not be sold to any other party. Seller shall deliver System Firm energy, when available, from one or more of the coal-fired units 1-6 located at EEI (Designated Network Resource). Seller retains the right to deliver energy from any of the System units.

Provided Buyer submits Day-Ahead Schedules in accordance with this proposal, Seller's failure to deliver shall only be excused: (i) by Buyer's failure to perform; (ii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on the System; (iii) to the extent the control area or reliability coordinator within which the System operates declares an emergency condition, as determined in the control area's or the reliability coordinator's reasonable judgment; (iv) by the interruption or curtailment of transmission to the Delivery Point; (v) by Force Majeure.

In the event of a Major Equipment Failure or like situation that prevents Seller from meeting its obligations, Seller is allowed to redefine the System. Such new definition of the System shall be limited to units located at EEI and shall also be contingent on Buyer being able to secure the transmission required to support the newly defined Designated Network Resource. [What is the intent of redefining the System. Please explain or include all generation units that could be considered part of the System in the definition of the System.]

Technology: Boilers: The boilers were designed as a natural circulation, balanced draft, sub-critical, radiant, reheat design type and are rated at 1.2MM lbs/hr with steam conditions of 1800 psig and 1055 degrees F. The burners are Low NOx Concentric Firing with Separated Over-fire Air on units 1, 3, 4, 5, and 6. Fuel is processed in type 673 Raymond Bowl Mills.

Turbines: The turbines are tandem compound, 3600 rpm, rated at 181MW gross. Each turbine is an F2 design with single HP, IP/LP and single double flow LP. Excitation is provided by an external motor generator set with a spare exciter that can be hot swapped with any of the units. Each unit is equipped with three single phase generator step up transformers and one auxiliary transformer.

Guaranteed Heat Rate (GHR): 10,501 BTU/KWh

Start Charge (SC): SC = (1,430 mmBtu * Gas Index)

Buyer shall only be charged for the actual System unit starts when the Buyer schedules from 0MWs to 167MWs or in Product B from 167MWs to 334MWs provided that a unit is actually started to serve the Buyer's Day Ahead schedule. ~~required to support Buyer's Day-Ahead Schedule.~~
For the purpose of clarity, Buyer is not responsible for a SC if the System units are already on-line regardless of the Day-Ahead Schedule.

Gas Index: Platt's Gas Daily / Daily Price Survey Midpoint / MichCon City-gate

Capacity Charge (MCC): Buyer shall pay to Seller a Monthly Capacity Payment (MCP) based upon the Monthly Capacity Charges (MCC) identified in the table below.

~~January~~	~~February~~	~~March~~	~~April~~	~~May~~	~~June~~
~~$11.94/KW month~~	~~$11.94/KW month~~	~~$9.24/KW month~~	~~$9.24/KW month~~	~~$9.24/KW month~~	~~$10.10/KW month~~
~~July~~	~~August~~	~~September~~	~~October~~	~~November~~	~~December~~
~~$11.94/KW month~~	~~$11.94/KW month~~	~~$11.94/KW month~~	~~$9.24/KW month~~	~~$9.24/KW month~~	~~$10.10/KW month~~

$/kw-mo	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$ 6.75	$ 6.75	$ 4.75	$ 4.75	$ 4.75	$ 5.45	$ 6.75	$ 6.75	$ 6.75	$ 4.75	$ 4.75	$ 5.45
2017	$ 6.75	$ 6.75	$ 4.75	$ 4.75	$ 4.75	$ 5.45	$ 6.75	$ 6.75	$ 6.75	$ 4.75	$ 4.75	$ 5.45
2018	$ 8.75	$ 8.75	$ 6.75	$ 6.75	$ 6.75	$ 7.45	$ 8.75	$ 8.75	$ 8.75	$ 6.75	$ 6.75	$ 7.45
2019	$ 11.10	$ 11.10	$ 9.10	$ 9.10	$ 9.10	$ 9.80	$ 11.10	$ 11.10	$ 11.10	$ 9.10	$ 9.10	$ 9.80

The monthly delivery factor shall be mega-watt hours delivered (MWD) divided by mega-watt hours scheduled (MDF).

MWD / MWS = MDF

In the event Buyer schedules zero (0) megawatt-hours in any month of the Term, then the MDF shall equal one (1).

The monthly capacity payment (MCP) shall be calculated as follows:
If the MDF is greater than or equal to .96 then: MCP = MCC * 1000 * Product capacity
If the MDF is less than .96 then: MCP = MDF * MCC * 1000 * Product capacity

Energy Charge and: MWh delivered * (((Coal Index + Transportation Charge) / 17.60) * (GHR/1,000)) + (~~VO&M~~EAC * MWh delivered) + (SC * number of actual starts required to support Buyer's Day-Ahead Schedule)

Coal Index: Final Monthly Average Price will be fixed on a monthly basis utilizing the OTC Broker Index for PRB – 8,800 Btu/lbm final monthly average price ("Index Price") obtained from Platts Coal Trader (or its successor), plus $0.25 per ton. The index price settles on the 25th date of the month prior to the contract delivery month and is published on or after the 26th day of the month prior to delivery. In addition, there will be a per ton SO_2 adjustment to be calculated as follows:

Targeted Sulfur Dioxide Value – 0.50 lbs. SO_2 per million Btu.
Adjustment Period for the sulfur dioxide value adjustment shall be monthly.

Actual SO_2 shall be used in the Sulfur Dioxide Value Adjustment formula below to determine a per ton adjustment to account for the variation:

$$\$ \text{ Per Ton } SO_2 \text{ Adjustment} = \frac{(C - S) \times A \times ADI}{1{,}000{,}000}$$

Where: A = Actual Btu of the Coal delivered in the relevant adjustment period

C = 0.80 lbs. SO_2/mmBtu (OTC Broker Index nominal Sulfur Dioxide Value).

S = Actual SO_2 content of the Coal delivered in the relevant adjustment period (expect to achieve 0.5).

ADI = Argus Air Daily Index: the monthly value of the Argus Air Daily SO_2 Allowance Index (as published in Argus Coal Daily, or its successor) arithmetically averaged over the relevant Adjustment Period (expressed as $/allowance SO_2).

* **Note:** For deliveries received through 2014, the SO2 Adjustment shall be multiplied by two (2) to account for changes implemented on January 1, 2010 in the Clean Air Interstate Rules (CAIR) where two (2) SO2 allowances are required for every one ton of SO2 emitted. For deliveries received after 2014, the SO2 adjustment shall be multiplied by 2.86 to account for changes implemented on January 1, 2010 in the CAIR, where 2.86 SO2 allowances are required for every ton of SO2 emitted. The above provisions for the multipliers shall not be applicable if CAIR rules or any other rule of regulation in effect at the time of deliveries effectively changes the number of SO2 allowances required for every ton of SO2 emitted. After executing this Agreement, in the event the SO2 price index published in Argus Air Daily is changed, or the CAIR rules are modified to change the number of SO2 allowances required for every ton of SO2 emitted, both parties agree to negotiate, in good faith, a new index and/or multiplier that reflects the intent of the current CAIR rules.

Transportation Charge (TC): The Transportation Charge shall be the actual, total cost of transport required to deliver coal to the System.

The current coal transportation contract expires on December 31, 2017

~~Variable Operations And Maintenance (VO&M)~~Energy Adder Charge (EAC): The ~~VO&M~~Energy Adder ~~C~~charge shall be in accordance with Table B below.

Table B

Year	2016	2017	2018	2019
$/MWh	$~~2~~6.69	$~~2~~6.73	$~~2~~6.78	$~~2~~6.84

Delivery Point: EEI/LGE interface or its successor

Transmission: Seller is responsible for all charges associated with delivery of energy to the Delivery Point. Buyer is responsible for all charges associated with delivery of energy at and from the Delivery Point.

Scheduling Requirements: Each Friday of the Term or the last Business Day prior if Friday is a NERC holiday, no later than 15:00 Eastern Standard Time, Buyer shall submit an non-binding energy forecast to Seller specifying the amounts of energy that Buyer anticipates it will purchase the following week (Weekly Forecast).

a) Additionally, Buyer shall submit a binding ~~n~~ energy schedule to Seller, in whole megawatts, in an agreed upon format no later than ~~one hundred twenty (120) minutes prior to the day ahead deadlines imposed by the Midcontinent Independent System Operator, Inc. (MISO),~~ 11:00 EST the day prior to the delivery day specifying for each hour of the applicable day, the amounts of energy Buyer will purchase from Seller (Day-Ahead Schedule).

Formatted: Indent: Left: 0", Hanging: 1.25", Numbered + Level: 1 + Numbering Style: a, b, c, … + Start at: 1 + Alignment: Left + Aligned at: 1.25" + Indent at: 1.5"

For Product A: Buyer is allowed to schedule 0MW or 167MW. Buyer is not allowed to schedule any other quantity in the Day-Ahead Schedule. In the event Buyer schedules 167MW in any hour of the Day-Ahead Schedule, then Buyer must schedule 167MW for a continuous eight (8) hour period (First Continuous Period Requirement). After meeting the First Continuous Period Requirement, Buyer is allowed to reduce the quantities of the Day-Ahead Schedule to 0MW. In the event Buyer reduces the quantities in the Day-Ahead Schedule to 0MW, then Buyer is no longer allowed to schedule any other quantities for the remainder of the Day-Ahead Schedule.

For Product B: Buyer is allowed to schedule 0MW or 167MW or 334MW. Buyer is not allowed to schedule any other quantity in the Day-Ahead Schedule. In the event Buyer schedules 167MW in any hour of the Day-Ahead Schedule, then Buyer must meet the First Continuous Period Requirement. Additionally, Buyer is allowed to schedule 334MW. In the event Buyer schedules 334MW in any hour of the Day-Ahead Schedule, Buyer must schedule 334MW for a continuous eight (8) hour period (Second Continuous Period Requirement). After meeting the First Continuous Period Requirement and/or the Second Continuous Period Requirement, as applicable, Buyer is allowed to reduce the quantities of the Day-Ahead Schedule to 0MW. In the event Buyer reduces the quantities in the Day-Ahead Schedule to 0MW, then Buyer is no longer allowed to schedule any other quantities for the remainder of the Day-Ahead Schedule.

Environmental: Seller is responsible for obtaining all necessary Permits and providing all credits and allowances necessary to comply with permit requirements for the Term.

System O & M: Seller, in its sole discretion, shall manage all aspects of System operations and maintenance in accordance with good utility practices and the concept of optimizing the market position of the System.

Operating Committee: An operating committee shall be established by the Parties as a means of securing effective cooperation and interchange of information and of providing consultation on a prompt and orderly basis between the Parties in connection with the Electric Service Agreement.

Confidentiality: All terms and conditions described in this proposal are considered proprietary and confidential information that shall only be disclosed to Seller and Buyer, their respective affiliates, representatives and duly appointed agents, unless disclosure is otherwise required by any laws, rules or regulations. The terms and conditions herein shall not be disclosed to third parties without the written consent of Buyer and Seller.

Contingencies And Acceptance: **THE PARTIES UNDERSTAND AND AGREE THAT UNTIL A DEFINITIVE AGREEMENT HAS BEEN EXECUTED AND DELIVERED, NO CONTRACT, OR AGREEMENT PROVIDING FOR A TRANSACTION AMONG THE PARTIES SHALL BE DEEMED TO EXIST AMONG THE PARTIES AND NO PARTY WILL BE UNDER ANY LEGAL OBLIGATION OF ANY KIND WHATSOEVER WITH RESPECT TO THIS PROPOSAL BY VIRTUE OF THIS OR ANY WRITTEN OR ORAL EXPRESSION THEREOF. THIS PROPOSAL NEITHER OBLIGATES A PARTY TO DEAL EXCLUSIVELY WITH THE OTHER PARTY NOR PREVENTS A PARTY OR ANY OF ITS AFFILIATES FROM COMPETING WITH ANOTHER PARTY OR ANY OF ITS AFFILIATES.**

THIS PROPOSAL IS CONTINGENT UPON:

~~a)~~b) **BOTH BUYER AND SELLER RECEIVING ALL REQUISITE APPROVALS, INCLUDING SELLER'S APPROVAL FROM THE AMEREN RISK MANAGEMENT STEERING COMMITTEE; AND**

c) **SELLER, OR SELLER'S SUCCESSOR, BEING ABLE TO RETAIN VARIANCE RELIEF FROM ILLINOIS' MULTI-POLLUTANT STANDARD GRANTED BY THE ILLINOIS POLLUTION CONTROL BOARD;** [We need to clarify each party's rights and obligations in the contract discussions.]

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~~b)~~d)
AND
~~c)~~e) THE PARTIES NEGOTIATING AN ACCEPTABLE PURCHASE POWER AGREEMENT, INCLUDING APPROPRIATE CREDIT DOCUMENTS AND ALL NECESSARY REPRESENTATIONS AND COVENANTS TO CONFIRM THE STATUS OF THE PURCHASE POWER AGREEMENT AS A NON-FINANCIAL COMMODITY FORWARD CONTRACT, EXCLUDED FROM THE DEFINITION OF "SWAP" UNDER THE COMMODITY FUTURES TRADING COMMISSION REGULATIONS AND INTERPRETATIONS;
AND
~~d)~~f) TRANSMISSION AVAILABILITY
AND
~~e)~~g) REGULATORY APPROVAL

Name:____

Title:____

From: Freibert, Charlie
To: Sinclair, David; Schram, Chuck; Brunner, Bob
Cc: Freibert, Charlie
Subject: FW: Non-binding for discuss on purposes only: AEM"s RFP Proposal
Date: Wednesday, August 07, 2013 11:24:19 AM
Attachments: image001.png

FYI.
We had our discussion with AEM and sent the email below.
They are most concerned about no minimum take. We will wait for heir response to this email.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Freibert, Charlie
Sent: Wednesday, August 07, 2013 11:03 AM
To: Dennis Beutler [redacted]
Cc: Brunner, Bob; Freibert, Charlie
Subject: Non-binding for discussion purposes only: AEM's RFP Proposal

Hi Dennis,

Thank you for Ameren's non-binding proposal yesterday in response to the LKE, 7/31/13, non-binding proposal. At this point in our process, we need AEM's response to the issues below in order to determine if we should continue to consider the AEM offer as one of the possible solutions in our RFP process.

1. The LKE 7/31/13 proposal intentionally contained no minimum energy take requirement. This is important, along with the new pricing terms, for the AEM offer to be favorable from a cost and risk perspective compared to the other alternatives we are considering. Thus the minimum MWH requirement in the AEM proposal is unacceptable. We would consider lowering the EAC by $0.50 per MWH with the appropriate increase in the monthly demand charges. See table below of a non-binding proposal of demand charges that are not an offer or bid.

$/kw-mo	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$ 6.74	$ 6.74	$ 4.76	$ 4.76	$ 4.76	$ 5.39	$ 6.74	$ 6.74	$ 6.74	$ 4.76	$ 4.76	$ 5.39
2017	$ 6.74	$ 6.74	$ 4.76	$ 4.76	$ 4.76	$ 5.39	$ 6.74	$ 6.74	$ 6.74	$ 4.76	$ 4.76	$ 5.39
2018	$ 9.74	$ 9.74	$ 7.76	$ 7.76	$ 7.76	$ 8.39	$ 9.74	$ 9.74	$ 9.74	$ 7.76	$ 7.76	$ 8.39
2019	$ 11.20	$ 11.20	$ 9.22	$ 9.22	$ 9.22	$ 9.85	$ 11.20	$ 11.20	$ 11.20	$ 9.22	$ 9.22	$ 9.85

2. As we discussed in our January meeting, adequate credit support is important for a contract to be acceptable to LKE. At one point you proposed a credit structure based on AER's financial capability. While we have not agreed to the AER credit proposal, how are you proposing to address this issue given the Dynegy acquisition?

3. LKE cannot accept system definition flexibility. AEM needs to define the System precisely with no flexibility.

4. After further consideration on the Scheduling provisions that AEM requires, we are not willing to accept such terms since the LKE DNR rights do not allow the capacity designated to be offered in a firm day-ahead market by AEM per our interpretation of FERC Order 890. We are not willing to proceed with this condition however we are willing to accept the noon scheduling time.

As we have informed you, LKE is proceeding with various solutions to our future capacity and energy needs. AEM' s response to these four significant issues will determine if LKE will proceed further. Please provide your response as soon as possible but no later than this Friday, 8/9/13.

Sincerely,

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From:	Early, John
To:	Sinclair, David
Cc:	Brunner, Bob
Subject:	S&P Default Rates
Date:	Friday, August 09, 2013 5:57:04 PM
Attachments:	Book2.xlsx

David,

Bob thought you might want to see this. We will give you a call shortly.

John

Table 24

Global Corporate Average Cumulative Default Rates (1981-2012) (%)

	--Time horizon (years)--														
Rating	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
AAA	0	0.03	0.14	0.25	0.36	0.48	0.54	0.63	0.69	0.76	0.79	0.83	0.86	0.94	1.02
AA	0.02	0.07	0.14	0.25	0.37	0.49	0.6	0.7	0.78	0.88	0.96	1.05	1.13	1.21	1.3
A	0.07	0.17	0.29	0.45	0.62	0.81	1.03	1.23	1.43	1.65	1.84	2.02	2.19	2.35	2.55
BBB	0.22	0.63	1.08	1.62	2.18	2.72	3.19	3.66	4.12	4.59	5.08	5.49	5.89	6.31	6.73
BB	0.86	2.6	4.63	6.59	8.37	10.06	11.52	12.82	14.03	15.09	15.95	16.7	17.34	17.88	18.52
B	4.28	9.58	14.07	17.56	20.18	22.3	24.03	25.42	26.64	27.84	28.84	29.65	30.4	31.1	31.82
CCC/C	26.85	35.94	41.17	44.19	46.64	47.71	48.67	49.44	50.39	51.13	51.8	52.58	53.45	54.26	54.26
Investment (	0.11	0.31	0.54	0.82	1.12	1.41	1.68	1.94	2.19	2.45	2.7	2.91	3.11	3.32	3.54
Speculative	4.11	8.05	11.46	14.22	16.44	18.3	19.85	21.16	22.36	23.46	24.38	25.15	25.85	26.48	27.12
All rated	1.55	3.06	4.4	5.53	6.48	7.29	7.98	8.58	9.12	9.63	10.08	10.45	10.8	11.12	11.45

Note: Numbers in parentheses are standard deviations. Sources: Standard & Poor's Global Fixed Income Research and Standard & Poor's CreditProÂ®.

From the 2012 Annual Global Corporate Default Study and Rating Transitions article dated March 18, 2013

https://www.globalcreditportal.com/ratingsdirect/showArticlePage.do?rand=yrWnTu6SoT&articleId=1097086

Dynegy
Genco

From: Freibert, Charlie
To: Sinclair, David; Schram, Chuck; Brunner, Bob
Cc: Freibert, Charlie
Subject: AEM Update. FW: LGE proposal
Date: Friday, August 09, 2013 5:01:35 PM

FYI

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Beutler, Dennis R [redacted]
Sent: Friday, August 09, 2013 5:00 PM
To: Freibert, Charlie
Subject: LGE proposal

Hello Charlie,

Glad we were able to chat today / very much appreciated.

We have and continue to run numerous scenarios around the capacity payments you proposed with different energy adders, including the one you suggested of $3.50. We are trying to get comfortable with the no "minimum energy takes", as you have suggested.

For credit, we asked our credit and risk folks to review and provide insight / we just called to make sure those discussions are in progress / any insight you are able to provide in this area would be greatly appreciated.

For the system definition, we believe we would leave the system as defined in the proposal, provided we agree that in the event of catastrophic failure of a unit, the transaction remains in place as long as we are meeting contractual obligations.

For scheduling, we prefer the 90 minutes prior to the day ahead deadline for the MISO market and we would commit to never selling the Designated Network Resource energy on a firm basis.

Charlie, we are sorry that we are not able to provide better clarity at this time / we will be working through the weekend so we are better prepared to respond on or before noon next Tuesday.

Thanks for your patience.

Best,

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....
Ameren Energy Marketing Company
1500 Eastport Plaza Drive
Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob
Cc:	Freibert, Charlie
Subject:	FW: LGE proposal
Date:	Monday, August 12, 2013 4:10:07 PM
Attachments:	LGEBeutlerProposalTollCoal(40)August12,2013.doc

FYI. AEM's response so far. I just talked w them too. They used our pricing suggestion – $0.50 shift from EAC to demand.

1. 47% must take per year
2. Hopefully a response on performance assurance by noon tomorrow with a hard number. It may be later this week.
3. System defined as the 6 coal units and NO option to redefine
4. Commitment not to sell firm the DNR amounts but still wanting DA schedules by 90 minutes before MISO DA offer deadline.

I informed them that we received the email and we will wait for their response to the 2 second point, specifically our question:

As we discussed in our January meeting, adequate credit support is important for a contract to be acceptable to LKE. At one point you proposed a credit structure based on AER's financial capability. While we have not agreed to the AER credit proposal, how are you proposing to address this issue given the Dynegy acquisition?

I will keep you posted

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Beutler, Dennis R [redacted]
Sent: Monday, August 12, 2013 3:19 PM
To: Freibert, Charlie
Cc: Stewart, Sheri L; Schukar, Shawn E; Seidler, Eric V; Steiner, Mike J; Sussen, Katie K
Subject: LGE proposal

Hello Charlie,

Hope all is well for you and the others in Kentucky.

Attached is our proposal in response to your proposal that you shared with us last week. We added language in the Product definition that states, "At all times during the Term, Seller is never allowed to sell Designated Network Resource energy on a Firm basis." We accepted your suggestion for the capacity payment schedule. We accepted your suggestion for a $3.50 energy adder. We removed language that allowed us to redefine the System. We ask that you accept current energy scheduling language, knowing we will not sell Designated Network Resource energy on a Firm basis. We are also asking for you to get comfortable with a minimum energy requirement; significantly reduced.

Regarding performance assurance, we are working diligently towards identifying a number. We have a transition team conference call scheduled this week.

Charlie, we are ready to move forward / trust you feel the same. If it is not too burdensome, please respond to this note so we are certain you have received it.

Looking forward to hearing from you,

Best,

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....
Ameren Energy Marketing Company
1500 Eastport Plaza Drive
Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

This document outlines a proposed transaction between Ameren Energy Marketing Company and the companies of Louisville Gas and Electric and Kentucky Utilities for the sale of capacity and energy under the terms and conditions of a yet to be drafted Electric Service Agreement.

The terms of the transaction are as follows:

Date: August 13, 2013

Seller: Ameren Energy Marketing Company

Buyer: Louisville Gas and Electric Company and Kentucky Utilities Company

Term: January 1, 2016 through December 31, 2019

Product:

A. 1/1/2016 – 12/31/2017 - 167MW - System Firm capacity and System Firm energy

B. 1/1/2018 – 12/31/2019 - 334MW – System Firm capacity and System Firm energy

Buyer shall have exclusive rights to the first MWs of production from the System.

For purposes of this proposal, System shall be defined as the coal-fired units 1-6, totaling approximately, 1,002MW located at the Electric Energy Inc. plant near Joppa, Illinois (EEI). The System Firm capacity is owned or controlled by Seller for the length of the Term and shall not be sold to any other party. Seller shall deliver System Firm energy, when available, from one or more of the coal-fired units 1-6 located at EEI (Designated Network Resource). Seller retains the right to deliver energy from any of the System units.

Provided Buyer submits Day-Ahead Schedules in accordance with this proposal, Seller's failure to deliver shall only be excused: (i) by Buyer's failure to perform; (ii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on the System; (iii) to the extent the control area or reliability coordinator within which the System operates declares an emergency condition, as determined in the control area's or the reliability coordinator's reasonable judgment; (iv) by the interruption or curtailment of transmission to the Delivery Point; (v) by Force Majeure.

At all times during the Term, Seller is never allowed to sell Designated Network Resource energy on a Firm basis.

Technology:

Boilers: The boilers were designed as a natural circulation, balanced draft, sub-critical, radiant, reheat design type and are rated at 1.2MM lbs/hr with steam conditions of 1800 psig and 1055 degrees F. The burners are Low NOx Concentric Firing with Separated Over-fire Air on units 1, 3, 4, 5, and 6. Fuel is processed in type 673 Raymond Bowl Mills.

Turbines: The turbines are tandem compound, 3600 rpm, rated at 181MW gross. Each turbine is an F2 design with single HP, IP/LP and single double flow LP. Excitation is provided by an external motor generator set with a spare exciter that can be hot swapped with any of the units. Each unit is equipped with three single phase generator step up transformers and one auxiliary transformer.

Guaranteed Heat Rate (GHR): 10,501 Btu/kWh

Start Charge (SC): SC = (1,430 mmBtu * Gas Index)

Buyer shall only be charged for the actual System unit starts when Buyer schedules, at any time, from 0MWs to 167MWs or, in Product B, from 167MWs to 334MWs, provided that a System unit is actually started to serve Buyer's Day-Ahead schedule.
For the purpose of clarity, Buyer is not responsible for a SC if the System units are already on-line regardless of the Day-Ahead Schedule.

Gas Index: Platt's Gas Daily / Daily Price Survey Midpoint / MichCon City-gate

Capacity Charge (MCC) and Payment: Buyer shall pay to Seller a Monthly Capacity Payment (MCP) based upon the Monthly Capacity Charges (MCC) identified in the Table A below.

Table A

2016	Jan	Feb	Mar	Apr	May	Jun
$/kW	6.74	6.74	4.76	4.76	4.76	5.39
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	6.74	6.74	6.74	4.76	4.76	5.39
2017	Jan	Feb	Mar	Apr	May	Jun
$/kW	6.74	6.74	4.76	4.76	4.76	5.39
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	6.74	6.74	6.74	4.76	4.76	5.39
2018	Jan	Feb	Mar	Apr	May	Jun
$/kW	9.74	9.74	7.76	7.76	7.76	8.39
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	9.74	9.74	9.74	7.76	7.76	8.39
2019	Jan	Feb	Mar	Apr	May	Jun
$/kW	11.20	11.20	9.22	9.22	9.22	9.85
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	11.20	11.20	11.20	9.22	9.22	9.85

The monthly delivery factor shall be mega-watt hours delivered (MWD) divided by mega-watt hours scheduled (MDF).

MWD / MWS = MDF

In the event Buyer schedules zero (0) megawatt-hours in any month of the Term, then the MDF shall equal one (1).

The monthly capacity payment (MCP) shall be calculated as follows:
If the MDF is greater than or equal to .96 then: MCP = MCC * 1000 * Product capacity

If the MDF is less than .96 then: MCP = MDF * MCC * 1000 * Product capacity

Energy Charge: MWh delivered * (((Coal Index + Transportation Charge) / 17.60) * (GHR/1,000)) + (EAC * MWh delivered) + (SC * number of actual starts required to support Buyer's Day-Ahead Schedule)

Coal Index: Final Monthly Average Price will be fixed on a monthly basis utilizing the OTC Broker Index for PRB – 8,800 Btu/lbm final monthly average price (Index Price) obtained from Platts Coal Trader (or its successor), plus $0.25 per ton. The index price settles on the 25th date of the month prior to the contract delivery month and is published on or after the 26th day of the month prior to delivery. In addition, there will be a per ton SO_2 adjustment to be calculated as follows:

Targeted Sulfur Dioxide Value – 0.50 lbs. SO_2 per million Btu.
Adjustment Period for the sulfur dioxide value adjustment shall be monthly.

Actual SO_2 shall be used in the Sulfur Dioxide Value Adjustment formula below to determine a per ton adjustment to account for the variation:

$$\$ \text{ Per Ton } SO_2 \text{ Adjustment} = \frac{(C - S) \times A \times ADI}{1{,}000{,}000}$$

Where: A = Actual Btu of the Coal delivered in the relevant adjustment period

C = 0.80 lbs. SO_2/mmBtu (OTC Broker Index nominal Sulfur Dioxide Value).

S = Actual SO_2 content of the Coal delivered in the relevant adjustment period (expect to achieve 0.5).

ADI = Argus Air Daily Index: the monthly value of the Argus Air Daily SO_2 Allowance Index (as published in Argus Coal Daily, or its successor) arithmetically averaged over the relevant Adjustment Period (expressed as $/allowance SO_2).

* **Note:** For deliveries received through 2014, the SO2 Adjustment shall be multiplied by two (2) to account for changes implemented on January 1, 2010 in the Clean Air Interstate Rules (CAIR) where two (2) SO2 allowances are required for every one ton of SO2 emitted. For deliveries received after 2014, the SO2 adjustment shall be multiplied by 2.86 to account for changes implemented on January 1, 2010 in the CAIR, where 2.86 SO2 allowances are required for every ton of SO2 emitted. The above provisions for the multipliers shall not be applicable if CAIR rules or any other rule of regulation in effect at the time of deliveries effectively changes the number of SO2 allowances required for every ton of SO2 emitted. After executing this Agreement, in the event the SO2 price index published in Argus Air Daily is changed, or the CAIR rules are modified to change the number of SO2 allowances required for every ton of SO2 emitted, both parties agree to negotiate, in good faith, a new index and/or multiplier that reflects the intent of the current CAIR rules.

Transportation Charge (TC): The Transportation Charge shall be the actual, total cost of transport required to deliver coal to the System.

The current coal transportation contract expires on December 31, 2017.

Energy Adder Charge: The Energy Adder Charge (EAC) shall be in accordance with Table B below.

Table B

Year	2016	2017	2018	2019
$/MWh	$6.19	$6.23	$6.28	$6.34

Minimum Megawatt-hour Requirement: The minimum annual megawatt-hours Buyer is required to schedule and pay for shall be in accordance with Table C below.

Table C

Year	2016	2017	2018	2019
MWh	733,464	731,460	1,462,920	1,462,920

Delivery Point: EEI/LGE interface or its successor

Transmission: Seller is responsible for all charges associated with delivery of energy to the Delivery Point. Buyer is responsible for all charges associated with delivery of energy at and from the Delivery Point.

Scheduling Requirements: Each Friday of the Term or the last Business Day prior if Friday is a NERC holiday, no later than 15:00 Eastern Standard Time, Buyer shall submit a non-binding energy forecast to Seller specifying the amounts of energy that Buyer anticipates it will purchase the following week (Weekly Forecast).

Additionally, Buyer shall submit a binding energy schedule to Seller, in whole megawatts, in an agreed upon format no later than ninety (90) minutes prior to the day-ahead deadlines imposed by the Midcontinent Independent System Operator, Inc. (MISO), specifying for each hour of the applicable day, the amounts of energy Buyer will purchase from Seller (Day-Ahead Schedule).

For Product A: Buyer is allowed to schedule 0MW or 167MW. Buyer is not allowed to schedule any other quantity in the Day-Ahead Schedule. In the event Buyer schedules 167MW in any hour of the Day-Ahead Schedule, then Buyer must schedule 167MW for a continuous eight (8) hour period (First Continuous Period Requirement). After meeting the First Continuous Period Requirement, Buyer is allowed to reduce the quantities of the Day-Ahead Schedule to 0MW. In the event Buyer reduces the quantities in the Day-Ahead Schedule to 0MW, then Buyer is no longer allowed to schedule any other quantities for the remainder of the Day-Ahead Schedule.

For Product B: Buyer is allowed to schedule 0MW or 167MW or 334MW. Buyer is not allowed to schedule any other quantity in the Day-Ahead Schedule. In the event Buyer schedules 167MW in any hour of the Day-Ahead Schedule, then Buyer must meet the First Continuous Period Requirement. Additionally, Buyer is allowed to schedule 334MW. In the event Buyer schedules 334MW in any hour of the Day-Ahead Schedule, Buyer must schedule 334MW for a continuous eight (8) hour period (Second Continuous Period Requirement). After meeting the First Continuous Period Requirement and/or the Second Continuous Period Requirement, as applicable, Buyer is allowed to reduce the quantities of the Day-Ahead Schedule to 0MW. In the event Buyer reduces the quantities in the Day-Ahead Schedule to 0MW, then Buyer is no longer allowed to schedule any other quantities for the remainder of the Day-Ahead Schedule.

For the purpose of clarity, at all times, Buyer is obligated to meet or exceed the Minimum Megawatt Hour Requirement.

Environmental: Seller is responsible for obtaining all necessary Permits and providing all credits and allowances necessary to comply with permit requirements for the Term.

System O & M: Seller, in its sole discretion, shall manage all aspects of System operations and maintenance in accordance with good utility practices and the concept of optimizing the market position of the System.

Operating Committee: An operating committee shall be established by the Parties as a means of securing effective cooperation and interchange of information and of providing consultation on a prompt and orderly basis between the Parties in connection with the Electric Service Agreement.

Confidentiality: All terms and conditions described in this proposal are considered proprietary and confidential information that shall only be disclosed to Seller and Buyer, their respective affiliates, representatives and duly appointed agents, unless disclosure is otherwise required by any laws, rules or regulations. The terms and conditions herein shall not be disclosed to third parties without the written consent of Buyer and Seller.

Contingencies And Acceptance: **THE PARTIES UNDERSTAND AND AGREE THAT UNTIL A DEFINITIVE AGREEMENT HAS BEEN EXECUTED AND DELIVERED, NO CONTRACT, OR AGREEMENT PROVIDING FOR A TRANSACTION AMONG THE PARTIES SHALL BE DEEMED TO EXIST AMONG THE PARTIES AND NO PARTY WILL BE UNDER ANY LEGAL OBLIGATION OF ANY KIND WHATSOEVER WITH RESPECT TO THIS PROPOSAL BY VIRTUE OF THIS OR ANY WRITTEN OR ORAL EXPRESSION THEREOF. THIS PROPOSAL NEITHER OBLIGATES A PARTY TO DEAL EXCLUSIVELY WITH THE OTHER PARTY NOR PREVENTS A PARTY OR ANY OF ITS AFFILIATES FROM COMPETING WITH ANOTHER PARTY OR ANY OF ITS AFFILIATES.**

THIS PROPOSAL IS CONTINGENT UPON:

a) BOTH BUYER AND SELLER RECEIVING ALL REQUISITE APPROVALS, INCLUDING SELLER'S APPROVAL FROM THE AMEREN RISK MANAGEMENT STEERING COMMITTEE;

AND

b) SELLER, OR SELLER'S SUCCESSOR, BEING ABLE TO RETAIN VARIANCE RELIEF FROM ILLINOIS' MULTI-POLLUTANT STANDARD GRANTED BY THE ILLINOIS POLLUTION CONTROL BOARD;

AND

c) THE PARTIES NEGOTIATING AN ACCEPTABLE PURCHASE POWER AGREEMENT, INCLUDING APPROPRIATE CREDIT DOCUMENTS AND ALL NECESSARY

REPRESENTATIONS AND COVENANTS TO CONFIRM THE STATUS OF THE PURCHASE POWER AGREEMENT AS A NON-FINANCIAL COMMODITY FORWARD CONTRACT, EXCLUDED FROM THE DEFINITION OF "SWAP" UNDER THE COMMODITY FUTURES TRADING COMMISSION REGULATIONS AND INTERPRETATIONS;

AND

d) TRANSMISSION AVAILABILITY

AND

e) REGULATORY APPROVAL

Name:____

Title:____

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Early, John; Wilson, Stuart
Subject:	Fwd: LGE proposal
Date:	Wednesday, August 21, 2013 1:03:31 PM
Attachments:	LGEBeutlerProposalTollCoal(41)August21.2013.doc ATT00001.htm

AEM forgot the usage tax on coal and is now including it. Redlined in attachment.

Sent from my iPhone

Begin forwarded message:

From: "Beutler, Dennis R" [redacted]
Date: August 21, 2013, 11:23:10 AM EDT
To: "Freibert, Charlie [redacted]
Subject: LGE proposal

Charlie,

Redlined as we discussed / sorry for the omission

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....
Ameren Energy Marketing Company
1500 Eastport Plaza Drive
Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

This document outlines a proposed transaction between Ameren Energy Marketing Company and the companies of Louisville Gas and Electric and Kentucky Utilities for the sale of capacity and energy under the terms and conditions of a yet to be drafted Electric Service Agreement.

The terms of the transaction are as follows:

Date: August 13, 2013

Seller: Ameren Energy Marketing Company

Buyer: Louisville Gas and Electric Company and Kentucky Utilities Company

Term: January 1, 2016 through December 31, 2019

Product:

A. 1/1/2016 – 12/31/2017 - 167MW - System Firm capacity and System Firm energy

B. 1/1/2018 – 12/31/2019 - 334MW – System Firm capacity and System Firm energy

Buyer shall have exclusive rights to the first MWs of production from the System.

For purposes of this proposal, System shall be defined as the coal-fired units 1-6, totaling approximately, 1,002MW located at the Electric Energy Inc. plant near Joppa, Illinois (EEI). The System Firm capacity is owned or controlled by Seller for the length of the Term and shall not be sold to any other party. Seller shall deliver System Firm energy, when available, from one or more of the coal-fired units 1-6 located at EEI (Designated Network Resource). Seller retains the right to deliver energy from any of the System units.

Provided Buyer submits Day-Ahead Schedules in accordance with this proposal, Seller's failure to deliver shall only be excused: (i) by Buyer's failure to perform; (ii) to the extent necessary to preserve the integrity of, or prevent or limit any instability on the System; (iii) to the extent the control area or reliability coordinator within which the System operates declares an emergency condition, as determined in the control area's or the reliability coordinator's reasonable judgment; (iv) by the interruption or curtailment of transmission to the Delivery Point; (v) by Force Majeure.

At all times during the Term, Seller is never allowed to sell Designated Network Resource energy on a Firm basis.

Technology:

Boilers: The boilers were designed as a natural circulation, balanced draft, sub-critical, radiant, reheat design type and are rated at 1.2MM lbs/hr with steam conditions of 1800 psig and 1055 degrees F. The burners are Low NOx Concentric Firing with Separated Over-fire Air on units 1, 3, 4, 5, and 6. Fuel is processed in type 673 Raymond Bowl Mills.

Turbines: The turbines are tandem compound, 3600 rpm, rated at 181MW gross. Each turbine is an F2 design with single HP, IP/LP and single double flow LP. Excitation is provided by an external motor generator set with a spare exciter that can be hot swapped with any of the units. Each unit is equipped with three single phase generator step up transformers and one auxiliary transformer.

Guaranteed Heat Rate (GHR): 10,501 Btu/kWh

Start Charge (SC): SC = (1,430 mmBtu * Gas Index)

Buyer shall only be charged for the actual System unit starts when Buyer schedules, at any time, from 0MWs to 167MWs or, in Product B, from 167MWs to 334MWs, provided that a System unit is actually started to serve Buyer's Day-Ahead schedule.
For the purpose of clarity, Buyer is not responsible for a SC if the System units are already on-line regardless of the Day-Ahead Schedule.

Gas Index: Platt's Gas Daily / Daily Price Survey Midpoint / MichCon City-gate

Capacity Charge (MCC) and Payment: Buyer shall pay to Seller a Monthly Capacity Payment (MCP) based upon the Monthly Capacity Charges (MCC) identified in the Table A below.

Table A

2016	Jan	Feb	Mar	Apr	May	Jun
$/kW	6.74	6.74	4.76	4.76	4.76	5.39
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	6.74	6.74	6.74	4.76	4.76	5.39
2017	Jan	Feb	Mar	Apr	May	Jun
$/kW	6.74	6.74	4.76	4.76	4.76	5.39
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	6.74	6.74	6.74	4.76	4.76	5.39
2018	Jan	Feb	Mar	Apr	May	Jun
$/kW	9.74	9.74	7.76	7.76	7.76	8.39
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	9.74	9.74	9.74	7.76	7.76	8.39
2019	Jan	Feb	Mar	Apr	May	Jun
$/kW	11.20	11.20	9.22	9.22	9.22	9.85
	Jul	Aug	Sep	Oct	Nov	Dec
$/kW	11.20	11.20	11.20	9.22	9.22	9.85

The monthly delivery factor shall be mega-watt hours delivered (MWD) divided by mega-watt hours scheduled (MDF).

MWD / MWS = MDF

In the event Buyer schedules zero (0) megawatt-hours in any month of the Term, then the MDF shall equal one (1).

The monthly capacity payment (MCP) shall be calculated as follows:
If the MDF is greater than or equal to .96 then: MCP = MCC * 1000 * Product capacity

If the MDF is less than .96 then: MCP = MDF * MCC * 1000 * Product capacity

Energy Charge: MWh delivered * (((Coal Index + Transportation Charge) / 17.60) * (GHR/1,000)) + (EAC * MWh delivered) + (SC * number of actual starts required to support Buyer's Day-Ahead Schedule)

Coal Index: Final Monthly Average Price will be fixed on a monthly basis utilizing the OTC Broker Index for PRB – 8,800 Btu/lbm final monthly average price (Index Price) obtained from Platts Coal Trader (or its successor), plus Illinois Use Tax, plus $0.25 per ton. The index price settles on the 25th date of the month prior to the contract delivery month and is published on or after the 26th day of the month prior to delivery. In addition, there will be a per ton SO_2 adjustment to be calculated as follows:

Targeted Sulfur Dioxide Value – 0.50 lbs. SO_2 per million Btu.
Adjustment Period for the sulfur dioxide value adjustment shall be monthly.

Actual SO_2 shall be used in the Sulfur Dioxide Value Adjustment formula below to determine a per ton adjustment to account for the variation:

$$\text{\$ Per Ton } SO_2 \text{ Adjustment} = \frac{(C - S) \times A \times ADI}{1{,}000{,}000}$$

Where: A = Actual Btu of the Coal delivered in the relevant adjustment period

C = 0.80 lbs. SO_2/mmBtu (OTC Broker Index nominal Sulfur Dioxide Value).

S = Actual SO_2 content of the Coal delivered in the relevant adjustment period (expect to achieve 0.5).

ADI = Argus Air Daily Index: the monthly value of the Argus Air Daily SO_2 Allowance Index (as published in Argus Coal Daily, or its successor) arithmetically averaged over the relevant Adjustment Period (expressed as $/allowance SO_2).

* **Note:** For deliveries received through 2014, the SO2 Adjustment shall be multiplied by two (2) to account for changes implemented on January 1, 2010 in the Clean Air Interstate Rules (CAIR) where two (2) SO2 allowances are required for every one ton of SO2 emitted. For deliveries received after 2014, the SO2 adjustment shall be multiplied by 2.86 to account for changes implemented on January 1, 2010 in the CAIR, where 2.86 SO2 allowances are required for every ton of SO2 emitted. The above provisions for the multipliers shall not be applicable if CAIR rules or any other rule of regulation in effect at the time of deliveries effectively changes the number of SO2 allowances required for every ton of SO2 emitted. After executing this Agreement, in the event the SO2 price index published in Argus Air Daily is changed, or the CAIR rules are modified to change the number of SO2 allowances required for every ton of SO2 emitted, both parties agree to negotiate, in good faith, a new index and/or multiplier that reflects the intent of the current CAIR rules.

Transportation Charge (TC): The Transportation Charge shall be the actual, total cost of transport required to deliver coal to the System.

The current coal transportation contract expires on December 31, 2017.

Energy Adder Charge: The Energy Adder Charge (EAC) shall be in accordance with Table B below.

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$/MWh	$6.19	$6.23	$6.28	$6.34

Minimum Megawatt-hour Requirement: The minimum annual megawatt-hours Buyer is required to schedule and pay for shall be in accordance with Table C below.

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MWh	733,464	731,460	1,462,920	1,462,920

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For the purpose of clarity, at all times, Buyer is obligated to meet or exceed the Minimum Megawatt Hour Requirement.

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System O & M: Seller, in its sole discretion, shall manage all aspects of System operations and maintenance in accordance with good utility practices and the concept of optimizing the market position of the System.

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a) BOTH BUYER AND SELLER RECEIVING ALL REQUISITE APPROVALS, INCLUDING SELLER'S APPROVAL FROM THE AMEREN RISK MANAGEMENT STEERING COMMITTEE;

AND

b) SELLER, OR SELLER'S SUCCESSOR, BEING ABLE TO RETAIN VARIANCE RELIEF FROM ILLINOIS' MULTI-POLLUTANT STANDARD GRANTED BY THE ILLINOIS POLLUTION CONTROL BOARD;

AND

c) THE PARTIES NEGOTIATING AN ACCEPTABLE PURCHASE POWER AGREEMENT, INCLUDING APPROPRIATE CREDIT DOCUMENTS AND ALL NECESSARY

REPRESENTATIONS AND COVENANTS TO CONFIRM THE STATUS OF THE PURCHASE POWER AGREEMENT AS A NON-FINANCIAL COMMODITY FORWARD CONTRACT, EXCLUDED FROM THE DEFINITION OF "SWAP" UNDER THE COMMODITY FUTURES TRADING COMMISSION REGULATIONS AND INTERPRETATIONS;

AND

d) TRANSMISSION AVAILABILITY

AND

e) REGULATORY APPROVAL

Name:____

Title:____

From:	Freibert, Charlie
To:	Schram, Chuck; Wilson, Stuart
Cc:	Sinclair, David; Brunner, Bob; Freibert, Charlie
Subject:	FW: LGE proposal
Date:	Wednesday, August 21, 2013 3:55:29 PM

More info on "use tax" that is really "sales tax.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Beutler, Dennis R [redacted]
Sent: Wednesday, August 21, 2013 3:48 PM
To: Freibert, Charlie
Subject: RE: LGE proposal

Hello Charlie,

My accounting folks tell me it is not "Use Tax"; it is "Sales Tax". The current rate is 6.25%.

http://www.revenue.state.il.us/businesses/taxinformation/sales/rot.htm

Glad to discuss further with you.

Thanks,

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....
Ameren Energy Marketing Company
1500 Eastport Plaza Drive

Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

From: Freibert, Charlie [redacted]
Sent: Wednesday, August 21, 2013 12:58 PM
To: Beutler, Dennis R
Cc: Freibert, Charlie
Subject: RE: LGE proposal

Dennis,
Email the current Illinois usage tax rate and a link to where it is stated
and perhaps changed on occasion by Illinois.
Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Beutler, Dennis R [redacted]
Sent: Wednesday, August 21, 2013 11:23 AM
To: Freibert, Charlie
Subject: LGE proposal

Charlie,

Redlined as we discussed / sorry for the omission

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....

Ameren Energy Marketing Company
1500 Eastport Plaza Drive
Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

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Ameren Corporation

From:	Freibert, Charlie
To:	Sinclair, David; Schram, Chuck; Brunner, Bob; Early, John
Cc:	Freibert, Charlie
Subject:	AEM response. FW: Performance Assurance
Date:	Wednesday, August 21, 2013 11:15:01 AM
Attachments:	CapacityForwardCurve_08_15_13_v6.xls LGE_ForwardCurve_White_Paper_15Aug2013_v17.doc LGE_Proposed_Settlement_Forward_Curve_19Aug2013_MarketHR_EEI.XLSX
Importance:	High

At last they have responded.

From my discussion w Dennis after I reviewed their documents the following points were made by Dennis.

1. AEM will agree to this methodology if we find it acceptable.
2. AEM noted in the 2nd document that AEM will not be required to post collateral as of 8/19/13.
3. AEM claims that if LKE applies the methodology that we will find that we would need to post $13M of collateral as of 8/19/13. Dennis claimed that AEM would probably accept an increase in the Threshold for a BBB rating to $15M.
4. AEM can arrange for their analyst and risk manager to conference call with us whenever convenient for us if we so desire.

David,
Let us know when you would like to discuss.

Thanks.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

From: Beutler, Dennis R [redacted]

Sent: Wednesday, August 21, 2013 10:17 AM
To: Freibert, Charlie
Cc: Schukar, Shawn E; Stewart, Sheri L; Steiner, Mike J; mikepullen; Sussen, Katie K; Seidler, Eric V
Subject: Performance Assurance

Hello Charlie,

Hope everything is going well for you and the others in Kentucky.

Attached are three documents we prepared for the purpose of identifying methodology to determine performance assurance associated with our proposed transaction. We recognize there are numerous approaches one might utilize to determine performance assurance / we look forward to learning more about your approach.

If it is not too burdensome, please respond to this note so we are certain you have received it.

Thanks for your patience with us as we worked through the process / really appreciated.

Best,

DENNIS BEUTLER
Wholesale Sales
Ameren Energy Marketing
[redacted]
....
Ameren Energy Marketing Company
1500 Eastport Plaza Drive
Collinsville, Illinois 62234
www.AmerenEnergyMarketing.com

Tab	Explanation
MISO DA EEI As Of 19Aug2013	This tab shows the yearly forward curve that is derived using the data from the tabs described below. Years 2016 thru 2017 are the prices that were derived based on visible power markets from the tab ICAP Sheet AO 19Aug2013. Years 2018 thru 2019 were derived using a market heat rate. This is the forward curve that will be used to create a market value for the LGE deal as of 08/19/2013.
ICAP Sheet AO 19Aug2013	AEM uses ICAP as a broker source for visible markets because it is widely used by other utilities. Since there are visible quotes for years 2016 thru 2017, a price can be derived by taking the average of the INDY Hub Cal ATC bid and offer starting in cells C39 and D39 for year 2016, add the $(2.60) basis, DART, and a transmission fee, which are all described in the assumptions below, to come up with the market based power price for the MISO DA EEI delivery point.
Market HR Derived Price	A market implied heat rate applied to the NYMEX NG forward curve, as posted by the CME Group, will be used for years 2018 and 2019. To come up with the monthly INDY Hub power price, the NYMEX NG settle price, which has visibile quotes out thru 2025, gets multiplied by the market implied heat rate, that was derived on the Implied Market HR tab. Take the monthly INDY Hub power price, multiply it by the hours in the month, sum this amount up by year and divide by the total hours in the year to come up with a calendar ATC INDY Hub power price. The basis, DART, and transmission fee described in the assumptions below, get added to this calendar ATC INDY Hub power price to come up with a derived power price for the MISO DA EEI delivery point.
Implied Market HR	This tab shows a four year market implied heat rate average. The market implied heat rate average is derived by taking the monthly ATC forward price for MISO RT INDY and dividing by the NYMEX NG future close price and multiplying it by 1000. The pivot table summarizes the results on a yearly and monthly basis to come up with an average for each month based on the four years worth of data. Since there are visible broker quotes for years 2014 thru 2017 for power and NG, AEM is able to derive an average market implied heat rate using the four years of data.

Assumptions	
Basis	AEM is using a basis, which is derived using a rolling 3 years of history, of ($2.60) from MISO INDY Hub to MISO DA EEI delivery point.

Rolling ATC	Basis
Rolling 3 year ATC	-2.60061
Rolling 2 year ATC	-2.89244
Rolling 1 year ATC	-3.04749

DART	AEM is using $0.85 for a DART between a MISO RT INDY Hub product to a MISO DA INDY Hub product.

Transmission Fee	AEM is using $5.00 for transmission fee to exit MISO.

Year	Forward Curve	
2016	$	35.8954
2017	$	36.9093
2018	$	38.3473
2019	$	40.3818

Market Based Prices
Market HR Derived Price

Year	INDY	BASIS	MISORT_EEI	DART	MISODA_EEI	Trans_Fee
2014	$ 30.63	$ (2.60)	$ 28.03	$ 0.85	$ 28.88	$ 5.00
2015	$ 31.65	$ (2.60)	$ 29.05	$ 0.85	$ 29.90	$ 5.00
2016	$ 32.65	$ (2.60)	$ 30.05	$ 0.85	$ 30.90	$ 5.00
2017	$ 33.66	$ (2.60)	$ 31.06	$ 0.85	$ 31.91	$ 5.00

	Indiana Hub		Adhub	
Daily	41.00	43.00	44.00	46.00
Bal week	41.00	43.00	42.50	44.50
Next week	42.00	44.00	44.50	46.00
2nd week	40.00	43.00	42.00	44.00
Bal month	41.50	42.50	43.50	45.00

CALENDAR PEAK

	Nat gas	*Indiana Hub*		*Adhub*	
UZ 13	*3.59*	34.37	35.01	37.47	38.05
Cal 2014	*3.89*	36.00	36.45	39.08	39.73
Cal 2015	*4.11*	37.35	37.85	40.05	40.75
Cal 2016	*4.24*	38.65	39.20	41.05	41.90
Cal 2017	*4.38*	39.75	40.65	42.33	43.03

CALENDAR OFFPEAK

	Indiana Hub		*Adhub*	
UZ 13	25.75	26.18	28.54	29.03
Cal 2014	25.60	25.90	28.35	28.85
Cal 2015	26.25	26.60	28.95	29.45
Cal 2016	27.00	27.40	29.30	30.50
Cal 2017	27.75	28.25	30.75	31.25

CAL ATC (FLAT)

	Indiana Hub			*Adhub*	
UZ 13	29.70	30.23		32.64	33.17
Cal 2014	30.44	30.81	30.63	33.35	33.92

Cal 2015		31.44	31.86	31.65	34.14	34.73
Cal 2016		32.41	32.88	32.65	34.76	35.80
Cal 2017		33.32	34.00	33.66	36.12	36.71

Cal 2013 PEAK

	Nat gas	Indiana 2013		Adhub 2013	
U 13	3.46	34.45	34.80	38.05	38.40
V 13	3.49	34.15	34.80	36.55	37.20
X 13	3.61	34.25	35.00	37.25	37.85
Z 13	3.79	34.65	35.45	38.15	38.85
Q4 13	3.62	34.35	35.08	37.29	37.94
UZ 13	3.59	34.37	35.01	37.47	38.05

Cal 13 OFFPEAK

	Indiana 2013		Adhub 2013	
U 13	24.15	24.50	26.40	26.80
V 13	26.25	26.65	27.70	28.70
X 13	26.10	26.60	29.00	29.80
Z 13	26.50	27.00	30.35	31.15
Q4 13	26.29	26.75	29.26	29.78
UZ 13	25.75	26.18	28.54	29.03

Cal 14 PEAK

	Indiana 2014		ADhub 2014	
FG 14	36.65	37.35	39.95	40.35
HJ 14	33.65	34.50	36.70	37.25
K 14	34.15	34.90	37.15	37.50
M 14	36.50	37.25	39.15	39.75
NQ 14	42.60	43.35	47.25	47.80
U 14	33.90	34.65	37.00	37.45
Q4 14	33.15	34.00	36.45	37.10

Cal 2014	35.82	36.61	39.22	39.74

Cal 14 OFFPEAK

	Indiana 2014		Adhub 2014	
FG 14	27.25	28.00	32.25	32.75
HJ 14	25.50	26.25	28.85	29.65
K 14	24.00	24.75	26.00	26.80
M 14	24.00	24.50	26.00	26.60
NQ 14	25.75	26.75	28.00	28.75
U 14	24.00	24.50	25.70	26.70
Q4 14	25.75	26.25	28.45	29.35
Cal 2014	25.51	26.20	28.40	29.17

Market Price

$	33.8782
$	34.8996
$	35.8954
$	36.9093

Nihub		PJM		PJM/Indy		PJM/Adh
44.00	45.00	47.50	49.00	4.50	8.00	1.50
40.50	44.00	49.75	51.25	6.75	10.25	5.25
41.00	44.00	48.25	49.25	4.25	7.25	2.25
40.00	43.50	43.75	44.50	0.75	4.50	-0.25
40.50	42.00	49.00	50.50	6.50	9.00	4.00

PEAK SPREADS

Nihub		PJM			PJM/Indy		PJM/Adh
34.14	35.05	41.32	41.58	UZ 13	6.56	6.95	3.52
36.20	36.85	43.70	43.85	Cal 2014	7.40	7.70	4.13
37.25	37.95	44.65	44.85	Cal 2015	7.00	7.30	4.10
38.10	38.95	45.75	46.00	Cal 2016	6.80	7.10	4.10
39.00	40.15	46.85	47.25	Cal 2017	6.60	7.10	4.23

CAL OFFPEAK SPREADS

Nihub		PJM			PJM/Indy		PJM/Adh
22.49	23.20	30.89	31.18	UZ 13	4.71	5.43	2.15
23.60	24.10	31.05	31.25	Cal 2014	5.15	5.65	2.30
24.25	24.60	31.60	31.85	Cal 2015	5.00	5.60	2.15
25.00	25.40	32.35	32.65	Cal 2016	4.95	5.65	2.15
25.75	26.45	33.50	33.90	Cal 2017	5.25	6.15	2.25

CAL ATC (FLAT) SPREADS

Nihub		PJM			PJM/Indy		PJM/Adh
27.84	28.64	35.68	35.95	UZ 13	5.56	6.13	2.78
29.47	30.04	36.94	37.12	Cal 2014	6.20	6.60	3.15

30.33	30.84	37.70	37.93	Cal 2015	5.94	6.39	3.06
31.08	31.69	38.57	38.85	Cal 2016	5.81	6.32	3.06
31.90	32.81	39.69	40.09	Cal 2017	5.88	6.59	3.17

Nihub 2013		PJM 2013			PJM/Indy		PJM
35.15	35.65	42.65	42.80	U 13	8.00	8.20	4.40
33.05	34.10	39.90	40.20	V 13	5.40	5.75	3.00
33.90	34.85	40.50	40.75	X 13	5.75	6.25	2.90
34.60	35.70	42.40	42.70	Z 13	7.25	7.75	3.85
33.82	34.86	40.91	41.19	Q4 13	6.12	6.56	3.25
34.14	35.05	41.32	41.58	UZ 13	6.56	6.95	3.52

Nihub 2013		PJM 2013			PJM/indy		PJM
21.25	21.78	28.90	29.10	U 13	4.40	4.95	2.30
20.70	22.20	29.85	30.20	V 13	3.20	3.95	1.50
22.25	23.45	31.35	31.65	X 13	4.75	5.55	1.85
24.85	26.15	33.35	33.65	Z 13	6.35	7.15	2.50
22.91	23.68	31.56	31.88	Q4 13	4.81	5.59	2.10
22.49	23.20	30.89	31.18	UZ 13	4.71	5.43	2.15

Nihub 2014		PJM 2014			PJM/Indy		PJM
37.10	37.70	44.65	44.85	FG 14	7.50	8.00	4.50
33.50	34.45	40.65	41.00	HJ 14	6.50	7.00	3.75
34.25	35.05	41.15	41.40	K 14	6.50	7.00	3.90
36.40	37.30	44.15	44.40	M 14	7.15	7.65	4.65
44.75	45.70	53.35	53.60	NQ 14	10.25	10.75	5.80
34.45	35.35	41.50	41.75	U 14	7.10	7.60	4.30
33.33	33.98	39.90	40.25	Q4 14	6.25	6.75	3.15

36.32	37.12	43.66	43.95	Cal 2014	7.34	7.84	4.20

Nihub 2014		PJM 2014			PJM/indy		PJM
28.25	29.05	35.75	36.00	Fg 14	7.75	8.75	3.25
23.60	24.65	31.25	31.75	Hj 14	5.00	6.25	2.10
20.75	21.95	27.90	28.40	K 14	3.15	4.40	1.60
21.65	22.75	28.25	28.50	M 14	3.75	4.50	1.90
24.80	25.90	31.00	31.50	NQ 14	4.25	5.75	2.75
21.05	22.55	28.30	28.90	U 14	3.80	4.90	2.20
21.95	23.35	30.75	31.40	Q4 14	4.50	5.65	2.05
23.51	24.67	31.02	31.50	Cal 2014	4.82	5.99	2.33

ub	PJM/Nihub		AD/Nihub		Indy/Nihub	
5.00	2.50	5.00	-1.00	2.00	-4.00	-1.00
8.75	5.75	10.75	-1.50	4.00	-3.00	2.50
4.75	4.25	8.25	0.50	5.00	-2.00	3.00
2.50	0.25	4.50	-1.50	4.00	-3.50	3.00
7.00	7.00	10.00	1.50	4.50	-0.50	2.00

ub	PJM/Nihub		Ad/Nihub		Indy/Nihub	
3.85	6.53	7.18	2.98	3.17	-0.43	0.62
4.63	7.00	7.50	2.80	2.95	-0.40	-0.20
4.60	6.90	7.40	2.75	2.85	-0.10	0.10
4.70	7.05	7.65	2.85	3.05	0.25	0.55
4.53	7.10	7.85	2.95	3.25	0.50	0.75

ub	PJM/Nihub		AD/Nihub		Indy/nihub	
2.35	7.98	8.40	5.80	6.05	2.55	3.69
2.80	7.05	7.55	4.70	4.80	1.80	2.00
2.90	7.00	7.60	4.70	4.85	1.90	2.10
3.05	6.95	7.65	4.60	4.80	1.90	2.10
3.15	7.05	8.15	4.80	5.00	1.85	2.20

ub	PJM/Nihub		AD/Nihub		Indy/Nihub	
3.04	7.31	7.84	4.50	4.73	1.18	2.28
3.65	7.03	7.53	3.82	3.94	0.78	0.98

3.69	6.95	7.51	3.79	3.91	0.96	1.16
3.82	7.00	7.65	3.78	3.98	1.13	1.38
3.79	7.07	8.01	3.94	4.19	1.22	1.53

/AD	PJM/Nihub		AD/Nihub		Indy/nihub	
4.60	7.15	7.50	2.75	2.90	-1.05	-0.50
3.35	6.10	6.85	3.10	3.50	0.35	1.45
3.25	5.90	6.60	3.00	3.35	-0.35	0.85
4.25	7.00	7.80	3.15	3.55	-0.75	0.55
3.61	6.33	7.08	3.05	3.25	-0.23	0.97
3.85	6.53	7.18	2.98	3.17	-0.43	0.62

/Ad	PJM/Nihub		AD/nihub		Indy/nihub	
2.50	7.33	7.65	4.90	5.15	2.38	3.25
2.15	8.00	9.15	6.50	7.00		
2.35	8.20	9.10	6.35	6.75		
3.00	7.50	8.50	5.00	5.50		
2.30	8.20	8.65	6.10	6.35	2.61	3.84
2.35	7.98	8.40	5.80	6.05	2.55	3.69

/AD	PJM/Nihub		AD/Nihub		Indy/Nihub	
4.70	7.15	7.55	2.65	2.85	-0.85	0.05
3.95	6.55	7.15	2.80	3.20	-0.45	0.65
4.00	6.35	6.90	2.45	2.90	-0.65	0.40
5.00	7.10	7.75	2.45	2.75	-0.55	0.60
6.10	7.90	8.60	2.10	2.50	-2.85	-1.65
4.50	6.40	7.05	2.10	2.55	-1.20	-0.05
3.45	6.28	6.58	2.90	3.35	-0.48	0.33

4.45	6.82	7.34	2.57	2.95	-1.01	0.00

/AD	PJM/nihub		AD/nihub		Indy/nihub	
3.50	6.95	7.50	3.70	4.00	-1.80	-0.25
2.40	7.10	7.65	5.00	5.25	0.85	2.65
1.90	6.45	7.15	4.85	5.25	2.05	4.00
2.25	5.75	6.60	3.85	4.35	1.25	2.85
3.00	5.60	6.20	2.85	3.20	-0.15	1.95
2.60	6.35	7.25	4.15	4.65	1.45	3.45
2.30	8.05	8.80	6.00	6.50	2.40	4.30
2.61	6.83	7.51	4.50	4.89	0.84	2.69

Year	Date	NYMEX NG as of 08/19/2013	HR	MISORT_INDY	ATC Hrs
2018	1/1/2018	4.7240	7,812	36.9047	744
2018	2/1/2018	4.7030	7,895	37.1283	672
2018	3/1/2018	4.6310	7,378	34.1681	744
2018	4/1/2018	4.3610	7,696	33.5606	720
2018	5/1/2018	4.3760	7,486	32.7608	744
2018	6/1/2018	4.4030	7,744	34.0954	720
2018	7/1/2018	4.4390	8,810	39.1092	744
2018	8/1/2018	4.4590	8,868	39.5436	744
2018	9/1/2018	4.4620	7,299	32.5678	720
2018	10/1/2018	4.4990	7,482	33.6595	744
2018	11/1/2018	4.6210	7,295	33.7082	720
2018	12/1/2018	4.8410	7,014	33.9570	744
2019	1/1/2019	4.9660	7,812	38.7952	744
2019	2/1/2019	4.9450	7,895	39.0388	672
2019	3/1/2019	4.8730	7,378	35.9536	744
2019	4/1/2019	4.6180	7,696	35.5384	720
2019	5/1/2019	4.6380	7,486	34.7222	744
2019	6/1/2019	4.6680	7,744	36.1475	720
2019	7/1/2019	4.7080	8,810	41.4792	744
2019	8/1/2019	4.7330	8,868	41.9735	744
2019	9/1/2019	4.7370	7,299	34.5750	720
2019	10/1/2019	4.7750	7,482	35.7244	744
2019	11/1/2019	4.8970	7,295	35.7215	720
2019	12/1/2019	5.1170	7,014	35.8930	744

ATC Multiplier
27,457
24,950
25,421
24,164
24,374
24,549
29,097
29,420
23,449
25,043
24,270
25,264
28,864
26,234
26,749
25,588
25,833
26,026
30,861
31,228
24,894
26,579
25,719
26,704

Row Labels	Sum of ATC Multiplier	Sum of ATC Hrs	MISORT_INDY_ATC
2018	307,458	8760	$ 35.10
2019	325,280	8760	$ 37.13

Month	Market Derived HR
1	7,812
2	7,895
3	7,378
4	7,696
5	7,486
6	7,744
7	8,810
8	8,868
9	7,299
10	7,482
11	7,295
12	7,014

BASIS	MISORT_EEI	DART	MISODA_EEI	Trans_Fee	Market Price
$ (2.60)	$ 32.50	$ 0.85	$ 33.35	$ 5.00	$ 38.3473
$ (2.60)	$ 34.53	$ 0.85	$ 35.38	$ 5.00	$ 40.3818

Month	Year	Date	MISORT_INDY_Forward	NYMEX NG as of 08/19/2013
1	2014	1/1/2014	32.1593	3.8760
2	2014	2/1/2014	32.1875	3.8760
3	2014	3/1/2014	29.5391	3.8430
4	2014	4/1/2014	29.8364	3.7830
5	2014	5/1/2014	28.9589	3.8040
6	2014	6/1/2014	30.1750	3.8340
7	2014	7/1/2014	34.1300	3.8660
8	2014	8/1/2014	33.8032	3.8830
9	2014	9/1/2014	28.9517	3.8830
10	2014	10/1/2014	29.7784	3.9020
11	2014	11/1/2014	29.2344	3.9810
12	2014	12/1/2014	29.6168	4.1460
1	2015	1/1/2015	32.3927	4.2320
2	2015	2/1/2015	32.6104	4.2150
3	2015	3/1/2015	30.0370	4.1600
4	2015	4/1/2015	30.1557	3.9720
5	2015	5/1/2015	29.1271	3.9870
6	2015	6/1/2015	30.5300	4.0140
7	2015	7/1/2015	36.0159	4.0450
8	2015	8/1/2015	35.2438	4.0610
9	2015	9/1/2015	29.1864	4.0610
10	2015	10/1/2015	30.1043	4.0800
11	2015	11/1/2015	29.8923	4.1530
12	2015	12/1/2015	30.1043	4.3250
1	2016	1/1/2016	33.6549	4.4130
2	2016	2/1/2016	34.1826	4.3950
3	2016	3/1/2016	31.6028	4.3260
4	2016	4/1/2016	31.3634	4.0860
5	2016	5/1/2016	30.6884	4.1010
6	2016	6/1/2016	31.9691	4.1270
7	2016	7/1/2016	36.4278	4.1620
8	2016	8/1/2016	37.7807	4.1810
9	2016	9/1/2016	30.5371	4.1810
10	2016	10/1/2016	31.3068	4.2080
11	2016	11/1/2016	31.4337	4.2860
12	2016	12/1/2016	31.3068	4.4580
1	2017	1/1/2017	34.8880	4.5480
2	2017	2/1/2017	35.1518	4.5300
3	2017	3/1/2017	32.5665	4.4610
4	2017	4/1/2017	32.1049	4.2090
5	2017	5/1/2017	31.8678	4.2240
6	2017	6/1/2017	32.9544	4.2510
7	2017	7/1/2017	37.5409	4.2870
8	2017	8/1/2017	38.9631	4.3040
9	2017	9/1/2017	31.2139	4.3060
10	2017	10/1/2017	32.4398	4.3390

11	2017	11/1/2017	32.3813	4.4340
12	2017	12/1/2017	32.0500	4.6240

Market Heat Rate
8297.026366
8304.308566
7686.472262
7886.965078
7612.742105
7870.37037
8828.239296
8705.440589
7456.004807
7631.563356
7343.492701
7143.463839
7654.227757
7736.746465
7220.440687
7592.05757
7305.512442
7605.878755
8903.816602
8678.594673
7186.999127
7378.496825
7197.749668
6960.524173
7626.318412
7777.603148
7305.326359
7675.818801
7483.138367
7746.31905
8752.472936
9036.294796
7303.78024
7439.826045
7334.049272
7022.608344
7671.072746
7759.770042
7300.262211
7627.6828
7544.460466
7752.146212
8756.911967
9052.7635
7248.926199
7476.331302

Average of Market Heat Rate	Year			
Months	2014	2015	2016	2017
1	8,297	7,654	7,626	7,671
2	8,304	7,737	7,778	7,760
3	7,686	7,220	7,305	7,300
4	7,887	7,592	7,676	7,628
5	7,613	7,306	7,483	7,544
6	7,870	7,606	7,746	7,752
7	8,828	8,904	8,752	8,757
8	8,705	8,679	9,036	9,053
9	7,456	7,187	7,304	7,249
10	7,632	7,378	7,440	7,476
11	7,343	7,198	7,334	7,303
12	7,143	6,961	7,023	6,931
Avg Market HR	**7,897**	**7,618**	**7,709**	**7,702**

7302.961236
6931.226682

Avg Market HR
7,812
7,895
7,378
7,696
7,486
7,744
8,810
8,868
7,299
7,482
7,295
7,014
7,732

Prices do not include reserves

	Planning Year	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
MISO DNR	$/MW Year			$283	$325	$ 383	$777	$1,575	$3,192	$6,470	$13,114	$26,583	$53,884	$109,223
	$/MW Day			0.77	0.89	1.05	2.13	4.30	8.74	17.73	35.93	72.63	147.63	299.24
							102.7%							
	MISO Cost of New Entry ($/MW Year)					$97,650	$ 98,041	$ 98,727	$ 99,714	$ 101,010	$ 102,526	$ 104,474	$ 106,668	$ 109,228
	Interest Rate (Growth Rate of of New Entry Costs)						0.40%	0.70%	1.00%	1.30%	1.50%	1.90%	2.10%	2.40%

	MISO ($/MW-Day)	MISO ($/kw-Month)
1/31/2015	$ 2.13	$ 0.07
2/28/2015	$ 2.13	$ 0.06
3/31/2015	$ 2.13	$ 0.07
4/30/2015	$ 2.13	$ 0.06
5/31/2015	$ 2.13	$ 0.07
6/30/2015	$ 4.30	$ 0.13
7/31/2015	$ 4.30	$ 0.13
8/31/2015	$ 4.30	$ 0.13
9/30/2015	$ 4.30	$ 0.13
10/31/2015	$ 4.30	$ 0.13
11/30/2015	$ 4.30	$ 0.13
12/31/2015	$ 4.30	$ 0.13
1/31/2016	$ 4.30	$ 0.13
2/29/2016	$ 4.30	$ 0.12
3/31/2016	$ 4.30	$ 0.13
4/30/2016	$ 4.30	$ 0.13
5/31/2016	$ 4.30	$ 0.13
6/30/2016	$ 8.74	$ 0.26
7/31/2016	$ 8.74	$ 0.27
8/31/2016	$ 8.74	$ 0.27
9/30/2016	$ 8.74	$ 0.26
10/31/2016	$ 8.74	$ 0.27
11/30/2016	$ 8.74	$ 0.26
12/31/2016	$ 8.74	$ 0.27
1/31/2017	$ 8.74	$ 0.27
2/28/2017	$ 8.74	$ 0.24
3/31/2017	$ 8.74	$ 0.27
4/30/2017	$ 8.74	$ 0.26
5/31/2017	$ 8.74	$ 0.27
6/30/2017	$ 17.73	$ 0.53
7/31/2017	$ 17.73	$ 0.55
8/31/2017	$ 17.73	$ 0.55
9/30/2017	$ 17.73	$ 0.53
10/31/2017	$ 17.73	$ 0.55
11/30/2017	$ 17.73	$ 0.53
12/31/2017	$ 17.73	$ 0.55
1/31/2018	$ 17.73	$ 0.55
2/28/2018	$ 17.73	$ 0.50
3/31/2018	$ 17.73	$ 0.55
4/30/2018	$ 17.73	$ 0.53
5/31/2018	$ 17.73	$ 0.55
6/30/2018	$ 35.93	$ 1.08
7/31/2018	$ 35.93	$ 1.11
8/31/2018	$ 35.93	$ 1.11
9/30/2018	$ 35.93	$ 1.08
10/31/2018	$ 35.93	$ 1.11
11/30/2018	$ 35.93	$ 1.08
12/31/2018	$ 35.93	$ 1.11
1/31/2019	$ 35.93	$ 1.11
2/28/2019	$ 35.93	$ 1.01
3/31/2019	$ 35.93	$ 1.11
4/30/2019	$ 35.93	$ 1.08
5/31/2019	$ 35.93	$ 1.11
6/30/2019	$ 72.63	$ 2.18

7/31/2019	$	72.63	$	2.25
8/31/2019	$	72.63	$	2.25
9/30/2019	$	72.63	$	2.18
10/31/2019	$	72.63	$	2.25
11/30/2019	$	72.63	$	2.18
12/31/2019	$	72.63	$	2.25

From:	Wilson, Stuart
To:	Schetzel, Doug; Sinclair, David
Cc:	Schram, Chuck
Subject:	FW: 10 MW Solar Project
Date:	Wednesday, September 25, 2013 12:12:19 PM

David/Doug,

Some feedback from Burns & McDonnell regarding solar costs (see below)…

Stuart

From: Parsons, Megan [redacted]
Sent: Wednesday, September 25, 2013 12:08 PM
To: Wilson, Stuart
Cc: Farhat, Monica; Schram, Chuck
Subject: RE: 10 MW Solar Project

Hi Stuart,

I've copied Peter's response below on solar pricing. Additionally, Peter had noted when developing the Tech Assessment that there is really no economies of scale between 10 MW and 50 MW.
I'm still reviewing the technology assessment to get out to you this week.

Hope this helps….let me know if you need any more info.

Thanks! Megan

From: Johnston, Peter
Sent: Wednesday, September 25, 2013 11:01 AM
To: Parsons, Megan; Poss, Zach
Subject: RE: 10 MW Solar Project

Hi Megan - there are all sorts of numbers out there and it's difficult to compare apples and apples!!

Generally, I agree with Stuart - $3.50/Wac is a little high today. In the TA we provided, the 50 MW system came out at $2.66/Wac for the installed cost without owner's costs etc – that's a little conservative since we had to make some assumptions regarding project siting, civil work etc.

I just received two quotes for a 10 MWac system – one came in at $1.96/Wac and the other at $2.00/Wac . These were for projects with identified sites so they were more refined than our TA estimate.

So I think Stuart can use a cost estimate in the $2.00 - $2.66 range.

Hope that helps

Peter

Peter Johnston
Project Manager – Renewable Energy
Burns & McDonnell
[redacted]

Megan Parsons, PE
Development Section Manager, Energy Division
Burns & McDonnell
[redacted]
*Registered in: MO

From: Wilson, Stuart [redacted]
Sent: Wednesday, September 25, 2013 10:15 AM
To: Parsons, Megan
Cc: Farhat, Monica; Schram, Chuck
Subject: 10 MW Solar Project

Megan,

Thanks for returning my call. We're trying to pull together cost estimates for a 10 MW solar PV project. Our generation technology assessment has a 50 MW solar PV project; I'm not sure to what extent a 10 MW project would have similar costs. For this particular request, we're only interested in the 'direct construction costs' for the panels. So, nothing for the site, project development, or construction management (we have separate estimates for these costs). We've been thinking about direct construction costs in the $3.5/W range (before ITC), but we've been hearing things that suggest the cost is much lower. For example…

1. According to this article (http://breakingenergy.com/2013/09/23/big-solar-is-having-a-banner-year-in-us/), a recent SEIA/GTM report for the quarter ended June 30 showed "utility system prices once again declined quarter-over-quarter and year-over-year, down from $2.60/W in Q2 2012 and $2.14/W in Q1 2013, settling at $2.10/W in Q2 2013." I'm not sure whether these prices are precisely comparable to our $3.5/W figure (or whether they're quoted before or after the ITC). Either way, they appear lower than what we've been thinking…
2. According to a recent filing by Excel Energy (http://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=240772&p_session_id=), it appears their costs are even lower. Excel's analysis of wind/solar begins on page 32 of the PDF (page 30 of the document). Several elements of their analysis are redacted, but based on non-redacted information, we estimated their costs to be in the $1.5/W range. Based on the report (see top of PDF page 34), the project is justified based on its ability to displace combined and simple-cycle gas

units with a combined heat rate of 8,600 btu/kWh (they're assuming $6/mmBtu gas, so this equates to approximately $50/MWh). The project is not credited for the capacity it provides to the system.

These reference points are just FYI (I'm not asking you to review them in detail). It seems that 'current' solar prices are much lower than we thought. Wanted to get your take on this (as a preview to the generation technology study).

Thanks for your help.

Stuart

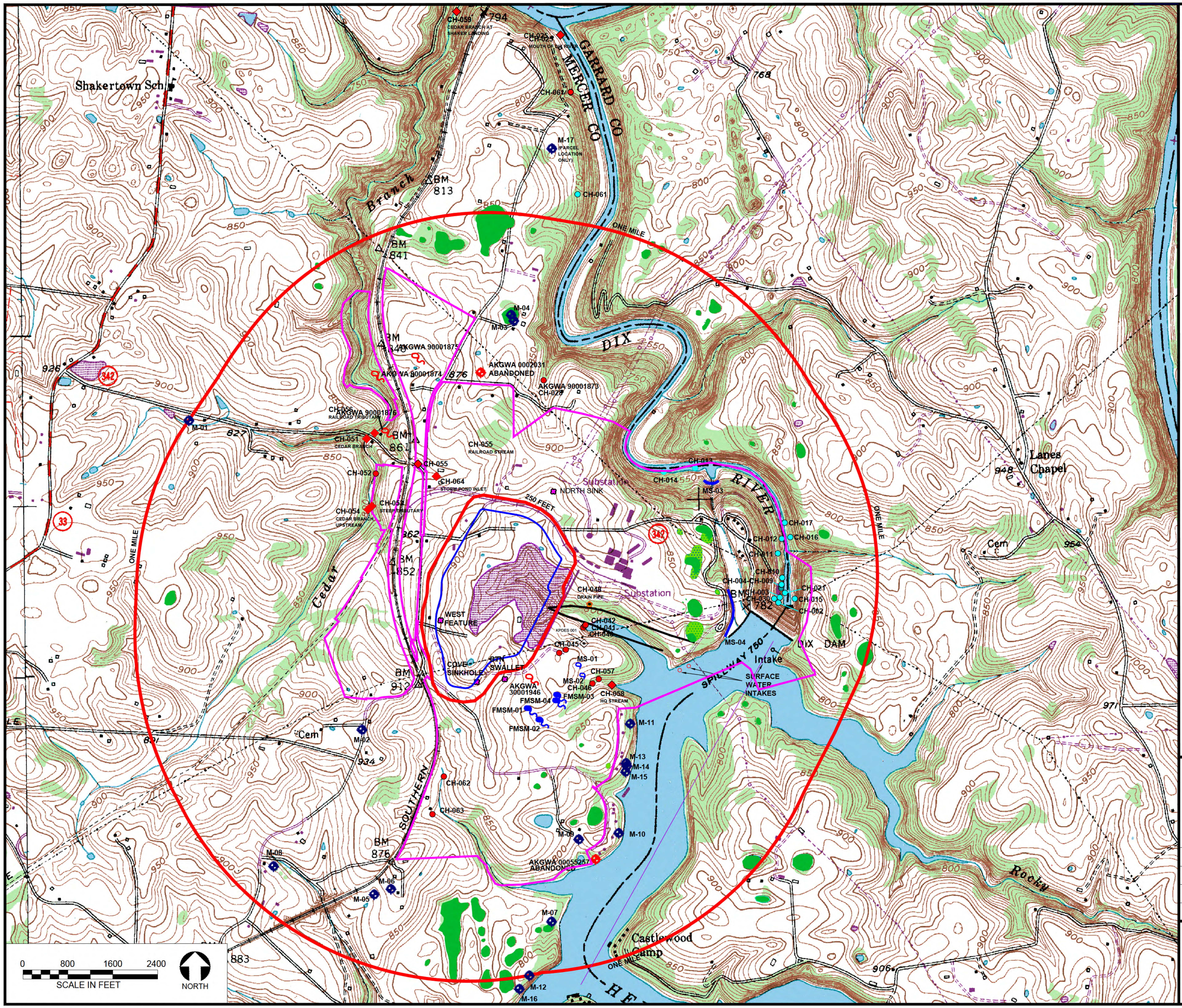
From:	Schetzel, Doug
To:	Brigham, Jim
Cc:	Lively, Noel; Fraley, Jeffrey; Voyles, John; Sinclair, David; Shuler, Carrie
Subject:	Solar Development
Date:	Monday, September 30, 2013 11:16:13 AM
Attachments:	HARDIN ESTATE PLAT 05-09-11.pdf Figure 3-1 - Property Boundary Map- Reduced.pdf 11 - Figure 14-1 - Site Topographic Map - Reduced.pdf 12 - Figure 15-1 - Local Features Map.pdf

---

Jim

We intend to pursue a nominal 10 MW PV solar plant in the upcoming CCN filing. The currently identified site is Thurman Hardin farm adjacent to our Brown Station. Please arrange a call with HDR's best PV siting expert. Assuming HDR can provide the required expertise, we would like HDR to walk the site to determine site feasibility, estimate the amount of capacity that could cost effectively installed on the site and update the capital cost estimate contained in the New Generation Options Feasibility Study with site specific cost estimates.

Douglas Schetzel
Director Business Development
LG&E and KU Energy, LLC
[redacted]



LEGEND

- KU PROPERTY BOUNDARY
- PROPOSED LANDFILL WASTE BOUNDARY
- SURFACE WATER INTAKE
- 250 FT LINE FROM WASTE BOUNDARY
- 1 MILE LINE FROM WASTE BOUNDARY
- HISTORICAL LOCATION OF MAIN POND (AS DEPICTED ON USGS TOPOGRAPHIC MAP)

KGS - MAPPED FEATURES (WITHIN ONE MILE)

- AKGWA 70001875 — SPRING
- AKGWA 0002031 — WELL
- FAULT (DASHED WHERE INFERRED)
- SINKHOLE

DYE MONITORING POINTS

- CH-048 — DRAIN PIPE
- CH-052 — SPRING
- CH-055 — STREAM

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- MS-03 — SEEP ZONE FIELD-MAPPED BY MACTEC/AMEC IN EARLY 2011
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- SINKHOLE FIELD-MAPPED BY MACTEC/AMEC IN EARLY 2011
- INJECTION POINT - MAPPED BY MACTEC/AMEC

SITE AREA TOPOGRAPHIC MAP

E.W. BROWN GENERATING STATION
MERCER COUNTY, KENTUCKY

AMEC PROJECT NUMBER: 3143-10-1364

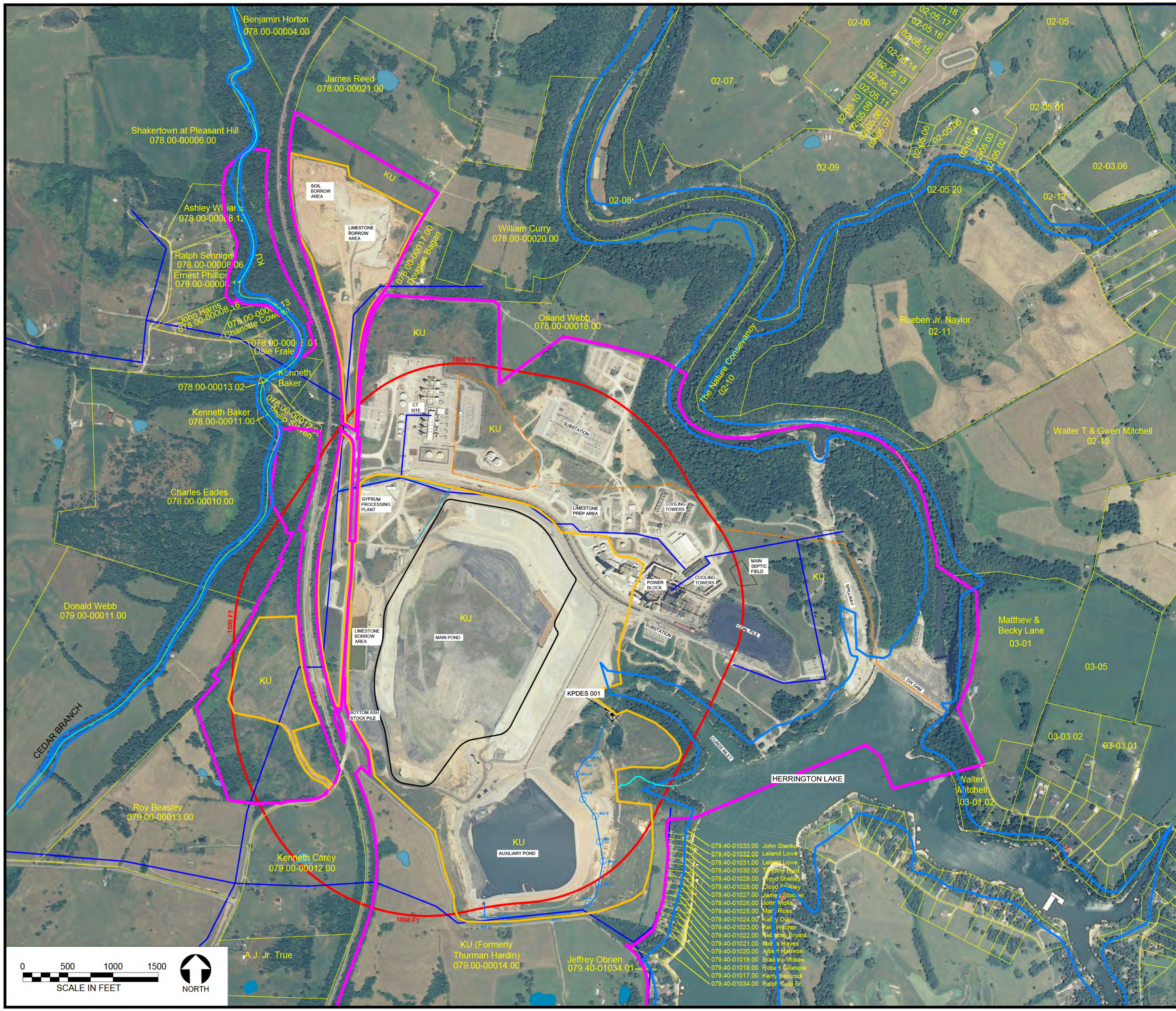
DATE	DRAWN BY	APPROVED	DESCRIPTION
08/03/2011	CSRP	ALD	ORIGINAL DRAWING
07/11/2012	CSRP	ALD	REVISION 1

KU Kentucky Utilities Company
Generation Services

amec
13425 EASTPOINT CENTRE DR #122
LOUISVILLE, KY 40223
PHONE: 1-502-253-2500

FIG 14-1

SOURCE: USGS 7.5' TOPOGRAPHIC QUADRANGLE MAP, WILMORE, KY, 1952. PHOTOREVISED 1979.



SOURCE PHOTOGRAPHS TAKEN JULY 2010, FSA NAIP IMAGERY, FROM KY GIS.

LEGEND

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- MANHOLE / AUXILIARY POND DISCHARGE LINE
- NATURAL GAS MAIN
- POTABLE WATER MAIN
- AUXILIARY POND OUTFALL (UNDER GROUND)
- FEMA 100 YEAR FLOODPLAIN BOUNDARY
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- 079.40-01034.01 PVA PARCEL NUMBER

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LOCAL FEATURES MAP

E.W. BROWN GENERATING STATION
MERCER COUNTY, KENTUCKY

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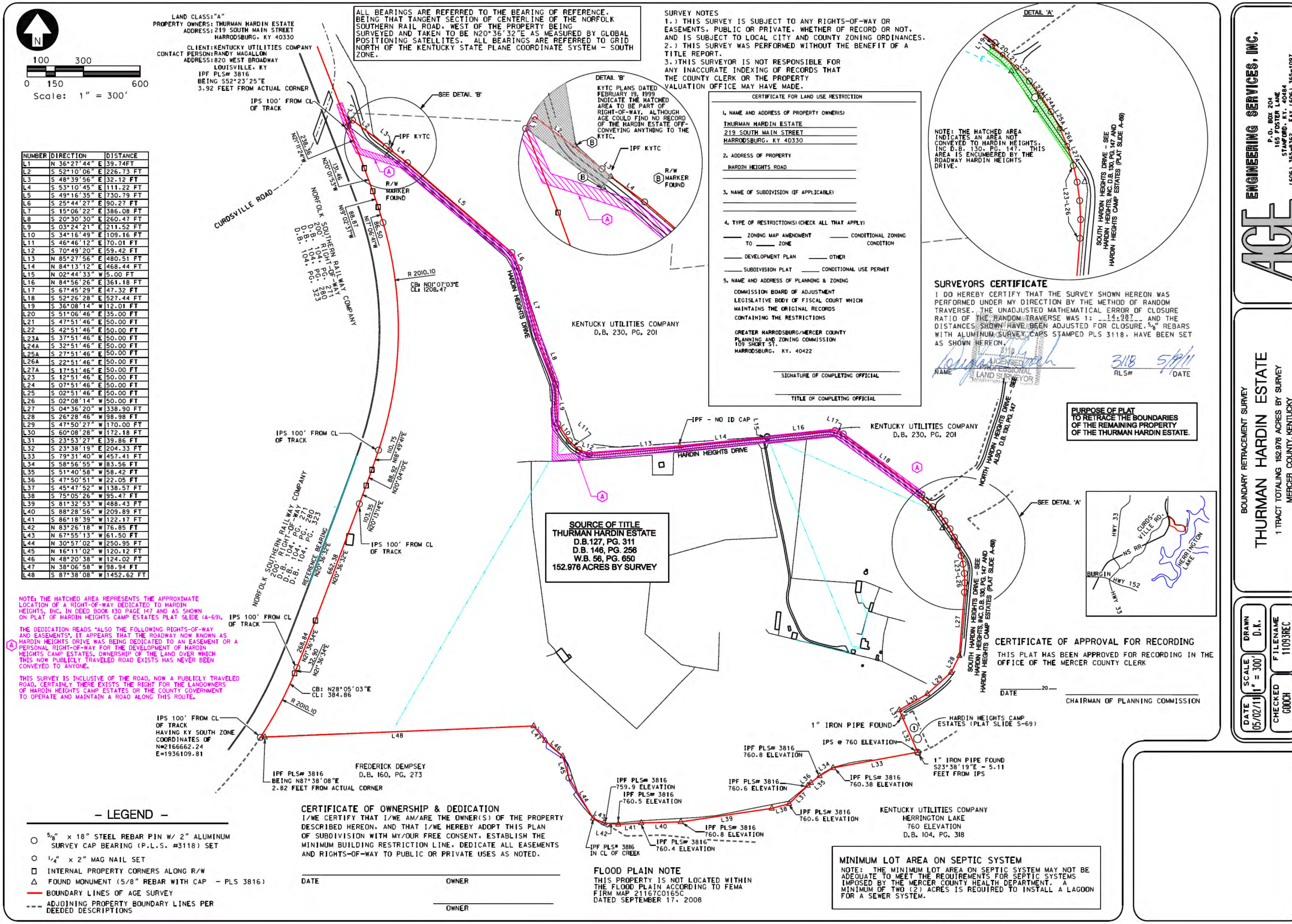
FIG 15-1



NUMBER	DIRECTION	DISTANCE
L1	N 36°27'44" E	39.74FT
L2	S 52°10'06" E	226.73 FT
L3	S 48°39'56" E	32.12 FT
L4	S 53°10'45" E	111.22 FT
L5	S 49°16'35" E	730.79 FT
L6	S 25°44'27" E	90.27 FT
L7	S 15°06'22" E	386.08 FT
L8	S 20°30'30" E	260.47 FT
L9	S 03°24'21" E	211.52 FT
L10	S 34°16'49" E	109.16 FT
L11	S 46°46'12" E	70.01 FT
L12	S 70°49'20" E	59.42 FT
L13	N 85°27'56" E	480.51 FT
L14	N 84°13'12" E	468.44 FT
L15	N 02°44'33" W	5.00 FT
L16	N 84°56'26" E	361.18 FT
L17	S 67°45'29" E	47.32 FT
L18	S 52°26'28" E	527.44 FT
L19	S 36°08'14" W	12.01 FT
L20	S 51°06'46" E	35.00 FT
L21	S 47°51'46" E	50.00 FT
L22	S 42°51'46" E	50.00 FT
L23A	S 37°51'46" E	50.00 FT
L24A	S 32°51'46" E	50.00 FT
L25A	S 27°51'46" E	50.00 FT
L26A	S 22°51'46" E	50.00 FT
L27A	S 17°51'46" E	50.00 FT
L23	S 12°51'46" E	50.00 FT
L24	S 07°51'46" E	50.00 FT
L25	S 02°51'46" E	50.00 FT
L26	S 02°08'14" W	50.00 FT
L27	S 04°36'20" W	338.90 FT
L28	S 26°28'46" W	98.98 FT
L29	S 47°50'27" W	170.00 FT
L30	S 60°08'28" W	172.18 FT
L31	S 23°53'27" E	39.86 FT
L32	S 23°38'19" E	204.33 FT
L33	S 79°31'40" W	457.41 FT
L34	S 58°56'55" W	83.56 FT
L35	S 51°40'58" W	58.42 FT
L36	S 47°50'51" W	22.05 FT
L37	S 45°47'52" W	138.57 FT
L38	S 75°05'26" W	95.47 FT
L39	S 81°32'53" W	488.43 FT
L40	S 88°28'56" W	209.89 FT
L41	S 86°18'39" W	122.17 FT
L42	N 83°26'18" W	76.85 FT
L43	N 67°55'13" W	61.50 FT
L44	N 30°57'02" W	250.95 FT
L45	N 16°11'02" W	120.12 FT
L46	N 48°20'38" W	124.02 FT
L47	N 38°06'58" W	98.94 FT
L48	S 87°38'08" W	1452.62 FT

ALL BEARINGS ARE REFERRED TO THE BEARING OF REFERENCE. BEING THAT TANGENT SECTION OF CENTERLINE OF THE NORFOLK SOUTHERN RAIL ROAD, WEST OF THE PROPERTY BEING SURVEYED AND TAKEN TO BE N20°36'32"E AS MEASURED BY GLOBAL POSITIONING SATELLITES. ALL BEARINGS ARE REFERRED TO GRID NORTH OF THE KENTUCKY STATE PLANE COORDINATE SYSTEM - SOUTH ZONE.

SURVEY NOTES
1.) THIS SURVEY IS SUBJECT TO ANY RIGHTS-OF-WAY OR EASEMENTS, PUBLIC OR PRIVATE, WHETHER OF RECORD OR NOT, AND IS SUBJECT TO LOCAL CITY AND COUNTY ZONING ORDINANCES.
2.) THIS SURVEY WAS PERFORMED WITHOUT THE BENEFIT OF A TITLE REPORT.
3.) THIS SURVEYOR IS NOT RESPONSIBLE FOR ANY INACCURATE INDEXING OF RECORDS THAT THE COUNTY CLERK OR THE PROPERTY VALUATION OFFICE MAY HAVE MADE.

CERTIFICATE FOR LAND USE RESTRICTION

1. NAME AND ADDRESS OF PROPERTY OWNER(S)
THURMAN HARDIN ESTATE
219 SOUTH MAIN STREET
HARRODSBURG, KY 40330

2. ADDRESS OF PROPERTY
HARDIN HEIGHTS ROAD

3. NAME OF SUBDIVISION (IF APPLICABLE)

4. TYPE OF RESTRICTION(S) (CHECK ALL THAT APPLY)
___ ZONING MAP AMENDMENT TO ___ ZONE
___ CONDITIONAL ZONING CONDITION
___ DEVELOPMENT PLAN
___ OTHER
___ SUBDIVISION PLAT
___ CONDITIONAL USE PERMIT

5. NAME AND ADDRESS OF PLANNING & ZONING
COMMISSION BOARD OF ADJUSTMENT
LEGISLATIVE BODY OF FISCAL COURT WHICH MAINTAINS THE ORIGINAL RECORDS CONTAINING THE RESTRICTIONS

GREATER HARRODSBURG/MERCER COUNTY PLANNING AND ZONING COMMISSION
109 SHORT ST.
HARRODSBURG, KY. 40422

SIGNATURE OF COMPLETING OFFICIAL

TITLE OF COMPLETING OFFICIAL

NOTE: THE HATCHED AREA REPRESENTS THE APPROXIMATE LOCATION OF A RIGHT-OF-WAY DEDICATED TO HARDIN HEIGHTS, INC. IN DEED BOOK 130 PAGE 147 AND AS SHOWN ON PLAT OF HARDIN HEIGHTS CAMP ESTATES PLAT SLIDE (A-69).

THE DEDICATION READS "ALSO THE FOLLOWING RIGHTS-OF-WAY AND EASEMENTS". IT APPEARS THAT THE ROADWAY NOW KNOWN AS HARDIN HEIGHTS DRIVE WAS BEING DEDICATED TO AN EASEMENT OR A PERSONAL RIGHT-OF-WAY FOR THE DEVELOPMENT OF HARDIN HEIGHTS CAMP ESTATES. OWNERSHIP OF THE LAND OVER WHICH THIS NOW PUBLICLY TRAVELED ROAD EXISTS HAS NEVER BEEN CONVEYED TO ANYONE.

THIS SURVEY IS INCLUSIVE OF THE ROAD. NOW A PUBLICLY TRAVELED ROAD, CERTAINLY THERE EXISTS THE RIGHT FOR THE LANDOWNERS OF HARDIN HEIGHTS CAMP ESTATES OR THE COUNTY GOVERNMENT TO OPERATE AND MAINTAIN A ROAD ALONG THIS ROUTE.

SOURCE OF TITLE
THURMAN HARDIN ESTATE
D.B.127, PG. 311
D.B. 146, PG. 256
W.B. 56, PG. 650
152.976 ACRES BY SURVEY

SURVEYORS CERTIFICATE
I DO HEREBY CERTIFY THAT THE SURVEY SHOWN HEREON WAS PERFORMED UNDER MY DIRECTION BY THE METHOD OF RANDOM TRAVERSE. THE UNADJUSTED MATHEMATICAL ERROR OF CLOSURE RATIO OF THE RANDOM TRAVERSE WAS 1: 14,987 AND THE DISTANCES SHOWN HAVE BEEN ADJUSTED FOR CLOSURE. 5/8" REBARS WITH ALUMINUM SURVEY CAPS STAMPED PLS 3118, HAVE BEEN SET AS SHOWN HEREON.

NAME 3118 RLS# 5/9/11 DATE

LICENSED PROFESSIONAL LAND SURVEYOR 3118

PURPOSE OF PLAT
TO RETRACE THE BOUNDARIES OF THE REMAINING PROPERTY OF THE THURMAN HARDIN ESTATE.

CERTIFICATE OF APPROVAL FOR RECORDING
THIS PLAT HAS BEEN APPROVED FOR RECORDING IN THE OFFICE OF THE MERCER COUNTY CLERK

DATE ____ 20__

CHAIRMAN OF PLANNING COMMISSION

- LEGEND -
○ 5/8" x 18" STEEL REBAR PIN W/ 2" ALUMINUM SURVEY CAP BEARING (P.L.S. #3118) SET
○ 1/4" x 2" MAG NAIL SET
□ INTERNAL PROPERTY CORNERS ALONG R/W
△ FOUND MONUMENT (5/8" REBAR WITH CAP - PLS 3816)
— BOUNDARY LINES OF ACE SURVEY
--- ADJOINING PROPERTY BOUNDARY LINES PER DEEDED DESCRIPTIONS

CERTIFICATE OF OWNERSHIP & DEDICATION
I/WE CERTIFY THAT I/WE AM/ARE THE OWNER(S) OF THE PROPERTY DESCRIBED HEREON, AND THAT I/WE HEREBY ADOPT THIS PLAN OF SUBDIVISION WITH MY/OUR FREE CONSENT, ESTABLISH THE MINIMUM BUILDING RESTRICTION LINE, DEDICATE ALL EASEMENTS AND RIGHTS-OF-WAY TO PUBLIC OR PRIVATE USES AS NOTED.

DATE OWNER

OWNER

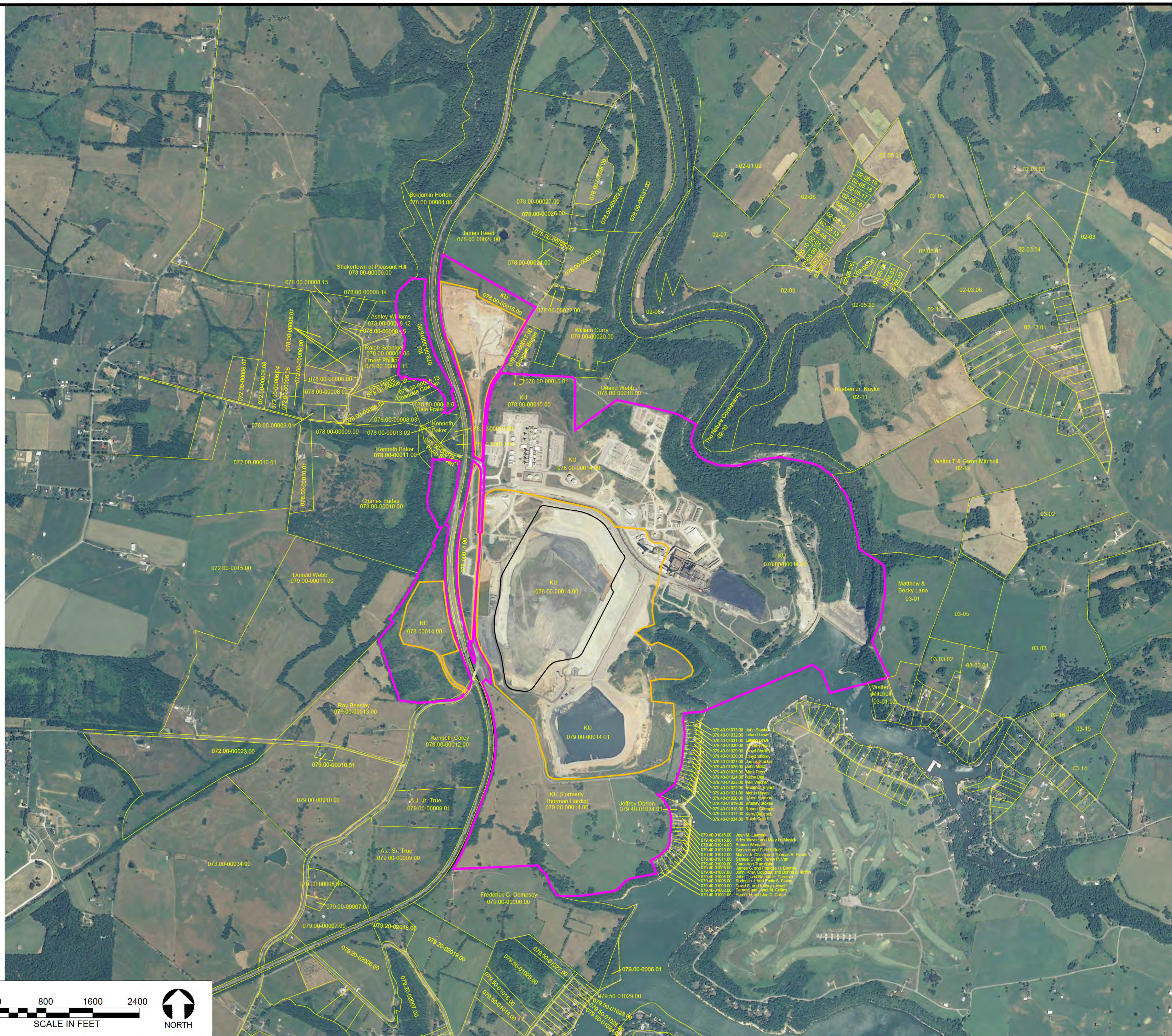
FLOOD PLAIN NOTE
THIS PROPERTY IS NOT LOCATED WITHIN THE FLOOD PLAIN ACCORDING TO FEMA FIRM MAP 21167C0165C DATED SEPTEMBER 17, 2008

MINIMUM LOT AREA ON SEPTIC SYSTEM
NOTE: THE MINIMUM LOT AREA ON SEPTIC SYSTEM MAY NOT BE ADEQUATE TO MEET THE REQUIREMENTS FOR SEPTIC SYSTEMS IMPOSED BY THE MERCER COUNTY HEALTH DEPARTMENT. A MINIMUM OF TWO (2) ACRES IS REQUIRED TO INSTALL A LAGOON FOR A SEWER SYSTEM.

ACE ENGINEERING SERVICES, INC.
P.O. BOX 204
165 FOSTER LANE
STANFORD, KY. 40484
(606) 365-8362 FAX (606) 365-1097

BOUNDARY RETRACEMENT SURVEY
THURMAN HARDIN ESTATE
1 TRACT TOTALING 152.976 ACRES BY SURVEY
MERCER COUNTY, KENTUCKY

DATE	SCALE	DRAWN	CHECKED	FILENAME
05/02/11	1" = 300'	D.K.	GOOCH	11093REC



LEGEND

- KU PROPERTY BOUNDARY
- PROPOSED PERMIT AREA OUTLINE
- PROPOSED LANDFILL WASTE BOUNDARY
- 078.00-00018.00 — PVA PARCEL NUMBER
- PVA PROPERTY LINE (OTHER THAN KU)

NOTE:

NON-KU PROPERTY BOUNDARIES OBTAINED FROM MERCER COUNTY PVA OFFICE. ALL PROPERTY BOUNDARIES ARE APPROXIMATE.

PROPERTY BOUNDARY MAP

E.W. BROWN GENERATING STATION
MERCER COUNTY, KENTUCKY

AMEC PROJECT NUMBER: 3143-10-1364

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07/12/2012	CSRP	ALD	REVISION 1

KU Kentucky Utilities Company
Generation Services

amec
13425 EASTPOINT CENTRE DR #122
LOUISVILLE, KY 40223
PHONE: 1-502-253-2500

FIG 3-1

SOURCE PHOTOGRAPHS TAKEN JULY 2010, FSA NAIP IMAGERY, FROM KY GIS.

From:	Schetzel, Doug
To:	Brigham, Jim
Cc:	Lively, Noel; Fraley, Jeffrey; Voyles, John; Sinclair, David; Shuler, Carrie
Subject:	Solar Development
Date:	Monday, September 30, 2013 11:16:13 AM
Attachments:	HARDIN ESTATE PLAT 05-09-11.pdf Figure 3-1 - Property Boundary Map- Reduced.pdf 11 - Figure 14-1 - Site Topographic Map - Reduced.pdf 12 - Figure 15-1 - Local Features Map.pdf

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Director Business Development
LG&E and KU Energy, LLC
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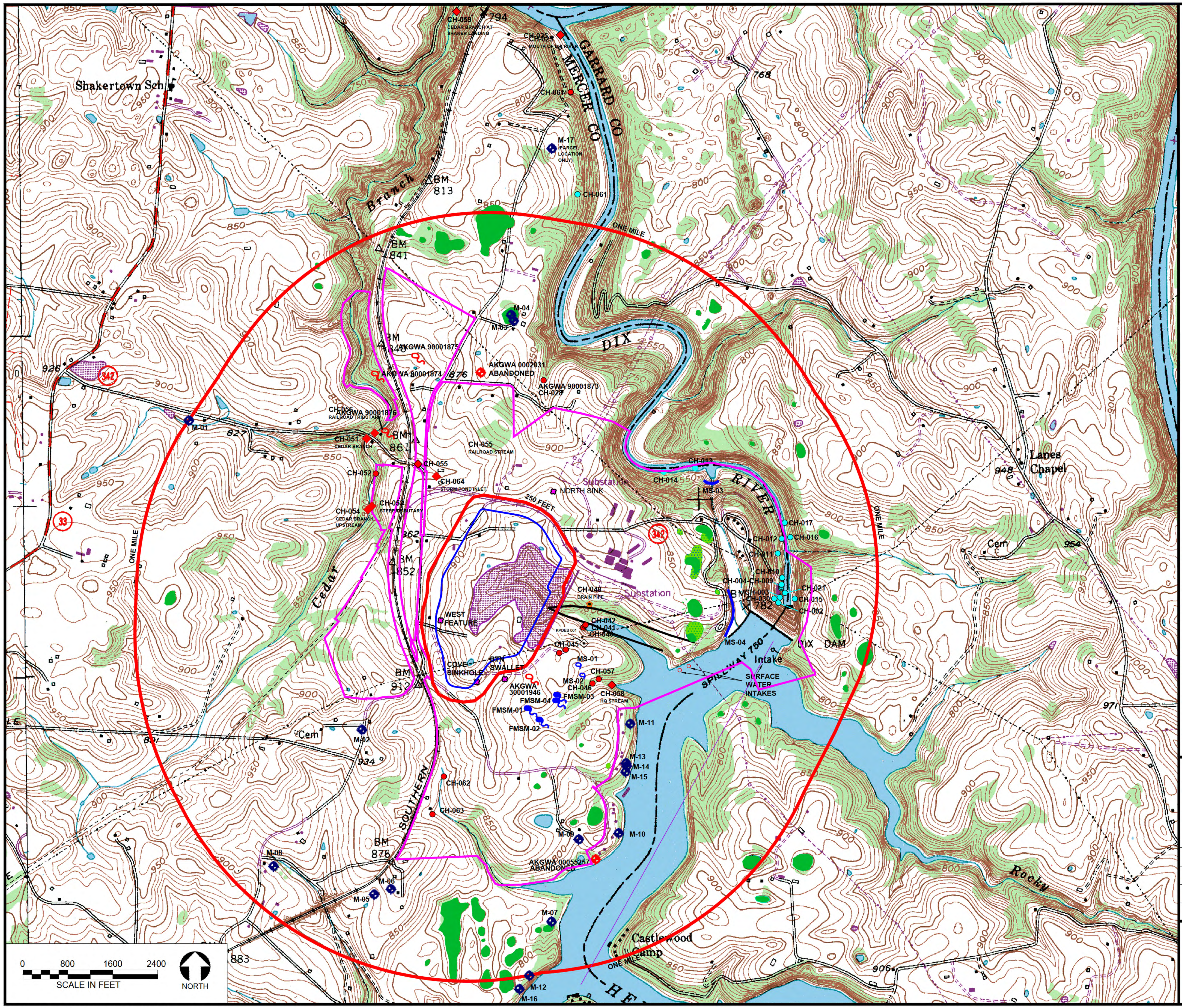

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- KU PROPERTY BOUNDARY
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- 250 FT LINE FROM WASTE BOUNDARY
- 1 MILE LINE FROM WASTE BOUNDARY
- HISTORICAL LOCATION OF MAIN POND (AS DEPICTED ON USGS TOPOGRAPHIC MAP)

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- AKGWA 70001875 SPRING
- AKGWA 0002031 WELL
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DYE MONITORING POINTS

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SITE AREA TOPOGRAPHIC MAP

E.W. BROWN GENERATING STATION
MERCER COUNTY, KENTUCKY

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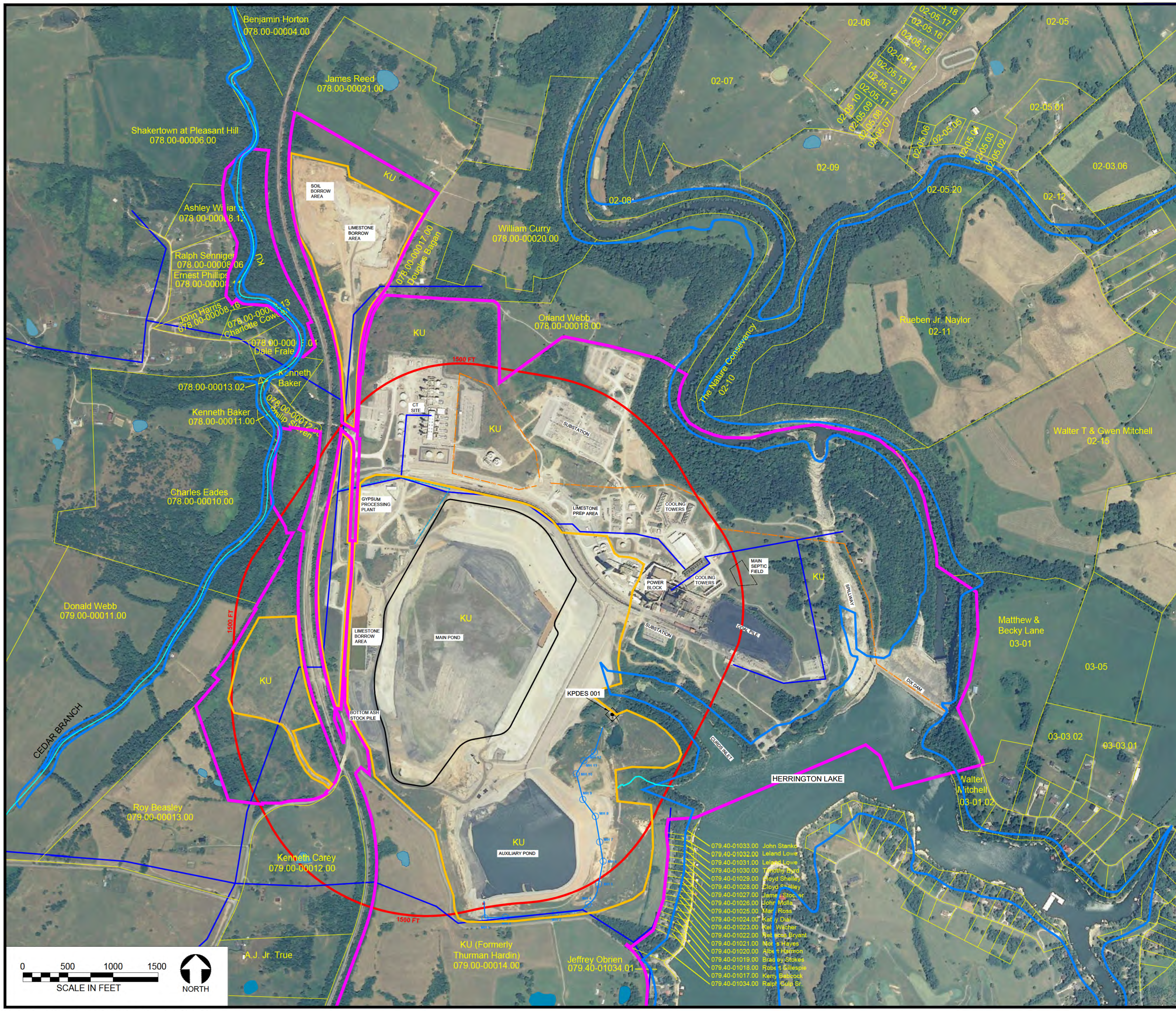
FIG 14-1

SOURCE: USGS 7.5' TOPOGRAPHIC QUADRANGLE MAP, WILMORE, KY, 1952. PHOTOREVISED 1979.



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MERCER COUNTY, KENTUCKY

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LOUISVILLE, KY 40223
PHONE: 1-502-253-2500

FIG 15-1

SOURCE PHOTOGRAPHS TAKEN JULY 2010, FSA NAIP IMAGERY, FROM KY GIS.

N

100 300
0 150 600
Scale: 1" = 300'

LAND CLASS:"A"
PROPERTY OWNERS: THURMAN HARDIN ESTATE
ADDRESS: 219 SOUTH MAIN STREET
HARRODSBURG, KY 40330

CLIENT: KENTUCKY UTILITIES COMPANY
CONTACT PERSON: RANDY MAGALLON
ADDRESS: 820 WEST BROADWAY
LOUISVILLE, KY

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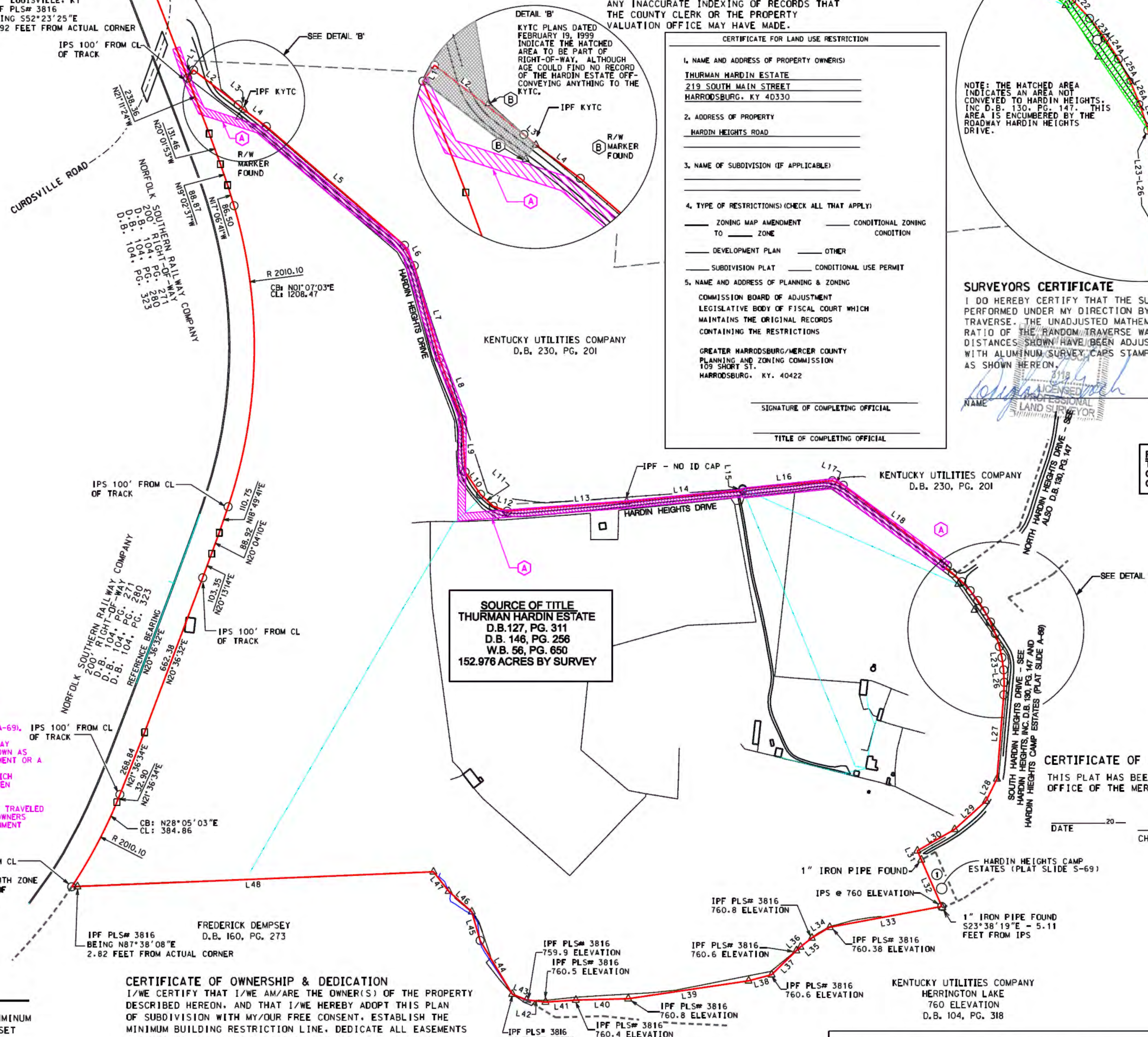
L7	S 15°06'22" E	386.08 FT
L8	S 20°30'30" E	260.47 FT
L9	S 03°24'21" E	211.52 FT
L10	S 34°16'49" E	109.16 FT
L11	S 46°46'12" E	70.01 FT
L12	S 70°49'20" E	59.42 FT
L13	N 85°27'56" E	480.51 FT
L14	N 84°13'12" E	468.44 FT
L15	N 02°44'33" W	5.00 FT
L16	N 84°56'26" E	361.18 FT
L17	S 67°45'29" E	47.32 FT
L18	S 52°26'28" E	527.44 FT
L19	S 36°08'14" W	12.01 FT
L20	S 51°06'46" E	35.00 FT
L21	S 47°51'46" E	50.00 FT
L22	S 42°51'46" E	50.00 FT
L23A	S 37°51'46" E	50.00 FT
L24A	S 32°51'46" E	50.00 FT
L25A	S 27°51'46" E	50.00 FT
L26A	S 22°51'46" E	50.00 FT
L27A	S 17°51'46" E	50.00 FT
L23	S 12°51'46" E	50.00 FT
L24	S 07°51'46" E	50.00 FT
L25	S 02°51'46" E	50.00 FT
L26	S 02°08'14" W	50.00 FT
L27	S 04°36'20" W	338.90 FT
L28	S 26°28'46" W	98.98 FT
L29	S 47°50'27" W	170.00 FT
L30	S 60°08'28" W	172.18 FT
L31	S 23°53'27" E	39.86 FT
L32	S 23°38'19" E	204.33 FT
L33	S 79°31'40" W	457.41 FT
L34	S 58°56'55" W	83.56 FT
L35	S 51°40'58" W	58.42 FT
L36	S 47°50'51" W	22.05 FT
L37	S 45°47'52" W	138.57 FT
L38	S 75°05'26" W	95.47 FT
L39	S 81°32'53" W	488.43 FT
L40	S 88°28'56" W	209.89 FT
L41	S 86°18'39" W	122.17 FT
L42	N 83°26'18" W	76.85 FT
L43	N 67°55'13" W	61.50 FT
L44	N 30°57'02" W	250.95 FT
L45	N 16°11'02" W	120.12 FT
L46	N 48°20'38" W	124.02 FT
L47	N 38°06'58" W	98.94 FT
L48	S 87°38'08" W	1452.62 FT



SOURCE OF TITLE
THURMAN HARDIN ESTATE
D.B.127, PG. 311
D.B. 146, PG. 256
W.B. 56, PG. 650
152.976 ACRES BY SURVEY

NOTE: THE HATCHED AREA REPRESENTS THE APPROXIMATE LOCATION OF A RIGHT-OF-WAY DEDICATED TO HARDIN HEIGHTS, INC. IN DEED BOOK 130 PAGE 147 AND AS SHOWN ON PLAT OF HARDIN HEIGHTS CAMP ESTATES PLAT SLIDE (A-69).

(A) THE DEDICATION READS "ALSO THE FOLLOWING RIGHTS-OF-WAY AND EASEMENTS". IT APPEARS THAT THE ROADWAY NOW KNOWN AS HARDIN HEIGHTS DRIVE WAS BEING DEDICATED TO AN EASEMENT OR A PERSONAL RIGHT-OF-WAY FOR THE DEVELOPMENT OF HARDIN HEIGHTS CAMP ESTATES. OWNERSHIP OF THE LAND OVER WHICH THIS NOW PUBLICLY TRAVELED ROAD EXISTS HAS NEVER BEEN CONVEYED TO ANYONE.

THIS SURVEY IS INCLUSIVE OF THE ROAD, NOW A PUBLICLY TRAVELED ROAD. CERTAINLY THERE EXISTS THE RIGHT FOR THE LANDOWNERS OF HARDIN HEIGHTS CAMP ESTATES OR THE COUNTY GOVERNMENT TO OPERATE AND MAINTAIN A ROAD ALONG THIS ROUTE.

CERTIFICATE FOR LAND USE RESTRICTION

1. NAME AND ADDRESS OF PROPERTY OWNER(S)
THURMAN HARDIN ESTATE
219 SOUTH MAIN STREET
HARRODSBURG, KY 40330

2. ADDRESS OF PROPERTY
HARDIN HEIGHTS ROAD

3. NAME OF SUBDIVISION (IF APPLICABLE)

4. TYPE OF RESTRICTION(S) (CHECK ALL THAT APPLY)
____ ZONING MAP AMENDMENT TO ____ ZONE
____ CONDITIONAL ZONING CONDITION
____ DEVELOPMENT PLAN
____ OTHER
____ SUBDIVISION PLAT
____ CONDITIONAL USE PERMIT

5. NAME AND ADDRESS OF PLANNING & ZONING COMMISSION BOARD OF ADJUSTMENT LEGISLATIVE BODY OF FISCAL COURT WHICH MAINTAINS THE ORIGINAL RECORDS CONTAINING THE RESTRICTIONS

GREATER HARRODSBURG/MERCER COUNTY
PLANNING AND ZONING COMMISSION
109 SHORT ST.
HARRODSBURG, KY. 40422

SIGNATURE OF COMPLETING OFFICIAL

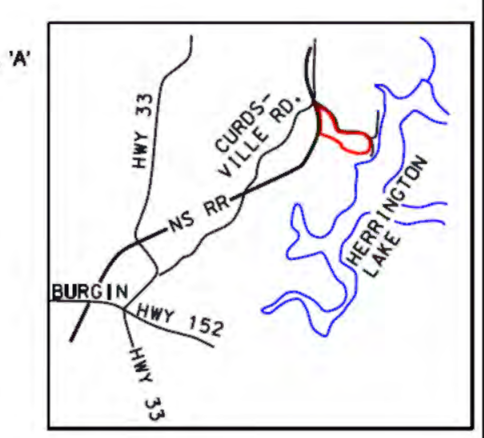
TITLE OF COMPLETING OFFICIAL

SURVEYORS CERTIFICATE
I DO HEREBY CERTIFY THAT THE SURVEY SHOWN HEREON WAS PERFORMED UNDER MY DIRECTION BY THE METHOD OF RANDOM TRAVERSE. THE UNADJUSTED MATHEMATICAL ERROR OF CLOSURE RATIO OF THE RANDOM TRAVERSE WAS 1: 14,987 AND THE DISTANCES SHOWN HAVE BEEN ADJUSTED FOR CLOSURE. 5/8" REBARS WITH ALUMINUM SURVEY CAPS STAMPED PLS 3118, HAVE BEEN SET AS SHOWN HEREON.

3118 LICENSED PROFESSIONAL LAND SURVEYOR

NAME 3118 RLS# 5/9/11 DATE

PURPOSE OF PLAT
TO RETRACE THE BOUNDARIES OF THE REMAINING PROPERTY OF THE THURMAN HARDIN ESTATE.



CERTIFICATE OF APPROVAL FOR RECORDING
THIS PLAT HAS BEEN APPROVED FOR RECORDING IN THE OFFICE OF THE MERCER COUNTY CLERK

DATE ____ 20__

CHAIRMAN OF PLANNING COMMISSION

- LEGEND -

○ 5/8" x 18" STEEL REBAR PIN W/ 2" ALUMINUM SURVEY CAP BEARING (P.L.S. #3118) SET
○ 1/4" x 2" MAG NAIL SET
□ INTERNAL PROPERTY CORNERS ALONG R/W
△ FOUND MONUMENT (5/8" REBAR WITH CAP - PLS 3816)
BOUNDARY LINES OF ACE SURVEY
ADJOINING PROPERTY BOUNDARY LINES PER DEEDED DESCRIPTIONS

CERTIFICATE OF OWNERSHIP & DEDICATION
I/WE CERTIFY THAT I/WE AM/ARE THE OWNER(S) OF THE PROPERTY DESCRIBED HEREON, AND THAT I/WE HEREBY ADOPT THIS PLAN OF SUBDIVISION WITH MY/OUR FREE CONSENT, ESTABLISH THE MINIMUM BUILDING RESTRICTION LINE, DEDICATE ALL EASEMENTS AND RIGHTS-OF-WAY TO PUBLIC OR PRIVATE USES AS NOTED.

DATE OWNER

OWNER

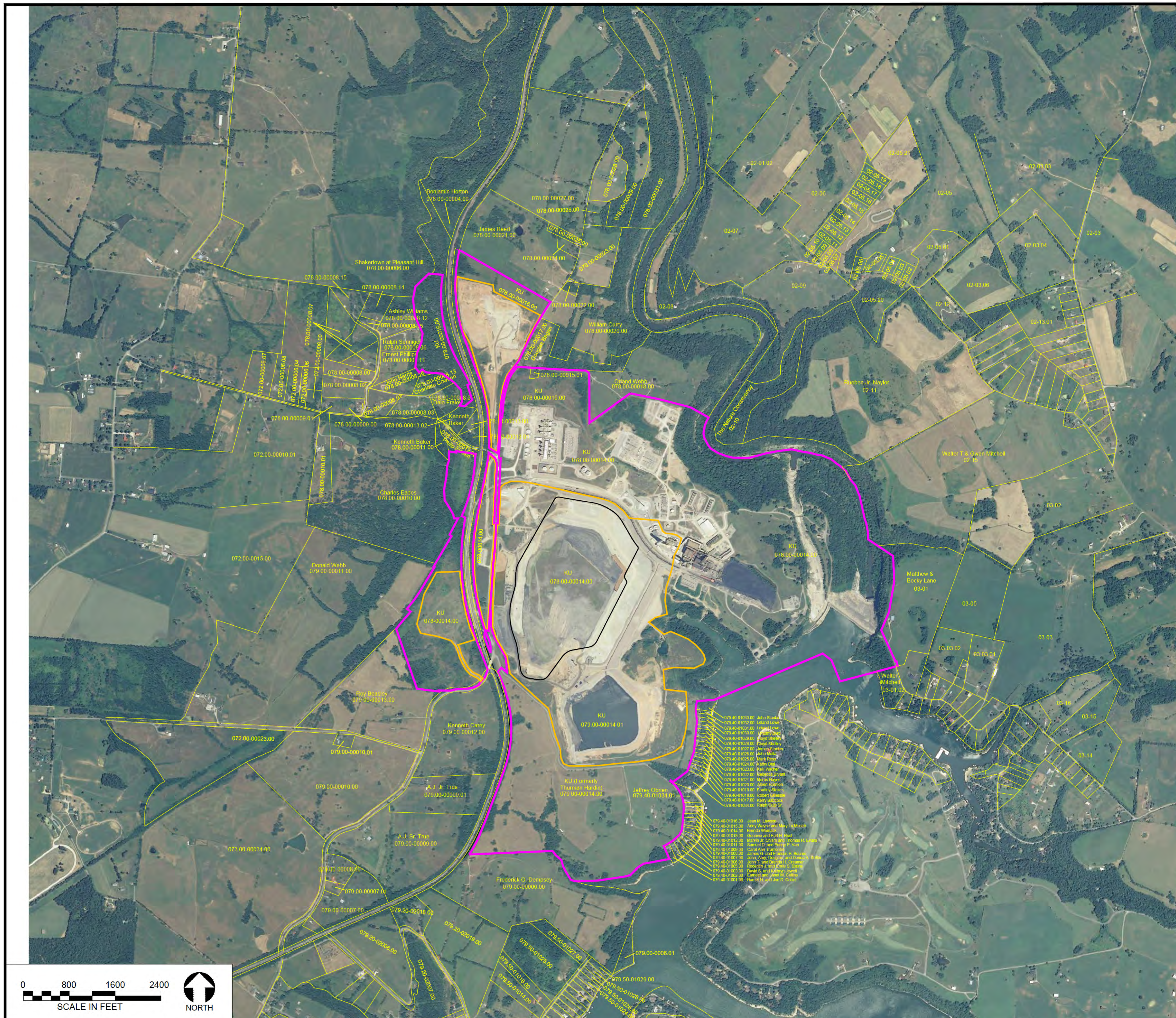
FLOOD PLAIN NOTE
THIS PROPERTY IS NOT LOCATED WITHIN THE FLOOD PLAIN ACCORDING TO FEMA FIRM MAP 21167C0165C DATED SEPTEMBER 17, 2008

MINIMUM LOT AREA ON SEPTIC SYSTEM
NOTE: THE MINIMUM LOT AREA ON SEPTIC SYSTEM MAY NOT BE ADEQUATE TO MEET THE REQUIREMENTS FOR SEPTIC SYSTEMS IMPOSED BY THE MERCER COUNTY HEALTH DEPARTMENT. A MINIMUM OF TWO (2) ACRES IS REQUIRED TO INSTALL A LAGOON FOR A SEWER SYSTEM.

ACE ENGINEERING SERVICES, INC.
P.O. BOX 204
165 FOSTER LANE
STANFORD, KY. 40484
(606) 365-8362 FAX (606) 365-1097

BOUNDARY RETRACEMENT SURVEY
THURMAN HARDIN ESTATE
1 TRACT TOTALING 152.976 ACRES BY SURVEY
MERCER COUNTY, KENTUCKY

DATE	SCALE	DRAWN	CHECKED	FILENAME
05/02/11	1" = 300'	D.K.	GOOCH	11093REC



LEGEND

KU PROPERTY BOUNDARY

PROPOSED PERMIT AREA OUTLINE

PROPOSED LANDFILL WASTE BOUNDARY

078.00-00018.00 PVA PARCEL NUMBER

PVA PROPERTY LINE (OTHER THAN KU)

NOTE:

NON-KU PROPERTY BOUNDARIES OBTAINED FROM MERCER COUNTY PVA OFFICE. ALL PROPERTY BOUNDARIES ARE APPROXIMATE.

PROPERTY BOUNDARY MAP

E.W. BROWN GENERATING STATION
MERCER COUNTY, KENTUCKY

AMEC PROJECT NUMBER: 3143-10-1364

DATE	DRAWN BY	APPROVED	DESCRIPTION
08/02/11	CSRP	ALD	ORIGINAL DRAWING
07/12/2012	CSRP	ALD	REVISION 1

Kentucky Utilities Company
Generation Services

amec
13425 EASTPOINT CENTRE DR #122
LOUISVILLE, KY 40223
PHONE: 1-502-253-2500

FIG 3-1

SOURCE PHOTOGRAPHS TAKEN JULY 2010, FSA NAIP IMAGERY, FROM KY GIS.

From: Wilson, Stuart
To: Sinclair, David
Cc: Schram, Chuck
Subject: Solar Project Revenue Requirements (RR)
Date: Wednesday, October 02, 2013 5:13:19 PM

David,

Based on recent cost estimates from Burns & McDonnell, the cost of constructing a 10 MW (AC rating) solar PV facility at one of our existing plants is approximately $2,400/kW. We evaluated this project over twelve gas, load, and carbon scenarios. Given its size, the project was not credited with the value of deferring the need for future generating resources. The revenue requirement (RR) impacts are summarized in the table below (positive impacts to revenue requirements are unfavorable). The project is favorable across the six mid carbon cases (impact to production costs more than offsets capital RR and O&M costs). When all scenarios are considered, the RR impact is unfavorable (by approximately $3.2 million).

Gas Price	Load	Carbon	RR Impact ($000s, $2013)
Mid Gas	Base Load	Zero Carbon	7,600
		Mid Carbon	600
	Low Load	Zero Carbon	7,100
		Mid Carbon	100
High Gas	Base Load	Zero Carbon	6,300
		Mid Carbon	-2,300
	Low Load	Zero Carbon	7,200
		Mid Carbon	-4,200
Low Gas	Base Load	Zero Carbon	9,700
		Mid Carbon	-4,600
	Low Load	Zero Carbon	11,200
		Mid Carbon	-200
Average (All Cases)			3,200
Average (Mid Carbon Cases)			-1,800

Stuart

From:	Sinclair, David
To:	Rives, Brad
Cc:	Thompson, Paul
Subject:	FW: Solar Project Revenue Requirements (RR)
Date:	Wednesday, October 02, 2013 5:52:00 PM

Brad,

Sorry for the delay in getting this to you. I had a few questions that I wanted answered before passing it on.

Below are the revenue requirement values for all 12 cases. As I mentioned on the phone, CO_2 costs are important since the project only lowers revenue requirements in the mid carbon cases absent giving the project some capacity deferral credit (which is about $4 million NPVRR). If the project is given credit for contributing to deferring capacity, then it would lower revenue requirement across the average of all cases but is still not very attractive without some cost to carbon.

In developing these cases, it was assumed that the energy profile would be the same for each day in the year so that the project produced around an 18% annual capacity factor (AC rating). While that is a good value for the year based on the PVWatts software that I mentioned, the "average day" assumption probably understates the project value because it will produce more energy in the summer (when potential fuel saving is more valuable) and less in the winter months. The daily profile was not critical when the capital costs made the project so far out of the money but now that we have updated the capital costs, we will update the energy profile prior to filing to better capture the value of the energy savings.

Thanks,
David

From: Wilson, Stuart
Sent: Wednesday, October 02, 2013 5:13 PM
To: Sinclair, David
Cc: Schram, Chuck
Subject: Solar Project Revenue Requirements (RR)

David,

Based on recent cost estimates from Burns & McDonnell, the cost of constructing a 10 MW (AC rating) solar PV facility at one of our existing plants is approximately $2,400/kW. We evaluated this project over twelve gas, load, and carbon scenarios. Given its size, the project was not credited with the value of deferring the need for future generating resources. The revenue requirement (RR) impacts are summarized in the table below (positive impacts to revenue requirements are unfavorable). The project is favorable across the six mid carbon cases (impact to production costs more than offsets capital RR and O&M costs). When all scenarios are considered, the RR impact is unfavorable (by approximately $3.2 million).

Gas Price	Load	Carbon	RR Impact ($000s, $2013)
Mid Gas	Base Load	Zero Carbon	7,600
		Mid Carbon	600
	Low Load	Zero Carbon	7,100
		Mid Carbon	100
High Gas	Base Load	Zero Carbon	6,300
		Mid Carbon	-2,300
	Low Load	Zero Carbon	7,200
		Mid Carbon	-4,200
Low Gas	Base Load	Zero Carbon	9,700
		Mid Carbon	-4,600
	Low Load	Zero Carbon	11,200
		Mid Carbon	-200
Average (All Cases)			3,200
Average (Mid Carbon Cases)			-1,800

Stuart

From: Wilson, Stuart
To: Sinclair, David
Cc: Schram, Chuck
Subject: Breakeven Cost for Solar
Date: Wednesday, October 02, 2013 9:29:23 AM

David,

The table below lists the breakeven cost for solar over the scenarios we considered. If direct construction costs are $2,000/kW (per Burns and McDonnell), our total capital cost (before ITC) is $2,380/kW. These breakeven costs are comparable to the $2,380/kW figure. No value of deferral is assumed. When we average the mid carbon cases, we break even. Capital cost have to drop to around $1,885/kW to break even across all cases (with no value of deferral).

Scenario	Solar Cost ($/kW)
BGBL0C	1,123
BGBLMC	2,613
BGLL0C	1,733
BGLLMC	2,036
HGBL0C	1,542
HGBLMC	3,183
HGLL0C	1,944
HGLLMC	2,650
LGBL0C	1,684
LGBLMC	1,824
LGLL0C	302
LGLLMC	1,989
Avg All Cases	1,885
Avg MC Cases	2,383

Stuart

From:	Early, John
To:	Sinclair, David
Cc:	Brunner, Bob; Cermack, Trish
Subject:	BREC
Date:	Friday, October 11, 2013 2:02:20 PM
Attachments:	2013AnnualReview_BigRiversElectricCorp.pdf Moodys_BREC_07.11.2013.pdf S&P_BigRiversElectricCorp_08.02.2013.pdf

---

David,

Bob asked me for BREC's credit status with LG&E. I have attached our most recent write-up containing key risks associated with them and the most recent Moody's and S&P articles for your review. Based on their below investment grade ratings of BB- and Ba2, they are considered a high risk counterparty and according to our internal credit model, qualify for only a $400,000 credit limit. I will be out of the office on vacation at Disneyworld next week but feel free to follow up with Trish if you have any additional questions.

Thanks,
John

ClearPath Company Insights – Internal Score

PPL Financial Scoring Report

Global Credit Services ClearPath

BIG RIVERS ELECTRIC CORPORATION

201 3rd St
Henderson, KY 42420--2979 USA
www.bigrivers.com

Exchange/Ticker:
Account # LKE-100129

Rating	Score	Risk
bb	4.32	Double b

Period: 12 Mos - 12/31/2012
Scorecard: COOP/MUNI UtilitY GC '09
Displayed Currency: US Dollar
Reporting Currency: US Dollar

Description of Business

Big Rivers Electric Corporation is an electric generation and transmission cooperative (G&T) headquartered in Henderson, Kentucky and owned by its three member system distribution cooperatives: Jackson Purchase Energy Corporation, headquartered in Paducah; Kenergy Corp., headquartered in Henderson; and Meade County Rural Electric Cooperative Corporation, headquartered in Brandenburg. Big Rivers supplies the wholesale power needs of its three-member systems and markets surplus power to non-member utilities and power markets. These members system cooperatives provide retail electric power and energy to more than 111,000 residential, commercial, and industrial customers in portions of 22 Western Kentucky counties.

Composite Score History

Summary	12 Mos 12/31/2012	12 Mos 12/31/2011	12 Mos 12/31/2010	12 Mos 12/31/2009	12 Mos 12/31/2008
Composite Score	4.32	4.28	4.38	3.90	4.87
Rating	bb	bb+	bb	bbb-	b+
Recommended Credit Limit	400,000	750,000	400,000	3,750,000	0
Component					
Primary Ratio Scoring	4.22	4.27	4.40	4.17	4.90
Analyst Score Adjustment	0.00	0.00	0.00	0.00	0.00
Agencies, lowest LT	4.55 BB-	0.00 NR	0.00 NR	0.00 NR	0.00 NR
Secondary Ratio Scoring & FYI	4.10	4.34	4.25	2.53	4.67

Approved Credit Line

Amount	Date Approved	Expiration Date	Collateral Amount
100,000	11/15/2012	10/31/2014	0

ClearPath Company Insights – Internal Score

PPL Financial Scoring Report

Global Credit Services ClearPath

Financial Credit Line Computation

Summary				
Recommended Credit Limit	**400,000**			
Calculation	**Amount**	**Date**	**% Weight**	**Weighted Amount**
Tangible Net Worth	402,882,000	12/31/2012	100.00%	402,882,000
Size Metric				402,882,000
Guideline %	2.00%			
Unadjusted Credit Limit	**8,057,640**			
Concentration Limit	**400,000**			

Analyst Recommendation & Comment

08/29/2013 | By Trish Cermack

Background: Henderson, Kentucky-based Big Rivers Electric Corporation (BREC) is a generation and transmission cooperative that produces and procures electricity for sale to three distribution cooperative members and their 113,000 customers. The three member cooperatives are Kenergy Corp., Jackson Purchase Energy and Meade County Rural Electric Cooperative. BREC owns and operates 1,444 megawatts of generating capacity in four stations with total generation capacity of 1,819 megawatts, which includes rights to Henderson Municipal Power and Light (HMP&L) Station Two and contracted capacity from Southeastern Power Administration (SEPA).

BREC is rated BB- by S&P, the equivalent risk rating of a 4. S&P currently has a negative outlook on BREC and notes the following recent developments:

- In August 2012, BREC's leading customer issued a 12-month notice to terminate its contract. The notice covers Century Aluminum Co.'s Hawesville, Kentucky smelter. Century accounted for 35% of the utility's 2012 operating revenues.
- After the utility filed a rate case with the KPSC on January 15, 2013, and requested rate relief that would, among other things, reallocate costs borne by Century to its remaining customers, a second smelter, Rio Tinto Alcan Inc., issued a 12-month notice to terminate its power contract with BREC. The notice covers the company's Sebree smelter, which accounted for 28% of BREC's 2012 operating revenues. The company's rate filing proposed raising Alcan's rates 16%. On June 1, Century succeeded Alcan as owner of the Sebree plant.
- S&P believes that losing these two loads will deprive the utility of substantial anchors that have supported much of its fixed costs. Additionally, S&P views the extent to which the KPSC will approve reallocating costs to remaining customers as uncertain.
- BREC and Century are seeking KPSC approval allowing the Hawesville facility to purchase market power over BREC and its member's lines as a means of preserving a portion of the smelter's contributions to revenues, but will not shield the utility from having surplus generation capacity. However, through May 1, 2014, if Century purchases market power, it will need to pay a portion of BREC's fixed and variable operating costs for the Coleman plant that is deemed to have reliability must run status within MISO's footprint.

- Many of the counties served by BREC have income levels that are 20%-30% below the national median household effective buying income. Consequently, the implications of the smelter departures on the member revenues that support the company's debt is uncertain.
- BREC depends almost exclusively on coal units, which also could constrain market sales opportunities. Coal has accounted for close to 90% of its power sales and its coal units are not as economical as competing gas-fired resources that are benefitting from the fuel's low prices. Market sales in 2012 of 1.5 million MWhs were half of 2011's market sales volume.
- Century's termination notice precluded BREC from borrowing on its $50 million line of credit with CoBank ACB and created a potential default event. Consequently, the utility terminated the line to avert a default and preserve its term loan with CoBank. BREC expects to extend its $50 million line with National Rural Utilities Cooperative Finance Corp. before its August 2013 expiration.
- BREC reports it deferred maintenance in 2012 to control expenses. Although it does not plan to defer maintenance in 2013, it is revisiting its capital program pending more certainty as to the timing and extent of rate rellief.

Transaction: BREC is a transmission customer of LG&E-KU.

2012 Financial Review: 2012 net margin was $11.3 million, an increase of $5.7 million as compared to net margins of $5.6 million in 2011. Several items account for the majority of the $5.7 million improvement. First, net sales margins for 2012 reflect a $10.1 million improvement due to a full year of the Member-Owner base rate increase that became effective September 2011, higher smelter sales volumes, and lower reagent, fuel and purchased power variable operating costs. These were offset by depressed off-system market prices. Interest expense reflects a favorable variance of $0.8 million on long-term debt, and interest income reflects a favorable variance of $0.8 million, both a result of the July 2012 refinancing. Offsetting the improvement is a $5.7 million increase in depreciation expense in 2012. This is due to a full year of higher depreciation rates resulting from the 2010 depreciation study implemented in December 2011 following PSC approval. Tangible Net Worth (TNW) was $403 million at December 31, 2012. Liquidity included $68.9 million in cash and cash equivalents and access to the CFC line of credit totaling $50 million until August 19, 2013 with approximately $45 million available at year-end 2012.

LKE Recommendation: We recommend a $100 thousand limit for BREC based on a review of their most recent monthly transmission charges and BREC's current 1.25 coverage ratio reported for the company's RUS (Rural Utilities Service) debt for the calendar year 2012 (see Attachment L, Section 3.2, Part c in LG&E-KU's Transmission Tariff for this customer credit requirement). We will be making a request for quarterly updates on the above noted coverage ratios, although it is only required to be reported for the most recent calendar year end.

Analyst: Trish Cermack Trish Cermack

Manager: John Early John Early

Composite Score Components

Summary			
Composite Score	4.32		
Component	Raw Score	% Weight	Weighted Score

ClearPath Company Insights – Internal Score

PPL Financial Scoring Report

Global Credit Services ClearPath

Primary Ratio Scoring	4.22	56.00	2.36
Agencies, lowest LT	4.55	33.33	1.52
Secondary Ratio Scoring & FYI	4.10	10.67	0.44
Analyst Score Adjustment	0.00	0.00	0.00

Primary Ratio Scoring

Group	12/31/2012	12/31/2011	% Change	Weight %	Score
Performance Indicators	3.91	4.27	8.43	45.00	1.76
Liquidity Indicators	6.03	6.07	0.66	5.00	0.30
Leverage Indicators	4.33	4.10	-5.61	50.00	2.17
Weighted Average Score					4.22

Metric	12/31/2012	12/31/2011	% Change	Raw Score	Weight %	Score
Performance Indicators						
EBITDA/Interest Exp LTM	2.17	1.91	13.61	4.37	70.00	3.06
Operating Margin % LTM	9.71	9.05	7.29	2.82	30.00	0.85
Weighted Average Score						3.91
Liquidity Indicators						
CFFO/Interest Exp LTM	0.93	0.85	9.41	6.03	100.00	6.03
Weighted Average Score						6.03
Leverage Indicators						
Debt/EBITDA LTM	9.61	9.11	5.49	4.80	46.00	2.21
Tot Liabilities/Assets	0.74	0.73	1.37	3.89	34.00	1.32
Debt/Total Capitalization	0.7	0.67	4.48	4.00	20.00	0.80
Weighted Average Score						4.33

Secondary Ratio Scoring & FYI

Group	12/31/2012	12/31/2011	% Change	Weight %	Score
Ind. Impact Indicators	4.10	4.34	5.53	100.00	4.10
Insight Indicators	0.00	0.00	0.00	0.00	0.00
Weighted Average Score					4.10

ClearPath Company Insights – Internal Score

PPL Financial Scoring Report

Global Credit Services ClearPath

Metric	12/31/2012	12/31/2011	% Change	Raw Score	Weight %	Score
Ind. Impact Indicators						
Net Sales - LTM	568,342,000	561,989,000	1.13	2.72	35.00	0.95
Times Int Earned LTM	1.25	1.13	10.62	5.21	35.00	1.82
TNW/Property & Equip	0.37	0.36	2.78	3.86	15.00	0.58
CAPEX % Sales LTM	7.01	6.89	1.74	5.00	15.00	0.75
Weighted Average Score						4.10
Insight Indicators						
Cash Convert Days LTM	59.93	61.07	-1.87	5.37	0.00	0.00
CFFO/Total Debt LTM	0.04	0.05	-20.00	5.67	0.00	0.00
Return on Assets % LTM	0.73	0.39	87.18	5.22	0.00	0.00
Working Cap% Sales LTM	16.35	5.3	208.49	3.52	0.00	0.00
Weighted Average Score						0.00

Agencies, lowest LT

Summary

Agency Rating Score 4.55

Component	Date	Rating	Latest Date	Latest Rating
S&P Rating (Long Term)	2/4/2013	BB-	2/4/2013	BB-
Use LT Issuer rating, lowest of S&P, Moody's or Fitch		BB-		

Related Companies

Company	Account #	Analyst	Status	S&P Rating	Department	Owing	Collateral	Credit Line	Credit Line Expiration
BIG RIVERS ELECTRIC CORPORATION	LKE-100129		F	BB-	Control				
Related Companies:									
BIG RIVERS ELECTRIC CORPORATION	LKE-100129		F	BB-	Company CL			100,000	10/31/2014
Total:								**100,000**	

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades rating of County of Ohio, Kentucky (Big Rivers Electric Corporation Project) to Ba2 from Ba1; outlook negative

Global Credit Research - 11 Jul 2013

Approximately $83.3 million of debt securities affected

New York, Ju y 11, 2013 -- Moody's Investors Serv ce ("Moody's") today downgraded the sen or secured rat ng of $83.3 m on of County of Oh o, Kentucky (the county) Po ut on Contro Refund ng Revenue Bonds (B g R vers E ectr c Corporat on Project; cus p number 677288AG7) to Ba2 from Ba1, conc ud ng the rev ew for downgrade wh ch commenced on February 6, 2013. The rat ng out ook s negat ve.

"The downgrade of the rat ng for the po ut on contro refund ng revenue bonds prev ous y ssued by the county on beha f of B g R vers E ectr c Corporat on (BREC) ref ects he ghtened cred t r sk for BREC as t moves c oser to the dates when t w need to be more dependent on rate ncreases and other m t gat on strateg es to compensate for the ant c pated s gn f cant oss of oad from two a um num sme ters" sa d Kev n Rose, V ce Pres dent-Sen or Ana yst. "Moody's expects depressed marg ns for off-system sa es n the MISO market to pers st, thus m t ng the effect veness of market ng excess power as part of BREC's oad concentrat on m t gat on strategy", Rose added.

As reported n pr or BREC re ated research, A can Corporat on announced on January 31, 2013 that ts subs d ary, A can Pr mary Products Corporat on (R o T nto A can) s proceed ng w th p ans to term nate ts power contract w th BREC. Th s announcement fo owed the August 20, 2012 announcement by Century A um num Company (Century) that ts subs d ary, Century A um num of Kentucky s tak ng a s m ar act on. At the t me of the announcements, both owners c ted that operat ons at the Sebree sme ter and the Hawesv e sme ter, respect ve y, were not econom ca y v ab e w th current contract power rates and under current market cond t ons. On a comb ned bas s, one of BREC's three member-owners, Kenergy Corp., has been serv ng the two a um num sme ters compr s ng rough y two-th rds of BREC's annua energy sa es and account ng for just under 60% of ts system demand and n excess of 60% of annua revenues. Revenues wh ch BREC has been rece v ng from base energy charges pa d by the sme ters w end on August 20, 2013 n the case of Century's Hawesv e sme ter and on January 31, 2014 n the case of the former R o T nto A can's Sebr ng sme ter now owned by Century s nce June 3, 2013.

Wh e n t a expectat ons contemp ated the prospect that both sme ters cou d cease operat ons upon exp rat on of the r respect ve power contracts, recent deve opments bode we for the sme ters to cont nue operat ng, wh e purchas ng power on the who esa e market. Effect ve June 3, 2013, Century comp eted a transact on w th R o T nto A can to acqu re substant a y a the assets of the Sebree a um num sme ter. Th s dea fo owed Century's def n t ve agreement w th BREC and Kenergy that, subject to var ous regu atory approva s, w a ow Century to cont nue operat ng ts Hawesv e sme ter by purchas ng e ectr c ty on the open market. Under the agreement, we expect that Kenergy w arrange for the energy purchases at who esa e market pr ces and Century w pay the market pr ce and agree to pay add t ona amounts to cover any ncrementa costs ncurred by BREC and Kenergy to accommodate Century's des re to purchase energy on the market for the Hawesv e sme ter. We understand that Century be eves that th s framework can serve as a mode for a s m ar arrangement for the Sebree sme ter once ts current term nat on per od exp res on January 31, 2014. When compared to the a ternat ve scenar o of hav ng both sme ters permanent y shut down, we v ew th s outcome as be ng acceptab e part cu ar y s nce BREC and Kenergy w be re mbursed for the ncrementa costs to purchase power at who esa e market pr ces for the sme ters.

That sa d, oss of the sme ter oad w negat ve y mpact revenues and BREC has pursued a var ety of m t gat on strateg es to address an ant c pated $115 m on revenue shortfa . On January 15, 2013, BREC f ed a rate case w th the Kentucky Pub c Serv ce Comm ss on (KPSC) seek ng approva for a $74.5 m on rate ncrease. The rate f ng pr mar y covered the mpend ng oad oss from Century when the not ce per od exp res (of the $74.5 m on, $23.7 m on s a ocated to A can), as we as add t ona amounts for dec n ng marg ns from off system sa es and other cost pressures. Th s request was subsequent y mod f ed downward to $68.6 m on due to the subsequent ssuance of orders from the KPSC to recogn ze cost sav ngs ach eved subsequent to the rate case f ng date. BREC s among the few e ectr c generat on and transm ss on cooperat ves subject to rate regu at on, wh ch we v ew as a negat ve rat ng cons derat on among G&T cooperat ves as t can somet mes pose cha enges n mp ement ng t me y rate ncreases. The January rate case s n ts f na stages; BREC now awa ts a f na rate order from the KPSC and s request ng that new rates become effect ve August 20, 2013. If the case s not dec ded by then, BREC wou d be perm tted under state statute to mp ement the rate ncrease, subject to refund, pend ng a f na KPSC dec s on n the rate case. Today's rat ng act on ncorporates a reasonab e outcome to the rate case dec s on.

On June 28, 2013, BREC f ed another rate case proceed ng, seek ng KPSC approva for ts rate strategy to address oad oss when the former A can (Sebree sme ter) not ce per od exp res on January 31, 2014. Important y and a key rat ng cons derat on are the p ans to acce erate use of the econom c reserve and rura econom c reserve accounts n the amount of $70.4 m on to offset th s second rate ncrease wh ch goes nto effect on February 1, 2014. The acce erated use of the reserve accounts wou d effect ve y neutra ze any add t ona non-sme ter customer rate mpact from th s second rate case f ng unt August 2014 for arge ndustr a (non-sme ter) customers and Apr 2015 for rura (res dent a) customers. Under th s approach, BREC hopes to de ay further non-sme ter customer rate shock as t mp ements other oad concentrat on m t gat on strateg es. Inc uded n the $70.4 m on rate ncrease s A can's $23.7 m on share of the $68.6 m on rate ncrease nc uded n the rate case f ng made January 15, 2013.

These strateg es, some of wh ch are a ready be ng mp emented, nc ude enter ng nto ong-term b atera sa es arrangements, temporar y d ng generat on and reduc ng staff, mak ng short-term off system sa es, part c pat ng n the capac ty markets, and se ng generat ng assets. In that ve n, BREC recent y announced that t wou d spec f ca y cons der the sa e of ts 417-MW D.B. W son and 443-MW K.C. Co eman coa -f red p ants. At the same t me, BREC has responded to requests for proposa s to se power from these p ants to other energy prov ders and awa ts further deve opments re ated to those responses. Longer term opportun t es may ar se for sa es of e ectr c ty, depend ng on econom c deve opment act v ty n ts serv ce terr tory. Shou d a transact on, e ther an outr ght sa e or a ong-term power arrangement for a capac ty nvo v ng both W son and Co eman occur, BREC's tota owned/ava ab e capac ty wou d reduce to 584 MW from 1,444 MW. BREC a so has r ghts to about 197 MW of coa -f red capac ty from Henderson Mun c pa Power and L ght Stat on Two and about 178 MW of contracted hydro capac ty from Southeastern Power Adm n strat on.

In terms of qu d ty cons derat ons, BREC addressed what had been ts most press ng near term ob gat on by us ng a port on of ts ex st ng cash on May 31, 2013 to repay a $58.8 m on tax-exempt debt matur ty wh ch was schedu ed for June 1, 2013. Fo ow ng the debt repayment, BREC reports ts cash ba ance s approx mate y $100 m on (wh ch nc udes $27 m on des gnated for cap ta expend tures) and ts debt matur t es over the next e ght quarters are arge y compr sed of schedu ed amort zat ons of ong-term debt to be pa d at a rate of rough y $5.5 m on per quarter. We understand that BREC has taken steps to ma nta n ts externa qu d ty as t s n f na stage negot at ons w th Nat ona Rura Ut t es Cooperat ve F nance Corp. (NRUCFC) for a sen or secured oan to fund an est mated $60 m on of KPSC approved env ronmenta re ated cap ta expend tures over the next two years. We understand that th s mu t -year oan, wh ch s prem sed on BREC rece v ng a favorab e order from the KPSC n the rate case f ed January 15, 2013, wou d serve as a br dge to ong-term sen or secured f nanc ng under the U.S. Department of Agr cu ture's Rura Ut t es Serv ce (RUS) oan program. BREC s a so f na z ng negot at ons to amend and extend ts $50 m on unsecured revo ver w th NRUCFC, wh ch current y exp res n Ju y 2014. Subject to comp et ng the negot at ons w th NRUCFC and approva from the KPSC, the new revo ver s expected to convert to a secured fac ty, perm t access to fund ng desp te mpend ng sme ter-re ated oad oss, and extend the term to Ju y 2017. Extens on of th s fac ty s an mportant qu d ty m estone s nce we understand that BREC term nated ts $50 m on CoBank fac ty, wh ch was schedu ed to exp re n Ju y 2017. The ex st ng cash on hand and the ant c pated extens on of the $50 m on revo ver w th NRUCFC, a ong w th the $60 m on three-year sen or secured term oan w th NRUCFC for env ronmenta cap ta expend tures w supp ement the cooperat ve's nterna y generated cash f ow go ng forward.

BREC's rat ng out ook s negat ve, due to the uncerta nty around the cooperat ve's success n mp ement ng m t gat ng strateg es, the most cr t ca one be ng the rate requests pend ng before the KPSC.

In ght of the negat ve out ook, BREC's rat ng s not ke y to be upgraded n the near term. S gn f cant support from the KPSC n the pend ng rate f ngs and successfu resu ts through other oad concentrat on m t gat on strateg es wou d be cred t pos t ve and he p to stab ze BREC's rat ng out ook.

A ternat ve y, there are a var ety of factors that cou d cause us to take further negat ve rat ng act on, nc ud ng nab ty to obta n adequate regu atory support n pend ng rate f ngs and de ays n shor ng up externa qu d ty. S nce we expect m ted opportun t es to earn marg ns on off-system sa es n the MISO markets over the next 24 months, nab ty to f nd other prof tab e energy and capac ty sa es opportun t es wou d a so be cred t negat ve. Furthermore, f fu and t me y recovery of env ronmenta comp ance costs does not occur as ant c pated under the KPSC approved env ronmenta cost recovery mechan sm, that wou d add downward rat ng pressure, espec a y f such amounts ncrease substant a y from current y ant c pated eve s.

B g R vers E ectr c Corporat on s an e ectr c generat on and transm ss on cooperat ve headquartered n Henderson, Kentucky and owned by ts three member system d str but on cooperat ves— Jackson Purchase Energy Corporat on; Kenergy Corp; and Meade County Rura E ectr c Cooperat ve Corporat on. These member system cooperat ves prov de reta e ectr c power and energy to approx mate y 113,000 res dent a , commerc a , and ndustr a customers n 22 Western Kentucky count es.

The pr nc pa methodo ogy used n th s rat ng was U.S. E ectr c Generat on & Transm ss on Cooperat ves pub shed n Apr 2013. P ease see the Cred t Po cy page on www.moodys.com for a copy of th s methodo ogy.

REGULATORY DISCLOSURES

For rat ngs ssued on a program, ser es or category/c ass of debt, th s announcement prov des certa n regu atory d sc osures n re at on to each rat ng of a subsequent y ssued bond or note of the same ser es or category/c ass of debt or pursuant to a program for wh ch the rat ngs are der ved exc us ve y from ex st ng rat ngs n accordance w th Moody's rat ng pract ces. For rat ngs ssued on a support prov der, th s announcement prov des certa n regu atory d sc osures n re at on to the rat ng act on on the support prov der and n re at on to each part cu ar rat ng act on for secur t es that der ve the r cred t rat ngs from the support prov der's cred t rat ng. For prov s ona rat ngs, th s announcement prov des certa n regu atory d sc osures n re at on to the prov s ona rat ng ass gned, and n re at on to a def n t ve rat ng that may be ass gned subsequent to the f na ssuance of the debt, n each case where the transact on structure and terms have not changed pr or to the ass gnment of the def n t ve rat ng n a manner that wou d have affected the rat ng. For further nformat on p ease see the rat ngs tab on the ssuer/ent ty page for the respect ve ssuer on www.moodys.com.

For any affected secur t es or rated ent t es rece v ng d rect cred t support from the pr mary ent ty(es) of th s rat ng act on, and whose rat ngs may change as a resu t of th s rat ng act on, the assoc ated regu atory d sc osures w be those of the guarantor ent ty. Except ons to th s approach ex st for the fo ow ng d sc osures, f app cab e to jur sd ct on: Anc ary Serv ces, D sc osure to rated ent ty, D sc osure from rated ent ty.

Regu atory d sc osures conta ned n th s press re ease app y to the cred t rat ng and, f app cab e, the re ated rat ng out ook or rat ng rev ew.

P ease see www.moodys.com for any updates on changes to the ead rat ng ana yst and to the Moody's ega ent ty that has ssued the rat ng.

P ease see the rat ngs tab on the ssuer/ent ty page on www.moodys.com for add t ona regu atory d sc osures for each cred t rat ng.

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Needham, Meredith

From:	Wilson, Stuart
Sent:	Monday, November 05, 2012 3:50 PM
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	RFP Responses
Attachments:	Duke Energy Ohio Proposal #1.pdf; Duke Energy Ohio Proposal #2.pdf; LGEBeutlerCoalCostBaseNov 2.2012.pdf; LGEBeutlerCoalTollNov.2.2012.pdf; LGEBeutlerCoverletterNov.2.2012.pdf; LGEBeutlerPlantCostBaseNov.2.2012.pdf; LGEGasTollBeutlerNov.2.2012.pdf; PDF to Freibert.pdf; Gulf Response to LG&E-KU RFP.pdf

David,

Here are the responses from Big Rivers (‘PDF to Freibert’), Southern Wholesale Energy (Plant Scherer; PDF name is ‘Gulf Response…’), Duke (OVEC), and Ameren/EEI (‘Beutler’ in PDF name).

Stuart

From: Freibert, Charlie
To: Sinclair, David
Cc: Freibert, Charlie
Subject: KMPA Proposal to RFP
Date: Wednesday, November 07, 2012 11:21:17 AM
Attachments: KMPA_LGEE_20121102.pdf.pdf

David,

They used our RFP letter and filled in the table at the end followed by a pricing sheet – 1 yr with 4yr extension at prices stated.

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC

Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

LG&E KU
PPL companies

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www.lge-ku.com

Charles A. Freibert, Jr.
Director Marketing
[redacted]

September 7, 2012

Subject: Request for Proposals to Sell Capacity and Energy (RFP)

Dear Colleague in Development, Marketing and Trading of Electrical Power,

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly the "Companies") are evaluating alternatives means to provide least-cost firm generating capacity and energy to our customers in the future. To this end, the Companies are requesting proposals from parties wishing to sell capacity and energy that will qualify as a Designated Network Resource (DNR) either as an owned asset by the Companies or a Power Purchase Agreement with the Companies. The Companies will consider offers that are reliable, feasible and represent the least-cost means of meeting our customers' capacity and energy needs, including cost for transmission service, transmission upgrades and voltage support. The Seller should make its proposal as comprehensive as possible so that the Companies may make a definitive and final evaluation of the proposal's benefits to its customers without further contact with the Seller. However, the Companies reserve the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Companies' internal evaluation of cost, risk, and value.

This inquiry is not a commitment to purchase and shall not bind the Companies or any subsidiaries of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine which Respondent(s), if any, it wishes to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses Respondents incur in connection with preparation of a response to this RFP. The Companies will not reimburse Respondents for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Companies at their sole discretion.

1. **<u>Background</u> -** This RFP is being issued in order to evaluate alternative means to provide least-cost firm generating capacity and energy to our customers in the future while meeting all laws and regulations. All alternatives (including any of the Companies' self-build options) will be evaluated in the context of meeting customers' load in a least-cost manner. If the Companies determine that a proposal maybe in the best interest of the Companies' customers, the Companies will enter into negotiations which may lead to the execution of definitive agreements. The Companies will consider all applicable factors including, but not limited to, the following to determine the least-cost proposal(s): (i) the terms of the purchased power proposal or facility or asset sale; (ii) Seller's creditworthiness; (iii) if applicable, the development status of Seller's generation facility including, but not limited to, site chosen, permitting, and transmission; or the operating history of Seller's generation facility; (iv) the degree of risk as to the availability of the power in the timeframe required; (v) the anticipated reliability of the power, particularly at times of winter and summer peak; and (vi) all other factors such as the cost of interconnection or transmission that may affect the Companies or their customers. The Companies are committed to implementing the best overall long-term solution for their customers.

2. **<u>Requirements</u> -** The Companies are interested in Power Purchase Agreements ("PPA"), Tolling Agreements ("TA") or Build Own Transfer Agreements ("BOT"), or alternative power supplies (combined "Supply Agreements") for minimum quantities of 1 MW up to a total of 700 MW of firm summer and winter capacity and associated energy per facility or offer. The power being proposed must be generated from a defined source, a specific unit(s) or system that will qualify as a DNR and supply capacity/energy during the peak demand of the Companies' customers (typical Midwest seasonal load characteristics). The delivery of capacity and energy should begin no earlier than January 1, 2015, and later start dates will be considered. The Companies are interested in both short term (1 to 5 years) and long term (10 to 20 years) proposals. The Companies may procure more or less than 700 MW and may aggregate capacity and energy from multiple Sellers to meet its needs. A Seller offering power from a resource connected directly to the Companies' transmission system must conform to the Companies' Open Access Transmission Tariff (OATT) and must obtain in a timely manner an Interconnection Agreement for the facility.

3. **<u>Key Terms and Conditions</u> -** The Seller's proposal should include the proposed terms and conditions, which should include, where applicable to the Seller's proposal, among other things:

    3.1. Seller will guarantee all pricing and terms that affect pricing such as but not limited to heat rate, fuel cost, fuel availability, fuel transport, operation and maintenance cost, etc., for at least 150 days after the Proposal Due Date.

    3.2. Any Capacity Payments to the Seller will be based upon guaranteed capacity at the Summer Design Conditions delivered to the Companies' transmission system unless the location of the Seller's facility justifies alternate conditions. Summer Design Conditions shall be the following.

3.2.1. Dry Bulb: 89°F
3.2.2. Mean Coincident Wet Bulb: 78°F

3.3. Seller will guarantee the annual and seasonal availability and describe required maintenance outage schedule.

3.4. Seller should address in their proposal its remedies for failure to meet availability guarantees.

3.5. Seller will be responsible for any and all compliance related cost and fines (environmental, NERC, FERC, etc) incurred due to the non-compliance of the assets designated to supply power to the Companies.

3.6. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

3.7. The Companies termination rights will include, but may not be limited to: (i) failure to obtain all required regulatory approvals, (ii) failure to post or maintain required financial credit requirements, (iii) failure to meet key development and implementation milestones, (iv) failure to meet reliability requirements, and (v) failure to cure a material breach under the Supply Agreement.

4. **Dispatching and Scheduling** (Required Proposal Content) - The Companies prefer flexibility in the utilization of the generation resource being offered by the Seller. The Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time control/dispatch of generation to follow load changes and respond to system frequency changes. The Seller should state its desire and willingness to allow and cooperate with the Companies in establishing real-time control of generation.

5. **Ancillary Services** (Required Proposal Content) - Under a Supply Agreement, the Companies desire to have the unrestricted right to utilize all ancillary services associated with generation being offered by the Seller. The Seller should describe the ancillary service capability of its proposal e.g., black start capability, voltage support, load following, energy imbalance, spinning reserve, and supplemental reserve. The ancillary services that would be available to the Companies should not be limited to those defined in this paragraph. The Companies desire to have the unrestricted rights to any future ancillary services defined by the industry and capable of being provided by the generation capacity being offered. In the case where the Companies purchase only part of the generation capacity from a unit, system or facility, then the Companies desire to have unrestricted rights to ancillary services on a prorated basis.

6. **Pricing** (Required Proposal Content) **-** The Seller's pricing must be a delivered price to the Companies' transmission system. The Companies will be responsible only for Network Integrated Transmission Service (NITS) on the Companies transmission system. Prices must be firm, representing best and final data and quoted in U.S. dollars. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

    6.1. The Seller's proposal must provide the product and generation characteristics on the attached form. Pricing information can be provided on the form or separately in another format that is appropriate for the offer. The Seller is encouraged to provide as much information as possible to aid in the evaluation of the offer. These attached data forms may be utilized in any filings with regulatory agencies (such as the KPSC) related to this RFP.

7. **Delivery** (Required Proposal Content) **-** The Companies consider reliable power delivery at the time of the typical summer and winter peak demand of its customers to be of the utmost importance. The delivery point is the Companies' transmission system. Under a Supply Agreement, Sellers would be responsible for providing firm transmission to the Companies' transmission system. The Seller is responsible for all costs associated with transmission interconnections and shall provide all studies and Interconnection Agreements. The Seller is responsible for all transmission reservations, losses and costs including system upgrades up to the delivery point and shall provide all studies and Transmission Reservations/Agreements. All costs associated with interconnections and transmission up to the delivery point should be included in the Seller's pricing where appropriate under current FERC orders and rulings. TranServ International, Inc., 2300 Berkshire Lane North, Minneapolis, Minnesota 55441, is an Independent Transmission Operator that administers the Companies' OATT. Tennessee Valley Authority (TVA) serves as the Companies' Reliability Coordinator (RC). For purposes of the Companies' evaluation of the proposals, the Companies may estimate any transmission costs that are not supported by the appropriate studies including deliverability and the associated voltage support to the Designated Network Load ("DNL") of the Companies. If the Seller has not completed all required transmission studies, it is essential that the following information be provided in order for the Companies to evaluate the proposal:
    - Size of the unit
    - Point of interconnection to the grid
    - Impedance of the generator step-up transformer
    - Transient and sub transient characteristics of the generator

8. **Environmental** **-** For the sale of generation capacity and energy to the Companies under a Supply Agreement, the Seller would be responsible for obtaining all necessary permits and providing all credits and allowances needed to comply with the

permit requirements for the life of the agreement, where permits, credits and allowances are applicable for the product being sold. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by Seller. The Companies require that Sellers provide the following information for evaluation:

- Unit heat rate, fuel specification, and control technologies employed.
- Emissions rates for NOx, SOx, CO, CO2, PM_{10}, and Hg.
- Copy of air permit or permit application if available.
- Timing and status of all permit applications including air, water withdrawal, wastewater disposal, fuel byproducts handling and disposal, etc.

9. **<u>Development Status</u>** – Seller shall provide a comprehensive narrative of the status of the development of any generation project intended to be used to meet Seller's obligations to the Companies. Seller's narrative shall include the following.
   9.1. A comprehensive development and construction schedule,
   9.2. A listing of all required permits and governmental approvals and their status,
   9.3. A listing of all required electric interconnection and or transmission agreements and their status,
   9.4. A financing plan, and
   9.5. A summary of key contracts (fuel, construction, major equipment) to the extent that they exist.

10. **<u>Other Information Requirements</u> -** Sellers shall provide a complete description of the generation facilities that would be used to fulfill the Seller's obligations to the Companies. The description should include the following:

- Seller's operating experience with similar technology.
- Guaranteed capacity rating and heat rate at Summer Design Conditions of:

Dry Bulb	89	F
Wet Bulb	78	F

- Guaranteed capacity rating and heat rate at winter design conditions of:

Dry Bulb	14	F

- Guaranteed capacity rating and heat rate at average day design conditions

Dry Bulb	57	F
Relative Humidity	60	%

- Guaranteed ramp rate in MWs/minute if applicable.

- Guaranteed annual and seasonal availabilities including EFOR values and planned maintenance schedules.
- Technology employed (combined cycle, pulverized coal, CFB, super-critical, etc.)
- Plant location along with proof or status of ownership or control of site.
- Zoning status of plant site.
- If the plant site is subject to site approval by a governmental authority, provide a description of the approval status including a copy of the application. If approval has been granted, provide a copy of the approval.
- Status of engineering and design work.
- Key project participants including owners, operators, engineer/contractors, fuel suppliers

The Seller should also provide any additional information the Seller deems necessary or useful to the Companies in making a definitive and final evaluation of the benefits of the Seller's proposal without further interaction between the Companies and Seller.

11. **<u>Financial Capability</u> -** Should the Companies elect to enter into an agreement with a Seller who fails to meet its obligations at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, the Sellers will be required to demonstrate, in a manner acceptable to the Companies, the Seller's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of the Supply Agreement. Under no circumstances, should the Companies' customers be exposed to increased costs relative to the cost defined in an agreement between the Seller and the Companies.

    11.1. At all times, the Seller will be required to maintain an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

    11.2. Upon execution of the Supply Agreement, Sellers will be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the Seller. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. This amount shall take into account the cost of replacement energy and associated environmental cost with the production of replacement energy and any byproducts of such replacement energy. If the Companies draw down the LOC amount at any time, the Seller must replace the LOC to the original value within five days.

12. **<u>Alternate Power Supplies</u> -** Alternate power supply arrangements may include the acquisition of generation assets, existing generation facilities, projects under development, system firm products, or other power supply arrangements that meet the Companies' requirements described in this RFP. The Seller must make all transmission arrangements for the delivery of alternate power supply arrangements to

the delivery point and include the cost for transmission in the pricing. Sellers interested in proposing alternative power supplies must provide all information specified in this document and applicable to the alternate power supply needed for the Companies to fully evaluate the proposal. Those Sellers proposing the sale of generation facilities should include the following:

- Complete description of the facilities included in the sale.
- Firm offer price
- Term sheet which identifies key terms and conditions
- Latest condition report
- Projected operating data including output, heat rate, and forced outage rate as appropriate
- Projected operating expenses and capital expenditures
- For existing facilities, provide historical operating data, operating expenses, and capital expenditures for a minimum of the latest five years or since the start of commercial operation if in commercial operation for less than five years.

13. **RFP Schedule -** All proposals must be complete in all material respects and be received no later than 4 p m. EDT on Friday, November 2, 2012. Email proposals must be followed up with a signed original within two business days.

RFP Issued	Friday, September 7, 2012
Proposals Due	Friday, November 2, 2012
Evaluation Completed	Friday, March 15, 2013

Proposals will not be viewed until 4 p m. EDT on Friday, November 2, 2012. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customer's best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

14. Treatment of Proposals

14.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. The Companies also reserve the right to modify the RFP or request further information, as necessary, to complete its evaluation of the proposals received.

14.2. Sellers who submit proposals do so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of capacity and/or energy for any reason. Sellers are responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

15. **Confidentiality** - As regulated utilities, it is expected that the Companies will be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as "Confidential." Please note that confidential treatment is more likely to be granted if limited amounts of information are designated as confidential rather than large portions of the proposal. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to this information. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the Seller's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

16. **Contacts** - All correspondence should be directed to:

Charles A. Freibert, Jr.
Director Marketing
LG&E and KU Energy LLC
Energy Services
220 West Main Street
Louisville, KY 40202

[redacted]

In closing, I look forward to your response by 4 p.m. EDT on Friday, November 2, 2012, and the possibility of doing business to meet the Companies' future power needs. Your interest in this request is greatly appreciated. Please contact me if you have any questions and would like to discuss further. For immediate concerns in my absence, please contact Donna LaFollette at [redacted].

Sincerely,

Charles A. Freibert, Jr.

LG&E and KU RFP Data Form

Note to bidder: Provide a separate term sheet for each different "Term of Contract" or capacity offering

Seller: KMPA

Product and Generation Characteristics:
Proposal Description: Prairie State Generating Company – Coal Unit Location

Generation Source Description: PSGC
Transmission Interconnection Point of the Source: AMIL-TEA-PSGC1
Point of interconnection to the grid: AMIL (MISO)
Fuel Commodity Price (if applicable): N/A
Firm Fuel Transport Price (if applicable): N/A
Start Date and Term of Contract: January 1, 2015, 5 Years
Summer Firm Capacity Amount: 25 MW
Summer Maximum Dispatch Capacity Amount (if applicable): 25 MW
Summer Minimum Dispatch Capacity Amount (if applicable): 25 MW
Guaranteed Heat Rate (or heat rate curve) (if applicable): N/A
Winter Firm Capacity Amount: 25 MW
Winter Maximum Dispatch Capacity Amount (if applicable): 25 MW
Winter Minimum Dispatch Capacity Amount (if applicable): 25 MW
Output in 10 minutes: N/A
Guaranteed Ramp capability (if applicable): N/A
Start-up time to minimum capability: N/A Fixed Offer
Start-up time to maximum capability: N/A Fixed Offer
Minimum run time: N/A Fixed Offer
Minimum down time: 24 Hours
Constraints on production time (if applicable): N/A
Forced Outage Rate: 92%
Guaranteed Availability: 89%
Planned Outage Schedule: March

Pricing Information (provide a separate pricing form if applicable):
Sale Price __________ or, Capacity Price _________________ ($/MW-yr)
Year of Capacity Price Quote _________________
Capacity Price Escalation/Year or Index_________________
Fixed O&M_______________($/MWH or $/MW-yr)
Year of Fixed O&M Price Quote ____
Fixed O&M Price Escalation/yr or Index_________
Energy Pricing (Provide energy pricing in one of the following formats)
1. Fixed Energy price over the term ____________($/MWH)
2. Escalating Price Over Term__________ ($/MWh) escalating at ____ % per year
3. Production Cost: Variable O&M + Guaranteed Heat Rate * Fuel Price over Term
    a. Variable O&M ___________ ($/MWh)
    b. Guaranteed Heat Rate _______ (Btu/kwh)
    c. Fuel Price ___________

Note: Energy pricing to include all ancillary service costs, taxes and other fees necessary for delivery of the energy to the Delivery Point.

TO: LG& E KU Energy

FROM: Kentucky Municipal Power Agency (KMPA)

DATE: October 23, 2012

SUBJECT: Capacity and Offer from Paducah peaking unit Proposal

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Dispatching and Scheduling: The units cannot be dispatched by LG& E KU energy as the unit is dispatched by MISO ("Midwest Independent System Operator").
Ancillary Services: The unit cannot be used for spinning and Supplemental services as the unit are dispatched by MISO.
Pricing: The energy and capacity can be offered at a fixed price as per the table below
Quantity: 26MW of Capacity and Energy from Prairie State Peaking Unit (PSGC) (summer and Winter Capacity)

Note: The offer is contingent upon the availability of the transmission service[1].

Year[2]	Capacity($/Mw-Day)	Energy[3]RTC[4]($/MWh)
2015	$93.85	$33.61
2016	$95.72	$34.76
2017	$97.64	$35.78
2018	$99.59	$36.82
2019	$101.58	$37.90

Delivery location: MISO.LGEE Interface.
Outage Schedule: March Each year.

Term: Starting: January 1, 2015
Ending: December 31, 2015 the term can be extended on a Yearly basis for 4Years at the Price listed above

This proposal shall remain effective through March **15, 2013** except minor adjustments in Energy Price at which time it shall expire. This proposal may be extended at the sole discretion of KMPA.

[1] KMPA will arrange transmission at the advanced stages of Negotiation
[2] The Year starts on January 1 and ends on December 31
[3] The energy is Unit Contingent
[4] Round the Clock Supply(7X24)

Needham, Meredith

From:	Wilson, Stuart
Sent:	Friday, November 09, 2012 5:44 PM
To:	Schram, Chuck
Cc:	Sinclair, David
Subject:	Detailed Summary of RFP Responses
Attachments:	20121112_DetailSummaryofRFPResponses_0060.xlsx

Chuck,

I've attached a detailed summary of the RFP responses (58 in all). I'll begin to prepare a summary of what appears to be the top contenders (ERORA, Big Rivers, Ameren/EEI, and LS Power) along with the renewable responses. Will try to pass that along tomorrow. Please let me know if you have any thoughts in the meantime.

Thanks.

Stuart

11/12/2012

Contract Description								Capital Cost	Fixed Costs (FCs, Expressed as $/MW at TIP)				Fuel/Energy Costs				Variable Costs				
Response	Counterparty	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Asset Sale Price ($M)	FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	Unfired Heat Rate @ TIP (Btu/kWh)	Fuel	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator
1A	ERORA	CCCT (2x1), GE	10 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	Index	6,705	Gas			20,000/strt or 680/hr			1.70	Index
1B	ERORA	CCCT (2x1), GE	20 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	Index	6,705	Gas			20,000/strt or 680/hr			1.70	Index
1C	ERORA	CCCT (2x1), GE	Asset Sale, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	765													
1D	ERORA	Site	Generation Site	Davies Cty - LGE	1/1/2016	700	2016	30													
2	AEP	Portfolio	11 yr PPA, % of Portfolio, Up to 700 MW	AEP Gen Hub, P-Node ID 34497125	1/1/2015	700	2015		147,022	0.00%					31.91	0.00%					
3	TPF Generation	SCCT	Asset Sale, 5 Units, 245 MW	CONSTELL PTID Node - PJM/AEP	TBD	245	2015	106													
4	Big Rivers	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			11,029	Coal			6,332		25,000	2.85	Index
5A	Quantum Choctaw Power	CCCT (2x1), Siemens	20-35 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		69,000 ($2015)	2.00%			7,064	Gas			23,900/strt or 800/hr			1.00	2.50%
5B	Quantum Choctaw Power	CCCT (2x1), Siemens	Asset Sale, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2015	450													
5C	Quantum Choctaw Power	CCCT (2x1), Siemens	20-35 yr PPA w/ Asset Purchase Option, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	462.5 ($2015)	67,200 ($2015)	2.75%			7,064	Gas			23,900/strt or 800/hr			1.00	2.50%
6A	Calpine	CCCT (2x1), Siemens	5 yr PPA, Day-Ahead Call Option, 500 MW	Trinity/Limestone - TVA	1/1/2015	500	2015		74,160	2.30%			7,400	Gas			25,700		1,000	2.00	Index
6B	Calpine	CCCT (1x1), Siemens	5 yr PPA, Day-Ahead Call Option, 250 MW	Trinity/Limestone - TVA	1/1/2015	250	2015		74,160	2.30%			7,500	Gas			12,850		475	2.00	Index
7A	Ameren	Coal	5 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,496	0.00%			10,586	Coal					1,430	2.61	Schedule
7B	Ameren	Coal	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,688	Schedule					25.68	Schedule					
7C	Ameren	Coal-to-NG Conversion	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		83,796	Schedule					43.94	Schedule					
7D	Ameren	Portfolio (Coal and NG)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		131,484	Schedule					25.80	Schedule					
7E	Ameren	Portfolio (NG) w/ Coal-to-NG Conv.	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		87,936	Schedule					43.80	Schedule					
7F	Ameren	SCCT	5 yr PPA, 5 units, 222 MW	EEI/LGE Interface	1/1/2015	222	2015		85,896	0.00%			13,366	Gas			16,900		290	1.40	Schedule
8	Paducah Power Systems	SCCT	5 yr PPA, 26 MW	LGEE-PPS1	1/1/2015	26	2015		1,825				Max of Market Price and 110% of Gen Cost								
9A	Agile	NG-Fired Recip Engine	Asset Sale, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016	157													
9B	Agile	NG-Fired Recip Engine	20 yr Tolling Agreement, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016		157,000	0.00%	29,800	Index	8,793	Gas					288	4.20	Index
10	KMPA	Coal	5 yr PPA, 25 MW (RTC)	AMIL, MISO	1/1/2015	25	2015		34,255	2.00%					33.61	Schedule					
11A	Khanjee	CCCT (2X1), Khanjee - FP	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Murdock, IL - MISO/LGE	1/1/2015	746	NA								54.27 in 2017	Schedule					
11B	Khanjee	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO/LGE	1/1/2015	746	NA		111,000 in 2017	Schedule					39.37 in 2017	Schedule	50,000				
11C	Khanjee	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO/LGE	1/1/2015	746	NA		111,000 in 2017	Schedule			7,150	Gas			50,000			5.05 in 2017	Schedule
11D	Khanjee	CCCT (2X1), Khanjee - FP	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Kentucky	1/1/2015	746	NA								48.40 in 2017	Schedule					
11E	Khanjee	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	NA		100,800 in 2017	Schedule					34.87 in 2017	Schedule	50,000				
11F	Khanjee	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	NA		100,800 in 2017	Schedule			7,150	Gas			50,000			0.55 in 2017	Schedule
12	Exelon Generation Company	Firm Physical Energy	10 yr PPA, 200 MW	Indiana Hub - MISO	1/1/2015	200	2015								47.78	0.00%					
13	CPV Smyth Generation Co.	CCCT (2X1), Alstom	20 yr PPA, 630 MW	Smyth County, VA - PJM	6/1/2017	630	2017		132,000	0.00%	23,400	Index	7,009	Gas			18,690		3,808	2.58	Index
14A	Duke	Coal	Asset Sale in 2015, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2015	203	2015	100													
14B	Duke	Coal	Asset Sale in 2013, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2013	203	2013	50													
15	Wellhead Energy Systems	NG-Fired Recip Engine	Asset Sale, 100 1 MW GridFox Units	LGE/KU System	1/1/2016	100	2013	99													
16A	Power4Georgians	Supercritical Coal	24 yr PPA, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%			32.40	1.85%				4.73	2.50%
16B	Power4Georgians	Supercritical Coal	24 yr Tolling Agreement, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	9,000	Coal (100% PRB or 50/50 PRB/SILB)						4.73	2.50%
16C	Power4Georgians	Supercritical Coal	Asset Sale, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	3,030													
17	Solar Energy Solutions	Solar (PV Array)	Asset Sale, 1-5 MW	LGE/KU System	1/1/2016	1	2015	2.7													
18A	EDP Renewables	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW	MISO/LGE Interface	1/1/2015	99	2015								50.00	3.00%					
18B	EDP Renewables	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW	MISO/LGE Interface	1/1/2016	151	2016								50.00	3.00%					
18C	EDP Renewables	Wind (As Available)	20 yr PPA, 100 MW	LGE/KU System	1/1/2016	100	2016								69.50	0.00%					
19A-C	LS Power	SCCT	20 yr PPA, Asset Sale Option in 2017/19, 495 MW	LGE Buckner Station	1/1/2015	495	2013	115 in 2017, 105 in 2019	30,000	Schedule			10,900	Gas			25,500			0.50	2.5%
19D-E	LS Power	SCCT	20 yr PPA, Asset Sale Option in 2014, 495 MW	LGE Buckner Station	1/1/2014	495	2013	119 in 2014	12,000	Schedule			10,900	Gas			25,500			0.50	2.5%
20	Sky Global, Elk Ridge Energy Center	CCCT (1X1), GE	10-20 yr PPA, 250-300 MW	KU's Pineville - Pocket North - LGE	1/1/2016	250	2016		108,000	0.00%	27,000	Index	7,000	Gas			TBD				
21	Wellington	Waste Coal w/ CFBC	20 yr PPA, 112 MW	PJM West	9/1/2016	112	2012		388,014	Schedule	41,050	2.00%			61.10	Schedule					
22A	Southern Company Services	SCCT	5 yr PPA, 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		45,000				12,850	Gas						4.65	0.0%
22B	Southern Company Services	SCCT	5 yr PPA (Summer Only), 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		35,000				12,850	Gas						4.65	0.0%
22C	Southern Company Services	Coal	15 yr PPA, 109-159 MW	Unit GSU - SOCO	1/1/2016	159	2016		246,000	1.50%			10,400	Coal			14,136				3.5%
23	Santee Cooper	Coal	7.8 yr PPA, 250 MW	Georgetown, SC	4/1/2017	250	2012		100,080	0.00%					105% of Avg Cost					5.00	0.0%
24A	Nextera	Coal	6 yr PPA, 30 MW	Into LG&E/KU	1/1/2015	30	2015								55.00	0.96%					
24B	Nextera	Coal	10 yr PPA, 50 MW	Into LG&E/KU	1/1/2015	50	2015								55.00	0.96%					
25A	South Point Biomass	Biomass	20 yr PPA, 165 MW	AEP/Bellefonte/Proctorville - PJM	5/1/2015	165	2015								65.50	Schedule					
25B	South Point Biomass	Biomass	Asset Sale, 165 MW	AEP/Bellefonte/Proctorville - PJM	5/1/2015	165	2012	583													
26	North American BioFuels	Landfill Gas	20 yr PPA, 19 MW	WI and PA - MISO and PJM	1/1/2014	19	2013								52.00	3.00%					
27A	Southern Power Company	CCCT (2X1), GE	20 yr PPA, 770 MW	Existing LG&E/KU Site	6/1/2017	770	2012		105,678	1.50%			7,250	Gas			42,000	1,275		0.80	Index
27B	Southern Power Company	CCCT (2X1), GE	20 yr PPA, 770 MW	Site TBD	6/1/2017	770	2012		113,481	1.50%			7,250	Gas			42,000	1,275		0.80	Index

From: Wilson, Stuart
To: Sinclair, David
Cc: Schram, Chuck
Subject: RFP Responses
Date: Monday, November 12, 2012 8:41:13 AM
Attachments: 20121112_DetailSummaryofRFPResponses_0060.xlsx

David, see below for a draft of the summary that Paul requested by noon today. Any suggested edits or additions?

Paul,

We're still in our initial screening process for all of the responses, but these are the offers that are likely to emerge as competitive:

1. LS Power – Bluegrass: 495 MW 20-year PPA with option to buy for $105-$119 million; $2.50/kW-month + fuel.
2. Ameren – Joppa: 668 MW 5-year PPA; 11.46/kW-month; $25-44/MWh.
3. Big Rivers – Wilson: 417 MW 1-15 year PPA; $12.14/kW-month + fuel.
4. AEP – Portfolio: Up to 700 MW 11-year PPA; $12.25/kW-month; $32/MWh.
5. Erora – Cash Creek (CCCT only, non-IGCC): 700 MW 10-20 year PPA or asset sale for $765 million; $5.40/kW-month + fuel.
6. Duke – OVEC: sale of 203 MW of OVEC for $50 million.

The only renewable responses received were:

1. Solar Energy Solutions: 1-5 MW PV array asset sale; $2,682/kW.
2. EDP Renewables – Wind: 99-151 MW; 15 or 20 year PPA; $50 - $70/MWh.
3. North American Biofuels 19 MW landfill gas (WI and PA) PPA; $52/MWh.
4. South Point Biomass 165 MW wood-burning project (OH) PPA or asset sale; $65.50/MWh or $583 million.

We are now in the process of final clarification of inputs on some of the bids. Our schedule is to complete our initial screening this week and then proceed with more detailed modeling. Attached is a spreadsheet containing worksheets for the responses above and further details for all bids received.

From:	Sebourn, Michael
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	Emailing: 2012-10-04_SynapseReport_CO2_Forecast.pdf
Date:	Tuesday, November 20, 2012 6:45:07 PM
Attachments:	2012-10-04_SynapseReport_CO2_Forecast.pdf

David,

Chuck asked me to send you the attached Oct-2012 Synapse report on CO2 prices, which we have used as a basis for our CO2 price sensitivities in the RFP analysis.

Mike

Michael Sebourn
LG&E and KU
Manager, Economic Analysis
[redacted]

Synapse
Energy Economics, Inc.

2012 Carbon Dioxide Price Forecast

October 4, 2012

AUTHORS
Rachel Wilson, Patrick Luckow,
Bruce Biewald, Frank Ackerman,
and Ezra Hausman

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Table of Contents

1. Executive Summary

Electric utilities and others should use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. Estimating this price can be difficult because, despite several attempts, the federal government has not come to consensus on a policy (or a set of policies) to reduce greenhouse gas (GHG) emissions in the U.S.

Although this lack of a defined policy certainly creates challenges, a "zero" price for the long-run cost of carbon emissions is not a reasonable estimate. The need for a comprehensive effort in the U.S. to reduce GHG emissions has become increasingly clear, and it is certain that any policy requiring, or leading to, these reductions will result in a cost associated with emitting CO_2 over some portion of the life of long-lived electricity resources. Prudent planning requires a reasonable effort to forecast CO_2 prices despite the considerable uncertainty with regard to specific regulatory details.

This 2012 forecast seeks to define a reasonable range of CO_2 price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. This forecast updates Synapse's 2011 CO_2 price forecast, which was published in February of 2011. Our 2012 forecast incorporates new data that has become available since 2011, and extends the study period end-date to 2040 in order to provide recommended CO_2 price estimates for utilities planning 30 years out into the future.

A. Key assumptions

Synapse's 2012 CO_2 price forecast reflects our expectation that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in or around 2020. These assumptions are based on the following reasoning:

- We believe that a federal cap-and-trade program for GHGs is a key component of the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost.
- We believe that federal legislation is likely by the end of the session in 2017 (with implementation by about 2020) prompted by one or more of the following factors:
    - technological opportunity
    - a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
    - a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
    - increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions that are driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

In addition to the assumptions regarding a federal GHG program described above, we anticipate that regional and state policies will lead to costs associated with GHGs in the near-term (i.e., prior to 2020). Prudent planning requires that utilities take these costs into account when engaging in resource planning.

B. Study approach

To develop its 2012 CO_2 price forecast, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years, including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)
- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO_2 price estimates used by utilities in a wide range of publicly available utility Integrated Resource Plans

Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of the various Congressional proposals to date using this approach offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

Synapse also considered the impact on CO_2 prices of regulatory measures outside of a cap-and-trade program—such as a federal Renewable Portfolio Standard—that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. These "complementary policies" result in lower CO_2 allowance prices, since they would reduce the demand for CO_2 emissions allowances under cap-and-trade.

C. Synapse's 2012 CO_2 price forecast

Based on analyses of the sources described above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. These cases represent different appetites for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040.[1] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario).
- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions.

Table ES-1 presents Synapse's Low, Mid, and High case price projections for each year of the study period, as well as the levelized cost for each case.

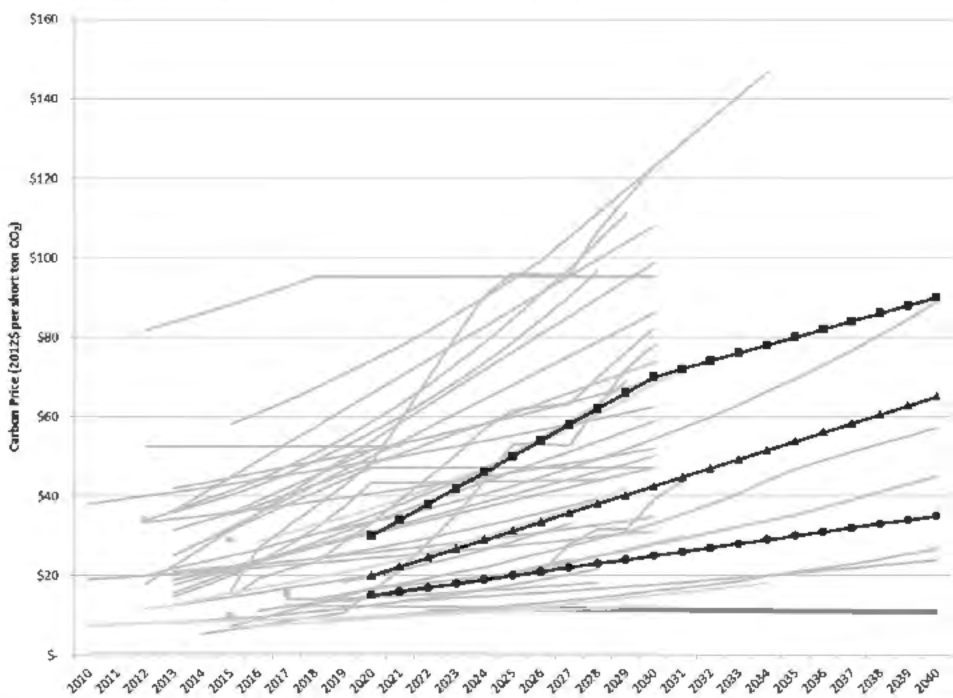
Figure ES-1 presents Synapse's Low, Mid, and High case forecasts as compared to a broad range of CO_2 allowance prices used by utilities in resource planning over the past three years. Synapse forecasts are represented by black lines, while utility forecasts are represented by grey.

[1] Throughout this report, CO_2 allowance prices are presented in $2012 per short ton CO_2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Results originally provided in metric tonnes were converted to short tons by multiplying by a factor of 1.1.

Table ES-1: Synapse 2012 CO_2 allowance price projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

Figure ES-1: Synapse forecasts compared to a range of utility forecasts



2. Structure of this Paper

This paper presents Synapse's assumptions, data sources, and estimates of reasonable future CO_2 prices for use in resource planning analyses. The report is structured as follows:

- Section 3 discusses the key assumptions behind Synapse's estimates
- Sections 4 through 8 present data from the sources reviewed by Synapse in developing its estimates of the future price of CO_2 emissions
- Section 9 presents Synapse's 2012 Low, Mid, and High CO_2 price forecasts, and compares these projections to a range of utility forecasts
- Appendix A provides a more detailed discussion of state and regional GHG initiatives. Collectively, these initiatives suggest that momentum is building toward federal GHG action

3. Discussion of Key Assumptions

A. Federal GHG legislation is increasingly likely

Congressional action in the form of cap-and-trade or clean energy standards is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. The states, the federal courts, and federal agencies are also grappling with the complex issues associated with climate change. Many of these efforts are proceeding simultaneously.

Nonetheless, we believe that a federal cap-and-trade program for GHGs is the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost. Several cap-and-trade proposals have been taken up by Congress in the past few years, though none yet have been passed by both houses. (More discussion of this topic is provided in Section 5 of this report.)

We further believe that federal action will occur in the near-term. This 2012 CO_2 price forecast assumes that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in 2020, prompted by one or more of the following factors:

- technological opportunity
- a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action
- a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies
- increasingly compelling evidence of climate change

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

B. State and regional initiatives building toward federal action

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to wait for federal action, are already pursuing policies on their own or in regional groups. These policies are described below, and are discussed in more detail in Appendix A of this report.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [2]

Under the Regional Greenhouse Gas Initiative (RGGI), ten Northeast and Mid-Atlantic states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.

Meanwhile, California's Global Warming Solutions Act (AB 32) has created the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS). The first compliance period for California's cap-and-trade program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e[3] per year. The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[4] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state-level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[5] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[6]

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[2] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[3] CO2e refers to carbon dioxide equivalent, a measure that includes both carbon dioxide and other greenhouse gases converted to an equivalent amount of carbon dioxide based on their global warming potential.

[4] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[5] Minnesota Statutes 2008 § 216B.241

[6] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

Currently, 29 U.S. states have renewable portfolio standards. Eight others have renewable portfolio goals. In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories, greenhouse gas registries, climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI (requiring specific emissions reductions from power plants in the state), and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

4. Marginal Abatement Costs and Technologies

This chapter presents key data related to marginal abatement costs for CO_2, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions.

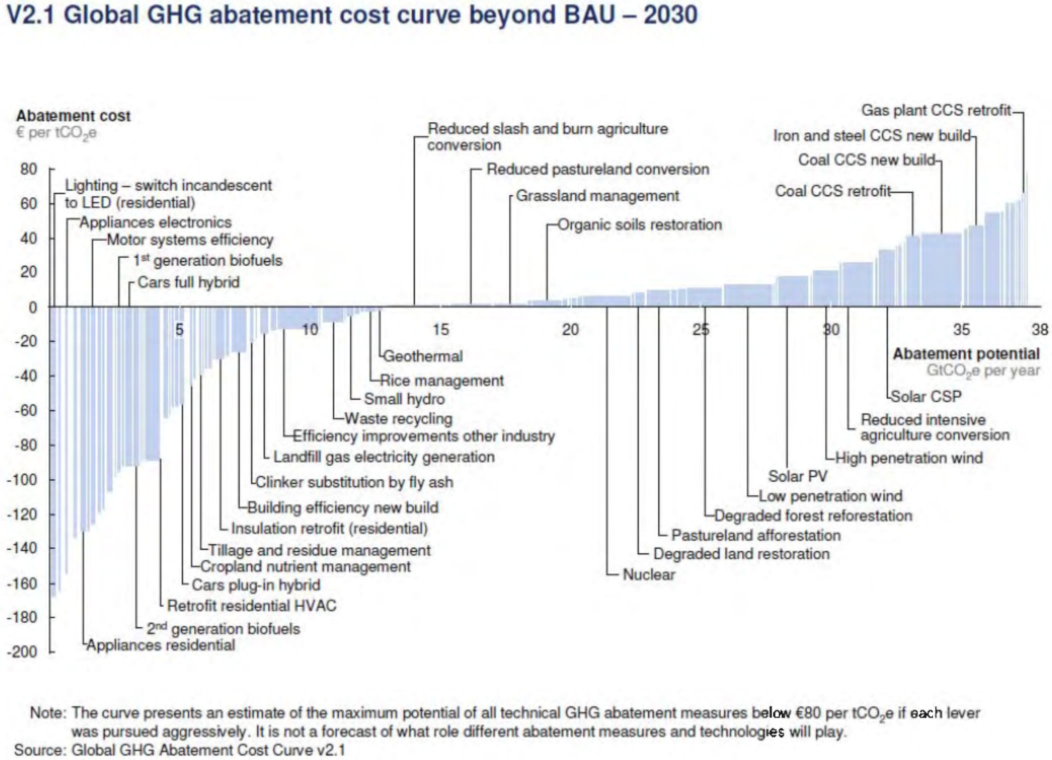
The long-run marginal abatement cost for CO_2 represents the cost of the control technologies necessary for the last (or most expensive) unit of emissions reduction required to comply with regulations. This cost depends on emission reduction goals: lower emissions reduction targets can be met by lower-cost technologies, while more stringent targets will require additional reduction technologies that are implemented at higher costs. The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2° Celsius. Atmospheric concentrations of CO_2 would need to be stabilized at 450 ppm in order to limit the global temperature increase to no more than 2°C.[7]

In recent years, there have been several analyses of technologies that would contribute to emission reductions consistent with an increase in temperature of no more than 2°C. McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are shown in Figure 1. Global mitigation options are ordered from least expensive to most expensive, and the width of each bar represents the amount of mitigation likely at these costs. The chart represents a marginal abatement cost price curve, where cost of abatement is shown on the y-axis and cumulative metric tonnes of GHG reductions are shown on the x-axis. It is likely that the lowest cost reductions will be implemented first, but as reduction targets become more stringent and low-cost options are saturated, the cost of the marginal abatement technology is likely to increase.

The chart below, from the McKinsey report, provides a useful reference to the types of options and technologies that might be employed at specific CO_2 prices.

[7] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Figure 1: McKinsey & Company marginal abatement technologies and associated costs for the year 2030[8]



As shown in Figure 1, technologies for carbon mitigation that are available to the electric sector include those related to energy efficiency, nuclear power, renewable energy, and carbon capture and storage (CCS) for fossil-fired generating resources. McKinsey estimates CCS technologies to cost 50-60 €/metric tonne (2005€). Converted into current dollars, this is equivalent to $65 to $85/ton ($71.5 to $93.5/metric tonne, 2012$). According to the International Energy Agency (IEA), "in order to reach the goal of stabilizing global emissions at 450 ppm by 2050, CCS will be necessary."[9] If this is true, it is reasonable to expect that a CO_2 allowance price will rise to $65/ton or higher under a GHG policy designed to limit the global temperature increase to no more than 2°C. However, if significant reductions could be accomplished with CCS at the high $65 to $85/ton CO_2 range, we would not expect CO_2 mitigation prices to significantly exceed the top of that range.

[8] McKinsey & Company. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.* 2010. Page 8.
[9] International Energy Agency. *Technology Roadmap: Carbon Capture and Storage*. 2009. Page 4.

5. Analyses of Major Climate Change Bills

This chapter presents key data related to analyses of major climate change bills proposed in Congress over the past few years, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions. Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of these proposals offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

A. Cap-and-trade proposals

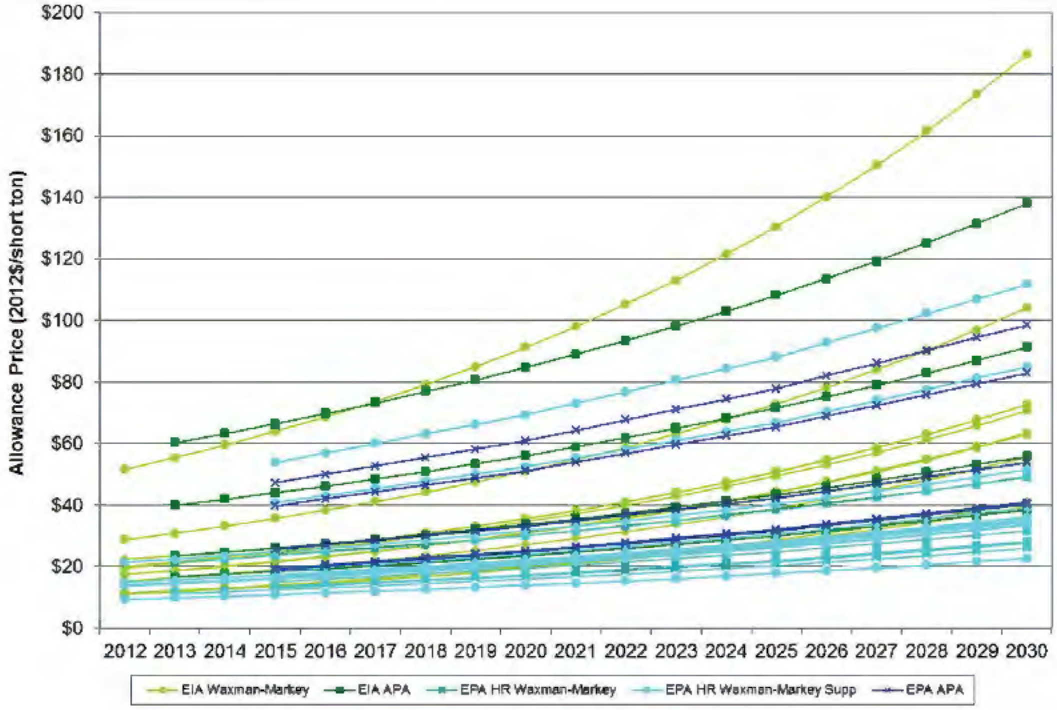
In the past decade, the expectation has been that action on climate change policy will occur at the Congressional level. Legislative proposals have largely taken the form of cap-and-trade programs, which would reduce greenhouse gas emissions through a federal cap, and would allow trading of allowances to promote reductions in GHG emissions where they are most economic. Legislative proposals and President Obama's stated target aim to reduce emissions by up to 80% from current levels by 2050.

Comprehensive climate legislation was passed in the House in the 111th Congress in the form of the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey and HR 2454); however, the Senate ultimately did not take up climate legislation in that session. HR 2454 was a cap-and-trade program that would have required a 17% reduction in emissions from 2005 levels by 2020, and an 83% reduction by 2050. It was approved by the House of Representatives in June, 2009, but the Senate bill, known as the American Power Act of 2010 (APA, also known as Kerry-Lieberman), never came to a vote.

Figure 2 shows the results of EIA and EPA analyses of HR 2454 and APA. The chart shows the forecasted allowance prices in the central scenarios, as well as a range of sensitivities. Figure 3 shows these values as levelized prices for the time period 2015 to 2030.[10]

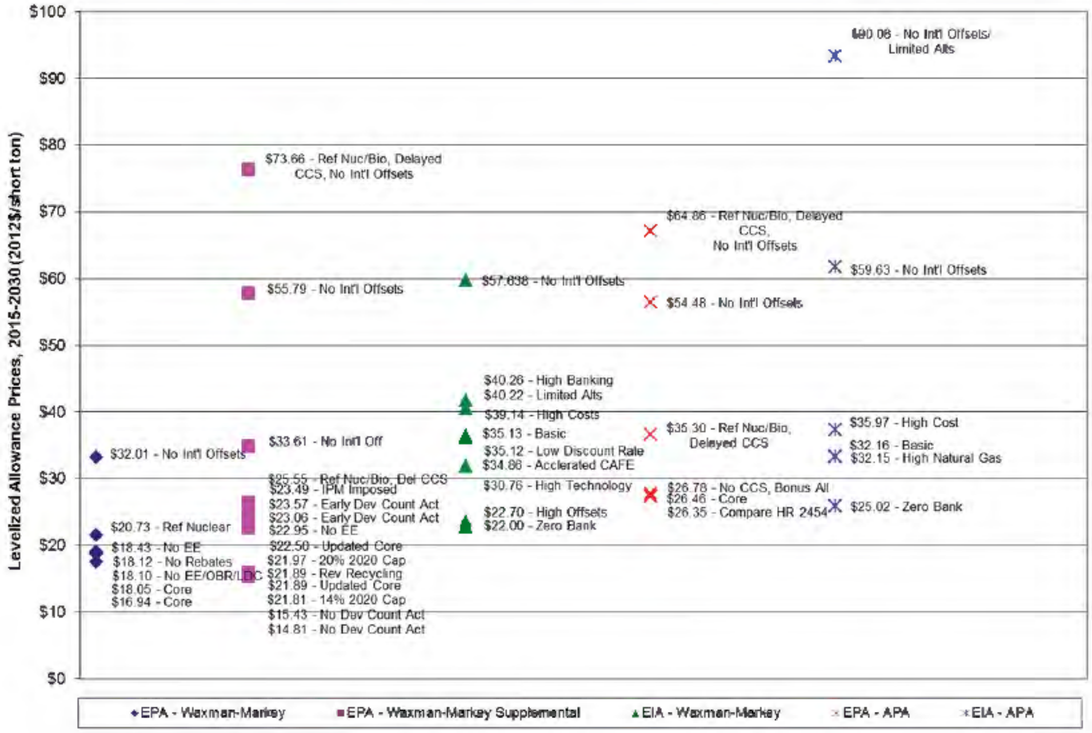
[10] Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

Figure 2: Greenhouse gas allowance price projections for HR 2454 and APA 2010[11]



[11] Sources for Figure 2 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
U.S. Environmental Protection Agency ("EPA"); *Analysis of the American Power Act of 2010 in the 111th Congress* (June 2010). Available at http://www.epa.gov/climatechange/Downloads/EPAactivities/EPA_APA_Analysis_6-14-10.pdf
EPA; *Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (January 2010). Available at: Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf
EPA; *Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (June 2009). Available at: http://www.epa.gov/climatechange/Downloads/EPAactivities/HR2454_Analysis.pdf

Figure 3: GHG allowance price projections for HR 2454 and APA 2010 - levelized 2015-2030



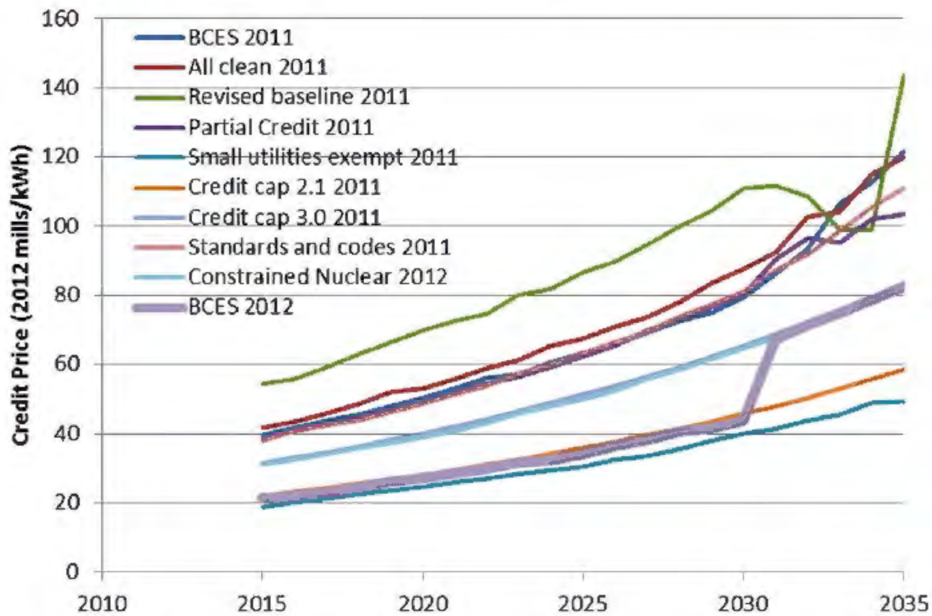
B. Clean Energy Standard

The 112th Congress chose not to revisit legislation establishing an economy-wide emissions cap, and instead focused on policies aimed at fostering technology innovation and developing renewable energy or clean energy standards. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S.2146), under which larger utilities would be required to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. All generation from wind, solar, geothermal, biomass, municipal solid waste, and landfill gas would earn a full CES credit, as would hydroelectric and nuclear facilities. Lower-carbon fossil facilities, such as natural gas and coal with carbon capture, would earn partial credits based on their CO_2 emissions. Generation owners would be required to hold credits equivalent to 24% of their sales beginning in 2015, and the CES requirement rises over time to 84% by 2035, creating demand for renewable energy and low-emissions technologies. The credits generated by these clean technologies would be tradable and have a value that would change depending on how costly the policy is to achieve. The Clean Energy Standard would apply to utilities with sales greater than 2 million MWh, and expand to include those with sales greater than 1 million MWh by 2025.

The EIA conducted analyses of a potential Clean Energy Standard in both 2011 and 2012.[12,13] All of these cases result in some level of increase in nuclear, gas, and renewable generation, typically at the expense of coal. The exact generation mix, as well as the resulting reduction in emissions, is highly dependent on both the technology costs and policy design. The resulting CES credit prices (Figure 4) vary widely, from 25 to 70 mills/kWh in 2020,[14] rising to 47 to 138 mills/kWh in 2035. The credit cap cases show a smaller rise in credit prices. When credit prices are capped at a specific value, clean energy deployment and emissions abatement is reduced.

An effective CO_2 allowance price can be calculated based on the fact that this policy gives existing gas combined cycle units 0.48 credits and existing coal units zero credits, and the emissions from an average gas unit are about 0.57 tCO_2/MWh and from an average coal unit 1.125 tCO_2/MWh.[15] For the BCES 2012 case, for example, this conversion would result in effective allowance prices of \$18.4/tCO_2 in 2015 and \$71.4/tCO_2 in 2035.

Figure 4: CES credit prices in EIA analyses of a U.S. Clean Energy Standard



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12 US EIA. 2011. Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman. http://www.eia.gov/analysis/requests/ces_bingaman/.

13 US EIA. 2012. Analysis of the Clean Energy Standard Act of 2012. http://www.eia.gov/analysis/requests/bces12/.

14 A mill is one one-hundredth of a cent. Therefore, these CES prices in 2020 represent costs of 0.25 to 0.70 c/kWh, or \$2.5 to \$7/MWh.

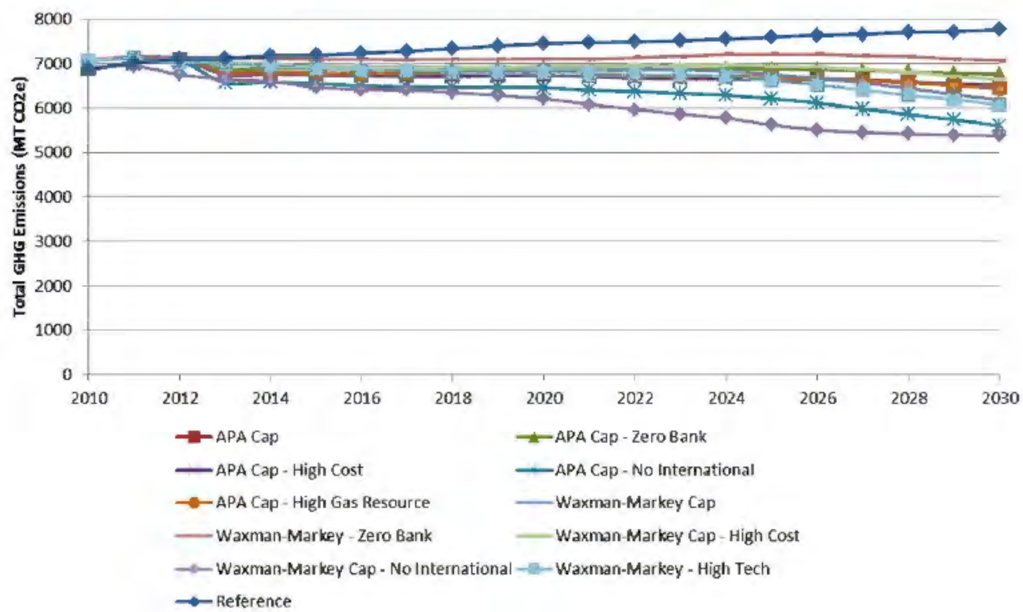
15 EPA Air Emissions Overview, Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.htm

6. Key Factors Affecting Allowance Price Projections

Dozens of analyses over the past several years have shown that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these factors derive from the details of policy design, while others pertain to the context in which a policy would be implemented.

Factors in a forecast include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps including international offsets) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and treatment of emissions co-benefits. Figures 5 and 6 show the very significant ranges in emissions and allowance prices for the Waxman-Markey and APA federal cap-and-trade policies, as well as several associated sensitivities, including assumptions on banking, international offsets, technology cost and progress, and gas supply.

Figure 5: GHG Emissions in Waxman-Markey and APA policies and sensitivities[16]



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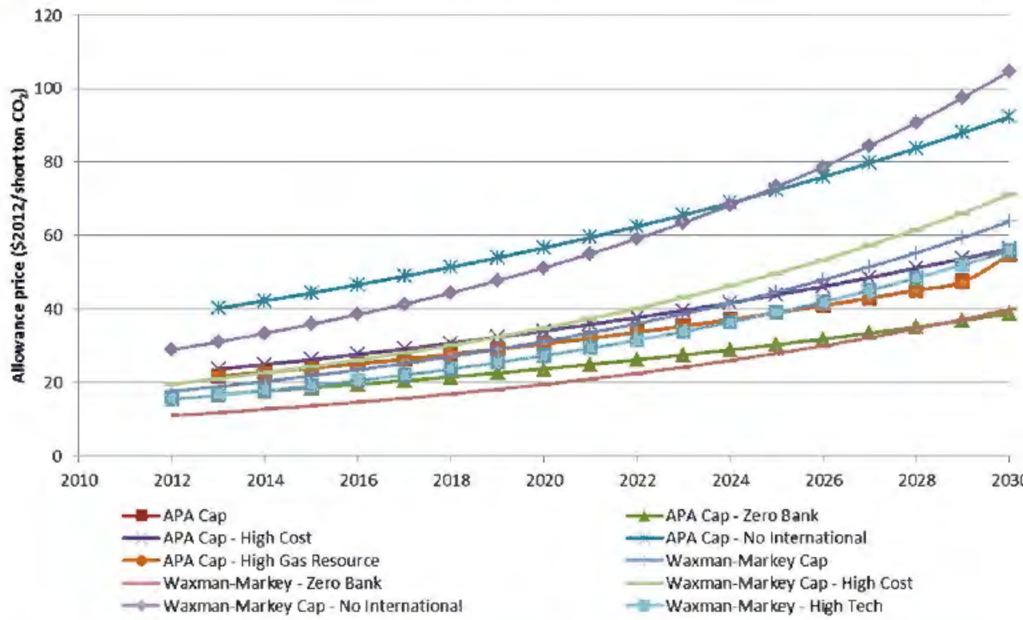
[16] Sources for Figure 5 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

Figure 6: Allowance prices in ACES and APA policies and sensitivities[17]



A. Assessing the potential impact of a natural gas supply increase

The recent shale gas boom has put substantial downward pressure on natural gas prices. Several factors could influence future gas prices, including the estimated ultimate recovery per well and regulations addressing the environmental impacts of hydraulic fracturing.[18] The impact of higher or lower gas prices on carbon prices is uncertain. In the near term, lower natural gas prices are likely to make emissions mitigation in the electric sector less expensive, as gas power plants can displace coal plants at lower cost. Conversely, as marginal electricity prices are frequently set by natural gas plants, lower gas prices will contribute to lower electricity prices, potentially increasing electricity consumption and associated emissions. Lower electricity prices also make it more difficult for renewable technologies with even lower emissions than gas to compete in electricity markets.

In 2010, Resources for the Future (RFF) used a version of the EIA's National Energy Modeling System (NEMS) energy model to test effects of increased gas supply from shale gas on the economics of energy policy. Under a moderate climate policy, the high gas scenario decreased the 2030 allowance price by less than 1%, from $61.1 to $60.8 per ton of CO_2.[19] The EIA showed

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[17] Sources for Figure 6 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

[18] EIA (2012) "Projected natural gas prices depend on shale gas resource economics" http://www.eia.gov/todayinenergy/detail.cfm?id=7710

[19] Brown et al (2010). "Abundant Shale Gas Resources: Some Implications for Energy Policy". Available at: http://www.rff.org/RFF/Documents/RFF-BCK-Brownetal-ShaleGas.pdf

similar results in its analysis of the American Power Act: increased gas supply decreased the 2030 allowance price by less than 0.1%, from $49.80 to $49.78 per ton of CO_2.[20] In the policies studied by EIA and RFF, the result of an increased gas supply amounted to an inconsequential reduction in CO_2 prices. At this point it appears that, while a large shale gas resource may change how each policy is met, it is not a significant factor in the CO_2 cost that utilities should use for planning. Ongoing studies are expected to provide further insight into this issue.[21]

[20] EIA (2010) "Energy Market and Economic Impacts of the American Power Act of 2010". Available at: http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[21] The Energy Modeling Forum will evaluate carbon constraints under cases of reference and high case supply levels in the EMF 26 study, which began in late 2011 and is ongoing (see http://emf.stanford.edu/research/emf_26/)

7. The U.S. Interagency Social Cost of Carbon

In 2010, the U.S. government began to use "social cost of carbon" values in an attempt to account for the damages resulting from climate change.[22] Four values for the social cost of carbon were initially provided by the Interagency Working Group on the Social Cost of Carbon, a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others. This group was tasked with the development of a consistent value for the global societal benefits of climate change abatement. These values, $5, $21, $35, and $65 per metric tonne of CO_2 in 2007 dollars ($4.9, $20.7, $34.5, and $64.0 per ton in 2012 dollars), reflected three discount rates and one estimate of the high cost tail-end of the distribution of impacts. As of May 2012, these estimates have been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[23]

The U.S. "social cost" values are the result of analysis using the DICE, PAGE, and FUND integrated assessment models. The combination of complex climate and economic systems with these reduced-form integrated assessment models leads to substantial uncertainties. In a 2012 paper, Ackerman and Stanton[24] explored the impact of specific assumptions used by the Interagency Working Group, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Despite limitations in the calculations for the social cost of carbon stemming from the choice of socio-economic scenarios, modeling of the physical climate system, and quantifying damages around the globe for hundreds of years into the future, this multi-agency effort represents an important initial attempt at incorporating consistent values for the benefits associated with CO_2 abatement in federal policy.

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[22] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

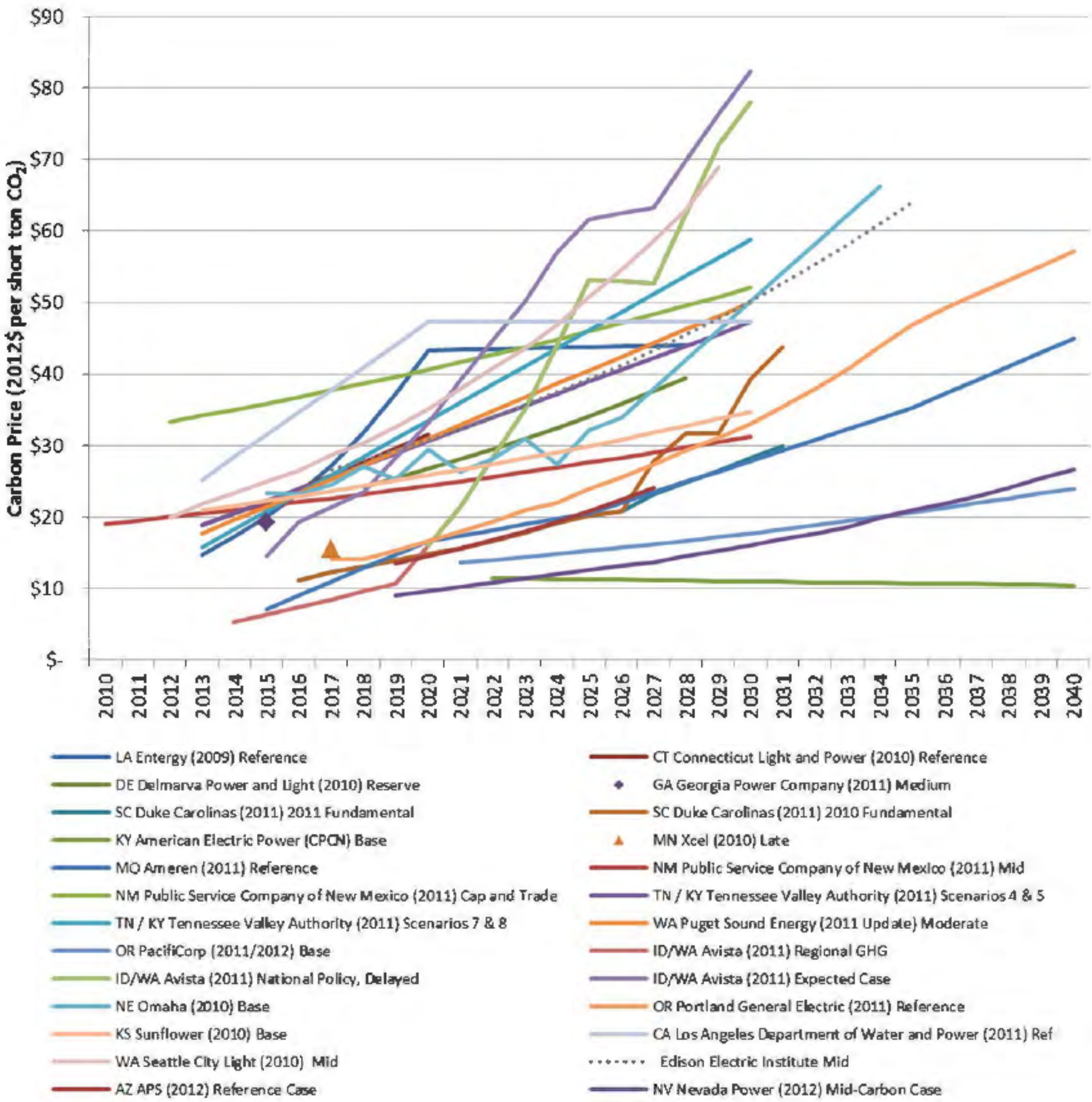
[23] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[24] Frank Ackerman and Elizabeth A. Stanton (2012). Climate Risks and Carbon Prices: Revising the Social Cost of Carbon. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

8. CO_2 Price Forecasts in Utility IRPs

A number of electric companies have included projections of costs associated with greenhouse gas emissions in their resource planning procedures. Figure 7 presents the mid-case values of publicly available forecasts used by utilities in resource planning over the past three years.

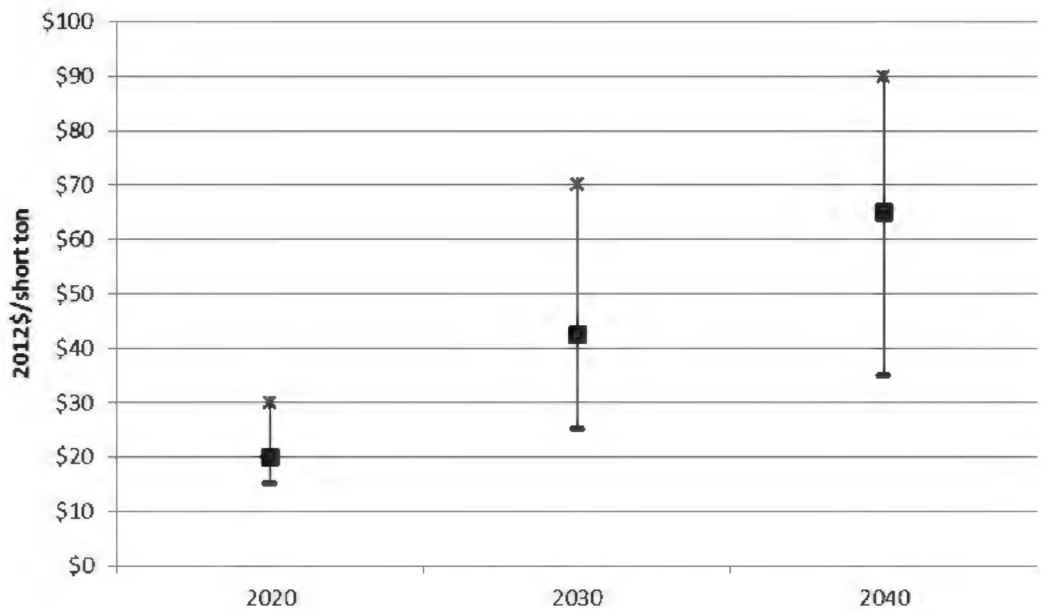
Figure 7: Utility Mid Case CO_2 Price Forecasts



9. Recommended 2012 CO_2 Price Forecast

Based on analyses of the sources described in Sections 4 through 8, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. Figure 8 shows the range covered by the Synapse forecasts in three years: 2020, 2030, and 2040. These forecasts share the common assumption that a federal cap-and-trade policy will be passed sometime within the next five years, and will go into effect in 2020. All annual allowance prices and levelized values are reported in 2012 dollars per ton of carbon dioxide.[25]

Figure 8: Synapse 2012 Forecast Values



Each of the forecasts shown in Figure 8 represents a different appetite for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040, representing a $23/ton levelized price over the period 2020-2040. This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario). Such complementary policies would

[25] All values in the Synapse Forecast are presented in 2012 dollars. Results from EIA and EPA modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade, and would thus lower the expected allowance prices associated with the achievement of any particular federally mandated goal.

- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040, representing a $39/ton levelized price over the period 2020-2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. These complementary policies would include renewables, energy efficiency, and transportation standards, as well as some level of allowance banking and offsets. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040, representing a $59/ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

Synapse's Low, Mid, and High case price projections for each year of the study period are presented in graphic and tabular form, below.

Figure 9: Synapse 2012 CO_2 Price Trajectories

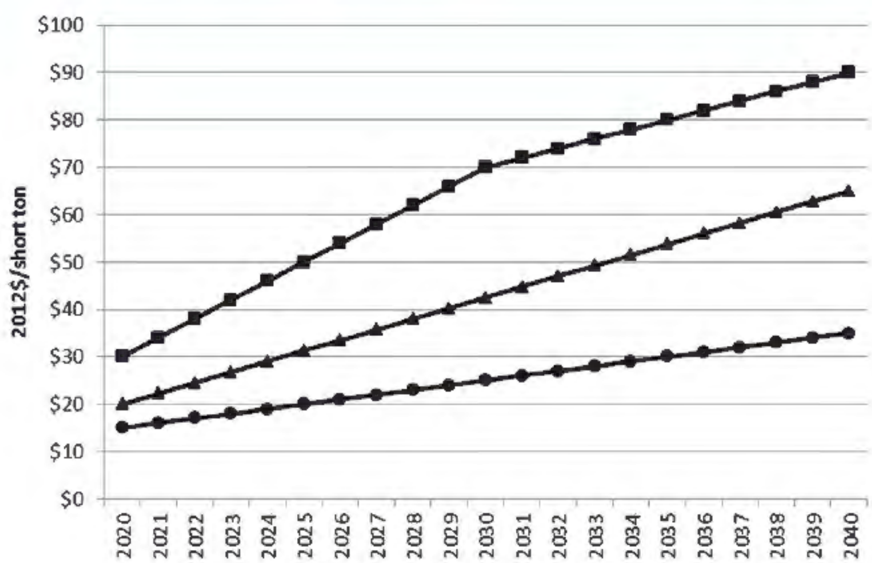


Table 1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

The following charts compare the Synapse Mid, High, and Low case forecasts against various utility estimates. Data on utility estimates was collected from a wide range of available public Integrated Resource Plans (IRPs). We have excluded several IRPs with zero carbon prices or IRPs with no carbon price given, accounting for 9 of 65 collected.

Figure 10 shows 26 utility CO_2 price forecasts, with 2030 prices ranging from $10/tCO_2$ to above $80/tCO_2$. Due to the extended development period of many IRPs, some of these forecasts may not accurately reflect very recent years; a NM Public Service forecast, for example, begins in 2010, when there was no economy-wide CO_2 price. Nevertheless, IRPs do their best to represent accurate views of the future, in order to develop least-cost plans. The Synapse Mid forecast, beginning at $20/tCO_2$ and rising to $65/tCO_2$, lies well within the range of the mid-case forecasts shown here.

Figure 10: Synapse 2012 Mid forecast as compared to the Mid forecasts of various U.S. utilities (2010-2012)[26]

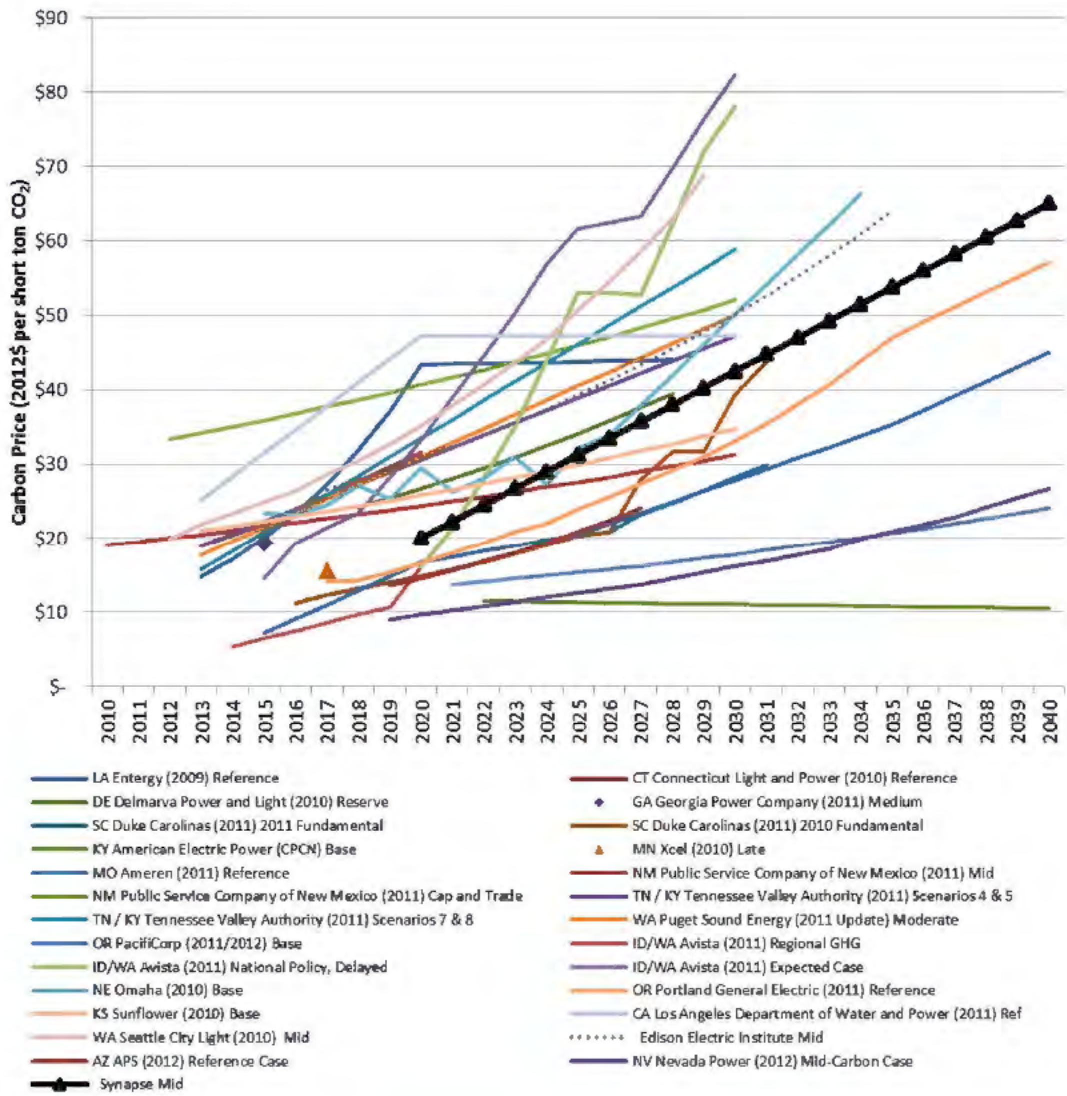


Figure 11 overlays the Synapse High case and the high case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (now shaded in grey). Not all IRPs that provide mid-level forecasts also provide high forecasts. The high cases generally reflect a nearer-term policy start date, as well as a more rapid rate of increase in prices with time. The Synapse forecast starts later than most, and rises from $30/tCO_2$ in 2020 to $90/tCO_2$ in 2040.

[26] Legend given here is common to all subsequent utility price forecast charts. While scenario names may change, colors are constant for a given utility.

Figure 11: Synapse High forecast as compared to the High and Mid forecasts of various utilities (see legend in Figure 10)

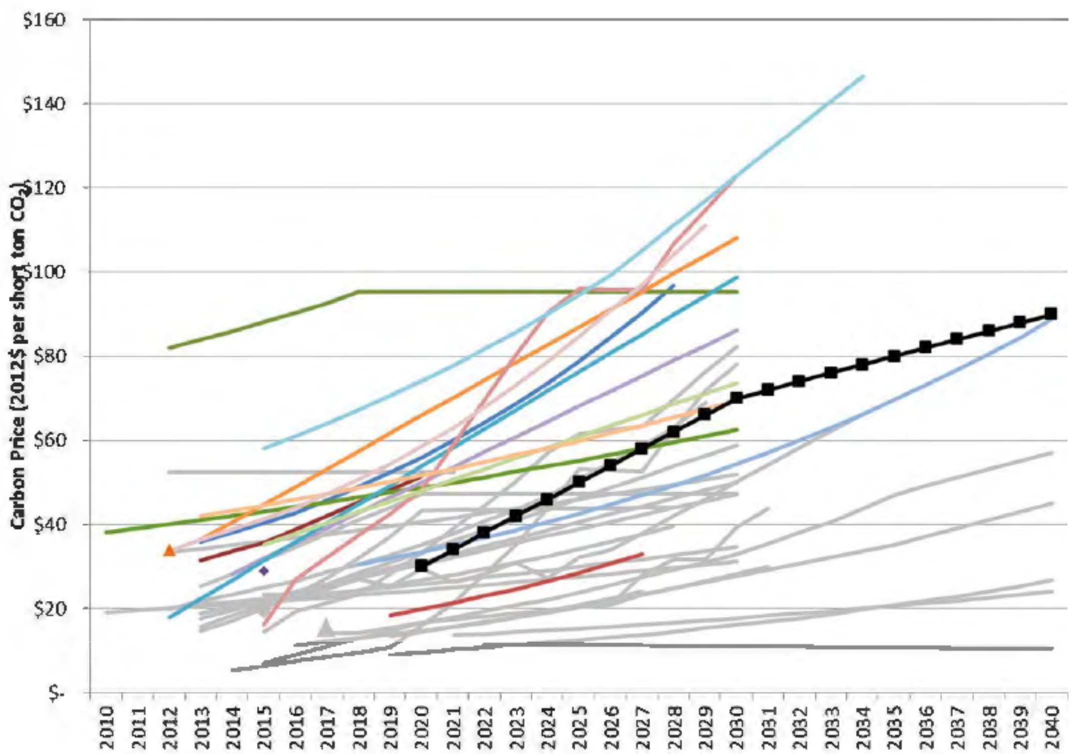


Figure 12 overlays the Synapse Low case and the low case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (shaded in grey). The low case forecasts both start at substantially lower values (occasionally at zero values), and rise at slower rates. The Synapse forecast starts later than most and rises from $15/tCO$_2$ in 2020 to $35/tCO$_2$ in 2040.

Figure 12: Synapse Low forecast as compared to the Low and Mid forecasts of various utilities (see legend in Figure 10)

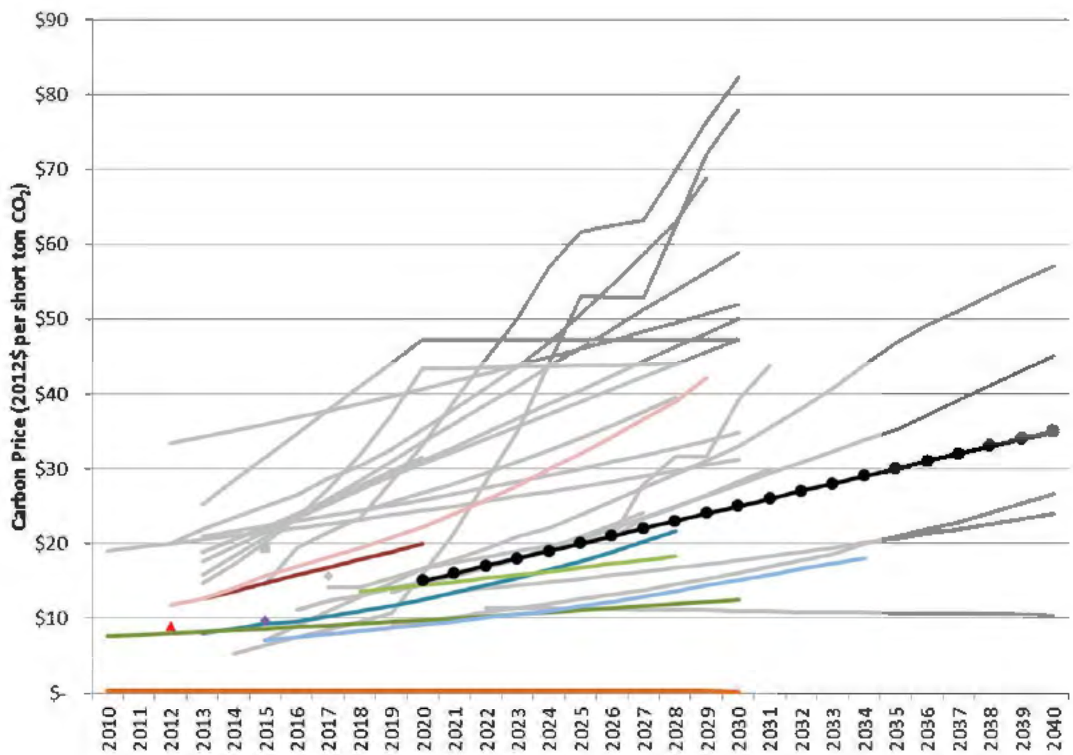


Figure 13 shows Synapse's Low, Mid, and High forecasts compared to the full range of utility forecasts shown above. The Synapse projections represent a plausible range of possible future costs. Using all three recommended price trajectories will facilitate sensitivity testing of long-term investment decisions in electric sector resource planning against likely federal climate policy scenarios.

Figure 13: Synapse forecasts compared to the range of utility forecasts

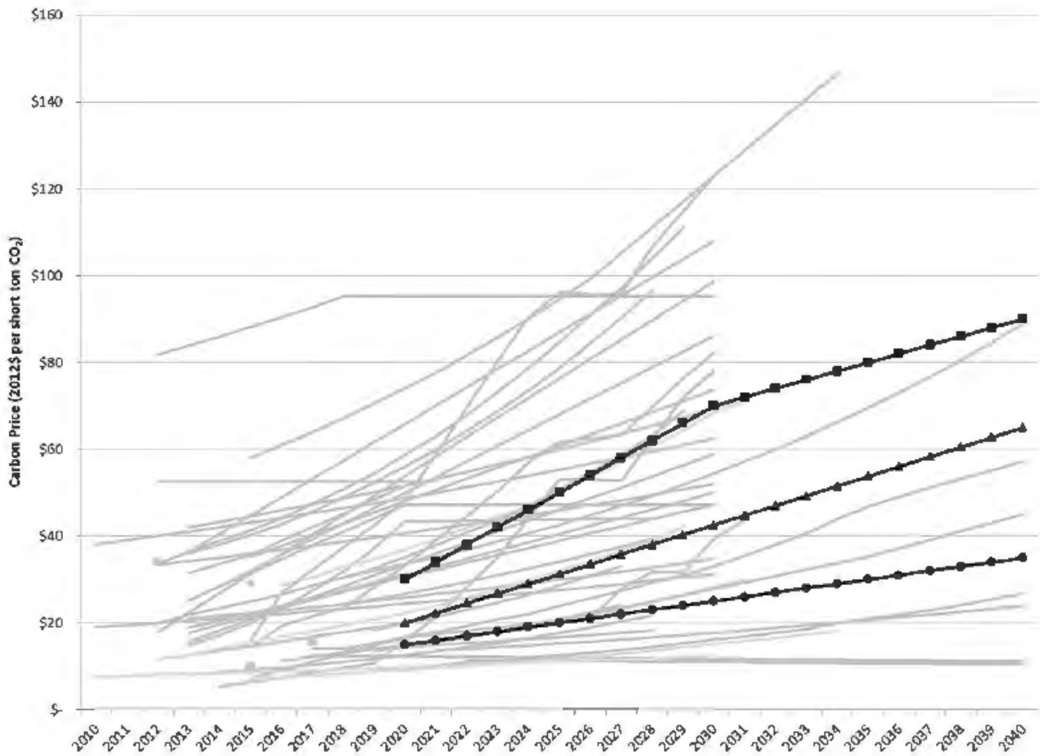
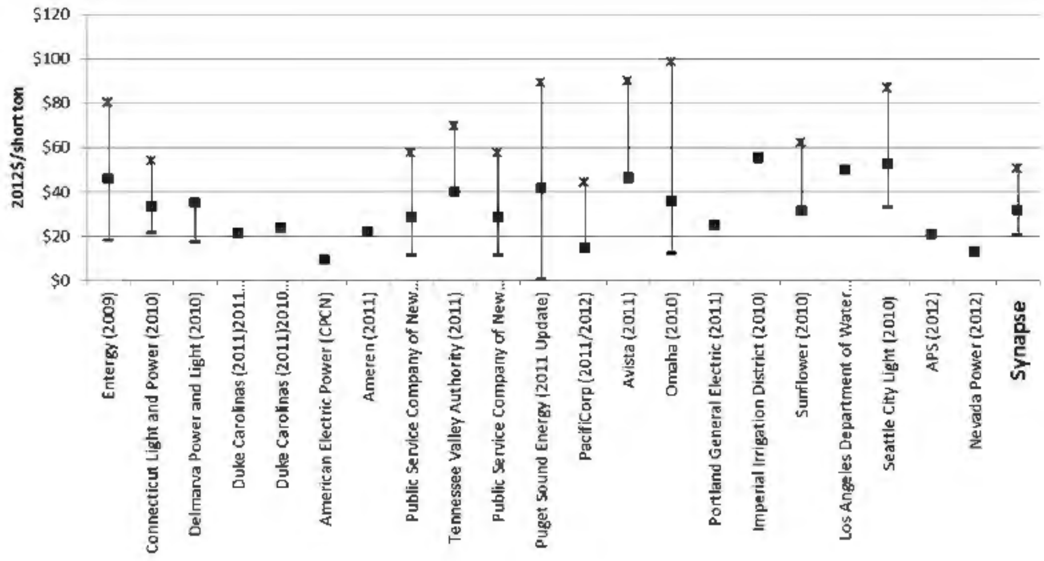


Figure 14 compares the levelized costs of Synapse's Low, Mid, and High cases to the levelized costs of utility estimates for 2020 through 2030, a period after the start and before the end of most forecasts. While levelizing between 2020 and 2030 results in different Synapse values than presented in Table 1 (where forecasts were levelized between 2020 and 2040), this approach allows for overlap and comparison with a broader range of utility estimates.

Figure 14: Levelized price of CO_2, 2020-2030, utilities and Synapse[27]



[27] All forecasts are levelized with a 5% discount rate based on CO_2 prices between 2020 and 2030. Forecasts with a price for only a single year excluded.

Appendix A: State and Regional GHG Initiatives

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

This appendix provides a more thorough discussion of state and regional greenhouse gas (GHG) initiatives. Collectively, these initiatives suggest that momentum is building toward more comprehensive federal GHG action.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [28]

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions, and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[29] This is the first mandatory carbon trading program in the nation. Recently, allowance prices have been hitting the CO_2 price floor, as actual emissions are far below the budget of 188 mtons/year.

California: In 2006, the California Legislature passed the Global Warming Solutions Act (AB 32), which requires the state to reduce emissions of GHGs to 1990 levels by 2020. The California Air Resources Board (CARB) outlined more than a dozen measures to reduce carbon emissions to target levels in its 2008 *Scoping Plan*. Those measures include a renewable portfolio standard, a low carbon fuel standard, and a cap-and-trade program. Approximately 22.5% of the emissions reductions called for by AB 32 are estimated to occur under the cap-and-trade program. California will have the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS).

The first compliance period for the program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The second compliance period will run from 2015-2017, and the third compliance period will cover 2018-2020. During these periods, the cap-and-trade program will expand to cover suppliers of natural gas, distillate fuel oil, and liquefied petroleum gas if the combustion of their products would result in 25,000 metric tons of CO_2e or more.[30] The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015. When additional sources are added, the cap increases to accommodate them, but then increases the percentage reductions in emissions to 3% in 2016, rising to 2.5% in 2020. The state plans to allocate the bulk of allowances for free in 2013, but will gradually auction

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[28] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[29] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org

[30] §95812 (d)(1), page 48

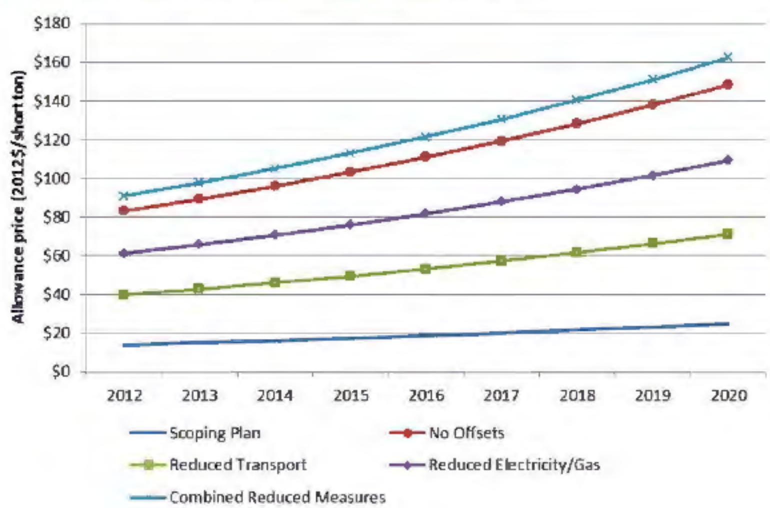
an increasing number of allowances between 2013 and 2020. Banking[31] and offsets[32] are both allowed under the California program.

The state of California has set a floor price for allowances beginning at $9.1/ton in 2013 ($10/metric tonne), and rising annually by 5% plus the rate of inflation.[33] In 2010 the Air Resources Board modeled the CO_2 allowance price trajectory that would enable reduction targets to be met under the following five cases:

1. Scoping Plan: Implements all of the measures contained in CARB's *Scoping Plan*
2. No Offsets: Does not allow offsets in the cap-and-trade program
3. Reduced Transport: Examines less effective implementation of the transportation-sector measures
4. Reduced Electricity/Gas: Examines less successful implementation of the electricity and natural gas measures
5. Combined Measures Reduced: Examines less successful implementation of transportation, electricity, and natural gas measures[34]

These five cases represent different scenarios of regulatory programs which, although different from the cap-and-trade program, can simultaneously help to achieve the goals of cap-and-trade. These regulatory measures are known as complementary policies. Figure A-1 shows the allowance price trajectories associated with those five cases.

Figure A-1: AB 32 Modeled Allowance Price Trajectories[35]



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31 §95922 (a), page 151
32 §95973 (a)(2)(C), page 156
33 §95911 (b)(6), page 129
34 California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board*. March 24, 2010. Page ES-6.
35 Id. Page 40.

As shown in Figure A-1, when the policies that are complementary to the cap-and-trade program are less effective, greater CO_2 reductions need to occur under the cap-and-trade program, and the allowance price is much higher. Similarly, the availability of offsets lowers the allowance price in the cap-and-trade program, as compliance with reduction targets can be met with offsets. This allows banking of allowances in the beginning of the program, which can keep allowance prices lower in later years.

California's first allowance auction is scheduled for November 14. A trial auction was completed on August 30, and more than 430 entities that will be regulated under the cap-and-trade program were invited to participate. CARB does not plan to release a settlement price, but on the date of the test auction, futures for December 2013 were trading at $14.77/ton, and forward contracts had sold for $14.77 and $14.82/ton.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[36] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[37] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[38]

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. These policies require electric utilities and other retail electric providers to supply a specified minimum amount—usually a percentage of total load served—with electricity from eligible resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

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[36] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan
[37] Minnesota Statutes 2008 § 216B.241
[38] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

In general the goal of an RPS policy is to increase the development of renewable resources by creating a market demand. Increasing demand makes these technologies more economically competitive with other less expensive, but polluting, forms of electric generation. Many other policy objectives drive the adoption of an RPS or renewable goal, including climate change mitigation, job creation, energy security, and cleaner air.

The impact of an RPS on CO_2 emissions is dependent on factors such as:

- the types of resources that are eligible to meet the standard,
- the target level set by the RPS,
- the base quantity of electricity sales upon which the standard is set,
- how renewable energy credits (RECs) or attributes are tracked or counted,
- how RECs are assigned to different resources,
- banking, trading and borrowing of RECs,
- alternative compliance options, and
- coordination with other state and federal policies.

Currently, 29 US states have renewable portfolio standards. Eight others have renewable portfolio goals.

In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories; greenhouse gas registries; climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI, requiring specific emissions reductions from power plants in the state, and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

Hawaii, while not part of a regional climate initiative, has an even more aggressive RPS, seeking to achieve 40% renewable energy by 2030, coupled with an Energy Efficiency Portfolio Standard with the goal of reducing electricity use by 4,300 GWh by 2030. After 2013, 2% of electricity revenues in Hawaii will go towards a Public Benefit Fund, an independent entity tasked with promoting and incentivizing energy efficiency measures across the state.

From:	News@snl.com on behalf of Sinclair, David
To:	Sinclair, David
Subject:	Dynegy scores rule variance for Illinois coal plants, closes in on acquiring Ameren assets
Date:	Friday, November 22, 2013 4:07:31 PM

To [redacted]

The article below was sent to you by [redacted]

DYNEGY SCORES RULE VARIANCE FOR ILLINOIS COAL PLANTS, CLOSES IN ON ACQUIRING AMEREN ASSETS

The Illinois Pollution Control Board on Nov. 21 granted a request by Dynegy subsidiary Illinois Power Holdings LLC and Ameren Corp. subsidiary AmerenEnergy Medina Valley Cogen LLC for multiyear variances to sulfur dioxide emissions limits for seven coal-fired power plants in the state.

Referenced Tickers: Illinois Power Holdings LLC, Ameren Energy Resources Co., MISO, DYN, AmerenEnergy Medina Valley, AEE

November 21, 2013 6:26 PM ET

Full Article (for subscribers only): http://www.snl.com/InteractiveX/articleabstract.aspx?ID=26022772&KPLT=2

Would you like information from SNL? If so, opt-in here:
http://www.snl.com/InteractiveX/optin.aspx?[redacted]

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From:	Wilson, Stuart
To:	Thompson, Paul
Cc:	Sinclair, David; Schram, Chuck; Farhat, Monica; Hurst, Brian; Karavayev, Louanne; Leitner, George; Ryan, Samuel; Wang, Chung-Hsiao
Subject:	RFP Status Report
Date:	Friday, November 30, 2012 11:50:30 AM
Attachments:	20121130_Phase2StatusReportandNextSteps_0060.docx

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Paul,

I've attached the document we plan to present at today's RFP status report meeting (in case you want a preview).

Stuart

2012 RFP Analysis
Status Report and Next Steps

PPL companies

Generation Planning & Analysis
November 30, 2012

Table of Contents

1 Summary of RFP Responses

Table 1 summarizes the number of RFP responses and proposals by response type. Several external responses include multiple proposals that refer to the same asset or asset portfolio. Table 2 contains summary statistics for the unique assets referenced in the external RFP responses.

Table 1 – Summary of RFP Responses

Response Type	Number of Responses	Number of Proposals
External	27	61
Self-Build	7	7
Retrofit	4	4
Energy Efficiency	7	7
Total	45	79

Table 2 – Summary Statistics for Assets Referenced in RFP Responses

Category	Number of 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

A detailed summary of all proposals is included in Appendix A – Detailed Summary of RFP Proposals.

2 Phase 1 Screening Analysis

In the Phase 1 Screening analysis, proposals were grouped (broadly) by technology and term. The proposals with the lowest levelized cost per megawatt-hour in each technology/term 'group' were evaluated in the next analysis Phase. These proposals are listed in Table 3.

Table 3 – Lowest Cost Responses from Phase 1 Screening Analysis

Group	Counterparty	Description	Levelized Cost ($/MWh)
CCCT (1X1)_5	Calpine	5 yr PPA, 250 MW	73
CCCT (1X1)_Own	LGE/KU (4 Options)	Self-Build, 299-379 MW	81 – 88
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	65
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	77
CCCT (2X1)_20	Khanjee (2 Options)	22 yr PPA, 700 MW	65 – 81
CCCT (2X1)_5	Calpine	5 yr PPA, 500 MW	72
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	63
CCCT (2X1)_Own	LGE/KU	Self-Build, 670 MW	78
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	79
Coal_10	Nextera	10 yr PPA, 50 MW	57
Coal_10	Big Rivers	1-15 yr PPA, 417 MW	78
Coal_10	AEP	11 yr PPA, Up to 700 MW	60
Coal_5	Nextera	6 yr PPA, 30 MW	56
Coal_5	Big Rivers	1–15 yr PPA, 417 MW	74
Coal_5	Ameren	5 yr PPA, 668 MW	58
Coal_Own	Duke	OVEC, 203 MW	82
Coal_Own	LGE/KU	Brown 1-2 Retrofit, 270 MW	72
DSM	LGE/KU (7 Options)	Lighting, T-stat Rebates, Windows & Doors, Mfg Homes, T-stat Pilot, Comm. New Constr., ADR	82+
RTC	KMPA	5 yr PPA, 25 MW	45
RTC	Exelon	10 yr PPA, 200 MW	53
SCCT_20	LS Power (2 Options)	20 yr PPA, 495 MW	282 – 284
SCCT_Own	LS Power (3 Options)	PPA w/ Asset Sale, 495 MW	249
Solar_Own	Solar Energy Solutions	Asset Sale, 1 – 5 MW	194
Solar_Own	LGE/KU	Self-Build, 10 MW	247
Wind	EDP Renewables (3 Options)	15 or 20 yr PPA, 99 – 151 MW	59 – 68

A complete summary of results from the Phase 1 Screening analysis is included in Appendix B – Phase 1 Screening Analysis Results.

3 LG&E/KU Resource Summary

After the Phase 1 Screening analysis, each alternative is evaluated using Strategist and PROSYM in the context of a generation portfolio that includes Cane Run 7 and the company's existing SCCTs and coal units (Brown 3, Mill Creek, Ghent, and Trimble County). Table 4 summarizes the Companies' capacity needs through 2021.[1]

[1] The capacity of Brown 1-2 is not included in the 'Existing Resources' line.

Table 4 – LG&E/KU Resource Summary (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Peak Reductions[2]	-137	-137	-137	-137	-137	-137	-137
Total Demand	6,903	6,954	7,010	7,077	7,144	7,212	7,281
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Total Supply	7,694	7,685	7,702	7,664	7,683	7,684	7,684
16% Reserve Requirements	8,008	8,067	8,132	8,209	8,287	8,366	8,446
Reserve Margin Shortfall	314	382	430	545	605	682	761
Reserve Margin	11.5%	10.5%	9.9%	8.3%	7.5%	6.5%	5.5%

4 Phase 2, Iteration 1 Alternatives

The responses that passed the Phase 1 Screening analysis were used to develop alternatives for the first iteration of the Phase 2 analysis. These alternatives are listed in Table 5. Each of these alternatives meets the Companies' reserve margin shortfall (see Table 4) through at least 2017. To streamline the evaluation process, this initial iteration focuses separately on alternatives that address the Companies' capacity shortfall in the short-term (5 years or less), medium-term (10 years), and long-term (20+ years). The top options in each of these categories will be evaluated further in subsequent iterations of the Phase 2 analysis.

The Phase 2, Iteration 1 alternatives were developed with the following capacity and timing considerations:

1. The self-build CCCT proposals were paired with the same LS Power proposal so the results for these alternatives would be comparable.
2. The self-build 1X1 CCCT proposals were paired with the same LS Power proposal and were assumed to be commissioned in 2020 to coincide with the first need for additional capacity (in these cases).
3. The self-build 2X1 CCCT proposals were assumed to be commissioned in 2017 so that these alternatives would be comparable to the ERORA proposals.
4. The Brown 1-2 retrofit and Duke's OVEC proposals were paired with the same Calpine proposal so that these alternatives would be comparable.
5. The Brown 1-2 retrofit and 250 MW Calpine proposals were both paired with the same LS Power proposal so that these alternatives would be comparable.

[2] Peak reductions include the impacts of interruptible loads and demand-side management programs.

Table 5 – Phase 2, Iteration 1 Alternatives

Term	Alt ID	Description	Delivered MWs
Short-Term	R07A	Ameren 5 yr PPA, Coal (2015)	668
	R04A	Big Rivers 3 yr PPA (2015)	407
	R06A	Calpine 5 yr PPA, 500 MW (2015)	485
	R19F	LS Power 5 yr PPA (2015)	495
	R05D	Quantum 5 yr PPA (2015)	680
Medium-Term	R02_	AEP Portfolio 11 yr PPA (2015)	700
	R04B	Big Rivers 10 yr PPA (2015)	407
	C05_	Calpine 5 yr PPA, 250 MW (2015), Exelon 10 yr PPA (2015)	438
	R19D	LS Power 20 yr PPA (2014)	495
	R19A	LS Power 20 yr PPA (2015)	495
	C08_	LS Power 20 yr PPA (2015), Calpine 5 yr PPA, 250 MW (2015)	738
Long-Term	C06_	Calpine 250 MW (2015), BR1-2 Retrofit	512
	C07_	Calpine 250 MW (2015), Duke (2013)	446
	R11E	Khanjee 22 yr PPA, Fixed Price (2015)	700
	R11F	Khanjee 22 yr PPA, Tolling (2015)	700
	R19E	LS Power (2014 Sale)	495
	R19B	LS Power (2018 Sale)	495
	R19C	LS Power (2020 Sale)	495
	C09A	LS Power 20 yr PPA (2015), BR1-2 Retrofit	764
	C09B	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2025 Retire)	764
	C09C	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2030 Retire)	764
	C10_	LS Power 20 yr PPA (2015), ERORA 10 yr PPA (2017)	1,195
	C11_	LS Power 20 yr PPA (2015), ERORA 20 yr PPA (2017)	1,195
	C17_	LS Power 20 yr PPA (2015), ERORA (2017 Sale)	1,195
	C12_	LS Power 20 yr PPA (2015), GE 1x1 F (2020)	794
	C18_	LS Power 20 yr PPA (2015), GE 2x1 (2017)	1,093
	C14_	LS Power 20 yr PPA (2015), MHI 1x1 (2020)	868
	C13_	LS Power 20 yr PPA (2015), Siemens 1x1 F (2020)	827
	C15_	LS Power 20 yr PPA (2015), Siemens 1x1 H (2020)	874
	C16_	LS Power 20 yr PPA (2015), Siemens 2x1 (2017)	1,165

5 Uncertainty in Natural Gas Prices, Load, and CO2 Regulations

To understand the impact on the analysis associated with the uncertainty in natural gas prices, native load, and potential CO2 regulations, each alternative was evaluated under three natural gas price scenarios, three native load scenarios, and 2 CO2 price scenarios (18 scenarios in all). Charts detailing these price and load scenarios are included in Appendix C – Natural Gas, Load, and CO2 Price Scenarios.

6 Phase 2, Iteration 1 Results

Table 6 contains a complete summary of the Phase 2, Iteration 1 results. Since the Phase 2 analysis will ultimately include several more iterations, these results should be considered preliminary and subject to change. In Table 6, the short-term, medium-term, and long-term alternatives are differentiated by color.

Table 6 – Phase 2, Iteration 1 Results – PRELIMINARY (NPVRR, $M)

Alternative	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
Khanjee Fixed Price PPA	22,301	1,076	799	225	81	218	24,701
LS Power (2018 Sale)	22,965	1,191	34	485	138	124	24,937
LS Power (2020 Sale)	22,968	1,171	54	485	137	124	24,939
Calpine 250, BR1-2	22,785	1,460	70	309	238	86	24,949
LS Power (2014 Sale)	22,962	1,225	3	500	140	124	24,953
LS Power PPA, BR1-2	22,859	1,222	151	396	259	89	24,978
Calpine 250, Duke (2013)	22,607	1,372	546	336	109	117	25,088
LS Power 20 yr PPA (2015)	22,965	1,240	151	466	144	124	25,091
Calpine 250, Exelon	22,959	1,448	70	366	118	166	25,128
LS Power 20 yr PPA (2014)	22,964	1,262	154	480	148	124	25,132
LS Power PPA, Siemens 1x1 H	22,935	1,294	151	466	162	124	25,133
LS Power PPA, BR1-2 (2030 Rt)	22,945	1,322	151	416	225	89	25,148
LS Power PPA, Siemens 1x1 F	22,981	1,268	151	457	167	124	25,149
LS Power PPA, ERORA 20 yr PPA	22,845	843	591	501	142	234	25,155
LS Power PPA, Siemens 2x1	22,915	1,329	151	484	156	124	25,159
LS Power PPA, GE 2x1	22,900	1,342	151	471	173	124	25,161
LS Power PPA, ERORA Sale	22,738	1,351	151	501	186	234	25,161
LS Power 5 yr PPA (2015)	22,922	1,495	54	421	145	124	25,162
AEP Portfolio 11 yr	22,530	1,342	686	301	105	200	25,164
LS Power PPA, Calpine 250	22,942	1,240	222	492	144	147	25,187
Calpine 500, 5 yr	22,880	1,495	140	408	130	141	25,194
Quantum 5 yr	22,864	1,495	149	397	130	160	25,195
Khanjee Tolling PPA	22,796	1,076	799	225	81	218	25,196
LS Power PPA, GE 1x1 F	22,957	1,334	151	461	191	124	25,219
LS Power PPA, BR1-2 (2025 Rt)	22,957	1,387	151	436	207	89	25,227
LS Power PPA, ERORA 10 yr PPA	22,884	1,063	421	500	144	222	25,233
LS Power PPA, MHI 1x1	22,942	1,374	151	474	171	124	25,236
Ameren Coal PPA	22,722	1,495	333	357	130	206	25,243
Big Rivers 3 yr	22,843	1,553	224	379	137	263	25,399
Big Rivers 10 yr	22,767	1,478	394	352	122	308	25,421

Short-Term Alternatives Medium Term Alternatives Long-Term Alternatives

The following are key takeaways from the Phase 2, Iteration 1 results:

1. Khanjee's proposal to construct a 2X1 combined-cycle plant in the LG&E/KU service territory and sell power at a fixed price is the least-cost alternative overall. Among the other proposals that include new 2X1 CCCT capacity in 2017, ERORA's 20-year PPA is the least-cost alternative.
2. The Brown 1-2 retrofit is a competitive alternative (and less costly than either Duke's OVEC proposal or the 250 MW Calpine proposal). However, if Brown 1-2 does not operate beyond 2030, the Brown 1-2 retrofit is not among the top options. A comparison of cost assumptions for the Brown 1-2 retrofit between the current analysis and the 2011 ECR filing is contained in Section 6.2.
3. Among the alternatives that include only the LS Power assets, the asset sale proposals are more economic than the PPA proposals. The expansion plans for these proposals include a 2X1 CCCT in 2020. These combinations are superior to the alternatives that pair 1X1 CCCTs with the LS Power CTs.

4. The 5-year PPA from LS Power is the least-cost alternative among the short-term alternatives (and clearly superior to the proposals from Big Rivers).[3] Excluding transmission costs, the Ameren proposal is also competitive.

6.1 Questions/Concerns Regarding Leading Alternatives

While a final list of leading alternatives cannot formally be identified at this time (given the amount of analysis that still has to be completed – see Section 7), it appears at this point that the list would include the following counterparties: LS Power, Ameren, ERORA, and Khanjee. The following questions/concerns exist for these counterparties:

1. LS Power
   a. FERC/market power concerns.
   b. The Companies requested a 5-year PPA from LS Power by November 30, but have not yet received a proposal.
2. Ameren
   a. Based on discussions with Transmission Planning, transmission costs may be significantly different for this alternative.
3. ERORA
   a. Elements of the proposal require further clarification. For example, unlike ERORA's response to the prior RFP, this proposal does not include transmission losses.
4. Khanjee
   a. No site has been formally identified.
   b. Uncertainty regarding credibility and experience developing generation projects.

6.2 Brown 1-2 Retrofit Costs

The differences in Brown 1-2 retrofit costs between the current analysis and the 2011 ECR analysis are summarized in Table 7. The current assumptions for annual capital were taken from the Companies' most recent business plan. The reduction in variable O&M is driven primarily by reductions in the assumed cost to operate the Brown 1-2 baghouse. When the 2011 Air Compliance Plan was developed, the Companies had limited operating experience with the Trimble County 2 baghouse. The updated operating expense estimates are based on almost two years of experience operating the Trimble County 2 baghouse.

Table 7 – Brown 1-2 Retrofit Costs

	2011 Air Compliance Plan	2012 RFP	Delta
Annual Capital (Levelized $M/yr)	6.5	3.5	-3.0
Baghouse/SAMM Capital (Nominal $M)	228	194	-34
Fixed O&M (Levelized $M/yr)	11.7	10.9	-0.9
Variable O&M ($/MWh)	15.34	1.98	-13.4

7 Next Steps

The following 'next steps' will be completed in subsequent Phase 2 iterations:

1. Incorporate into the analysis responses received in the last week.
2. Evaluate energy efficiency and other 'green' options.

[3] Note: The Companies requested a 5-year PPA from LS Power by November 30, but have not yet received a proposal.

3. Meet with HDR to confirm self-build cost assumptions. Ensure that comparisons to other CCCT proposals are 'apples to apples.'
4. Meet with Transmission to further discuss transmission cost assumptions. Transmission will use existing information to develop additional transmission cost estimates for the leading alternatives. Some proposals include transmission flows beyond those contemplated in the preparatory transmission studies.
5. Consider risk/uncertainty more completely.
6. Revisit cost assumptions for LS Power (PPA versus asset sale).
7. Factor reliability costs into 1X1 versus 2X1 combined cycle considerations.
8. Iteratively combine proposals for small amounts of capacity (less than 200 MW) with leading alternatives.
9. Data integrity checking.

8 Appendices

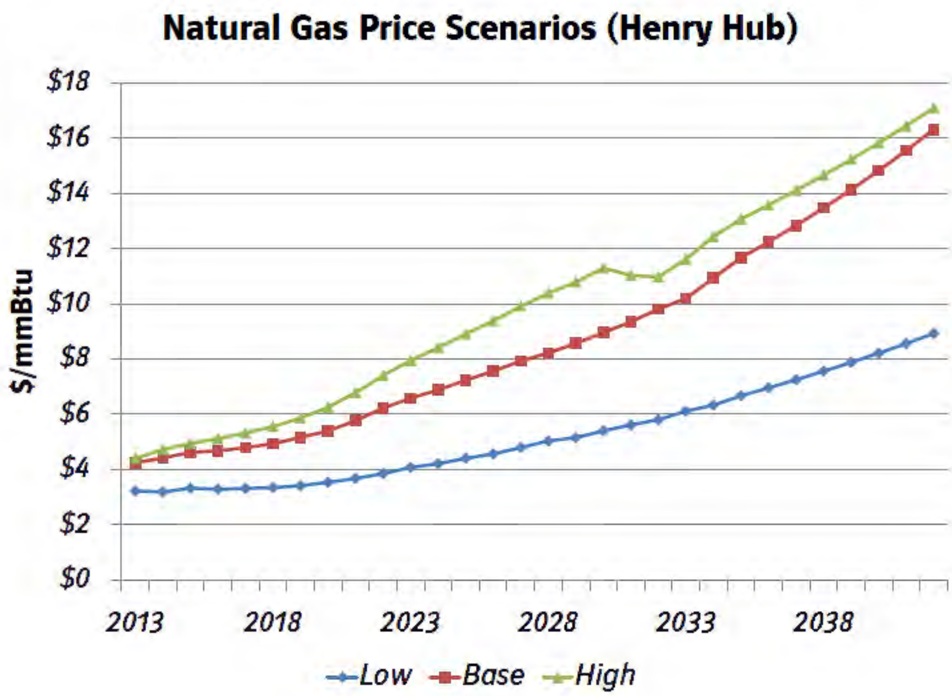
8.1 Appendix A – Detailed Summary of RFP Proposals

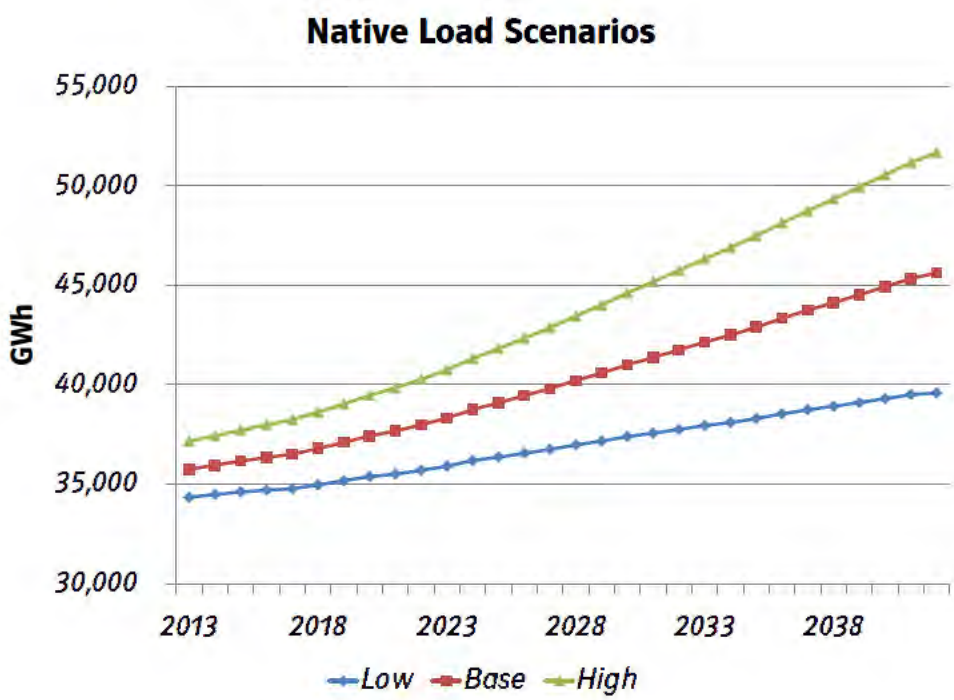
Contract Description									Capital Cost	Fixed Costs (FCs, Expressed as $/MW at TIP)				Additional Costs Incurred by LGE/KU ($2015)				Fuel/Energy Costs			Variable Costs					Additional Costs Incurred by LGE/KU ($2015)				
									Per Bid	Per Bid								Per Bid			Per Bid									
Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Asset Sale Price ($M)	FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M	Fixed Cost Escalator	Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu)	Variable O&M ($/MWh)	Start Cost and VOM Escalator
1A	ERORA	CCCT (2X1)_10	CCCT (2x1), GE	10 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1B	ERORA	CCCT (2X1)_20	CCCT (2x1), GE	20 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1C	ERORA	CCCT (2X1)_Own	CCCT (2x1), GE	Asset Sale, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	765						23,074		2.00%	6,705								0	264	3,019	0.36	2.00%
2	AEP	Coal_10	Portfolio	11 yr PPA, Up to 700 MW	AEP Gen Hub	1/1/2015	700	2015		147,022	0.00%			20,894			2.00%		31.91	0.00%				0.55	2.00%					
3	TPF Generation	SCCT_Own	SCCT	Asset Sale, 5 Units, 245 MW	CONSTELL PTID Node - PJM/AEP	TBD	245	2015	106					20,895	30,009	13,509	2.00%	10,650						0.55	2.00%			320	4.10	2.00%
4A	Big Rivers	Coal_5	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
4B	Big Rivers	Coal_10	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
5A	Quantum Choctaw Power	CCCT (2X1)_20	CCCT (2x1), Siemens	20-35 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		69,000 ($2015)	2.00%			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5B	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	Asset Sale, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	450	12,114 in 2015; 7,513 in 2016 esc at 2%				24,998	15,431		2.00%	7,064								0	883	3,019	0.35	2.00%
5C	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	20-35 yr PPA w/ Asset Sale Option, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	462.5 ($2015)	67,200 in 2015; 12,356 in 2016; 7,663 in 2017 esc at 2%				24,998	15,431		2.00%	7,064						1.00 in 2015; 0.35 at 2%		0	883	3,019		2.00%
5D	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		48,000 ($2015)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5E	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2016	701	2013		60,000 ($2016)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5F	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2014	701	2013		36,000 ($2014)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
6A	Calpine	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, Day-Ahead Call Option, 500 MW	Trinity/Limestone - TVA	1/1/2015	500	2015		74,160	2.30%			24,998	27,418		2.00%	7,400			25,700		1,000	2.00	2.00%					
6B	Calpine	CCCT (1X1)_5	CCCT (1x1), Siemens	5 yr PPA, Day-Ahead Call Option, 250 MW	Trinity/Limestone - TVA	1/1/2015	250	2015		74,160	2.30%			24,998	27,418		2.00%	7,500			12,850		475	2.00	2.00%					
7A	Ameren	Coal_5	Coal	5 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,496	0.00%								31.41	Schedule	7,428			2.61	Schedule					
7B	Ameren	Coal_10	Coal	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,688	Schedule								25.68	Schedule										
7C	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		83,796	Schedule				17,662				43.94	Schedule										
7D	Ameren	Coal_10	Portfolio (Coal and NG)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		131,484	Schedule								25.80	Schedule										
7E	Ameren	Coal_10	Portfolio (Coal to NG Conv.)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		87,936	Schedule				17,662				43.80	Schedule										
7F	Ameren	SCCT_5	SCCT	5 yr PPA, 5 units, 222 MW	EEI/LGE Interface	1/1/2015	222	2015		85,896	0.00%				17,662			13,366			16,900		290	1.40	Schedule					
8	Paducah Power Systems	SCCT_5	SCCT	5 yr PPA, 26 MW	LGEE-PPS1	1/1/2015	26	2015		1,825					27,200			13,090												
9A	Agile	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016	157						23,268	29,800	2.00%	8,793										288	4.2	2.00%
9B	Agile	SCCT_20	NG-Fired Recip Engine	20 yr Tolling Agreement, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016		157,000	0.00%	29,800	2.00%		23,268			8,793					288	4.20	2.00%					
10	KMPA	RTC	Coal, Base Load	5 yr PPA, 25 MW (RTC)	AMIL, MISO	1/1/2015	25	2015		34,255	2.00%			36,056					33.61	Schedule										
11A	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Murdock, IL - MISO	1/1/2015	746	2016						36,056	33,279				50.04 in 2017	Schedule										
11B	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279				35.13 in 2017	Schedule	0									
11C	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279			6,800			0			4.24 in 2017	Schedule					
11D	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Kentucky	1/1/2015	746	2016							23,898				44.16 in 2017	Schedule										
11E	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898				30.63 in 2017	Schedule	0									
11F	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898			6,800			0			0.55 in 2017	Schedule					
12	Exelon Generation Company	RTC	Firm Physical Energy	10 yr PPA, 200 MW	Indiana Hub - MISO	1/1/2015	200	2015						36,056					47.78	0.00%										
13	CPV Smyth Generation Co.	CCCT (2X1)_20	CCCT (2X1), Alstom	20 yr PPA, 630 MW	Smyth County, VA - PJM	6/1/2017	630	2017		132,000	0.00%	23,400		20,895	30,941			7,009			18,690		3,808	3.13	2.00%					
14A	Duke	Coal_Own	OVEC	Asset Sale in 2015, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2015	203	2015	100								2.00%		34.87	Schedule										
14B	Duke	Coal_Own	OVEC	Asset Sale in 2013, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2013	203	2013	50								2.00%		34.87	Schedule										
15	Wellhead Energy Systems	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 100 1 MW GridFox Units	LGE/KU System	1/1/2016	100	2013	99						23,898	29,800		10,000										3	4.20	
16A	Power4Georgians	RTC	Supercritical Coal	24 yr PPA, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349					32.40	1.85%				4.73	2.50%					
16B	Power4Georgians	RTC	Supercritical Coal	24 yr Tolling Agreement, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349				9,000						4.73	2.50%					
16C	Power4Georgians	RTC	Supercritical Coal	Asset Sale, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	3,030					56,349		27,673	2.50%	9,000								162,694			1.87	2.00%
17	Solar Energy Solutions	Solar_Own	Solar (PV Array)	Asset Sale, 1-5 MW	LGE/KU System	1/1/2016	1	2015	2.9							10,185	2.00%													
18A	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW	MISO/LGE Interface	1/1/2015	99	2015											50.00	3.00%										
18B	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW	MISO/LGE Interface	1/1/2016	151	2016											50.00	3.00%										
18C	EDP Renewables	Wind	Wind (As Available)	20 yr PPA, 100 MW	LGE/KU System	1/1/2016	100	2016											69.50	0.00%										
19A	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19B	LS Power	SCCT_Own	SCCT	3 yr PPA 1/1/2015, Asset Sale 2018, 495 MW	LGE Buckner Station	1/1/2015	495	2013	115	38,195	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19C	LS Power	SCCT_Own	SCCT	5 yr PPA 1/1/2015, Asset Sale 2020, 495 MW	LGE Buckner Station	1/1/2015	495	2013	105	38,195	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19D	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2014, 495 MW	LGE Buckner Station	1/1/2014	495	2013		12,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19E	LS Power	SCCT_Own	SCCT	5-mon PPA 1/1/2014, Asset Sale 2014, 495 MW	LGE Buckner Station	1/1/2014	495	2014	119	11,662	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19F	LS Power	SCCT_5	SCCT	5 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
20	Sky Global	CCCT (1X1)_10	CCCT (1X1), GE	10-20 yr PPA, 250-300 MW	KU's Pineville/Pocket North LGE	1/1/2016	250	2016		108,000	0.00%	27,000			49,005		2.00%	7,000					500							
21	Wellington	RTC	Waste Coal w/ CFBC	20 yr PPA, 112 MW	PJM West	9/1/2016	112	2012		388,014	Schedule	41,050	2.00%						61.10	Schedule										
22A	Southern Company Services	SCCT_5	SCCT	5 yr PPA, 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		45,000				56,349	25,266			12,850						4.65	0.0%					
22B	Southern Company Services	SCCT_5	SCCT	5 yr PPA (Summer Only), 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		35,000				56,349	25,266			12,850						4.65	0.0%					
22C	Southern Company Services	Coal_10	Coal	15 yr PPA, 109-159 MW	Unit GSU - SOCO	1/1/2016	159	2016		246,000	1.50%			56,349				10,400			14,136				3.5%					
23	Santee Cooper	Coal_10	Coal	7.8 yr PPA, 250 MW	Georgetown, SC	4/1/2017	250	2012		100,080	0.00%			84,038			2.00%		40	2.00%				5.00	0.0%					
24A	Nextera	Coal_5	Coal	6 yr PPA, 30 MW	Into LG&E/KU	1/1/2015	30	2015											55.00	0.96%										
24B	Nextera	Coal_10	Coal	10 yr PPA, 50 MW	Into LG&E/KU	1/1/2015	50	2015											55.00	0.96%										
25	South Point Biomass	RTC	Biomass	20 yr PPA, 165 MW	AEP/Bellefonte/Proctorville PJM	5/1/2015	165	2015						20,895					65.50	Schedule				0.55	2.00%					
26	North American BioFuels	RTC	Landfill Gas	20 yr PPA, 19 MW	WI and PA - MISO and PJM	1/1/2014	19	2013											52.00	3.00%				0.55	2.00%					
27A	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Existing LG&E/KU Site	6/1/2017	770	2012		110,520 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
27B	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Site TBD	6/1/2017	770	2012		118,680 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
28	LGE/KU	CCCT (1X1)_Own	GE CCCT (1X1) - F Class	Self-Build, 298.5 MW	Site TBD	6/1/2017	299	2015	438						21,924		2.00%	6,857								0	175	1,510	0.37	2.00%
29	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - F Class	Self-Build, 332 MW	Site TBD	6/1/2017	332	2015	420						21,924		2.00%	6,880								0	441	1,510	0.35	2.00%
30	LGE/KU	CCCT (1X1)_Own	MHI CCCT (1X1)	Self-Build, 372.7 MW	Site TBD	6/1/2017	373	2015	463						21,924		2.00%	6,813								0	633	1,510	0.34	2.00%
31	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - H Class	Self-Build, 379.4 MW	Site TBD	6/1/2017	379	2015	458						21,924		2.00%	6,613								0	687	1,510	0.33	2.00%
32	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), GE	Self-Build, 598 MW	Site TBD	6/1/2017	598	2015	609						21,924		2.00%	6,848								0	264	3,019	0.36	2.00%
33	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), Siemens	Self-Build, 670.4 MW	Site TBD	6/1/2017	670	2015	617						21,924		2.00%	6,866								0	883	3,019	0.35	2.00%
35	LGE/KU	Solar_Own	Solar (PV Array)	Self-Build, 10 MW	Site TBD	1/1/2016	10	2015	46							10,185	2.00%												0.91	2.00%
36	LGE/KU	Coal_Own	BR1-2 Retrofit	Retrofitted Coal, 270 MW	Brown Station	1/1/2015	269	2015	194									10,500						3.10 in 2016	Schedule			2,443		2.00%
37	LGE/KU	SCCT_Own	SCCT	Trimble CT Retrofit	Trimble County Station	4/1/2015	54	2015	108									10,139												2.00%
38	LGE/KU	CCCT (1X1)_Own	Steam Augmentation	Steam Augmentation for Trimble CTs	Trimble County Station	4/1/2015	1	2015	10									9,969												
39	LGE/KU	Coal_Own	Coal-to-NG Conversion	BR1-2 Coal to NG Conversion	Brown Station	4/1/2016	1	2015	10									10,000												
40A	LGE/KU	DSM	DSM	Lighting	LGE/KU System	1/1/2015	1	2015																						
40B	LGE/KU	DSM	DSM	Thermostat Rebates	LGE/KU System	1/1/2015	1	2015																						
40C	LGE/KU	DSM	DSM	Windows & Doors	LGE/KU System	1/1/2015	1	2015																						
40D	LGE/KU	DSM	DSM	Manufactured Homes	LGE/KU System	1/1/2015	1	2015																						
40E	LGE/KU	DSM	DSM	Behavioral Thermostat Pilot	LGE/KU System	1/1/2015	1	2015																						
40F	LGE/KU	DSM	DSM	Commercial New Construction	LGE/KU System	1/1/2015	1	2015																						
40G	LGE/KU	DSM	DSM	Automated Demand Response	LGE/KU System	1/1/2015	1	2015	22																					

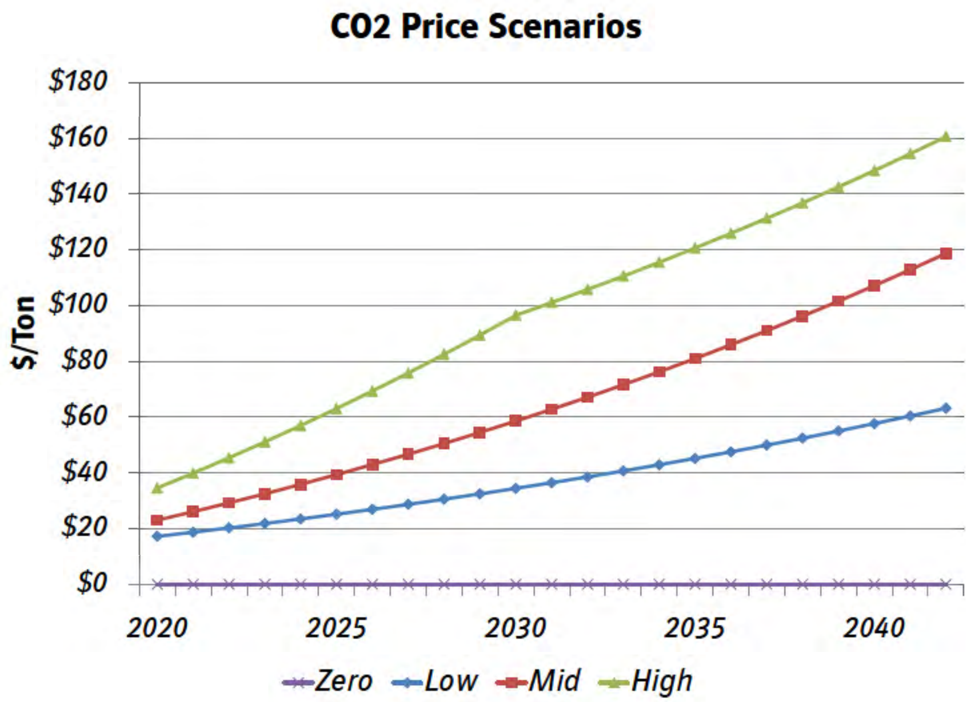
8.2 Appendix B – Phase 1 Screening Analysis Results

Class_Term	Counterparty	Description	Capital ($/kW)	Fixed O&M ($/MW-yr)	Energy Price	Total Costs	Rank
CCCT (1X1)_10	Sky Global	10-20 yr PPA, 250-300 MW	0	184,005	0	81	1
CCCT (1X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 250 MW	0	126,576	0	73	1
CCCT (1X1)_Own	LGE/KU	Steam Augmentation for Trimble CTs	1,059	0	0	275	5
CCCT (1X1)_Own	LGE/KU	Self-Build, 298.5 MW	1,468	21,924	0	88	4
CCCT (1X1)_Own	LGE/KU	Self-Build, 332 MW	1,264	21,924	0	84	3
CCCT (1X1)_Own	LGE/KU	Self-Build, 372.7 MW	1,242	21,924	0	84	2
CCCT (1X1)_Own	LGE/KU	Self-Build, 379.4 MW	1,206	21,924	0	81	1
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	0	94,389	0	65	1
CCCT (2X1)_20	CPV Smyth Generation Co.	20 yr PPA, 630 MW	0	207,236	0	100	9
CCCT (2X1) 20	ERORA	20 yr PPA, 700 MW	0	94,389	0	77	2
CCCT (2X1)_20	Quantum Choctaw Power	20-35 yr PPA, 701 MW	0	106,750	0	86	5
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	82	4
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	98	8
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	65	1
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	81	3
CCCT (2X1)_20	Southern Power Company	20 yr PPA, 770 MW	0	122,026	0	89	6
CCCT (2X1)_20	Southern Power Company	20 yr PPA, 770 MW	0	129,416	0	91	7
CCCT (2X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 500 MW	0	126,576	0	72	4
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	63	2
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	65	3
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	63	1
CCCT (2X1)_Own	LGE/KU	Self-Build, 598 MW	1,018	21,924	0	79	3
CCCT (2X1) Own	LGE/KU	Self-Build, 670.4 MW	921	21,924	0	78	1
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	1,093	23,074	0	79	2
CCCT (2X1)_Own	Quantum Choctaw Power	Asset Sale, 701 MW	642	40,429	0	82	4
CCCT (2X1)_Own	Quantum Choctaw Power	20-35 yr PPA w/ Asset Purchase Option, 701 MW	629	40,429	0	83	5
Coal_10	Nextera	10 yr PPA, 50 MW	0	0	55	57	3
Coal_10	Southern Company Services	15 yr PPA, 109-159 MW	0	302,349	0	105	9
Coal_10	Santee Cooper	7.8 yr PPA, 250 MW	0	184,118	40	82	8
Coal_10	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	78	7
Coal_10	Ameren	10 yr PPA, 668 MW	0	0	0	51	2
Coal_10	Ameren	10 yr PPA, 668 MW	0	17,662	0	67	5
Coal_10	AEP	11 yr PPA, Up to 700 MW	0	167,916	32	60	4
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	0	0	49	1
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	17,662	0	67	6
Coal 5	Nextera	6 yr PPA, 30 MW	0	0	55	56	1
Coal_5	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	74	3
Coal_5	Ameren	5 yr PPA, 668 MW	0	137,496	0	58	2
Coal_Own	LGE/KU	BR1-2 Coal to NG Conversion	10,000	0	0	120	4
Coal_Own	Duke	Asset Sale in 2015, 203 MW of OVEC	493	0	0	84	3
Coal_Own	Duke	Asset Sale in 2013, 203 MW of OVEC	246	0	0	82	2
Coal_Own	LGE/KU	Retrofitted Coal, 270 MW	721	0	0	71	1
DSM	LGE/KU	Lighting	0	0	0	202	2
DSM	LGE/KU	Thermostat Rebates	0	0	0	223	3
DSM	LGE/KU	Windows & Doors	0	0	0	637	5
DSM	LGE/KU	Manufactured Homes	0	0	0	1,043	6
DSM	LGE/KU	Behavioral Thermostat Pilot	0	0	0	252	4
DSM	LGE/KU	Commercial New Construction	0	0	0	82	1
DSM	LGE/KU	Automated Demand Response	21,899	0	0	26,253	7
RTC_20	North American BioFuels	20 yr PPA, 19 MW	0	0	52	69	4
RTC_5	KMPA	5 yr PPA, 25 MW (RTC)	0	70,311	0	45	1
RTC_20	Wellington	20 yr PPA, 112 MW	0	41,050	0	144	10
RTC_20	South Point Biomass	20 yr PPA, 165 MW	0	20,895	0	86	6
RTC_10	Exelon	10 yr PPA, 200 MW	0	36,056	48	53	2
RTC_22	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	69,335	0	70	5
RTC_22	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	23,898	0	57	3
RTC_24	Power4Georgians	24 yr PPA, 850 MW	0	444,005	32	102	8
RTC_24	Power4Georgians	24 yr Tolling Agreement, 850 MW	0	444,005	0	102	9
RTC_60	Power4Georgians	Asset Sale, 850 MW	3,565	84,022	0	88	7
SCCT_20	Agile	20 yr Tolling Agreement, 12 units, 112.9 MW	0	210,068	0	560	3
SCCT_20	LS Power	20 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	284	2
SCCT_20	LS Power	20 yr PPA starting 1/1/2014, 495 MW	0	42,524	0	282	1
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	0	29,025	0	140	1
SCCT_5	Southern Company Services	5 yr PPA, 75-675 MW	0	126,615	0	388	5
SCCT_5	Southern Company Services	5 yr PPA (Summer Only), 75-675 MW	0	116,615	0	363	4
SCCT_5	Ameren	5 yr PPA, 5 units, 222 MW	0	103,558	0	323	3
SCCT_5	LS Power	5 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	238	2
SCCT_Own	LGE/KU	Trimble CT Retrofit	2,000	0	0	433	6
SCCT_Own	Wellhead Energy Systems	Asset Sale, 100 1 MW GridFox Units	988	53,698	0	398	5
SCCT_Own	Agile	Asset Sale, 12 units, 112.9 MW	1,386	53,068	0	469	7
SCCT_Own	TPF Generation	Asset Sale, 5 Units, 245 MW	434	64,413	0	329	4
SCCT_Own	LS Power	3 yr PPA 1/2015, Asset Sale in 2017, 495 MW	232	34,724	0	249	2
SCCT_Own	LS Power	5 yr PPA 1/2015, Asset Sale in 2019, 495 MW	212	34,724	0	252	3
SCCT_Own	LS Power	5-mon PPA 1/2014, Asset Sale in 2014, 495 MW	240	34,724	0	240	1
Solar_Own	Solar Energy Solutions	Asset Sale, 1-5 MW	2,932	10,185	0	194	1
Solar_Own	LGE/KU	Self-Build, 10 MW	4,633	10,185	0	247	2
Wind_15	EDP Renewables	15 or 20 yr PPA, 99 MW	0	0	50	60	2
Wind_20	EDP Renewables	20 yr PPA, 100 MW	0	0	70	68	3
Wind_15	EDP Renewables	15 yr PPA, 151.2 MW	0	0	50	59	1

8.3 Appendix C – Natural Gas, Load, and CO2 Price Scenarios







Note: The Phase 2, Iteration 1 analysis considered the Zero and Mid CO2 price scenarios only.

From:	Voyles, John
To:	Sinclair, David
Subject:	FW: Green River NGCC Development Schedule 9-19-13.xlsx
Date:	Wednesday, December 11, 2013 3:51:40 PM
Attachments:	Green River NGCC Development Schedule 9-19-13.xlsx

From: Schetzel, Doug
Sent: Thursday, September 19, 2013 3:23 PM
To: Voyles, John
Cc: Balmer, Chris
Subject: Green River NGCC Development Schedule 9-19-13.xlsx

John

Revised Green River 5 development schedule includes Transmission CCN timed for order contemporaneous with generation CCN order.

Green River NGCC Development Schedule for 2018 COD

Task	Date	Comment	Responsibility	
3rd Party RFP	9/7/2012			
RFP Bids Due	11/2/2012			
Expansion Plan	**9/23/2013**	**When & Where**	**Schram**	
Issue Gas Route Study RFP	9/25/2013		Ryan	
Select Configuration	9/30/2013		Sinclair	Gen Planning
Begin Land Option Discussions	9/30/2013		Cockerill/Magallon	
Begin Geotehnical Survey	10/21/2013		Lively	
Begin Wetlands Survey	10/14/2013		Winkler	
File Supplemental Interconnection Request	10/21/2013		Schetzel	TranServ
Begin Pipeline Routing Study	10/24/2013		Ryan	
Complete Conceptual Design	11/4/2013		Lively	HDR
Begin CEA and Siting Study	11/11/2013		Winkler	
Begin Air Permit Application	11/11/2013		Revlett	
Execute Land Option	12/29/2013		Cockerill/Magallon	
Begin Supplemental SIS	2/1/2014		Schetzel	TranServ
Pipeline Route Selection	2/1/2014	Includes Budgetary Cost Estimate	Ryan	
Pipeline Build/Buy Decision	2/22/2014		Sinclair	
Begin PL ROW Option Discussions	3/1/2014		Cockerill/Kurgier	
Siting Study Complete	1/17/2014		Winkler	
CEA Complete	1/17/2014		Winkler	
Complete Supplemental SIS	7/21/2014		Schetzel	TranServ
File Generation CCN Application	2/2/2014		Lovekamp	
File Air Permit Application	3/21/2014		Revlette	
Complete EPC Bid Package	3/17/2014		Lively	HDR
Issue EPC Bid Package	4/16/2014		Lively	HDR
Begin Facility Study	9/4/2014		Schetzel	TranServ
File Transmission CCN (if necessary)	8/20/2014	If existing ROW minimal routing study	Lovekamp	
Complete Facility Study	2/1/2015		Schetzel	TranServ
EPC Bids Due	7/30/2014		Lively	HDR
Sign LGIA	4/2/2015		Schetzel	TranServ
EPC Short List	10/13/2014		Lively	HDR
Best & Final Bid Due	11/19/2014		Lively	HDR
Begin EPC Negotiations	12/19/2014		Schetzel	
Secure ROW Options	12/26/2014	Gas or Electric	Cockerill/Kurgier	
Generation CCN Order	2/2/2015		Lovekamp	
Final Air Permit	3/16/2015		Revlette	
Transmission CCN Order	2/16/2015		Lovekamp	
File ROW ED Actions if necessary	2/23/2015	Gas or Electric	Dimas	
Execute Gas Transport Agreement	3/26/2015		Sinclair	
EPC Award	3/19/2015		Schetzel	
LNTP	4/9/2015		Lively	
FNTP	6/8/2015		Lively	
Green River 3 & 4 Retire	4/15/2015		Troost	
ROW Acquisition Complete	2/23/2016	Gas or Electric	Dimas	
Back Feed Power	4/8/2017		Balmer	
Raw Water Available	4/8/2017		Lively	
Operations Staff Avail. For Training	4/11/2017		Troost	
Fuel Available	8/8/2017		Bruner	
Full Elec Export Available	9/8/2017		Balmer	
Target COD	2/9/2018		Lively	
Guaranteed COD	**4/11/2018**		Lively	

NOTES

Assumes Transmission CCN is Required but little or no new ROW is required

From:	Schetzel, Doug
To:	Thompson, Paul; Voyles, John; Straight, Scott; Sinclair, David
Cc:	Schram, Chuck; Wilson, Stuart; Heun, Jeff
Subject:	Solar Cost Comparison
Date:	Friday, December 13, 2013 1:32:07 PM
Attachments:	Solar Cost Comparison 12-13-13.xlsx

Attached is the comparison of the various estimates we have developed for the solar project.

Column 1 is the original HDR estimate in the Feasibility Study
Column 2 is a more aggressive internal modification of the HDR Feasibility Study estimate
Column 3 is the press release basis and was supported by other project costs as report in public documents.
Column 4 is the December 13 Brown site specific cost estimate.
Column 5 removes site prep. costs from the direct construction cost in column 4 and uses the more aggressive owner's cost and contingency used in columns 2 & 3.

Column 5 has about $6.5 million more in direct construction cost than the column 3 estimate used as the basis for the CCN filing.

Douglas Schetzel
Director Business Development
LG&E and KU Energy, LLC
[redacted]

	1	2		3	4	5	
				Press Release			
10 MW Solar Project	March 29, 2013			Least Cost	Dec. 13,2013	Dec. 13,2013	
	Base	Reduced	Comment	Alternative	Std. Efficency	Reduced	
Direct Construction Cost	37,750,000	33,975,000	10% Reduction	20,000,000	36,500,000	26,500,000	Removed Site Prep
Development Cost							
Development	650,000	500,000			650,000	500,000	
Elec. Trans. Studies	450,000	400,000			450,000	400,000	
Legal	250,000	200,000			250,000	200,000	
Owner's Engineer	70,000	70,000			70,000	70,000	
Land	1,300,000	-	Existing Co. Land		500,000	-	
Total Development Cost	2,720,000	1,170,000		1,170,000	1,920,000	1,170,000	
Construction Management							
Project Management	500,000	300,000			500,000	300,000	
Construction Power	50,000	50,000			50,000	50,000	
Owner's Engineer	100,000	75,000			100,000	75,000	
Spare Parts	100,000	75,000			100,000	75,000	
Site Security	100,000	50,000			50,000	50,000	
AFUDC	150,000	50,000			150,000	50,000	
Total Const. Management	1,000,000	600,000		600,000	950,000	600,000	
Contingency	7,550,000	3,397,500		2,000,000	5,475,000	2,000,000	
Total	49,020,000	39,142,500		23,770,000	44,845,000	30,270,000	
$/W	4.90	3.91		2.38			
ITC	1.47	1.17		0.71			
Net Capital Cost $/W	3.43	2.74		1.66			
Net Capital Cost $	34,314,000	27,399,750		16,639,000			
Fixed O&M							
Property Tax	70,000	35,000	50% Abatement				
Insurance	40,000	40,000					
Security	75,000	-	Existing Security				
Ground Maintenance	50,000	50,000					
Total	235,000	125,000		125,000			
Total FO&M $/MWH	14.94	7.95					
Variable O&M $/MWH	1	0.8		0.8			

From: Schetzel, Doug
To: Sinclair David; Schram Chuck; Wilson Stuart
Subject: Solar Presentation
Date: Friday, December 13, 2013 9:53:51 AM
Attachments: LG&E KU 10 MW Solar PV Siting Study Review Presentation Rev A.pptx

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Attached is the draft report for the site specific solar study for Brown. The project cost is approximately $4,500/kw Vs. $2,500/in current assumptions. Site prep is contributing approximately $1,000/kw of the difference. Scott is looking at alternate sites that would have lower site prep costs.

Douglas Schetzel
Director Business Development
LG&E and KU Energy, LLC
[redacted]

From: Wiitanen, Mark [redacted]
Sent: Friday, December 13, 2013 8:25 AM
To: Schetzel, Doug
Subject: Presentation

MARK A. WIITANEN
P.E.
HDR | Power Generation
Sr Project Manager | Associate Vice President
[redacted]

HDR | ONE COMPANY *Many Solutions*®

December 13, 2013

LG&E KU
PPL companies

EW Brown 10 MW Solar PV Siting Study Review

HDR

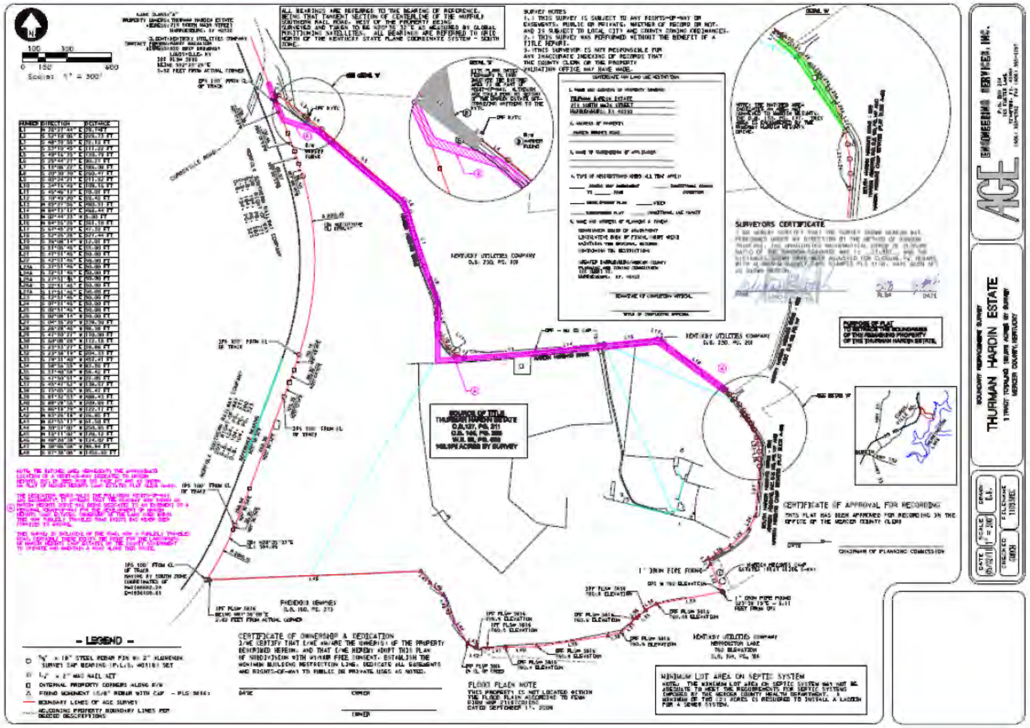
Agenda

- Siting Study Objectives
- Technology Considered
- Interconnection Evaluation
- Site Environmental Review
- Capital Costs
- Cost of Generation

Siting Study Objectives

- Selection of solar PV technology type and configuration to suit specific site.
- Identification of available electrical interconnection options and work with LG&E/KU to select a preferred option.
- High level review of environmental considerations to identify any issues of concern for the selected site.
- Develop a conceptual site general arrangement.
- Develop a conceptual project cost estimate based on lowest cost of generation option.

EW Brown Solar Site Overview
Former Hardin Estate – 153 Acres



HDR

PV Technology Available for Consideration

PANEL TECHNOLOGY

- Thin Film Type – First Solar 90W (FS-390) 12.54% efficiency at STC
- Crystalline Standard Efficiency Type – JA Solar 300W 15.57% efficiency at STC
- Crystalline High Efficiency Type – SunPower 320W 19.67% efficiency at STC

TRACKING SYSTEMS

- Fixed Axis Array - Southern Facing
- Single Axis Tracking – Track East to West Throughout Day

PV Technology Site Specific Evaluation

TRACKING SYSTEMS

- Fixed Axis Array – East/West Slope Limitation of 10% to 15% Acceptable for EW Brown
- Single Axis Tracking – East/West Slope Limitation of 1% to 5% is not compatible with EW Brown site topography

PANEL TECHNOLOGY

- Thin Film Type – Lower panel power density (W/ft2) cannot produce 10 MW AC on portion of EW Brown suitable for PV. A 6.5 MW AC capacity can be supported.
- Crystalline Standard Efficiency Type – 10 MW AC can be provided on EW Brown site utilizing approximately 50 acres
- Crystalline High Efficiency Type – Footprint nominally 6% smaller than Standard Efficiency Type at 47 acres

Electrical Interconnection Options

POTENTIAL INTERCONNECTION LEVELS/LOCATION

- Interconnection at 69 kV via Line Tap or Bay Addition at West Cliff Substation

- Interconnection at local distribution system

- Integration with proposed/approved CCRT 13.2 kV electrical distribution system. The CCRT 13.2 kV system will be served via two transformers supplied from the Brown South and West Cliff substations. The CCRT peak demand is estimated to be 5 MW to 10 MW.

SITING STUDY INTERCONNECTION BASIS

- CCRT 13.2 kV Distribution System Expansion has been determined to be the lowest cost option. Provides less external interface (for Solar PV Project) and potential interconnection study cost savings. The interconnection to consist of a 1 mile 13.2 kV OH line routed on LG&E-KU property.

Environmental – Critical Issues Analysis

ANALYSIS

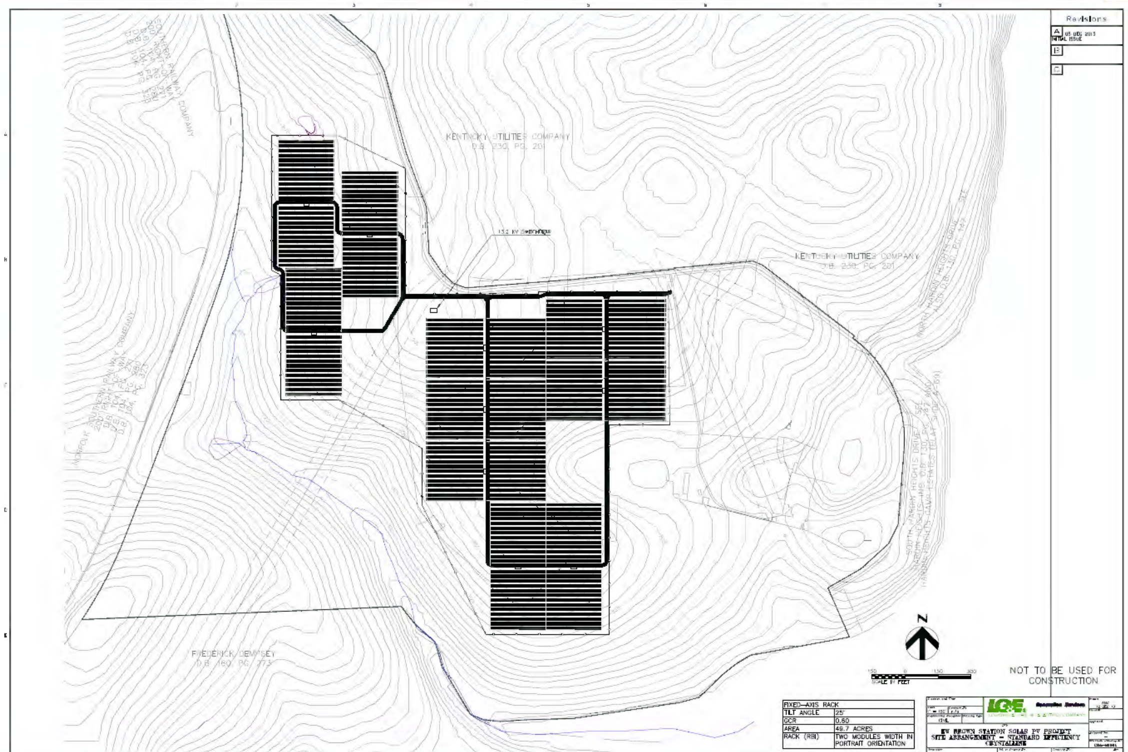
- Desktop Review
- Site Investigation 11/12/13
- LG&E-KU Record Review (Indiana Bat MOA and Soil Borings)

CIA FINDINGS AND RECOMMENDATIONS

- Agency Coordination
- Technical Studies
- Jurisdictional Waters Delineation
- Rare Plant and Mammal Study

HDR

10 MW Standard Efficiency Crystalline Site Arrangement w/ Topography



HDR

10 MW Standard Efficiency Crystalline Site Layout Aerial View

HDR

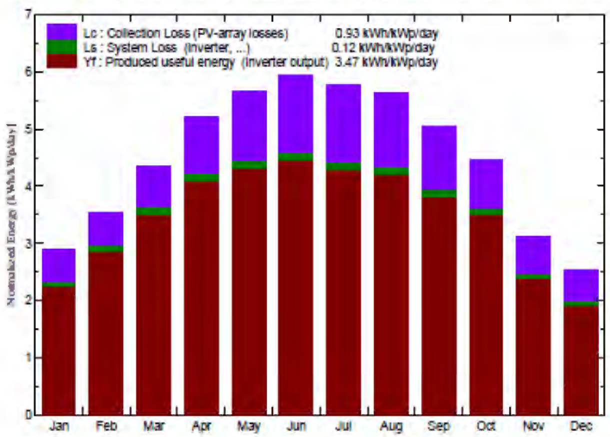
Solar Array Performance Calculations
PVSyst Software – Production

Main simulation results

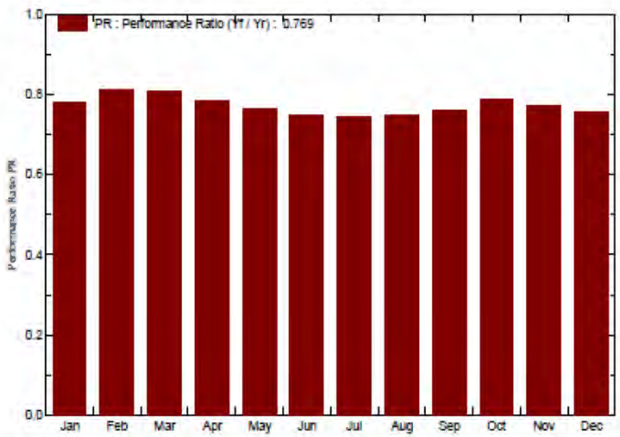
System Production

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

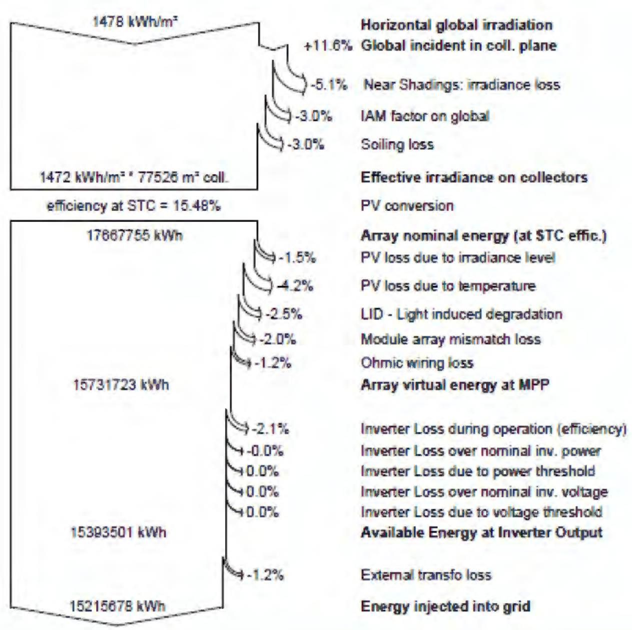


Performance Ratio PR



Solar Array Performance Calculations
PVSyst Software – Losses

Loss diagram over the whole year



Solar Array Performance Comparison

Module	Efficiency	$/W(dc)	Quantity	DC Power, kW	DC/AC Ratio	MWh/yr
First Solar 90W - 6.5 MW	12.54%	$0.62	86,660	7799	1.20	10,428
JA Solar 300W	15.57%	$0.75	39,995	11999	1.20	15,216
SunPower 320W	19.32%	$1.00	37,505	12002	1.20	15,979

HDR

Capital Cost and Cost of Generation

Description	Thin Film	Standard Efficiency	High Efficiency	Feasibility Study
EPC Direct Cost				
Site Preparation	$10,000,000	$10,000,000	$10,000,000	$875,000
Panel Modules & Support	$11,000,000	$15,000,000	$19,000,000	$30,875,000
500 kW Inverter	$3,000,000	$3,000,000	$3,000,000	$3,000,000
Medium Voltage Electric Distribution	$5,000,000	$5,000,000	$5,000,000	$1,500,000
Electrical Interconnect	$500,000	$500,000	$500,000	$1,500,000
Engineering, Permitting, Geotech	$3,000,000	$3,000,000	$3,000,000	-
EPC Cost	$32,500,000	$36,500,000	$40,500,000	$37,750,000
Owner Cost				
Project Development	$650,000	$650,000	$650,000	$650,000
Electrical Interconnect	$450,000	$450,000	$450,000	$450,000
Construction Power	$50,000	$50,000	$50,000	$50,000
Owners Project Management	$500,000	$500,000	$500,000	$500,000
Owners Engineer	$170,000	$170,000	$170,000	$170,000
Owners Legal Counsel	$250,000	$250,000	$250,000	$250,000
Land	$500,000	$500,000	$500,000	$500,000
Electric Transmission Service	$50,000	$50,000	$50,000	$50,000
Site Security	$50,000	$50,000	$50,000	$50,000
Spare Parts	$100,000	$100,000	$100,000	$100,000
AFUDC (KU Ownership Portion)	$150,000	$150,000	$150,000	$150,000
Contingency (15% of EPC)	$4,875,000	$5, 475,000	$6,075,000	$5,663,000
Owner Cost	**$7,795,000**	**$8, 395,000**	**$8,995,000**	**$8,583,000**
Total Project Cost	**$40,295,000**	**$44, 895,000**	**$49,495,000**	**$46,333,000**
Total Cost $/kW (AC)	**$6200/kW**	**$4490/kW**	**$4950/kW**	**$4633/kW**
Levelized Cost ($/MWHR)	**$286.53**	**$218.14**	**$228.46**	**$219.37**

HDR

From:	Wilson, Stuart
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	RE: Solar Cost Comparison
Date:	Monday, December 16, 2013 3:12:05 PM
Attachments:	RE 10 MW Solar Project.msg

David,

The $20 million figure is based on the attached email. We do not have a more detailed breakout of the costs.

Stuart

From: Thompson, Paul
Sent: Monday, December 16, 2013 3:08 PM
To: Sinclair, David
Cc: Schram, Chuck; Wilson, Stuart; Heun, Jeff; Schetzel, Doug; Voyles, John; Straight, Scott
Subject: RE: Solar Cost Comparison

David,

For the $20mm in Col 3, did we have any more component breakout for that number? What was the math that we used to get from $10 mW to that $20mm cost figure?

Thanks.

Paul

From: Schetzel, Doug
Sent: Friday, December 13, 2013 1:32 PM
To: Thompson, Paul; Voyles, John; Straight, Scott; Sinclair, David
Cc: Schram, Chuck; Wilson, Stuart; Heun, Jeff
Subject: Solar Cost Comparison

Attached is the comparison of the various estimates we have developed for the solar project.

Column 1 is the original HDR estimate in the Feasibility Study
Column 2 is a more aggressive internal modification of the HDR Feasibility Study estimate
Column 3 is the press release basis and was supported by other project costs as report in public documents.
Column 4 is the December 13 Brown site specific cost estimate.
Column 5 removes site prep. costs from the direct construction cost in column 4 and uses the more aggressive owner's cost and contingency used in columns 2 & 3.

Column 5 has about $6.5 million more in direct construction cost than the column 3 estimate used as the basis for the CCN filing.

Douglas Schetzel
Director Business Development
LG&E and KU Energy, LLC
[redacted]

From:	Parsons, Megan
To:	Wilson, Stuart
Cc:	Farhat, Monica; Schram, Chuck
Subject:	RE: 10 MW Solar Project
Date:	Wednesday, September 25, 2013 12:08:06 PM

Hi Stuart,

I've copied Peter's response below on solar pricing. Additionally, Peter had noted when developing the Tech Assessment that there is really no economies of scale between 10 MW and 50 MW.
I'm still reviewing the technology assessment to get out to you this week.

Hope this helps….let me know if you need any more info.

Thanks! Megan

From: Johnston, Peter
Sent: Wednesday, September 25, 2013 11:01 AM
To: Parsons, Megan; Poss, Zach
Subject: RE: 10 MW Solar Project

Hi Megan - there are all sorts of numbers out there and it's difficult to compare apples and apples!!

Generally, I agree with Stuart - $3.50/Wac is a little high today. In the TA we provided, the 50 MW system came out at $2.66/Wac for the installed cost without owner's costs etc – that's a little conservative since we had to make some assumptions regarding project siting, civil work etc.

I just received two quotes for a 10 MWac system – one came in at $1.96/Wac and the other at $2.00/Wac . These were for projects with identified sites so they were more refined than our TA estimate.

So I think Stuart can use a cost estimate in the $2.00 - $2.66 range.

Hope that helps

Peter

Peter Johnston
Project Manager – Renewable Energy
Burns & McDonnell
[redacted]

Megan Parsons, PE
Development Section Manager, Energy Division
Burns & McDonnell

[redacted]
*Registered in: MO

From: Wilson, Stuart [redacted]
Sent: Wednesday, September 25, 2013 10:15 AM
To: Parsons, Megan
Cc: Farhat, Monica; Schram, Chuck
Subject: 10 MW Solar Project

Megan,

Thanks for returning my call. We're trying to pull together cost estimates for a 10 MW solar PV project. Our generation technology assessment has a 50 MW solar PV project; I'm not sure to what extent a 10 MW project would have similar costs. For this particular request, we're only interested in the 'direct construction costs' for the panels. So, nothing for the site, project development, or construction management (we have separate estimates for these costs). We've been thinking about direct construction costs in the $3.5/W range (before ITC), but we've been hearing things that suggest the cost is much lower. For example…

1. According to this article (http://breakingenergy.com/2013/09/23/big-solar-is-having-a-banner-year-in-us/), a recent SEIA/GTM report for the quarter ended June 30 showed "utility system prices once again declined quarter-over-quarter and year-over-year, down from $2.60/W in Q2 2012 and $2.14/W in Q1 2013, settling at $2.10/W in Q2 2013." I'm not sure whether these prices are precisely comparable to our $3.5/W figure (or whether they're quoted before or after the ITC). Either way, they appear lower than what we've been thinking…
2. According to a recent filing by Excel Energy (http://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=240772&p_session_id=), it appears their costs are even lower. Excel's analysis of wind/solar begins on page 32 of the PDF (page 30 of the document). Several elements of their analysis are redacted, but based on non-redacted information, we estimated their costs to be in the $1.5/W range. Based on the report (see top of PDF page 34), the project is justified based on its ability to displace combined and simple-cycle gas units with a combined heat rate of 8,600 btu/kWh (they're assuming $6/mmBtu gas, so this equates to approximately $50/MWh). The project is not credited for the capacity it provides to the system.

These reference points are just FYI (I'm not asking you to review them in detail). It seems that 'current' solar prices are much lower than we thought. Wanted to get your take on this (as a preview to the generation technology study).

Thanks for your help.

Stuart

From:	Wilson, Stuart
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	Solar Considerations
Date:	Tuesday, December 17, 2013 3:21:33 PM
Attachments:	Document1.docx

David,

Here's the information I pulled together for tomorrow's review of John's testimony. The cost of the solar project can be as high as $28.1 million and the impact is 'neutral' across the mid CO_2 scenarios.

Stuart

From:	Wilson, Stuart
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	Mtg Materials for RFP Meeting
Date:	Tuesday, December 18, 2012 7:45:30 AM
Attachments:	20121218_2012RFPAnalysis_0060.pptx 20121218_Phase2StatusReportandNextSteps_0060.docx

David,

I've attached the meeting materials for this morning's meeting. Per our discussion, the plan is to hand out the larger document at the end of the meeting.

Stuart

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Analysis of Responses to 2012 RFP

Generation Planning & Analysis
December 18, 2012






Without Brown 1 and 2, the reserve margin shortfall in 2015 is 336 MW

LG&E/KU Resource Summary – Base Load Forecast (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	7,885
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demand	137	137	137	137	137	137	137
Total Supply	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin (RM)	11.2%	10.3%	9.7%	8.1%	7.4%	6.4%	5.4%
RM Shortfall (16% RM)	336	404	452	567	627	704	783
RM Shortfall (15% RM)	265	333	380	495	554	631	709

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Phase 1 Screening Results

Group	Counterparty	Description	Levelized Cost ($/MWh)
CCCT (1X1)_5	Calpine	5 yr PPA, 250 MW	68
CCCT (1X1)_Own	LGE/KU (4 Proposals)	Self-Build, 299-379 MW	73 – 80
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	60
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	77
CCCT (2X1)_20	Khanjee (2 Proposals)	22 yr PPA, 700 MW	65 – 72
CCCT (2X1)_5	Calpine	5 yr PPA, 500 MW	68
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	59
CCCT (2X1)_Own	LGE/KU (2 Proposals)	Self-Build, 670 MW	70-71
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	71
Coal_10	Nextera	10 yr PPA, 50 MW	57
Coal_10	Big Rivers	1-15 yr PPA, 417 MW	83
Coal_5	Nextera	6 yr PPA, 30 MW	56
Coal_5	AEP	5 yr PPA, Up to 700 MW	81
Coal_5	Big Rivers	1–15 yr PPA, 417 MW	79
Coal_5	Ameren	5 yr PPA, 668 MW	61
Coal_Own	Duke	OVEC, 203 MW	91
Coal_Own	LGE/KU	Brown 1-2 Retrofit, 269 MW	69
DSM	LGE/KU (7 Proposals)	Lighting, T-stat Rebates, Windows & Doors, Mfg Homes, T-stat Pilot, Comm. New Constr., ADR	104+
RTC	KMPA	5 yr PPA, 25 MW	45
RTC	Exelon	10 yr PPA, 200 MW	53
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	133
SCCT_5	LS Power	5 yr PPA, 495 MW	249
SCCT_20	LS Power (2 Proposals)	20 yr PPA, 495 MW	269 – 271
SCCT_Own	LS Power (3 Proposals)	PPA w/ Asset Sale, 495 MW	227 – 239
Solar_Own	Solar Energy Solutions	Asset Sale, 1 – 5 MW	194
Solar_Own	LGE/KU	Self-Build, 10 MW	247
Wind	EDP Renewables (3 Proposals)	15 or 20 yr PPA, 99 – 151 MW	59 – 68

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Phase 2 Analysis Methodology

- *Iteration 1 focuses separately on alternatives that address the Companies' capacity shortfall in the short-term (5 years or less), medium-term (10 years), and long-term (20+ years).*
- *Iteration 2 focuses on the following types of alternatives:*
  - *'Optimized' short-term PPA*
  - *Short-term PPA + Brown 1-2 retrofit*
  - *'Refined' long-term PPA*
- *In iteration 3, proposals for smaller amounts of capacity are iteratively combined with other short-term PPAs to understand the impact of these proposals on production costs.*

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Phase 2 Results

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	AEP Port 350 - 2 yr, Khanjee ('17)	'21 SCT	22,522	1,082	800	234	86	64	24,788
2	Khanjee Fixed Price PPA	'21 SCT	22,537	1,082	799	234	86	52	24,791
3	Ameren Coal 3 yr 167, BR1-2	'18 2x1	22,982	1,569	53	322	251	-30	25,148
4	LS Power (2020 Sale)	'19 2x1	23,200	1,221	54	501	157	64	25,197
5	LS Power (2018 Sale)	'19 2x1	23,196	1,240	34	501	162	64	25,197
6	LS Power (2014 Sale)	'19 2x1	23,191	1,274	3	516	172	64	25,220
7	LS Power PPA, ERORA 20 yr PPA	'28 2x1	23,050	864	591	505	143	112	25,265
8	Ameren Coal PPA (334) – 5 yr	'17 SCT	23,053	1,536	166	383	143	-7	25,275
9	Ameren Coal PPA (501) – 5 yr	'19 SCT	23,015	1,493	250	366	136	30	25,290
10	Khanjee Tolling PPA	'21 SCT	23,042	1,082	799	234	86	52	25,295
11	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	22,983	1,146	522	406	132	124	25,312
12	Ameren Coal 334 - 2yr	'17 2x1	23,074	1,631	73	405	146	-7	25,323
13	LS Power 20 yr PPA (2015)	'19 2x1	23,200	1,290	151	481	149	64	25,336
14	Ameren Coal 501 - 4 yr	'19 2x1	23,022	1,572	206	382	138	30	25,350
15	LS Power PPA, ERORA Sale	'28 2x1	23,028	1,372	151	506	188	112	25,356
16	Ameren Coal 501 - 3 yr	'18 2x1	23,039	1,601	159	393	142	30	25,365
17	LS Power PPA, GE 2x1 (2019)	'27 2x1	23,164	1,348	151	470	170	64	25,367
18	Ameren Coal PPA (668)	'20 2x1	22,960	1,543	333	371	135	30	25,372
19	Ameren Coal 668 5 yr	'20 2x1	22,960	1,543	333	371	135	30	25,372
20	LS Power PPA, Siemens 2x1 (2017)	'28 2x1	23,164	1,350	151	489	157	64	25,375
21	AEP Portfolio 350 - 2 yr	'17 2x1	23,090	1,631	82	405	146	21	25,376
22	Ameren Coal 501 - 2 yr	'17 2x1	23,055	1,631	110	405	146	30	25,377
23	LS Power 20 yr PPA (2014)	'19 2x1	23,201	1,311	154	495	153	64	25,379
24	LS Power PPA, ERORA 10 yr PPA	'27 2x1	23,113	1,084	421	505	145	112	25,380
25	LS Power PPA, Siemens 1x1H (2019)	'24 2x1	23,159	1,372	151	469	166	64	25,383
26	Ameren Coal 668 - 4 yr	'19 2x1	22,988	1,572	275	382	138	30	25,384
27	AEP Portfolio 400 - 2 yr	'17 2x1	23,087	1,631	94	405	146	23	25,385
28	LS Power 5 yr PPA (2015)	'19 SCT	23,183	1,493	67	430	152	64	25,389
29	Calpine 250, Exelon	'18 SCT	23,214	1,476	70	386	129	121	25,396
30	LS Power 2 CTs - 2 yr	'17 2x1	23,116	1,631	20	423	151	64	25,405

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Key Takeaways from Phase 2 Analysis

- *The Khanjee fixed price PPA is the most competitive option.*
- *The Brown 1-2 retrofit (paired with a shorter-term PPA) is also competitive if Brown 1-2 operate through 2042.*
- *The LS Power sale alternatives are more favorable than the LS Power PPA alternatives.*
- *A short-term Ameren PPA is more competitive than the LS Power PPA proposals.*
- *The longer-term alternatives are generally more competitive than shorter-term alternatives.*

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Several assumptions impact the valuation of the Brown 1-2 retrofit alternative

- *In the base gas price scenario, coal becomes relatively less expensive than natural gas over time. Beginning in 2022, dispatch costs for Brown 1 and 2 are expected to be lower than new CCCT generation.*
- *Brown 1 and 2 operate through the end of the analysis period (2042). In 2013, Brown 1 and 2 will be 55 and 49 years old, respectively. In 2042, Brown 1 and 2 will be 85 and 79 years old, respectively.*
- *Brown 1 and 2 will require no additional environmental controls through 2042.*
- *No CO_2 regulations resulting in a cost for CO_2 emissions will be promulgated through 2042.*

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Changing key assumptions significantly impacts the valuation of Brown 1-2

	$M
Difference between Best BR1-2 Retrofit Option and Best Short-Term PPA	*$175*
Impact of Ignoring Long-Term Production Costs	*($110)*
Impact of Retiring BR1-2 in 2030	*($125)*
Impact of Installing SCR on BR1-2	*($165)*
Net Difference	*($225)*

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Shortlist of External Respondents

- *Initial discussions will be held with the following parties:*
  - *AEP*
  - *Ameren*
  - *Big Rivers*
  - *ERORA*
  - *Khanjee*
  - *LS Power*

- *Discussions may be held with the following parties (depending on the outcome of discussions with the above-mentioned parties):*
  - *Calpine*
  - *Exelon*
  - *Quantum*

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Next Steps

- *Meetings with shortlisted respondents begin January 7.*
- *Open Questions:*
  - *Long-term commodity price assumptions significantly impact this analysis. What alternative(s) has the least risk as far as long-term commodity prices are concerned?*
  - *The prospects for plant-wide averaging for MATS compliance at E.W. Brown are not certain. What alternative is most competitive in a scenario with minimal retrofit costs for Brown 1-2?*
  - *What impact do the energy efficiency alternatives have on the analysis?*
  - *What transmission considerations may impact the recommendation?*

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Appendix

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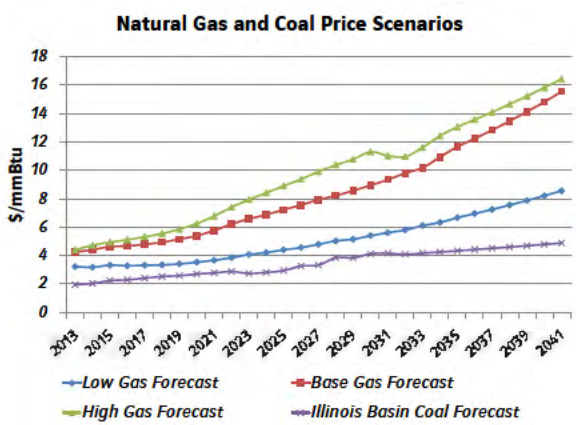
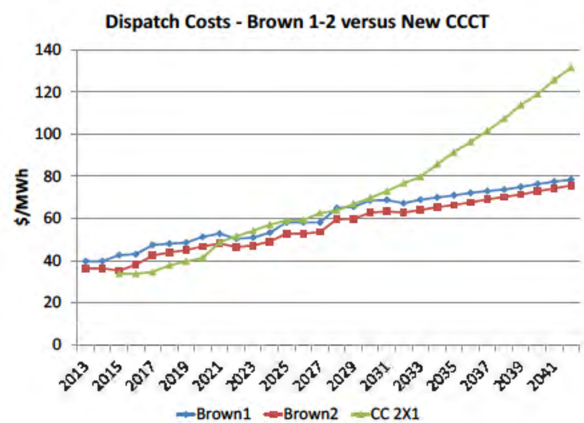
Coal becomes relatively less expensive than gas over time





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Purchasing the LS Power CTs is less costly than a PPA

- *The difference in NPVRR between the top sale alternative and the top PPA alternative is $140 million.*
  - *At the end of the PPA, new capacity must be acquired to replace the LS Power CTs. These costs account for $90 million of the $140 million difference.*
  - *The LS Power assets are priced to sell. The NPVRR of the capital costs in the sale alternative is $30 million less than the NPVRR of the capacity charges in the PPA alternative.*
  - *Differences in fixed O&M between the alternatives explain the majority of the remaining $20 million difference.*

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2012 RFP Analysis
Status Report and Next Steps

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Generation Planning & Analysis
December 18, 2012

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Table of Contents

1 Summary of RFP Responses

Table 1 summarizes the number of RFP responses and proposals by response type. Several external responses include multiple proposals that refer to the same asset or asset portfolio. Table 2 contains summary statistics for the unique assets referenced in the external RFP responses.

Table 1 – Summary of RFP Responses

Response Type	Number of Responses	Number of Proposals
External	29	68
Self-Build	8	8
Retrofit	4	4
Energy Efficiency	7	7
Total	48	87

Table 2 – Summary Statistics for Assets Referenced in External RFP Responses

Category	Number of Assets	MWs
Total	35	11,853
Coal	9	2,734
Gas	17	7,669
Renewable[1]	7	550
Portfolio	2	900
New	14	4,686
Existing	21	7,166
In-State	13	3,757
Out-of-State	22	8,095

A detailed summary of all proposals is included in *Appendix A – Detailed Summary of RFP Proposals*.

2 Analysis Methodology

The analysis of the RFP proposals was completed in multiple phases. In the Phase 1 screening analysis, proposals were grouped (broadly) by technology and term. The proposals with the lowest levelized cost per megawatt-hour in each technology/term 'group' were evaluated in the Phase 2 analysis. The Phase 2 analysis was completed in several iterations. Each alternative in the Phase 2 analysis was evaluated using Strategist and PROSYM in the context of a generation portfolio that includes Cane Run 7 and the company's existing SCCTs and coal units (Brown 3, Mill Creek, Ghent, and Trimble County). Table 3 summarizes the Companies' capacity needs through 2021 in the base load forecast scenario.[2] Table 17 and Table 18 in *Appendix C – LG&E/KU Resource Summaries (High & Low Load Forecasts)* summarize the Companies' capacity needs in the high and low load forecast scenarios.

[1] MW total for renewable assets is not considered firm capacity.
[2] The capacity of Brown 1-2 is not included in the 'Existing Resources' line.

Table 3 – LG&E/KU Resource Summary – Base Load Forecast (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	7,885
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demand	137	137	137	137	137	137	137
Total Supply	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin (RM)	11.2%	10.3%	9.7%	8.1%	7.4%	6.4%	5.4%
RM Shortfall (16% RM)	336	404	452	567	627	704	783
RM Shortfall (15% RM)	265	333	380	495	554	631	709

Strategist is used to develop resource expansion plans for meeting the Companies' forecasted energy requirements. Alternatives with greater capacity may have higher initial costs but they will defer the need (and associated costs) for long-term capacity resources (LCRs). The following resources are included as LCRs in Strategist:

1. SCCT (Siemens F Class)
2. 2X1 CCCT (Siemens F Class)
3. 1X1 CCCT (Siemens H Class)

3 Phase 1 Screening Analysis

In the Phase 1 screening analysis, proposals were grouped (broadly) by technology and term. The proposals with the lowest levelized cost per megawatt-hour in each technology/term 'group' are listed in Table 4.

Table 4 – Lowest Cost Responses from Phase 1 Screening Analysis

Group	Counterparty	Description	Levelized Cost ($/MWh)
CCCT (1X1)_5	Calpine	5 yr PPA, 250 MW	68
CCCT (1X1)_Own	LGE/KU (4 Proposals)	Self-Build, 299-379 MW	73 – 80
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	60
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	69
CCCT (2X1)_20	Khanjee (2 Proposals)	22 yr PPA, 700 MW	65 – 72
CCCT (2X1)_5	Calpine	5 yr PPA, 500 MW	68
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	59
CCCT (2X1)_Own	LGE/KU (2 Proposals)	Self-Build, 670 MW	70-71
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	71
Coal_10	Nextera	10 yr PPA, 50 MW	57
Coal_10	Big Rivers	1-15 yr PPA, 417 MW	83
Coal_5	Nextera	6 yr PPA, 30 MW	56
Coal_5	AEP	5 yr PPA, Up to 700 MW	81
Coal_5	Big Rivers	1–15 yr PPA, 417 MW	79
Coal_5	Ameren	5 yr PPA, 668 MW	61
Coal_Own	Duke	OVEC, 203 MW	91
Coal_Own	LGE/KU	Brown 1-2 Retrofit, 269 MW	69
DSM	LGE/KU (7 Proposals)	Lighting, T-stat Rebates, Windows & Doors, Mfg Homes, T-stat Pilot, Comm. New Constr., ADR	104+
RTC	KMPA	5 yr PPA, 25 MW	45
RTC	Exelon	10 yr PPA, 200 MW	53
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	133
SCCT_5	LS Power	5 yr PPA, 495 MW	249
SCCT_20	LS Power (2 Proposals)	20 yr PPA, 495 MW	269 – 271
SCCT_Own	LS Power (3 Proposals)	PPA w/ Asset Sale, 495 MW	227 – 239
Solar_Own	Solar Energy Solutions	Asset Sale, 1 – 5 MW	194
Solar_Own	LGE/KU	Self-Build, 10 MW	247
Wind	EDP Renewables (3 Proposals)	15 or 20 yr PPA, 99 – 151 MW	59 – 68

A complete summary of results from the Phase 1 Screening analysis is included in *Appendix B – Phase 1 Screening Analysis Results*.

4 Phase 2 Analysis

The responses that passed the Phase 1 Screening analysis were used to develop alternatives for the Phase 2 analysis. The Phase 2 analysis was completed in several iterations.

4.1 Phase 2, Iteration 1

To streamline the evaluation process, iteration 1 focuses separately on alternatives that address the Companies' capacity shortfall in the short-term (5 years or less), medium-term (10 years), and long-term

(20+ years). The top options in each of these categories will be evaluated further in subsequent iterations of the Phase 2 analysis.

4.1.1 Alternatives

The alternatives evaluated in the first iteration of the Phase 2 analysis are listed in Table 5. Each of these alternatives meets the Companies' reserve margin shortfall (see Table 3) through at least 2016.

The Phase 2, iteration 1 alternatives were developed with the following capacity and timing considerations:

1. The self-build CCCT proposals were paired with the same 20-year LS Power PPA proposal so the results for these alternatives would be comparable.
2. The self-build 1X1 CCCT proposals (which were paired with the same LS Power proposal) were assumed to be commissioned in 2019 to coincide with the first need for additional capacity (in these cases).
3. The self-build 2X1 CCCT proposals were assumed to be commissioned in 2017 so that these alternatives would be comparable to the ERORA proposals. The GE self-build 2X1 CCCT was also assumed to be commissioned in 2019 so that this alternative would be comparable to the self-build 1X1 CCCT proposals and any of the 20-year LS Power PPA proposals that include a Siemens 2X1 CCCT as the first LCR in their expansion plans.
4. The Brown 1-2 retrofit and Duke's OVEC proposals were paired with the same Calpine proposal so that these alternatives would be comparable.
5. The Brown 1-2 retrofit and 250 MW Calpine proposals were paired with the same LS Power proposal so that these alternatives would be comparable.

Table 5 – Phase 2, Iteration 1 Alternatives

	Term	Alt ID	Description	Delivered MWs
1	Short-Term	R04A	Big Rivers 5 yr PPA (2015)	407
2		R05D	Quantum 5 yr PPA (2015)	680
3		R06A	Calpine 5 yr PPA, 500 MW (2015)	485
4		R07A	Ameren 5 yr PPA, 668 MW (Coal, 2015)	668
5		R07G	Ameren 5 yr PPA, 334 MW (Coal, 2015)	334
6		R07J	Ameren 5 yr PPA, 501 MW (Coal, 2015)	501
7		R19F	LS Power 5 yr PPA (495 MW, 2015)	495
8		R19G	LS Power 5 yr PPA (330 MW, 2015)	330
9	Medium-Term	C05_	Calpine 5 yr PPA, 250 MW (2015), Exelon 10 yr PPA (2015)	438
10		R04B	Big Rivers 10 yr PPA (2015)	407
11	Long-Term	C06_	Calpine 250 MW (2015), BR1-2 Retrofit	512
12		C07A	Calpine 250 MW (2015), Duke (2015)	446
13		C07B	Calpine 250 MW (2015), Duke (2015 Sale, 2030 Retire)	446
14		C08_	LS Power 20 yr PPA (2015), Calpine 5 yr PPA, 250 MW (2015)	738
15		C09A	LS Power 20 yr PPA (2015), BR1-2 Retrofit	764
16		C09B	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2025 Retire)	764
17		C09C	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2030 Retire)	764
18		C09D	LS Power 20 yr PPA (2015), BR1-2 Retrofit w/ SCR	764
19		C10_	LS Power 20 yr PPA (2015), ERORA 10 yr PPA (2017)	1,195
20		C11_	LS Power 20 yr PPA (2015), ERORA 20 yr PPA (2017)	1,195
21		C12_	LS Power 20 yr PPA (2015), GE 1x1 F (2019)	794
22		C13_	LS Power 20 yr PPA (2015), Siemens 1x1 F (2019)	827
23		C14_	LS Power 20 yr PPA (2015), MHI 1x1 (2019)	868
24		C15_	LS Power 20 yr PPA (2015), Siemens 1x1 H (2019)	874
25		C16_	LS Power 20 yr PPA (2015), Siemens 2x1 (2017)	1,165
26		C17_	LS Power 20 yr PPA (2015), ERORA (2017 Sale)	1,195
27		C18A	LS Power 20 yr PPA (2015), GE 2x1 (2017)	1,093
28		C18B	LS Power 20 yr PPA (2015), GE 2x1 (2019)	1,093
29		C19A	LS Power 5 yr PPA (495 MW, 2015), BR1-2	764
30		C19B	LS Power 5 yr PPA (330 MW, 2015), BR1-2	599
31		R11E	Khanjee 22 yr PPA, Fixed Price (2015)	700
32		R11F	Khanjee 22 yr PPA, Tolling (2015)	700
33		R19A	LS Power 20 yr PPA (2015)	495
34		R19B	LS Power (2018 Sale)	495
35		R19C	LS Power (2020 Sale)	495
36		R19D	LS Power 20 yr PPA (2014)	495
37		R19E	LS Power (2014 Sale)	495

4.1.2 Uncertainties

To understand the impact on the analysis associated with the uncertainty in natural gas prices, native load, potential CO_2 regulations, and access to economy purchases, each alternative in iteration 1 was evaluated under three natural gas price scenarios, three native load scenarios, two CO_2 price scenarios, and two economy purchases scenarios (36 scenarios in all). Charts detailing the price and load scenarios are included in *Appendix D – Natural Gas, Load, and CO2 Price Scenarios*. The following economy purchases scenarios were evaluated:

1. No economy purchases.
2. Limited economy purchases.

4.1.3 Phase 2, Iteration 1 Results

Table 6 contains a complete summary of the Phase 2, iteration 1 results. The short-term, medium-term, and long-term alternatives are differentiated by color.

Table 6 – Phase 2, Iteration 1 Results (NPVRR, $M, Base Case Assumptions, No Purchases)[3]

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	Khanjee Fixed Price PPA	'21 SCT	22,537	1,082	799	234	86	52	24,791
2	LS Power (2020 Sale)	'19 2x1	23,200	1,221	54	501	157	64	25,197
3	LS Power (2018 Sale)	'19 2x1	23,196	1,240	34	501	162	64	25,197
4	Calpine 250, BR1-2	'19 2x1	23,006	1,540	70	336	247	1	25,200
5	LS Power (2014 Sale)	'19 2x1	23,191	1,274	3	516	172	64	25,220
6	LS Power 5 yr PPA ('15, 2CTs), BR1-2	'20 2x1	23,043	1,512	44	343	254	25	25,221
7	LS Power PPA, BR1-2	'22 2x1	23,096	1,276	151	414	266	25	25,228
8	LS Power PPA, ERORA 20 yr PPA	'28 2x1	23,050	864	591	505	143	112	25,265
9	LS Power 5 yr PPA (2015), BR1-2	'20 2x1	23,043	1,512	67	364	259	25	25,270
10	Ameren Coal PPA (334)	'17 SCT	23,053	1,536	166	383	143	-7	25,275
11	Ameren Coal PPA (501)	'19 SCT	23,015	1,493	250	366	136	30	25,290
12	Khanjee Tolling PPA	'21 SCT	23,042	1,082	799	234	86	52	25,295
13	LS Power 20 yr PPA (2015)	'19 2x1	23,200	1,290	151	481	149	64	25,336
14	LS Power PPA, ERORA Sale	'28 2x1	23,028	1,372	151	506	188	112	25,356
15	LS Power PPA, GE 2x1 (2019)	'27 2x1	23,164	1,348	151	470	170	64	25,367
16	Ameren Coal PPA (668)	'20 2x1	22,960	1,543	333	371	135	30	25,372
17	LS Power PPA, Siemens 2x1 (2017)	'28 2x1	23,164	1,350	151	489	157	64	25,375
18	LS Power PPA, BR1-2 (2030 Rt)	'22 2x1	23,181	1,360	151	430	229	25	25,377
19	LS Power 20 yr PPA (2014)	'19 2x1	23,201	1,311	154	495	153	64	25,379
20	LS Power PPA, ERORA 10 yr PPA	'27 2x1	23,113	1,084	421	505	145	112	25,380
21	LS Power PPA, Siemens 1x1H (2019)	'24 2x1	23,159	1,372	151	469	166	64	25,383
22	LS Power 5 yr PPA (2015)	'19 SCT	23,183	1,493	67	430	152	64	25,389
23	Calpine 250, Exelon	'18 SCT	23,214	1,476	70	386	129	121	25,396
24	LS Power PPA, BR1-2 (SCR)	'22 2x1	23,103	1,418	151	414	288	25	25,399
25	LS Power PPA, Calpine 250	'20 2x1	23,190	1,261	222	496	146	92	25,407
26	LS Power PPA, GE 2x1 (2017)	'27 2x1	23,126	1,407	151	489	179	64	25,417
27	Big Rivers 5 yr	'18 SCT	23,101	1,500	224	369	138	87	25,419
28	Calpine 250, Duke (2015)	'18 2x1	22,850	1,504	70	364	552	78	25,419
29	Calpine 500, 5 yr	'19 SCT	23,135	1,493	140	417	136	104	25,425
30	LS Power PPA, Siemens 1x1F (2019)	'23 2x1	23,188	1,392	151	475	170	64	25,441
31	LS Power PPA, BR1-2 (2025 Rt)	'22 2x1	23,193	1,425	151	450	212	25	25,457
32	LS Power PPA, GE 1x1 F (2019)	'23 2x1	23,181	1,407	151	468	188	64	25,461
33	LS Power 5 yr PPA ('15, 2CTs)	'17 2x1	23,119	1,631	44	448	157	64	25,463
34	Quantum 5 yr	'20 2x1	23,110	1,543	149	412	135	123	25,471
35	LS Power PPA, MHI 1x1 (2019)	'24 2x1	23,165	1,456	151	479	176	64	25,492
36	Big Rivers 10 yr	'18 2x1	23,013	1,499	394	356	124	132	25,518
37	Calpine 250, Duke (2015, 2030 Rt)	'18 2x1	22,993	1,599	70	384	450	78	25,574

Short-Term Alternatives | Medium Term Alternatives | Long-Term Alternatives

The following are key takeaways from the Phase 2, iteration 1 results:

1. Khanjee's proposal to construct a 2X1 combined-cycle plant in the LG&E/KU service territory and sell power at a fixed price is the least-cost alternative overall. Among the other proposals that include new 2X1 CCCT capacity in 2017, ERORA's 20-year PPA is the least-cost alternative.
2. The Brown 1-2 retrofit is a competitive alternative (and less costly than either Duke's OVEC proposal or the 250 MW Calpine proposal). However, if Brown 1-2 does not operate beyond 2030, the Brown 1-2 retrofit is not among the top options. A comparison of cost assumptions

[3] References to LS Power PPA (with no additional qualifiers) pertain to the 20-year PPA beginning in 2015. Base case results reflect 'zero' CO_2 price scenario.

for the Brown 1-2 retrofit between the current analysis and the 2011 ECR filing is contained in Section 4.2.

3. Among the alternatives that include only the LS Power assets, the asset sale proposals are more economic than the PPA proposals. The expansion plans for these proposals include a 2X1 CCCT in 2019. These combinations are superior to the alternatives that pair 1X1 CCCTs with the LS Power CTs.
4. The 5-year PPA for 334 MW from Ameren is the least-cost alternative among the short-term alternatives (and clearly superior to the proposals from Big Rivers due to Big Rivers' higher fixed transmission costs).

4.2 Brown 1-2 Retrofit Costs

The differences in Brown 1-2 retrofit costs between the current analysis and the 2011 ECR analysis are summarized in Table 7. The current assumptions for annual capital were taken from the Companies' most recent business plan. The reduction in variable O&M is driven primarily by reductions in the assumed cost to operate the Brown 1-2 baghouse. When the 2011 Air Compliance Plan was developed, the Companies had limited operating experience with the Trimble County 2 baghouse. The updated operating expense estimates are based on almost two years of experience operating the Trimble County 2 baghouse.

Table 7 – Brown 1-2 Retrofit Costs

	2011 Air Compliance Plan	2012 RFP	Delta
Annual Capital (Levelized $M/yr)	6.5	3.5	-3.0
Baghouse/SAMM Capital (Nominal $M)	228	194	-34
Fixed O&M (Levelized $M/yr)	11.7	10.9	-0.9
Variable O&M ($/MWh)	15.34	1.98	-13.4

4.3 Phase 2, Iteration 2

Iteration 2 of the Phase 2 analysis considers the following types of alternatives:

1. Short-term PPAs. 'Based on the reserve margin shortfall values in Table 3, 300-400 MW of capacity and energy will defer the next need for capacity and energy to 2017. Likewise, 350-450 MW of capacity and energy defers the next need for capacity and energy to 2018. In iteration 2, the short- and medium-term alternatives from iteration 1 are modified to more precisely meet the Companies' reserve margin needs.[4] Lessons learned from iteration 2 will be used to guide discussions with short-listed bidders.
2. Brown 1-2 retrofit + short-term PPA.
3. Long-term CCCT.

4.3.1 Alternatives

The alternatives evaluated in iteration 2 are summarized in Table 8. These alternatives were developed to answer the following questions:

1. Among the PPA proposals, what proposal and PPA term is most economic?
2. What is the impact of pairing the Brown 1-2 retrofit with a short-term PPA?
3. How does retiring Brown1-2 prior to the end of the analysis period impact the results?

[4] For example, AEP proposed a 5-year PPA for up to 700 MW. Iteration 2 included two four-year PPAs from AEP for 500 and 600 MWs since 700 MW more than exceeds the Companies' reserve margin needs through 2018.

4. How does the ERORA PPA compare to the Khanjee fixed price PPA when it is not paired with the LS Power CTs?

Table 8 – Phase 2, Iteration 2 Alternatives

	Alt Type	Alt ID	Description	2015 Delivered MWs
1	2-yr PPA	C05B	Calpine 250, Exelon - 2 yr PPA	438
2		R02D	AEP Portfolio 350 - 2 yr	350
3		R02E	AEP Portfolio 400 - 2 yr	400
4		R04C	Big Rivers - 2 yr	407
5		R05G	Quantum 2 yr	680
6		R06C	Calpine 500, 2 yr	485
7		R07K	Ameren Coal 334 - 2yr	334
8		R07L	Ameren Coal 501 - 2 yr	501
9		R19H	LS Power 2 CTs - 2 yr	330
10		R19I	LS Power - 2 yr	495
11	3-yr PPA	C05C	Calpine 250, Exelon - 3 yr PPA	438
12		C22F	Ameren Coal 3 yr 167, BR1-2	436
13		R02O	AEP Portfolio 450 - 3 yr	450
14		R02P	AEP Portfolio 500 - 3 yr	500
15		R04E	Big Rivers - 3 yr	407
16		R05J	Quantum 3 yr	680
17		R06J	Calpine 500, 3 yr	485
18		R07R	Ameren Coal 501 - 3 yr	501
19		R19N	LS Power - 3 yr	495
20	4-yr PPA	R02F	AEP Portfolio 500 - 4 yr	500
21		R02G	AEP Portfolio 600 - 4 yr	600
22		R05H	Quantum 4 yr	680
23		R06D	Calpine 500, 4 yr	485
24		R07M	Ameren Coal 501 - 4 yr	501
25		R07N	Ameren Coal 668 - 4 yr	668
26		R19J	LS Power - 4 yr	495
27	5-yr PPA	R02H	AEP Portfolio 650 - 5 yr	650
28		R05D	Quantum 5 yr	680
29		R07A	Ameren Coal 668 5 yr	668
30	6-yr PPA	R05I	Quantum 6 yr	680
31	Brown 1-2 Retrofit + PPA	C06B	Calpine 250 2 yr, BR1-2	512
32		C06C	Calpine 250 4 yr, BR1-2	512
33		C06D	Calpine 500 5 yr, BR1-2	754
34		C06E	Calpine 500 6 yr, BR1-2	754
35		C06F	Calpine 250 3 yr, BR1-2	512
36		C19A	LS Power 5 yr PPA, BR1-2	764
37		C19C	LS Power 2 yr PPA, BR1-2	764
38		C19D	LS Power 2 yr PPA 2 CTs, BR1-2	599
39		C19E	LS Power 2 yr PPA 1 CTs, BR1-2	434
40		C19F	LS Power 4 yr PPA, BR1-2	764
41		C19G	LS Power 4 yr PPA 2 CTs, BR1-2	599
42		C19H	LS Power 6 yr PPA, BR1-2	764

	Alt Type	Alt ID	Description	2015 Delivered MWs
43	Brown 1-2 Retrofit + PPA	C19I	LS Power 3 yr PPA 2 CTs, BR1-2	599
44		C19J	LS Power 3 yr PPA, BR1-2	764
45		C19K	LS Power 5 yr PPA, BR1-2 (Rt 2025)	764
46		C19L	LS Power 5 yr PPA, BR1-2 (Rt 2030)	764
47		C20A	AEP 2 yr (150), BR1-2	419
48		C20B	AEP 4 yr (250), BR1-2	519
49		C20C	AEP 4 yr (300), BR1-2	569
50		C20D	AEP 5 yr (400), BR1-2	669
51		C20E	AEP 6 yr (450), BR1-2	719
52		C20F	AEP 3 yr (150), BR1-2	419
53		C20G	AEP 3 yr (200), BR1-2	469
54		C21A	Quantum 2 yr, BR1-2	949
55		C21B	Quantum 4 yr, BR1-2	949
56		C21C	Quantum 5 yr, BR1-2	949
57		C21D	Quantum 6 yr, BR1-2	949
58		C21E	Quantum 3 yr, BR1-2	949
59		C22A	Ameren Coal 2 yr 334, BR1-2	603
60		C22B	Ameren Coal 2 yr 167, BR1-2	436
61		C22C	Ameren Coal 4 yr 334, BR1-2	603
62		C22D	Ameren Coal 5 yr 501, BR1-2	770
63		C22G	Ameren Coal 3 yr 334, BR1-2	603
64		C22H	Ameren Coal 4 yr 334, BR1-2 (Rt 2025)	603
65		C22I	Ameren Coal 4 yr 334, BR1-2 (Rt 2030)	603
66		C23A	Big Rivers 2 yr, BR1-2	676
67		C23B	Big Rivers 4 yr, BR1-2	676
68		C23C	Big Rivers 5 yr, BR1-2	676
69		C23D	Big Rivers 3 yr, BR1-2	676
70		C24A	Calpine 250 5 yr, Exelon 5 yr, BR1-2	707
71		C24B	Calpine 250 6 yr, Exelon 6 yr, BR1-2	707
72	Long-Term	C25A	AEP Portfolio 350 - 2 yr, Khanjee ('17)	350
73		C26A	AEP Portfolio 350 - 2 yr, ERORA PPA	350

4.3.2 Uncertainties
The iteration 2 alternatives were evaluated under three natural gas price scenarios, three native load scenarios, one CO_2 price scenario, and two economy purchases scenarios (18 scenarios in all). The iteration 2 alternatives were not evaluated under the mid carbon scenario, since this scenario will not impact the short-term PPAs. The impact of the mid carbon scenario on the longer-term options (including the Brown 1-2 retrofit options) can be deduced from the iteration 1 results.

4.3.3 Results
The results for the short-term PPA alternatives evaluated in iteration 2 are summarized in Table 9. For these alternatives, the PPA term determines the timing of the first LCR (see ‘1st LCR’ column).

Table 9 – Phase 2, Iteration 2 Results for Short-Term PPAs (NPVRR, $M, Base Case Assumptions, No Purchases)

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	Ameren Coal 3 yr 167, BR1-2	'18 2x1	22,982	1,569	53	322	251	-30	25,148
2	Ameren Coal 334 - 2yr	'17 2x1	23,074	1,631	73	405	146	-7	25,323
3	Ameren Coal 501 - 4 yr	'19 2x1	23,022	1,572	206	382	138	30	25,350
4	Ameren Coal 501 - 3 yr	'18 2x1	23,039	1,601	159	393	142	30	25,365
5	Ameren Coal 668 5 yr	'20 2x1	22,960	1,543	333	371	135	30	25,372
6	AEP Portfolio 350 - 2 yr	'17 2x1	23,090	1,631	82	405	146	21	25,376
7	Ameren Coal 501 - 2 yr	'17 2x1	23,055	1,631	110	405	146	30	25,377
8	Ameren Coal 668 - 4 yr	'19 2x1	22,988	1,572	275	382	138	30	25,384
9	AEP Portfolio 400 - 2 yr	'17 2x1	23,087	1,631	94	405	146	23	25,385
10	LS Power 2 CTs - 2 yr	'17 2x1	23,116	1,631	20	423	151	64	25,405
11	AEP Portfolio 450 - 3 yr	'18 2x1	23,090	1,601	153	393	142	31	25,411
12	Big Rivers - 2 yr	'17 2x1	23,082	1,631	97	405	146	54	25,416
13	AEP Portfolio 500 - 3 yr	'18 2x1	23,084	1,601	170	393	142	34	25,424
14	LS Power - 2 yr	'17 2x1	23,118	1,631	29	432	153	64	25,428
15	LS Power - 3 yr	'18 2x1	23,136	1,601	43	434	152	64	25,429
16	Big Rivers - 3 yr	'18 2x1	23,086	1,601	142	393	142	66	25,429
17	LS Power - 4 yr	'19 2x1	23,153	1,572	55	435	151	64	25,430
18	Calpine 250, Exelon - 2 yr PPA	'17 2x1	23,137	1,631	30	416	146	70	25,430
19	Calpine 250, Exelon - 3 yr PPA	'18 2x1	23,160	1,601	44	409	142	80	25,437
20	AEP Portfolio 500 - 4 yr	'19 2x1	23,086	1,572	220	382	138	41	25,439
21	Quantum 2 yr	'17 2x1	23,097	1,631	57	422	146	85	25,439
22	Calpine 500, 2 yr	'17 2x1	23,100	1,631	60	427	146	77	25,441
23	Quantum 3 yr	'18 2x1	23,104	1,601	87	419	142	98	25,451
24	Calpine 500, 3 yr	'18 2x1	23,109	1,601	88	425	142	86	25,451
25	Calpine 500, 4 yr	'19 2x1	23,116	1,572	115	424	138	95	25,460
26	Quantum 4 yr	'19 2x1	23,108	1,572	117	415	138	111	25,460
27	Quantum 5 yr	'20 2x1	23,110	1,543	149	412	135	123	25,471
28	Quantum 6 yr	'21 2x1	23,112	1,516	180	408	131	134	25,482
29	AEP Portfolio 600 - 4 yr	'19 2x1	23,082	1,572	264	382	138	48	25,485
30	AEP Portfolio 650 - 5 yr	'20 2x1	23,076	1,543	346	371	135	60	25,532

Generally, shorter-term PPAs are more favorable than longer-term PPAs. This result is driven primarily by longer-term commodity price assumptions. In the base case natural gas price scenario, the energy price for most alternatives is higher than the energy cost of a new CCCT through 2021. For these alternatives, the reduction in production costs associated with building new CCCT capacity sooner more than offsets the increased capital costs. This is not the case for the Ameren alternatives, where the energy price is lower. The four year PPA from Ameren is preferred over the two or three year PPA from Ameren.

The alternatives in iteration 2 with the Brown 1-2 Retrofit are lower cost than the alternatives without the Brown 1-2 retrofit. Table 10 compares the least-cost 'Brown 1-2 Retrofit + PPA' alternative to the least-cost short-term PPA alternative.

Table 10 – Impact of Brown 1-2 Retrofit on Short-Term PPA (NPVRR, $M, Base Case Assumptions, No Purchases)

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	Ameren Coal 3 yr 167, BR1-2	'18 2x1	22,982	1,569	53	322	251	-30	25,148
2	Ameren Coal 334 – 2 yr	'17 2x1	23,074	1,631	73	405	146	-7	25,323

The NPVRR difference between the alternatives in Table 10 is $175 million. Several assumptions drive this difference:

1. In the base gas price scenario, coal becomes relatively less expensive than natural gas over time. As a result, unlike today, the dispatch costs for Brown 1 and 2 are lower than combined cycle generation in the period beyond 2021 (see Figure 1). Differences in production costs beyond 2021 between the two portfolios in Table 10 account for approximately $110 million of the total $175 million difference.
2. Brown 1 and 2 operate through the end of the analysis period (2042). In 2013, Brown 1 and 2 will be 55 and 49 years old, respectively. In 2042, Brown 1 and 2 will be 85 and 79 years old, respectively (see Table 11). If Brown 1 and 2 do not operate beyond 2030, the NPVRR of the Brown 1-2 retrofit alternatives is increased by approximately $125 million.
3. Brown 1 and 2 will require no additional environmental controls through 2042. Based on the results from iteration 1, adding an SCR to Brown 1 and 2 increases the NPVRR by approximately $165 million.
4. No CO_2 regulations resulting in a cost for CO_2 emissions will be promulgated through 2042. CO_2 regulations increase the cost of the Brown 1-2 retrofit alternatives.

Figure 1 – Dispatch Costs (Brown 1-2 versus New CCCT) ($/MWh)

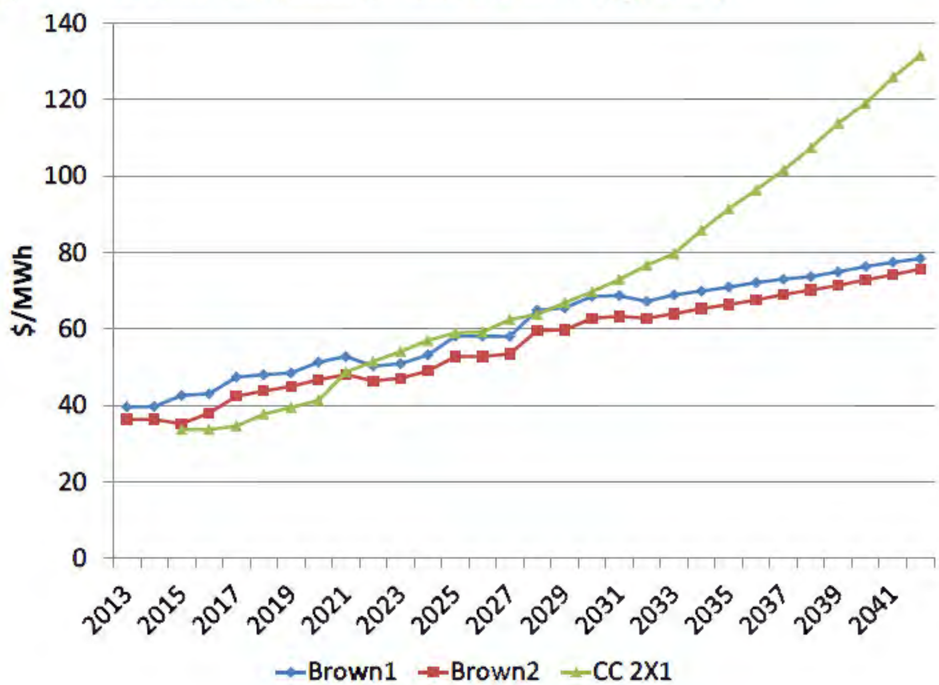


Table 11 – Age of Brown 1 and 2 (years)

Year	Brown 1	Brown 2
2013	56	50
2025	68	62
2030	73	67
2035	78	72
2042	85	79

Table 12 compares the total NPVRR for the long-term alternatives in iteration 2 under three gas price scenarios. In the base and high gas price scenarios, the Khanjee fixed-price proposal is least-cost. In the low gas price scenario, the Companies' self-build option is least-cost.

Table 12 – Phase 2, Iteration 2 Results for Long-Term PPAs (NPVRR, $M, Base Case Assumptions, No Purchases)

	Alternative	1st LCR	Grand Total
Base Gas Scenario			
1	AEP Portfolio 350 - 2 yr, Khanjee FP (2017)	'21 SCT	24,788
2	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	25,312
3	AEP Portfolio 350 - 2 yr, Self-build	'21 2x1	25,376
High Gas Scenario			
1	AEP Portfolio 350 - 2 yr, Khanjee FP (2017)	'21 2x1	25,339
2	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	26,043
3	AEP Portfolio 350 - 2 yr, Self-build	'21 2x1	26,152
Low Gas Scenario			
1	AEP Portfolio 350 - 2 yr, Self-build	'21 2x1	22,072
2	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	22,166
3	AEP Portfolio 350 - 2 yr, Khanjee FP (2017)	'21 2x1	22,362

4.4 Phase 2, Iteration 3

In iteration 3 of the Phase 2 analysis, the proposals that passed the Phase 1 screening analysis with smaller amounts of generating capacity are evaluated in turn with some of the top alternatives in iterations 1 and 2.

4.4.1 Alternatives

The alternatives evaluated in iteration 3 are summarized in Table 13. Each of the nine proposals not previously evaluated is combined with the LS Power 5-year PPA and the 501 MW 5-year PPA from Ameren. The LS Power and Ameren proposals were selected because they compare favorably to other alternatives and have very different dispatch characteristics. The Ameren PPA has a lower energy cost and therefore has a much higher capacity factor than the LS Power PPA.

Table 13 – Phase 2, Iteration 3 Alternatives

	Alt Type	Alt ID	Description	Delivered MWs
1	Small Proposal + LS Power PPA	C27A	LS Power 5 yr PPA, Paducah	521
2		C27B	LS Power 5 yr PPA, KMPA	520
3		C27C	LS Power 5 yr PPA, Nextera 30 MW	525
4		C27D	LS Power 5 yr PPA, Nextera 50 MW	545
5		C27E	LS Power 5 yr PPA, Wind 99 MW	525*
6		C27F	LS Power 5 yr PPA, Wind 151 MW	540*
7		C27G	LS Power 5 yr PPA, Wind 99 MW (KY)	525*
8		C27H	LS Power 5 yr PPA, Solar	496*
9		C27I	LS Power 5 yr PPA, Self-build Solar	497*
10	Small Proposal + Ameren PPA	C28A	Ameren Coal 501 5 yr, Paducah	527
11		C28B	Ameren Coal 501 5 yr, KMPA	526
12		C28C	Ameren Coal 501 5 yr, Nextera 30 MW	531
13		C28D	Ameren Coal 501 5 yr, Nextera 50 MW	551
14		C28E	Ameren Coal 501 5 yr, Wind 99 MW	531*
15		C28F	Ameren Coal 501 5 yr, Wind 151 MW	546*
16		C28G	Ameren Coal 501 5 yr, Wind 99 MW (KY)	531*
17		C28H	Ameren Coal 501 5 yr, Solar	502*
18		C28I	Ameren Coal 501 5 yr, Self-build Solar	503*

*Delivered MWs for alternatives with wind and solar generation reflect 30% and 15% of the total wind and solar capacity, respectively.

4.4.2 Uncertainties

The iteration 3 alternatives were evaluated under the same scenarios as iteration 2: three natural gas price scenarios, three native load scenarios, one CO_2 price scenario, and two economy purchases scenarios (18 scenarios in all). The iteration 3 alternatives were not evaluated under the mid carbon scenario, since this scenario will not impact the short-term PPAs.

4.4.3 Results

The iteration 3 results are summarized in Table 14 along with the results of the LS Power and Ameren PPA proposals from iteration 1. The results of the LS Power and Ameren PPA proposals are highlighted.

Table 14 – Phase 2, Iteration 3 Results (NPVRR, $M, Base Case Assumptions, No Purchases)

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	Ameren 501 5 yr – Iter 1	'19 SCT	23,015	1,493	250	366	136	30	25,290
2	Ameren 501 5 yr, KMPA	'19 SCT	23,011	1,493	253	366	136	34	25,293
3	Ameren 501 5 yr, Paducah	'19 SCT	23,016	1,493	250	368	136	30	25,293
4	Ameren 501 5 yr, Solar	'19 SCT	23,011	1,506	250	366	137	30	25,300
5	Ameren 501 5 yr, Nextera 30 MW	'19 SCT	23,032	1,493	250	366	136	30	25,306
6	Ameren 501 5 yr, Self-build Solar	'19 SCT	23,004	1,535	250	366	137	30	25,322
7	Ameren 501 5 yr, Nextera 50 MW	'19 SCT	23,050	1,493	250	366	136	30	25,325
8	Ameren 501 5 yr, Wind 99 MW	'19 SCT	23,053	1,493	250	366	136	30	25,328
9	Ameren 501 5 yr, Wind 99 MW (KY)	'19 SCT	23,061	1,493	250	366	136	30	25,336
10	Ameren 501 5 yr, Wind 151 MW	'19 SCT	23,066	1,493	250	366	136	30	25,340
11	LS Power 5 yr PPA (2015) – Iter 1	'19 SCT	23,183	1,493	67	430	152	64	25,389
12	LS Power 5 yr PPA, KMPA	'19 SCT	23,177	1,493	70	430	152	68	25,390
13	LS Power 5 yr PPA, Paducah	'19 SCT	23,182	1,493	67	433	152	64	25,390
14	LS Power 5 yr PPA, Solar	'19 SCT	23,179	1,506	67	430	153	64	25,399
15	LS Power 5 yr PPA, Nextera 30 MW	'19 SCT	23,194	1,493	67	430	152	64	25,400
16	LS Power 5 yr PPA, Nextera 50 MW	'19 SCT	23,212	1,493	67	430	152	64	25,418
17	LS Power 5 yr PPA, Self-build Solar	'19 SCT	23,172	1,535	67	430	153	64	25,421
18	LS Power 5 yr PPA, Wind 99 MW	'19 SCT	23,217	1,493	67	430	152	64	25,423
19	LS Power 5 yr PPA, Wind 99 MW (KY)	'19 SCT	23,225	1,493	67	430	152	64	25,431
20	LS Power 5 yr PPA, Wind 151 MW	'19 SCT	23,229	1,493	67	430	151	64	25,434

Based on the results in Table 14, the combination of proposals with smaller amounts of generating capacity with either the LS Power or Ameren PPA did not improve the value of the PPAs on a stand-alone basis.

5 Combined Results and Conclusions

The results from iterations 1 and 2 were combined and all but the top Brown 1-2 retrofit alternatives were removed. The top 30 alternatives from this set of alternatives are summarized in Table 15.

Table 15 – Combined Phase 2 Results (NPVRR, $M, Base Case Assumptions, No Purchases)

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	AEP Port 350 - 2 yr, Khanjee ('17)	'21 SCT	22,522	1,082	800	234	86	64	24,788
2	Khanjee Fixed Price PPA	'21 SCT	22,537	1,082	799	234	86	52	24,791
3	Ameren Coal 3 yr 167, BR1-2	'18 2x1	22,982	1,569	53	322	251	-30	25,148
4	LS Power (2020 Sale)	'19 2x1	23,200	1,221	54	501	157	64	25,197
5	LS Power (2018 Sale)	'19 2x1	23,196	1,240	34	501	162	64	25,197
6	LS Power (2014 Sale)	'19 2x1	23,191	1,274	3	516	172	64	25,220
7	LS Power PPA, ERORA 20 yr PPA	'28 2x1	23,050	864	591	505	143	112	25,265
8	Ameren Coal PPA (334) – 5 yr	'17 SCT	23,053	1,536	166	383	143	-7	25,275
9	Ameren Coal PPA (501) – 5 yr	'19 SCT	23,015	1,493	250	366	136	30	25,290
10	Khanjee Tolling PPA	'21 SCT	23,042	1,082	799	234	86	52	25,295
11	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	22,983	1,146	522	406	132	124	25,312
12	Ameren Coal 334 - 2yr	'17 2x1	23,074	1,631	73	405	146	-7	25,323
13	LS Power 20 yr PPA (2015)	'19 2x1	23,200	1,290	151	481	149	64	25,336
14	Ameren Coal 501 - 4 yr	'19 2x1	23,022	1,572	206	382	138	30	25,350
15	LS Power PPA, ERORA Sale	'28 2x1	23,028	1,372	151	506	188	112	25,356
16	Ameren Coal 501 - 3 yr	'18 2x1	23,039	1,601	159	393	142	30	25,365
17	LS Power PPA, GE 2x1 (2019)	'27 2x1	23,164	1,348	151	470	170	64	25,367
18	Ameren Coal PPA (668)	'20 2x1	22,960	1,543	333	371	135	30	25,372
19	Ameren Coal 668 5 yr	'20 2x1	22,960	1,543	333	371	135	30	25,372
20	LS Power PPA, Siemens 2x1 (2017)	'28 2x1	23,164	1,350	151	489	157	64	25,375
21	AEP Portfolio 350 - 2 yr	'17 2x1	23,090	1,631	82	405	146	21	25,376
22	Ameren Coal 501 - 2 yr	'17 2x1	23,055	1,631	110	405	146	30	25,377
23	LS Power 20 yr PPA (2014)	'19 2x1	23,201	1,311	154	495	153	64	25,379
24	LS Power PPA, ERORA 10 yr PPA	'27 2x1	23,113	1,084	421	505	145	112	25,380
25	LS Power PPA, Siemens 1x1H (2019)	'24 2x1	23,159	1,372	151	469	166	64	25,383
26	Ameren Coal 668 - 4 yr	'19 2x1	22,988	1,572	275	382	138	30	25,384
27	AEP Portfolio 400 - 2 yr	'17 2x1	23,087	1,631	94	405	146	23	25,385
28	LS Power 5 yr PPA (2015)	'19 SCT	23,183	1,493	67	430	152	64	25,389
29	Calpine 250, Exelon	'18 SCT	23,214	1,476	70	386	129	121	25,396
30	LS Power 2 CTs - 2 yr	'17 2x1	23,116	1,631	20	423	151	64	25,405

The following are key takeaways from Table 15:

1. The Khanjee fixed price PPA is the most competitive option.
2. The Brown 1-2 retrofit (paired with a shorter-term PPA) is also very competitive.
3. The LS Power sale alternatives are more favorable than the LS Power PPA alternatives. The NPVRR difference between the top sale alternative and the 20-year PPA is $140 million. Several factors drive this difference:
    a. At the end of the PPA, new capacity must be acquired to replace the LS Power CTs. These costs account for $90 million of the $140 million difference.
    b. The LS Power assets are priced to sell. The NPVRR of the capital costs in the sale alternative is $30 million less than the NPVRR of the capacity charges in the PPA alternative.
    c. Differences in fixed O&M between the alternatives explain the majority of the remaining $20 million difference.
4. A short-term Ameren PPA is more competitive than the LS Power PPA proposals.
5. The longer-term alternatives are generally more competitive than shorter-term alternatives. This result is driven primarily by the longer-term relationship between natural gas and coal prices. After 2021, due to higher natural gas prices, the impact of combined cycle generation on production costs is not as significant. Therefore, the ability of the longer-term alternatives to

defer the need for additional generating capacity causes these alternatives to be more highly valued than the shorter-term alternatives.

Table 14 summarizes the top 30 alternatives in the high and low gas price scenarios. The ranking of alternatives in the high gas price scenario is similar to the ranking of alternatives in the base gas price scenario. Shorter-term PPAs are generally preferred in the low gas price scenario. In this scenario, the positive impact of combined cycle generation on production costs more than offsets the value of deferring the need for generating capacity.

Table 16 – Combined Phase 2 Results (NPVRR, $M, No Purchases)

	High Gas Price Scenario				Low Gas Price Scenario		
	Alternative	1st LCR	Grand Total		Alternative	1st LCR	Grand Total
1	Khanjee Fixed Price PPA	'21 2x1	25,339	1	Khanjee Tolling PPA	'21 2x1	21,936
2	AEP Port 350 - 2 yr, Khanjee ('17)	'21 2x1	25,339	2	Ameren Coal 334 - 2yr	'17 2x1	22,019
3	Ameren Coal 3 yr 167, BR1-2	'18 2x1	25,772	3	Quantum 2 yr	'17 2x1	22,064
4	LS Power (2020 Sale)	'19 2x1	25,960	4	Ameren Coal PPA (334)	'17 2x1	22,068
5	LS Power (2018 Sale)	'19 2x1	25,961	5	AEP Portfolio 350 - 2 yr	'17 2x1	22,072
6	LS Power (2014 Sale)	'19 2x1	25,983	6	Quantum 3 yr	'18 2x1	22,072
7	LS Power PPA, ERORA 20 yr PPA	'28 2x1	25,991	7	Quantum 4 yr	'19 2x1	22,078
8	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	26,043	8	Ameren Coal 501 - 2 yr	'17 2x1	22,078
9	Calpine 250, Duke (2015)	'18 2x1	26,093	9	AEP Portfolio 400 - 2 yr	'17 2x1	22,084
10	Ameren Coal 334 - 2yr	'17 2x1	26,098	10	LS Power 2 CTs - 2 yr	'17 2x1	22,085
11	LS Power 20 yr PPA (2015)	'19 2x1	26,099	11	Calpine 500, 2 yr	'17 2x1	22,088
12	Ameren Coal 501 - 4 yr	'19 2x1	26,101	12	Quantum 6 yr	'21 2x1	22,095
13	Ameren Coal PPA (668)	'20 2x1	26,107	13	Ameren Coal 501 - 3 yr	'18 2x1	22,105
14	Ameren Coal 668 5 yr	'20 2x1	26,107	14	Calpine 250, Exelon - 2 yr PPA	'17 2x1	22,107
15	Ameren Coal PPA (501)	'19 2x1	26,108	15	LS Power - 2 yr	'17 2x1	22,107
16	LS Power PPA, ERORA Sale	'28 2x1	26,112	16	Calpine 500, 3 yr	'18 2x1	22,108
17	LS Power PPA, Siemens 1x1H (2019)	'24 2x1	26,120	17	Big Rivers - 2 yr	'17 2x1	22,115
18	Ameren Coal PPA (334)	'17 2x1	26,122	18	Calpine 500, 4 yr	'19 2x1	22,124
19	LS Power PPA, GE 2x1 (2019)	'27 2x1	26,125	19	Ameren Coal 501 - 4 yr	'19 2x1	22,128
20	LS Power PPA, ERORA 10 yr PPA	'27 2x1	26,126	20	Calpine 250, Exelon - 3 yr PPA	'18 2x1	22,136
21	Ameren Coal 501 - 3 yr	'18 2x1	26,127	21	LS Power - 3 yr	'18 2x1	22,136
22	Ameren Coal 668 - 4 yr	'19 2x1	26,131	22	LS Power 5 yr PPA ('15, 2CTs)	'17 2x1	22,138
23	LS Power 20 yr PPA (2014)	'19 2x1	26,139	23	Calpine 500, 5 yr	'19 2x1	22,139
24	LS Power PPA, Siemens 2x1 (2017)	'28 2x1	26,147	24	AEP Portfolio 450 - 3 yr	'18 2x1	22,148
25	Ameren Coal 501 - 2 yr	'17 2x1	26,149	25	Ameren Coal PPA (501)	'19 2x1	22,149
26	AEP Portfolio 350 - 2 yr	'17 2x1	26,152	26	Big Rivers - 3 yr	'18 2x1	22,164
27	AEP Portfolio 400 - 2 yr	'17 2x1	26,161	27	LS Power - 4 yr	'19 2x1	22,164
28	Big Rivers 5 yr	'18 SCT	26,162	28	AEP Portfolio 500 - 3 yr	'18 2x1	22,165
29	LS Power PPA, Calpine 250	'20 2x1	26,170	29	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	22,166
30	Calpine 250, Exelon	'18 2x1	26,172	30	Ameren Coal 668 - 4 yr	'19 2x1	22,171

6 Short-Listed Respondents

Based on the analyses to date, the following respondents will be asked to participate in additional discussions regarding their proposals:

1. AEP
2. Ameren
3. Big Rivers
4. ERORA

5. Khanjee
6. LS Power

Depending on the outcome of the above-mentioned discussions, the following respondents may be asked to participate in additional discussions:
1. Calpine
2. Exelon
3. Quantum

The purpose of the next series of discussions will be to clarify terms of the proposals where necessary and drive toward each respondent's best-and-final offer.

7 Next Steps

The following questions will be answered as the short-listed proposals are evaluated further:
1. Long-term commodity price assumptions significantly impact this analysis. What alternative(s) has the least risk as far as long-term commodity prices are concerned?
2. The cost to retrofit Brown 1-2 (and comply with the MATS rule) may be significantly less than what is currently assumed. What alternative is most competitive in both a scenario where Brown 1-2 is retired and a scenario where Brown 1-2 is not retired?
3. What impact do the energy efficiency alternatives have on the analysis?
4. What transmission considerations may impact the recommendation?

8 Appendices

8.1 Appendix A – Detailed Summary of RFP Proposals

Contract Description									Capital Cost	Fixed Costs (FCs, Expressed as $/MW at TIP)								Fuel/Energy Costs			Variable Costs									
									Per Bid	Per Bid				Additional Costs Incurred by LGE/KU ($2015)				Per Bid			Per Bid					Additional Costs Incurred by LGE/KU ($2015)				
Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Asset Sale Price ($M)	FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M	Fixed Cost Escalator	Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu)	Variable O&M ($/MWh)	Start Cost and VOM Escalator
1A	ERORA	CCCT (2X1)_10	CCCT (2x1), GE	10 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1B	ERORA	CCCT (2X1)_20	CCCT (2x1), GE	20 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1C	ERORA	CCCT (2X1)_Own	CCCT (2x1), GE	Asset Sale, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	765						23,074		2.00%	6,705								0	264	3,019	0.36	2.00%
2	AEP	Coal_5	Portfolio	5 yr PPA, Up to 700 MW	AEP Gen Hub, P-Node ID 3449712!	1/1/2015	700	2015		147,022	0.00%			20,894			2.00%		38.70	Schedule				0.55	2.00%					
3	TPF Generation	SCCT_Own	SCCT	Asset Sale, 5 Units, 245 MW	CONSTELL PTID Node - PJM/AEP	TBD	245	2015	106					20,895	30,009	13,509	2.00%	10,650						0.55	2.00%			320	4.10	2.00%
4A	Big Rivers	Coal_5	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
4B	Big Rivers	Coal_10	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
5A	Quantum Choctaw Power	CCCT (2X1)_20	CCCT (2x1), Siemens	20-35 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		69,000 ($2015)	2.00%			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5B	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	Asset Sale, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	450	12,114 in 2015; 7,513 in 2016 esc at 2%				24,998	15,431		2.00%	7,064								0	883	3,019	0.35	2.00%
5C	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	20-35 yr PPA w/ Asset Sale Option, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	462.5 ($2015)	67,200 in 2015; 12,356 in 2016; 7,663 in 2017 esc at 2%				24,998	15,431		2.00%	7,064						1.00 in 2015; 0.35 at 2%		0	883	3,019		2.00%
5D	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		48,000 ($2015)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5E	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2016	701	2013		60,000 ($2016)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5F	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2014	701	2013		36,000 ($2014)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
6A	Calpine	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, Day-Ahead Call Option, 500 MW	Trinity/Limestone - TVA	1/1/2015	500	2015		74,160	2.30%			24,998	27,418		2.00%	7,400			25,700		1,000	2.00	2.00%					
6B	Calpine	CCCT (1X1)_5	CCCT (1x1), Siemens	5 yr PPA, Day-Ahead Call Option, 250 MW	Trinity/Limestone - TVA	1/1/2015	250	2015		74,160	2.30%			24,998	27,418		2.00%	7,500			12,850		475	2.00	2.00%					
7A	Ameren	Coal_5	Coal	5 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,496	0.00%								31.41	Schedule	7,428			2.61	Schedule					
7B	Ameren	Coal_10	Coal	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,688	Schedule								25.68	Schedule										
7C	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		83,796	Schedule				17,662				43.94	Schedule										
7D	Ameren	Coal_10	Portfolio (Coal and NG)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		131,484	Schedule								25.80	Schedule										
7E	Ameren	Coal_10	Portfolio (Coal to NG Conv.)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		87,936	Schedule				17,662				43.80	Schedule										
7F	Ameren	SCCT_5	SCCT	5 yr PPA, 5 units, 222 MW	EEI/LGE Interface	1/1/2015	222	2015		85,896	0.00%				17,662			13,366			16,900		290	1.40	Schedule					
7G	Ameren	Coal_5	Coal	5 yr PPA, 334 MW	EEI/LGE Interface	1/1/2015	334	2015		137,496	0.00%								31.41	Schedule	13,900									
7H	Ameren	Coal_10	Coal	10 yr PPA, 334 MW	EEI/LGE Interface	1/1/2015	334	2015											25.68	Schedule										
7I	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 334 MW	EEI/LGE Interface	1/1/2015	334	2015	10.8						17,662				43.94	Schedule										
7J	Ameren	Coal_5	Coal	5 yr PPA, 501 MW	EEI/LGE Interface	1/1/2015	501	2015		137,496	0.00%								31.41	Schedule	20,850									
8	Paducah Power Systems	SCCT_5	SCCT	5 yr PPA, 26 MW	LGEE-PPS1	1/1/2015	26	2015		1,825					27,200			13,090												
9A	Agile	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016	157						23,268	29,800	2.00%	8,793										288	4.2	2.00%
9B	Agile	SCCT_20	NG-Fired Recip Engine	20 yr Tolling Agreement, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016		157,000	0.00%	29,800	2.00%		23,268			8,793					288	4.20	2.00%					
10	KMPA	RTC	Coal, Base Load	5 yr PPA, 25 MW (RTC)	AMIL, MISO	1/1/2015	25	2015		34,255	2.00%			36,056					33.61	Schedule										
11A	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Murdock, IL - MISO	1/1/2015	746	2016						36,056	33,279				50.04 in 2017	Schedule										
11B	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279				35.13 in 2017	Schedule	0									
11C	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279			6,800			0			4.24 in 2017	Schedule					
11D	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Kentucky	1/1/2015	746	2016							23,898				44.16 in 2017	Schedule										
11E	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898				30.63 in 2017	Schedule	0									
11F	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898			6,800			0			0.55 in 2017	Schedule					
12	Exelon Generation Company	RTC	Firm Physical Energy	10 yr PPA, 200 MW	Indiana Hub - MISO	1/1/2015	200	2015						36,056					47.78	0.00%										
13	CPV Smyth Generation Co.	CCCT (2X1)_20	CCCT (2X1), Alstom	20 yr PPA, 630 MW	Smyth County, VA - PJM	6/1/2017	630	2017		132,000	0.00%	23,400		20,895	30,941			7,009			18,690		3 808	3.13	2.00%					
14A	Duke	Coal_Own	OVEC	Asset Sale in 2015, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2015	203	2015	100								2.00%		34.87	Schedule										
14B	Duke	Coal_Own	OVEC	Asset Sale in 2013, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2013	203	2013	50								2.00%		34.87	Schedule										
15	Wellhead Energy Systems	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 100 1 MW GridFox Units	LGE/KU System	1/1/2016	100	2013	99						23,898	29,800		10,000										3	4.20	
16A	Power4Georgians	RTC	Supercritical Coal	24 yr PPA, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349					32.40	1.85%				4.73	2.50%					
16B	Power4Georgians	RTC	Supercritical Coal	24 yr Tolling Agreement, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349				9,000						4.73	2.50%					
16C	Power4Georgians	RTC	Supercritical Coal	Asset Sale, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	3,030					56,349		27,673	2.50%	9,000								162,694			1.87	2.00%
17	Solar Energy Solutions	Solar_Own	Solar (PV Array)	Asset Sale, 1-5 MW	LGE/KU System	1/1/2016	1	2015	2.9							10,185	2.00%													
18A	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW	MISO/LGE Interface	1/1/2015	99	2015											50.00	3.00%										
18B	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW	MISO/LGE Interface	1/1/2016	151	2016											50.00	3.00%										
18C	EDP Renewables	Wind	Wind (As Available)	20 yr PPA, 100 MW	LGE/KU System	1/1/2016	100	2016											69.50	0.00%										
19A	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19B	LS Power	SCCT_Own	SCCT	3 yr PPA 1/1/2015, Asset Sale 2018, 495 MW	LGE Buckner Station	1/1/2015	495	2013	115	30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19C	LS Power	SCCT_Own	SCCT	5 yr PPA 1/1/2015, Asset Sale 2020, 495 MW	LGE Buckner Station	1/1/2015	495	2013	105	30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19D	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2014, 495 MW	LGE Buckner Station	1/1/2014	495	2013		12,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19E	LS Power	SCCT_Own	SCCT	5-mon PPA 1/1/2014, Asset Sale 2014, 495 MW	LGE Buckner Station	1/1/2014	495	2014	119	11,662	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19F	LS Power	SCCT_5	SCCT	5 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
20	Sky Global	CCCT (1X1)_10	CCCT (1X1), GE	10-20 yr PPA, 250-300 MW	KU's Pineville/Pocket North LGE	1/1/2016	250	2016		108,000	0.00%	27,000			49,005		2.00%	7,000					500							
21	Wellington	RTC	Waste Coal w/ CFBC	20 yr PPA, 112 MW	PJM West	9/1/2016	112	2012		388,014	Schedule	41,050	2.00%						61.10	Schedule										
22A	Southern Company Services	SCCT_5	SCCT	5 yr PPA, 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		45,000				56,349	25,266			12,850						4.65	0.0%					
22B	Southern Company Services	SCCT_5	SCCT	5 yr PPA (Summer Only), 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		35,000				56,349	25,266			12,850						4.65	0.0%					
22C	Southern Company Services	Coal_10	Coal	15 yr PPA, 109-159 MW	Unit GSU - SOCO	1/1/2016	159	2016		246,000	1.50%			56,349				10,400			14,136				3.5%					
23	Santee Cooper	Coal_10	Coal	7.8 yr PPA, 250 MW	Georgetown, SC	4/1/2017	250	2012		100,080	0.00%			84,038			2.00%		40	2.00%				5.00	0.0%					
24A	Nextera	Coal_5	Coal	6 yr PPA, 30 MW	Into LG&E/KU	1/1/2015	30	2015											55.00	0.96%										
24B	Nextera	Coal_10	Coal	10 yr PPA, 50 MW	Into LG&E/KU	1/1/2015	50	2015											55.00	0.96%										
25	South Point Biomass	RTC	Biomass	20 yr PPA, 165 MW	AEP/Bellefonte/Proctorville PJM	5/1/2015	165	2015						20,895					65.50	Schedule				0.55	2.00%					
26	North American BioFuels	RTC	Landfill Gas	20 yr PPA, 19 MW	WI and PA - MISO and PJM	1/1/2014	19	2013											52.00	3.00%				0.55	2.00%					
27A	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Existing LG&E/KU Site	6/1/2017	770	2012		110,520 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
27B	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Site TBD	6/1/2017	770	2012		118,680 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
41A	Union Power Partners	CCCT (2X1)_Own	CCCT (2X1), GE	Asset Sale end 2014, 500 MW	Entergy AK XM at the El Dorado su	1/1/2015	500	2015	298					24,998	22,111		2.00%	7,085								0	264	3,019	0.36	0.02
41B	Union Power Partners	CCCT (2X1)_10	CCCT (2X1), GE	20 Yr PPA	Entergy AK XM at the El Dorado su	1/1/2015	500	2015		91,200	0.00%			24,998	22,111		2.00%	7,100			0	1,038		1.06	2.00%					
42	Energy Development, Inc	RTC	Landfill Gas	20 yr PPA, 14.4 MW	Kentucky	1/1/2015	14	2015											62	2.00%				0.55	2.00%					
28	LGE/KU	CCCT (1X1)_Own	GE CCCT (1X1) - F Class	Self-Build, 298.5 MW	Site TBD	6/1/2017	299	2015	438						21,924		2.00%	6,857								0	175	1,510	0.37	2.00%
29	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - F Class	Self-Build, 332 MW	Site TBD	6/1/2017	332	2015	420						21,924		2.00%	6,880								0	441	1,510	0.35	2.00%
30	LGE/KU	CCCT (1X1)_Own	MHI CCCT (1X1)	Self-Build, 372.7 MW	Site TBD	6/1/2017	373	2015	463						21,924		2.00%	6,813								0	633	1,510	0.34	2.00%
31	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - H Class	Self-Build, 379.4 MW	Site TBD	6/1/2017	379	2015	458						21,924		2.00%	6,613								0	687	1,510	0.33	2.00%
32	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), GE	Self-Build, 598 MW	Site TBD	6/1/2017	598	2015	609						21,924		2.00%	6,848								0	264	3,019	0.36	2.00%
33	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), Siemens	Self-Build, 670.4 MW	Site TBD	6/1/2017	670	2015	617						21,924		2.00%	6,866								0	883	3,019	0.35	2.00%
35	LGE/KU	Solar_Own	Solar (PV Array)	Self-Build, 10 MW	Site TBD	1/1/2016	10	2015	46							10,185	2.00%												0.91	2.00%
36	LGE/KU	Coal_Own	BR1-2 Retrofit	Retrofitted Coal, 270 MW	Brown Station	1/1/2015	269	2015	194									10,500						3.10 in 2016	Schedule			2,443		2.00%
37	LGE/KU	SCCT_Own	SCCT	Trimble CT Retrofit	Trimble County Station	4/1/2015	54	2015	108									10,139												2.00%
38	LGE/KU	CCCT (1X1)_Own	Steam Augmentation	Steam Augmentation for Trimble CTs	Trimble County Station	4/1/2015	1	2015	10									9,969												
39	LGE/KU	Coal_Own	Coal-to-NG Conversion	BR1-2 Coal to NG Conversion	Brown Station	4/1/2016	1	2015	10									10,000												
40A	LGE/KU	DSM	DSM	Lighting	LGE/KU System	1/1/2015	1	2015																						
40B	LGE/KU	DSM	DSM	Thermostat Rebates	LGE/KU System	1/1/2015	1	2015																						
40C	LGE/KU	DSM	DSM	Windows & Doors	LGE/KU System	1/1/2015	1	2015																						
40D	LGE/KU	DSM	DSM	Manufactured Homes	LGE/KU System	1/1/2015	1	2015																						
40E	LGE/KU	DSM	DSM	Behavioral Thermostat Pilot	LGE/KU System	1/1/2015	1	2015																						
40F	LGE/KU	DSM	DSM	Commercial New Construction	LGE/KU System	1/1/2015	1	2015																						
40G	LGE/KU	DSM	DSM	Automated Demand Response	LGE/KU System	1/1/2015	1	2015	22																					

8.2 Appendix B – Phase 1 Screening Analysis Results

Class_Term	Counterparty	Description	Capital ($/kW)	Fixed O&M ($/MW-yr)	Energy Price	Total Costs	Pass
CCCT (1X1)_10	Sky Global	10-20 yr PPA, 250-300 MW	0	184,005	0	75	
CCCT (1X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 250 MW	0	126,576	0	68	✓
CCCT (1X1)_Own	LGE/KU	Steam Augmentation for Trimble CTs	1,059	0	0	263	
CCCT (1X1)_Own	LGE/KU	Self-Build, 298.5 MW	1,468	21,924	0	80	✓
CCCT (1X1)_Own	LGE/KU	Self-Build, 332 MW	1,264	21,924	0	76	✓
CCCT (1X1)_Own	LGE/KU	Self-Build, 372.7 MW	1,242	21,924	0	76	✓
CCCT (1X1)_Own	LGE/KU	Self-Build, 379.4 MW	1,206	21,924	0	73	✓
CCCT (2X1)_10	Union Power Partners	20 Yr PPA	0	138,309	0	73	
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	0	94,389	0	60	✓
CCCT (2X1)_20	CPV Smyth Generation Co.	20 yr PPA, 630 MW	0	207,236	0	91	
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	0	94,389	0	69	✓
CCCT (2X1)_20	Quantum Choctaw Power	20-35 yr PPA, 701 MW	0	106,750	0	77	
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	82	
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	89	
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	65	✓
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	72	✓
CCCT (2X1)_20	Southern Power Company	20 yr PPA, 770 MW	0	122,026	0	81	
CCCT (2X1)_20	Southern Power Company	20 yr PPA, 770 MW	0	129,416	0	82	
CCCT (2X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 500 MW	0	126,576	0	68	✓
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	59	✓
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	61	
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	57	
CCCT (2X1)_Own	Union Power Partners	Asset Sale end 2014, 500 MW	596	47,109	0	74	
CCCT (2X1)_Own	LGE/KU	Self-Build, 598 MW	1,018	21,924	0	71	✓
CCCT (2X1)_Own	LGE/KU	Self-Build, 670.4 MW	921	21,924	0	70	✓
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	1,093	23,074	0	71	✓
CCCT (2X1)_Own	Quantum Choctaw Power	Asset Sale, 701 MW	642	40,429	0	73	
CCCT (2X1)_Own	Quantum Choctaw Power	20-35 yr PPA w/ Asset Sale Option, 701 MW	629	40,429	0	74	
Coal_10	Nextera	10 yr PPA, 50 MW	0	0	55	57	✓
Coal_10	Southern Company Services	15 yr PPA, 109-159 MW	0	302,349	0	114	
Coal_10	Santee Cooper	7.8 yr PPA, 250 MW	0	184,118	40	95	
Coal_10	Ameren	10 yr PPA, 334 MW	0	0	0	58	
Coal_10	Ameren	10 yr PPA, 334 MW	32	17,662	0	72	
Coal_10	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	83	✓
Coal_10	Ameren	10 yr PPA, 668 MW	0	0	0	60	
Coal_10	Ameren	10 yr PPA, 668 MW	67	17,662	0	74	
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	0	0	58	
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	17,662	0	73	
Coal_5	Nextera	6 yr PPA, 30 MW	0	0	55	56	✓
Coal_5	AEP	5 yr PPA, Up to 700 MW	0	167,916	0	81	✓
Coal_5	Ameren	5 yr PPA, 334 MW	0	137,496	0	61	✓
Coal_5	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	79	✓
Coal_5	Ameren	5 yr PPA, 501 MW	0	137,496	0	61	✓
Coal_5	Ameren	5 yr PPA, 668 MW	0	137,496	0	61	✓
Coal_Own	Duke	Asset Sale in 2015, 203 MW of OVEC	493	0	0	91	✓
Coal_Own	Duke	Asset Sale in 2013, 203 MW of OVEC	246	0	0	88	
Coal_Own	LGE/KU	Retrofitted Coal, 270 MW	721	0	0	69	✓
Coal_Own	LGE/KU	BR1-2 Coal to NG Conversion	173	23,898	0	91	
DSM	LGE/KU	Lighting	0	0	0	270	✓
DSM	LGE/KU	Thermostat Rebates	0	0	0	279	✓
DSM	LGE/KU	Windows & Doors	0	0	0	828	✓
DSM	LGE/KU	Manufactured Homes	0	0	0	1,397	✓
DSM	LGE/KU	Behavioral Thermostat Pilot	0	0	0	383	✓
DSM	LGE/KU	Commercial New Construction	0	0	0	104	✓
DSM	LGE/KU	Automated Demand Response	21,899	0	0	27,473	✓
RTC	Energy Development, Inc	20 yr PPA, 14.4 MW	0	0	62	73	
RTC	North American BioFuels	20 yr PPA, 19 MW	0	0	52	69	
RTC	KMPA	5 yr PPA, 25 MW (RTC)	0	70,311	0	45	✓
RTC	Wellington	20 yr PPA, 112 MW	0	41,050	0	144	
RTC	South Point Biomass	20 yr PPA, 165 MW	0	20,895	0	86	
RTC	Exelon	10 yr PPA, 200 MW	0	36,056	48	53	✓
RTC	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	69,335	0	70	
RTC	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	23,898	0	57	
RTC	Power4Georgians	24 yr PPA, 850 MW	0	444,005	32	102	
RTC	Power4Georgians	24 yr Tolling Agreement, 850 MW	0	444,005	0	96	
RTC	Power4Georgians	Asset Sale, 850 MW	3,565	84,022	0	81	
SCCT_20	Agile	20 yr Tolling Agreement, 12 units, 112.9 MW	0	210,068	0	549	
SCCT_20	LS Power	20 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	271	✓
SCCT_20	LS Power	20 yr PPA starting 1/1/2014, 495 MW	0	42,524	0	269	✓
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	0	29,025	0	133	✓
SCCT_5	Southern Co. Services	5 yr PPA, 75-675 MW	0	126,615	0	380	
SCCT_5	Southern Co. Services	5 yr PPA (Summer Only), 75-675 MW	0	116,615	0	356	
SCCT_5	Ameren	5 yr PPA, 5 units, 222 MW	0	103,558	0	315	
SCCT_5	LS Power	5 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	249	✓
SCCT_Own	LGE/KU	Trimble CT Retrofit	2,000	0	0	421	
SCCT_Own	Wellhead Energy Systems	Asset Sale, 100 1 MW GridFox Units	988	53,698	0	386	
SCCT_Own	Agile	Asset Sale, 12 units, 112.9 MW	1,386	53,068	0	458	
SCCT_Own	LGE/KU	Self-Build, 206 MW	840	23,898	0	305	
SCCT_Own	TPF Generation	Asset Sale, 5 Units, 245 MW	434	64,413	0	317	
SCCT_Own	LS Power	3 yr PPA 1/2015, Asset Sale12/2017, 495 MW	232	34,724	0	236	✓
SCCT_Own	LS Power	5 yr PPA 1/2015, Asset Sale 12/2019, 495 MW	212	34,724	0	239	✓
SCCT_Own	LS Power	5-mon PPA 1/2014, Asset Sale 2014, 495 MW	240	34,724	0	227	✓
Solar_Own	Solar Energy Solutions	Asset Sale, 1-5 MW	2,932	10,185	0	194	✓
Solar_Own	LGE/KU	Self-Build, 10 MW	4,633	10,185	0	247	✓
Wind	EDP Renewables	15 or 20 yr PPA, 99 MW	0	0	50	60	✓
Wind	EDP Renewables	20 yr PPA, 100 MW	0	0	70	68	✓
Wind	EDP Renewables	15 yr PPA, 151.2 MW	0	0	50	59	✓

8.3 Appendix C – LG&E/KU Resource Summaries (High & Low Load Forecasts)

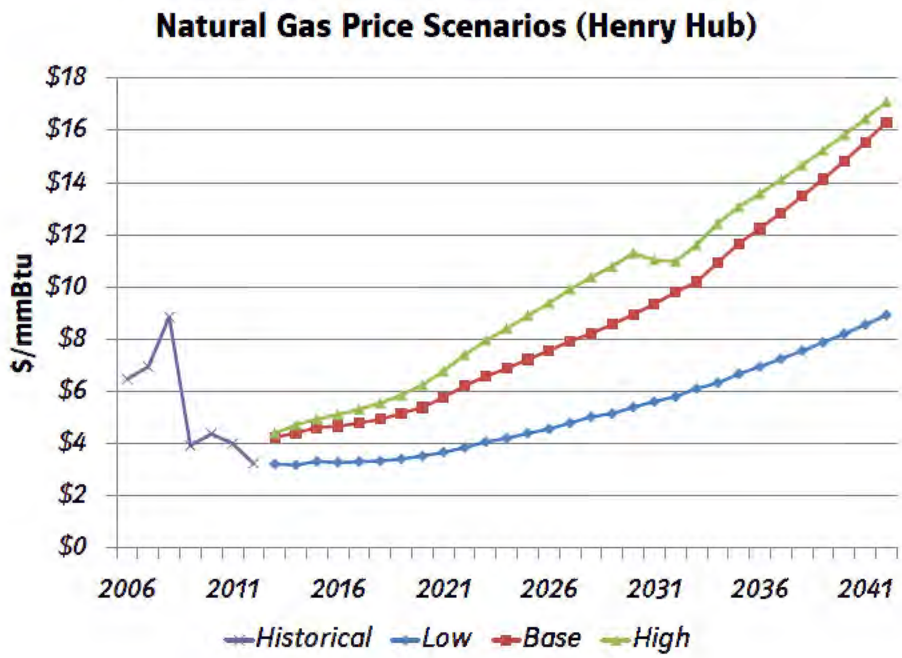
Table 17 – LG&E/KU Resource Summary – High Load Forecast (MW)

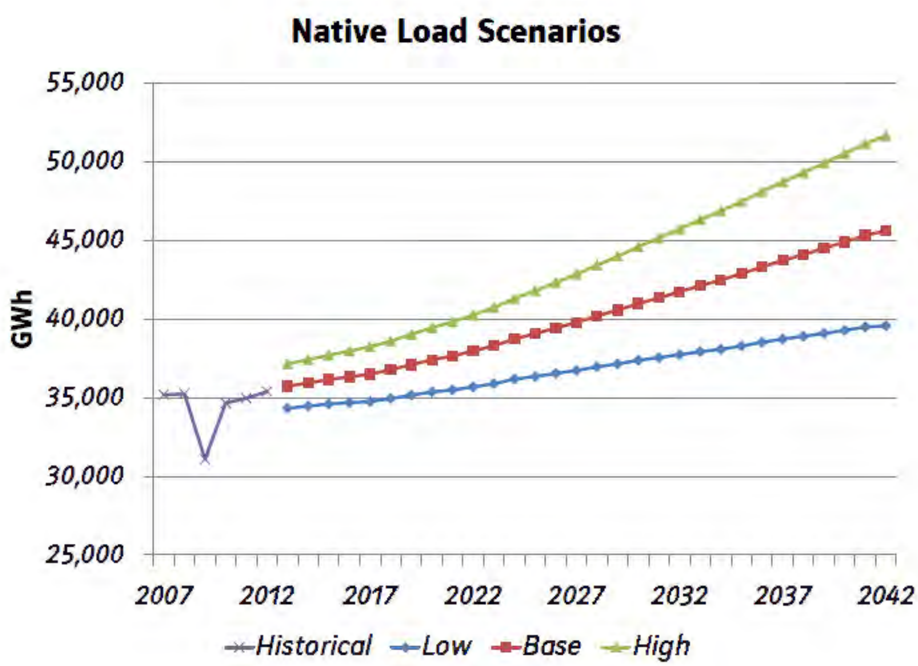
	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,733	7,833	7,940	8,056	8,125	8,218	8,312
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,347	7,415	7,490	7,574	7,661	7,752	7,845
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demand	137	137	137	137	137	137	137
Total Supply	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin (RM)	6.6%	5.5%	4.7%	3.0%	2.1%	0.9%	-0.3%
RM Shortfall (16% RM)	692	780	849	985	1,067	1,171	1,279
RM Shortfall (15% RM)	618	705	774	909	990	1,093	1,200

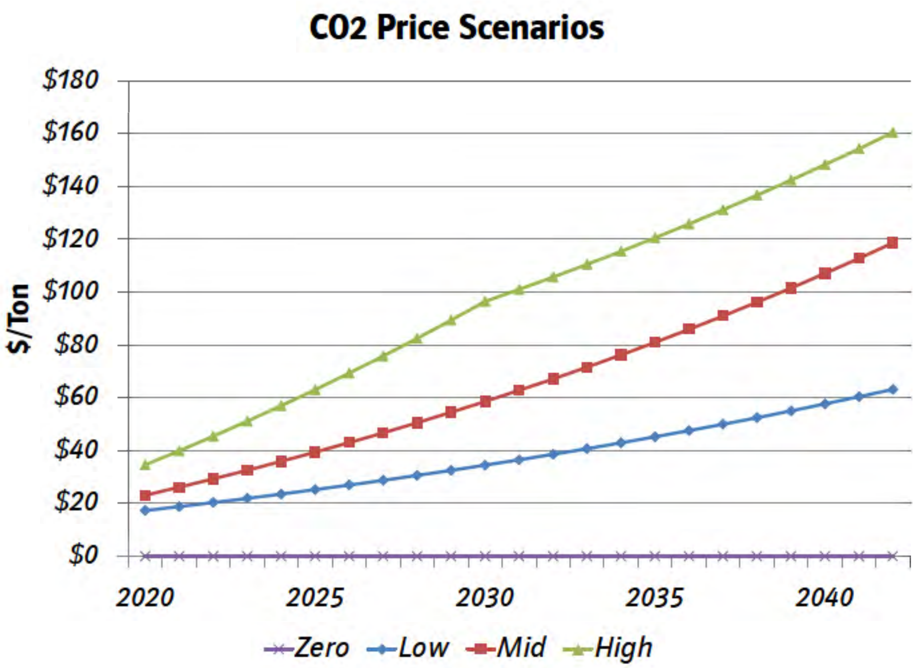
Table 18 – LG&E/KU Resource Summary – Low Load Forecast (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,120	7,185	7,255	7,336	7,366	7,414	7,458
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	6,734	6,767	6,805	6,854	6,902	6,948	6,991
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demand	137	137	137	137	137	137	137
Total Supply	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin (RM)	16.3%	15.6%	15.2%	13.8%	13.3%	12.6%	11.9%
RM Shortfall (16% RM)	-19	28	55	149	186	238	288
RM Shortfall (15% RM)	-87	-40	-13	81	117	169	218

8.4 Appendix D – Natural Gas, Load, and CO_2 Price Scenarios







Note: The Phase 2, iteration 1 analysis considered the Zero and Mid CO_2 price scenarios only.

From:	Wilson, Stuart
To:	Thompson, Paul; Staton, Ed; Balmer, Chris; Freibert, Charlie; Brunner, Bob; Voyles, John; Schetzel, Doug; Bowling, Ralph; Sinclair, David; Schram, Chuck
Cc:	Karavayev, Louanne; Farhat, Monica; Wang, Chung-Hsiao; Leitner, George; Ryan, Samuel
Subject:	Summary of RFP Responses
Date:	Tuesday, December 18, 2012 4:14:37 PM
Attachments:	20121113_SummaryofRFPResponses_0060D4.docx

All,

We made a few minor changes to the summary of RFP responses I distributed last night. Please refer to this version moving forward.

Thanks.

Stuart

Summary of RFP Responses

1. **AEP**
   - 5 year PPA for a fixed percentage of an existing generation portfolio (up to 700 MW) including coal, combined cycle gas, and simple cycle gas generation, which would be dispatched by PJM
   - Flexible with regard to length of term, start date, and volume
   - Capacity charge quoted is $~~402.80~~12.3/k~~M~~W-~~Day~~month ~~(or $147,022/MW-yr)~~, and energy price starts at $38.70/MWh in 2015
2. **Agile**
   - Asset sale or 20 year tolling agreement for 113 MW of natural gas fired reciprocating engine generation in Muhlenburg County KY starting June 2016
   - Tolling agreement costs include~~has~~ a capacity price of $~~157,000~~ 13.1/~~M~~kW-~~year~~month starting in 2016 ~~in addition to~~ firm gas transport and VO&M. Heat rate is 8 793 Btu/kWh. ~~in 2016 dollars~~
   - ~~Proposal does not include fixed gas transport costs~~
   - Asset sale price is $156.5 million in 2016 ~~dollars~~
   - ~~Construction will be completed June 2016~~
   - ~~Generators will be located in Muhlenburg, Kentucky and connect to a KU substation~~
3. **Ameren**
   - Several options were presented:
     - 5 or 10 year PPA for 334 MW, 501 MW, or 668 MW of coal generation from EEI with the option to pay for coal to gas conversion
     - 10 year PPA for 700 MW of a coal and natural gas portfolio with the option to pay for coal to gas conversion
     - 5 year PPA for 222 MW of simple cycle gas generation
   - ~~EEI units assumed to retire in 2019 due to environmental regulations~~
   - Station is located in Joppa, Illinois
   - Costs include capacity payments, fuel costs, start charge, and VO&M
   - Pricing varies by proposal
4. **Big Rivers**
   - 1-15 year PPA for up to 417 MW of coal capacity with a guaranteed heat rate of 10,450 Btu/kWh from their Wilson Station in Centertown, KY
   - Flexible with regard to length of term, start date, and volume
   - Capacity price quoted is $11.5~~0~~/kW-month ~~(or $138,000/MW-yr)~~
5. **Calpine**
   - 5 year PPA for either 250 MW or 500 MW of CCCT capacity by selecting either one or two gas turbines that are part of a 3x1 Siemens 501F CCCT
   - Guaranteed heat rates of 7,500 Btu/kWh for the 250 MW option and 7,400 Btu/kWh for the 500 MW option ~~at full load~~
   - Located in Decatur, Alabama

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- Costs include capacity price of $6.2/kW-month~~($74,160/MW-year)~~, fuel, start charges, and VO&M

~~5.~~6. CCCT 1X1 Self Build (LGE/KU)

- Four options: GE F-Class, Siemens F-Class and H-Class, and Mitsubishi G-Class
- Capacities range between 299 MW and 380 MW
- Capital costs range between $420 million and $460 million, not including cost of land, additional electric transmission, or gas transportation
- Assumed to be available June 2017
- Heat rates range between 6,600 Btu/kWh and 6,900 Btu/kWh

~~6.~~7. CCCT 2X1 Self Build (LGE/KU)

- ~~2~~Two options:
  - GE F-Class 598 MW at a heat rate of 6,848 Btu/kWh for $609 million
  - Siemens F-Class 670 MW at a heat rate of 6,866 Btu/kWh for $617 million
- Capital costs do not include cost of land, additional electric transmission, or gas transportation
- Assumed to be available June 2017

8. ~~CCCT 1X1~~Trimble County CT ~~Steam Augmentation~~Upgrades (LGE/KU)

- Two options:
  - Steam Injection for Power Augmentation
    - Simple HRSG added to each CT to increase capacity by 10.6% and improve heat rate by 4.5%~~Steam Augmentation for Trimble CTs~~
    - Capital costs of $108 million for 102 MW upgrade in April 2015
    - ~~Upgrades completed April 2015~~
    - Upgraded ~~unfired~~ heat rate ~~approximately~~estimated at 9,969 Btu/kWh compared to ~~the~~ current heat rate of ~~approximately~~ 10 439 Btu/kWh
  - Advanced Gas Path Upgrade
    - Increases capacity by 5.6% and improves heat rate by 2.8%
    - Capital costs of $108 million for 54 MW upgrade in April 2015
    - Upgraded heat rate estimated at 10,139 Btu/kWh compared to current heat rate of 10,439 Btu/kWh

9. CPV Smyth Generation Co.

- 20 year tolling agreement for 630 MW of 2X1 combined cycle capacity with a guaranteed heat rate of 7,009 Btu/kWh located in
- ~~Delivery point~~ Smyth County VA
- Assumed to be available~~Anticipated start date~~ June 2017

~~7.~~ Capacity charge quoted is $1~~32 001~~.0/~~M~~kW-month~~year and FOM $23 400/MW-year~~

~~8.~~10. Demand Side Management/Energy Efficiency (LGE/KU)

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- DSM options include Lighting, Thermostat Rebates, Windows & Doors, Manufactured Homes, Behavioral Thermostat Pilot, Commercial New Construction and Automated Demand Response programs

~~9.~~11. **Duke**

- Asset sale of a 9% (203 MW) share of OVEC
- Sale price is $50 million if purchased in 2013 or $100 million if purchased in 2015
- Terms include monthly fixed and variable payments

~~10.~~12. **EDP Renewables**

- ~~3~~Three options:
  - 15 or 20 year PPA for an existing 99 MW wind farm in Caddo County, Oklahoma at $50/MWh escalating at 3%
  - 15 year PPA for an existing 151 MW wind farm in Caddo and Comanche Counties, Oklahoma at $50/MWh escalating at 3%
  - 20 year PPA for a 100 MW wind farm under development in Ballard County, Kentucky at $69.50/MWh (no escalation)
- PPAs for existing wind farms will deliver 80% of the total energy in RTC blocks based on a monthly schedule; the remaining 20% of the energy will be delivered as it is generated
- Energy from the wind farm under development in Kentucky will be delivered as generated, with no schedule

13. **Energy Development, Inc.**

- 20 year PPA for 14.4 MW of round the clock~~RTC~~ landfill gas generation at 4 different sites in Kentucky
- Costs include energy cost of $62-/-MWh ~~energy cost~~ starting in 2015 and escalating at 2% ~~plus~~and VO&M ~~in 2015 dollars~~
- ~~Generation will come from four sites to be constructed at different landfills~~

~~11.~~14. **ERORA (Cash Creek Generation)**

- 700 MW of 2X1 CCCT, with a guaranteed heat rate of 6,705 Btu/kWh for the first 535 MW and 8,546 Btu/kWh for the next 165 MW (duct firing)
- Units are assumed to be available in June 2017 and will be located in Henderson, KY
- ~~3~~Three options:
  - 10 or 20 year tolling agreement at $~~64,800~~5.4/~~M~~kW~~-yr~~month capacity charge
  - Asset sale for $765 million
  - Fully permitted 2,050 acre site for $30 million

~~12.~~15. **E.W. Brown Units 1 & 2 Retrofit (LGE/KU)**

- Baghouse required for environmental compliance
- Capital cost of baghouse is $194 million in
- ~~Construction to be completed in~~ April 2016
- Without retrofit, Brown units 1 & 2 would retire in April 2015

16. **E. W. Brown Units 1 & 2 Coal to Gas Conversion (LGE/KU)**

- Capital cost of $46.7 million in April 2016
- Heat rate estimated at 11 000 Btu/kWh for Brown 1 and 10 500 Btu/kWh for Brown 2

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- Additional costs would include firm gas transport

~~13.~~17. **Exelon Generating Company**

- 10 year PPA for 200 MW of round the clock energy
- Energy price quoted is $47.78/MWh (no escalation)

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~~14.~~18. **Khanjee**

- Two 20 year options with three different terms:
  - 700 MW of 2X1 CCCT located in Murdock, IL
    - Fixed price baseload operation with minimum take of 85% capacity factor starting at $50.04/MWh in June 2017 with escalation
    - Fixed price of $35.13/MWh and capacity charge of $~~111,000~~9.3/kM~~M~~W-~~yr~~month starting in June 2017 with escalation
    - Tolling agreement with a guaranteed heat rate of 6,800 Btu/kWh and capacity charge of $9.3/kW-month ~~$111,000/MW-yr~~ starting in June 2017 with escalation
  - 700 MW of 2X1 CCCT located in Kentucky
    - Fixed price baseload operation with minimum take of 85% capacity factor starting at $44.16/MWh in June 2017 with escalation
    - Fixed price of $30.63/MWh and capacity charge of $8.4/kW-month ~~$100,800/MW-yr~~ starting in June 2017 with escalation
    - Tolling agreement with a guaranteed heat rate of 6,800 Btu/kWh and capacity charge of $8.4/kW-month ~~$100,800/MW-yr~~ starting in June 2017 with escalation
- Since the unit will not be available until 2017, Khanjee offered to provide energy in 2015 and 2016 at $45/MWh in addition to the above options

~~15.~~19. **KMPA**

- 5-year fixed price PPA of 25 MW of base load coal fired round the clock capacity
- Unit located in MISO
- Costs include $~~34,255~~2.9/~~M~~kW-~~yr~~month capacity charge, and energy price of $33.61/MWh starting in 2015

~~16.~~20. **LS Power (Bluegrass Generation Station)**

- ~~3~~Three options for 3 SCCTs of 495 MW capacity at a heat rate of 10,900 Btu/kWh:
  - 20-year tolling agreement starting in 2015 with options to purchase end of 2017 (for $115 million) and end of 2019 (for $105 million). Capacity charge is $2.5/kW-month starting in 2015.
  - 20-year tolling agreement starting in 2014 with option to purchase mid 2014 (for $119 million). Capacity charge is $1.0/kW-month in 2014 then $2.5/kW-month starting in 2015.
  - 5 year PPA with no purchase option. Capacity charge is $3.1/kW-month starting in 2015.
- Costs include capacity charge, fixed O&M, fuel, VO&M, and start costs

~~17.~~21. **Nextera**

- 30 MW or 50 MW PPA of coal generation with a 6-year or 10-year term, respectively, starting in 2015
- Energy price quoted is $55/MWh, escalated at 0.96%

22. **North American Biofuels**
- 20 year PPA for 19 MW of round the clock ~~RTC~~ landfill gas generation from sites located in Wisconsin and Pennsylvania
- Costs include energy cost of $52~~/~~/MWh starting in 2014 and escalating at 3% ~~plus VO&M in 2013 dollars~~ and VO&M
- ~~Energy available beginning in January, 2014~~
- ~~Sites are located in WI and PA and will interconnect through MISO and PJM~~

~~18.~~23. **Paducah Power Systems**
- 5 year tolling agreement for 26 MW of simple cycle capacity with a heat rate of 13,090 Btu/kWh (including losses)
- Costs include $~~1,825~~0.2/kMW-~~yr~~month capacity charge and energy cost defined as the higher of 110% of production cost or market price

24. **Power4Georgians**
- Three options for 850 MW supercritical coal unit located in Washington County Georgia assumed to be available January 2019:
  - 24 year fixed price ~~P~~PPA with fixed capacity charge of $30.0/kW-month and energy price of $32.40/MWh starting in 2019 and escalating at 1.85%
  - 24 year tolling agreement with fixed capacity charge of $30.0/kW-month and heat rate of 9 000 Btu/kWh~~or~~
  - ~~a~~Asset sale ~~of supercritical coal plant with a delivered capacity of 802 MW~~
  - ~~The asset sale price is~~ for $3.03 billion
- ~~The fixed cost of the PPA and tolling agreement is $ 387,656/ MW-year in addition to fuel costs and VO&M in 2019 dollars~~
- ~~Proposal does not include transmission costs~~
- ~~Construction will be completed in January 2019~~

~~19.~~25. **Quantum Choctaw Power**
- 701 MW of 2X1 combined cycle capacity, with a guaranteed heat rate of 7,064 Btu/kWh for the first 665 MW and 9,400 Btu/kWh for the next 36 MW (duct firing)
- ~~3~~Three options:
  - 20-35 year tolling agreement with capacity charge of $~~66,321~~5.8/kMW-~~yr~~month with option to purchase end of 2015 for $462.5 million
  - Asset sale for $450 million in 2015
  - 5 year tolling agreement with capacity charge of $4~~8,00~~.0/kMW-~~yr~~month starting in 2015
- Built in 2007 and located in Ackerson, MS

26. **Santee Cooper**
- 7.8 year PPA beginning in April 2017 for 250 MW of coal capacity located in Georgetown SC

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- ~~Located in Georgetown, SC~~
- ~~Expected to begin April 2017~~
- Costs include ~~C~~capacity charge~~s are~~ of $~~100,080~~8.4/~~M~~kW-~~year~~month
- ~~E~~energy ~~costs are~~price based on 105% of average operating cost, and VO&M ~~$40.00/MWh in addition to VO&M~~
-

27. Sky Global
- 10~~-or~~ to 20 year tolling agreement beginning January 2016 for 250-300 MW of 1x1 CCCT ~~(1X1)~~ generation located in Pineville, KY
- ~~Delivery point is LG&E/KU system~~
- Capacity charge quoted is $~~108,009~~.0/~~M~~kW-~~year~~month ~~Capacity Charges~~
- Estimated ~~guaranteed~~ heat rate between 7000--7500 Btu/kWh

~~20.~~28. **Solar Energy Solutions**
- 1-5 MW PV asset sale for $2.9 million per MW assumed to be available beginning 2015

~~21.~~29. **Solar PV Array Self Build (LGE/KU)**
- 10 MW PV capacity for $4.6~~3~~ million per ~~/~~MW (assuming no tax credit)

30. South Point Biomass
- 20 year PPA beginning in May 2015 for 165 MW of round the clock~~RTC~~ biomass generation located in Lawrence, OH
- Costs include ~~Energy is available starting in May, 2015~~
- ~~The e~~energy cost of~~is~~ $65.50~~/~~/MW~~-year~~h starting in 2015 ~~in addition to VO&M~~ and VO&M
- ~~Proposal does not include transmission costs~~
- ~~Station is located in Lawrence, Ohio~~

31. Southern Company Services
- T~~wo~~hree options:
  - 5 year ~~PPA~~tolling agreement beginning in January 2015 for 75-675 MW of SCCT ~~capacity~~generation located in Demopolis, AL. Costs include capacity cost of $3.8/kW-month, heat rate of 12,850 Btu/kWh, and VO&M.
  - 5 year summer only (June – September) tolling agreement beginning in January 2015 for 75-675 MW of SCCT generation located in Demopolis, AL. Costs include capacity cost of $8.8/kW-month, heat rate of 12,850 Btu/kWh, and VO&M.
  - 15 year ~~PPA~~tolling agreement beginning in January 2016 for 109-159 MW of ~~c~~Coal ~~capacity~~generation ~~starting in January, 2016~~ located in Juliette, GA. Costs include capacity cost of $20.5/kW-month, heat rate of 10,400 Btu/kWh, and start costs.
  -
  - ~~The assets are located in the SOCO service territory~~
  - ~~Capacity charges range from $35,000/MW-year to $246,000/MW-year~~
  - ~~Guaranteed unfired heat rate is 12,850 Btu/kWh (SCCT) and 10,400 Btu/kWh (coal)~~
  - ~~Energy costs are $5.00/MWh for SCCT and $14,136/Start for Coal~~

32. Southern Power Company

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- Two options f~~20 year PPA f~~or -20 year tolling agreement starting in June 2017 for 770 MW of 2x1 CCCT ~~(2X1)~~ generation with a guaranteed heat rate of 7,250 Btu/kWh:
  - ~~Location will be either an e~~Existing LG&E/KU site. Costs include capacity charge starting at $9.2/kW-month and escalating at 1.5% start costs and VO&M.
  - TBD site. Costs include capacity charge starting at $9.9/kW-month and escalating at 1.5%, start costs, and VO&M.~~or a site TBD~~
- ~~Capacity is available starting in June, 2017~~
- ~~Capacity charges are $100,101/MW-year and $107,492/MW-year respectively~~

33. **Union Power Partners**

- Two options for 500 MW of 2x1 CCCT generation located in El Dorado, AK starting in January 2015:
  - Asset sale for $298 million with heat rate estimated at 7 250 Btu/kWh
  - ~~or~~10 year tolling agreement. Costs include -$7.6/kW-month capacity charge ~~for 485 MW of 2X1 combined cycle capacity with~~ heat rate of 7,100 Btu/kWh, start costs, and VO&M.
  - ~~Guaranteed heat rates of 7,100 Btu/kWh (asset sale) and 7,085 Btu/kWh (tolling)~~
  - ~~They offered this capacity ($91 200/MW-year) as a 10 year tolling agreement and as an asset sale for $298 million in 2014~~
  - ~~TIP is Entergy AK XM at the El Dorado substation~~

34. **Wellhead Energy Systems**

- Asset sale of 100 1 MW ~~natural gas powered~~ GridFox natural gas~~Units~~ reciprocating engines for $98.8 million in January 2016
- ~~Asset sale price is $98.8 million in 2013 dollars~~
- ~~Proposal does not include fixed gas transport fixed O&M VO&M or start costs related to unit operation~~
- ~~Construction will be completed in January 2016~~

35. **Wellington**

- 20 year PPA starting in September 2016 for 112 MW of round the clock~~RTC~~ waste coal generation located in Green County PA
- Costs include ~~Energy available beginning in September, 2016~~
- ~~C~~capacity cost ~~is~~of $~~41 050~~ 28.2/~~M~~kW-~~year~~month escalating at 2% ~~in addition to~~and energy ~~costs~~price of $61.10/MWh starting in 2016~~and VO&M~~
  - ~~Unit is currently under construction in Greene County Pennsylvania~~

Note: Start date is assumed to be 1/1/2015 unless otherwise stated

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From:	Wilson, Stuart
To:	Sinclair, David
Cc:	Schram, Chuck
Subject:	Credit Ratings
Date:	Wednesday, December 18, 2013 9:23:11 AM

Just heard back from Dan… Nothing has changed with Dynegy's credit rating since the sale of the Joppa assets.

From:	Straight, Scott
To:	Sinclair, David; Wilson, Stuart; Schram, Chuck
Cc:	Voyles, John; Schetzel, Doug
Subject:	FW: EW Brown 10 MW Solar PV Siting Study Review Presentation Update
Date:	Thursday, December 19, 2013 8:40:47 AM
Attachments:	LG&E KU 10 MW Solar PV Siting Study Review Presentation Rev B.pptx

David, Stuart and Chuck,

Here is the revised HDR document. Please note the new values for the Standard Efficiency option on the last page.

Scott

From: Schetzel, Doug
Sent: Thursday, December 19, 2013 8:32 AM
To: Straight, Scott; Voyles, John
Subject: FW: EW Brown 10 MW Solar PV Siting Study Review Presentation Update

John

Attached is the revised solar presentation from HDR. Please let me know if you have additional comments.

Douglas Schetzel
Director Business Development
LG&E and KU Energy, LLC
[redacted]

From: Wiitanen, Mark [redacted]
Sent: Thursday, December 19, 2013 8:27 AM
To: Schetzel, Doug
Subject: EW Brown 10 MW Solar PV Siting Study Review Presentation Update

Doug,

Attached is an updated EW Brown 10 MW PV Solar Siting Study Review Presentation incorporating revised Site Work costs with an established level of accuracy range and basis. Note the level of accuracy has been assigned to the Site Preparation line item – if desired this can be assigned to the total EPC cost for presentation purposes. The engineering, permitting and Geotech line item and Owner contingency were reduced linearly with the EPC direct cost.

If any format changes or edits are desired please advise.

Regards,
Mark

MARK A. WIITANEN
P.E.

HDR | Power Generation
Sr Project Manager | Associate Vice President

[redacted]

ONE COMPANY
Many Solutions

December 13, 2013

PPL companies

EW Brown 10 MW Solar PV Siting Study Review

Agenda

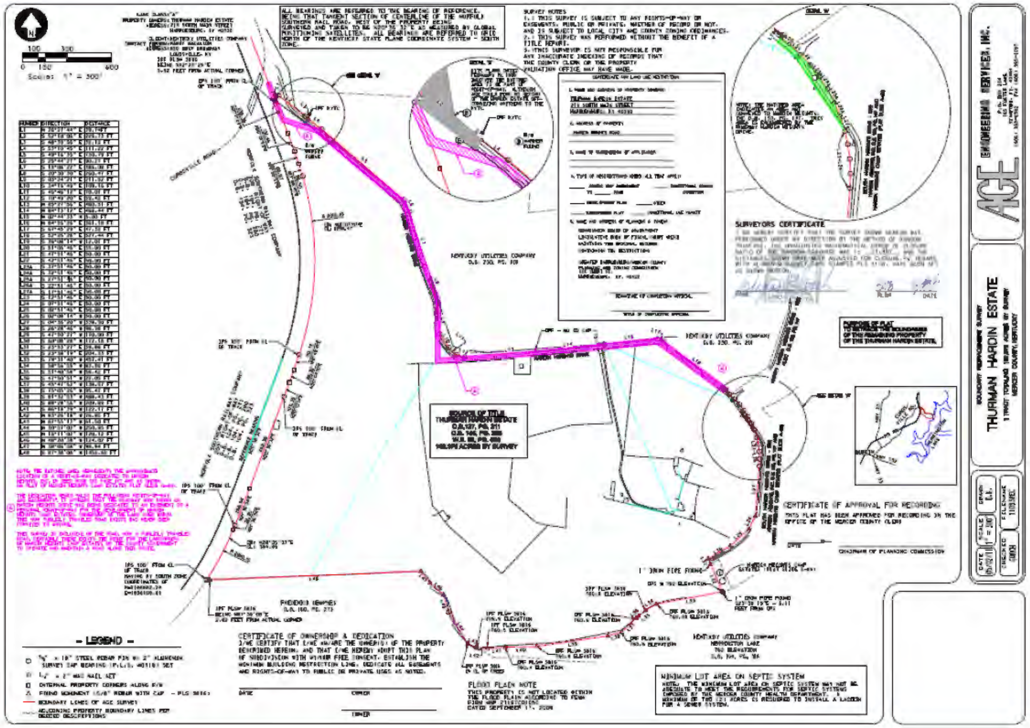
- Siting Study Objectives
- Technology Considered
- Interconnection Evaluation
- Site Environmental Review
- Capital Costs
- Cost of Generation

HDR

Siting Study Objectives

- Selection of solar PV technology type and configuration to suit specific site.
- Identification of available electrical interconnection options and work with LG&E/KU to select a preferred option.
- High level review of environmental considerations to identify any issues of concern for the selected site.
- Develop a conceptual site general arrangement.
- Develop a conceptual project cost estimate based on lowest cost of generation option.

EW Brown Solar Site Overview
Former Hardin Estate – 153 Acres



HDR

PV Technology Available for Consideration

PANEL TECHNOLOGY

- Thin Film Type – First Solar 90W (FS-390) 12.54% efficiency at STC
- Crystalline Standard Efficiency Type – JA Solar 300W 15.57% efficiency at STC
- Crystalline High Efficiency Type – SunPower 320W 19.67% efficiency at STC

TRACKING SYSTEMS

- Fixed Axis Array - Southern Facing
- Single Axis Tracking – Track East to West Throughout Day

PV Technology Site Specific Evaluation

TRACKING SYSTEMS

- Fixed Axis Array – East/West Slope Limitation of 10% to 15% Acceptable for EW Brown

- Single Axis Tracking – East/West Slope Limitation of 1% to 5% is not compatible with EW Brown site topography

PANEL TECHNOLOGY

- Thin Film Type – Lower panel power density (W/ft2) cannot produce 10 MW AC on portion of EW Brown suitable for PV. A 6.5 MW AC capacity can be supported.

- Crystalline Standard Efficiency Type – 10 MW AC can be provided on EW Brown site utilizing approximately 50 acres

- Crystalline High Efficiency Type – Footprint nominally 6% smaller than Standard Efficiency Type at 47 acres

Electrical Interconnection Options

POTENTIAL INTERCONNECTION LEVELS/LOCATION

- Interconnection at 69 kV via Line Tap or Bay Addition at West Cliff Substation
- Interconnection at local distribution system
- Integration with proposed/approved CCRT 13.2 kV electrical distribution system. The CCRT 13.2 kV system will be served via two transformers supplied from the Brown South and West Cliff substations. The CCRT peak demand is estimated to be 5 MW to 10 MW.

SITING STUDY INTERCONNECTION BASIS

- CCRT 13.2 kV Distribution System Expansion has been determined to be the lowest cost option. Provides less external interface (for Solar PV Project) and potential interconnection study cost savings. The interconnection to consist of a 1 mile 13.2 kV OH line routed on LG&E-KU property.

HDR

Environmental – Critical Issues Analysis

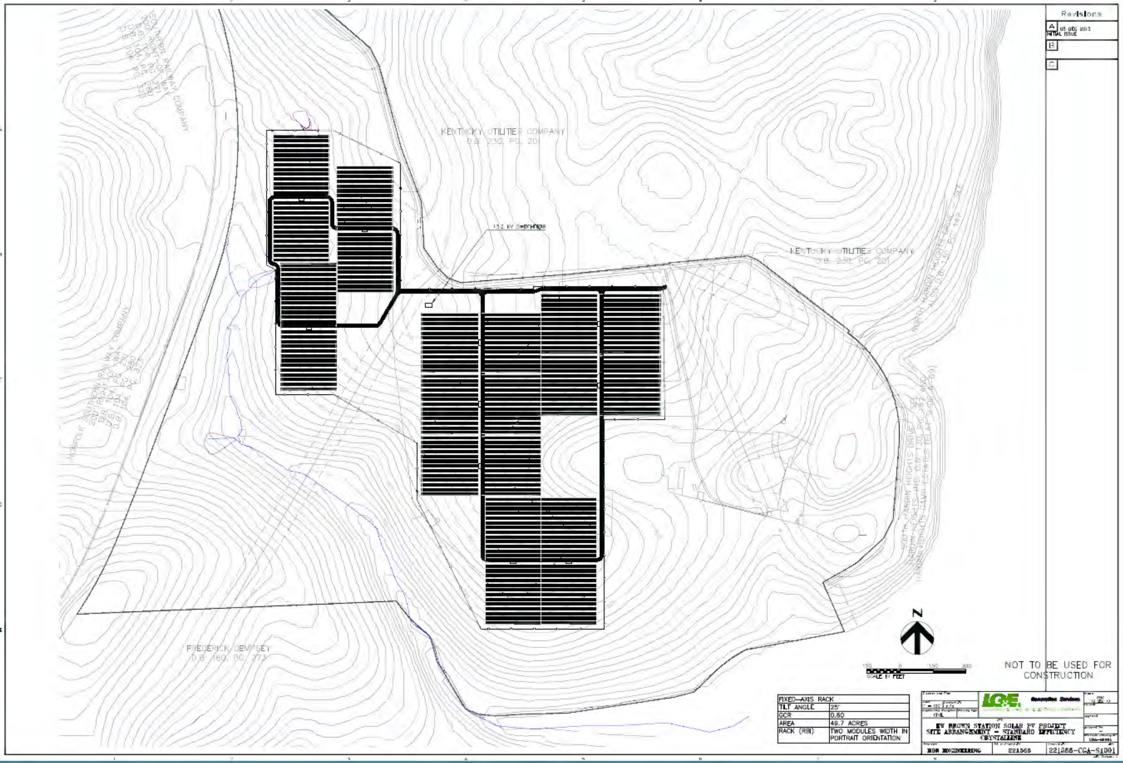
ANALYSIS

- Desktop Review
- Site Investigation 11/12/13
- LG&E-KU Record Review (Indiana Bat MOA and Soil Borings)

CIA FINDINGS AND RECOMMENDATIONS

- Agency Coordination
- Technical Studies
- Jurisdictional Waters Delineation
- Rare Plant and Mammal Study

10 MW Standard Efficiency Crystalline Site Arrangement w/ Topography



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10 MW Standard Efficiency Crystalline Site Layout Aerial View

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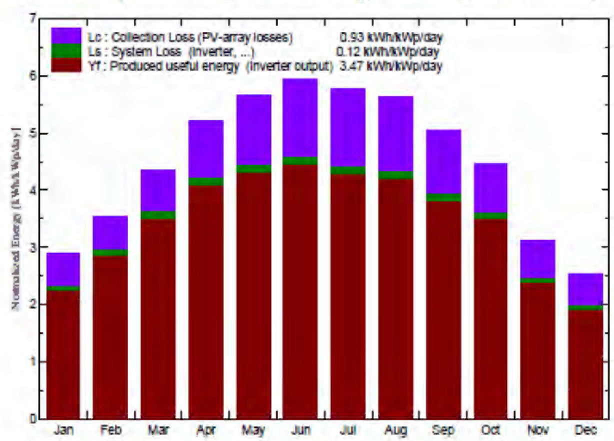
Solar Array Performance Calculations
PVSyst Software – Production

Main simulation results

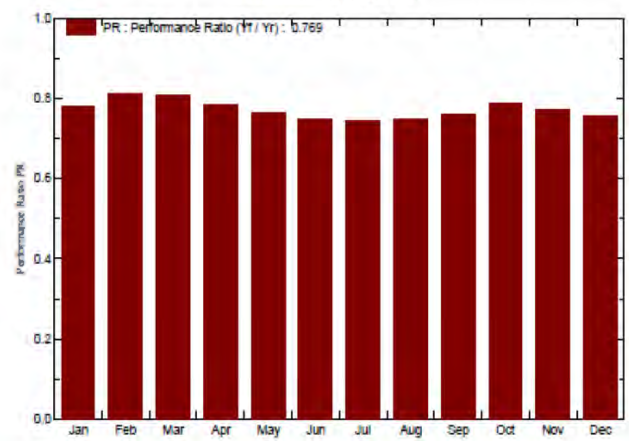
System Production

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

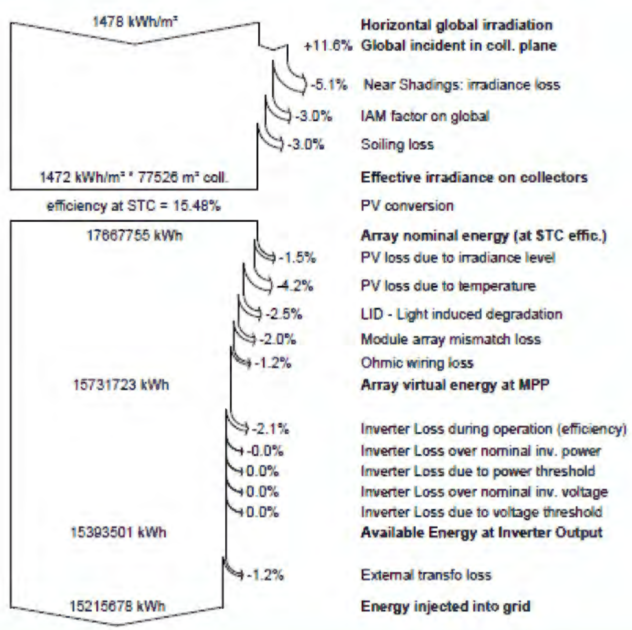


Performance Ratio PR



Solar Array Performance Calculations
PVSyst Software – Losses

Loss diagram over the whole year



Solar Array Performance Comparison

Module	Efficiency	$/W(dc)	Quantity	DC Power, kW	DC/AC Ratio	MWh/yr
First Solar 90W - 6.5 MW	12.54%	$0.62	86,660	7799	1.20	10,428
JA Solar 300W	15.57%	$0.75	39,995	11999	1.20	15,216
SunPower 320W	19.32%	$1.00	37,505	12002	1.20	15,979

Capital Cost and Cost of Generation

Description	Thin Film	Standard Efficiency	High Efficiency	Feasibility Study
EPC Direct Cost				
Site Preparat on	$3,000,000 **(see Note 1)**	$3,000,000 **(see Note 1)**	$3,000,000 **(see Note 1)**	$875,000
Panel Modules & Support	$11,000,000	$15,000,000	$19,000,000	$30,875,000
500 kW Inverters	$3,000,000	$3,000,000	$3,000,000	$3,000,000
Electr cal Distribut on System	$5,000,000	$5,000,000	$5,000,000	$1,500,000
Electr cal Interconnect	$500,000	$500,000	$500,000	$1,500,000
Engineering, Permitting, Geotech	$2,500,000	$2,500,000	$2,500,000	-
EPC Cost	**$25,000,000**	**$29,000,000**	**$33,000,000**	**$37,750,000**
Owner Cost				
Project Development	$650,000	$650,000	$650,000	$650,000
Electrical Interconnect	$450,000	$450,000	$450,000	$450,000
Construct on Power	$50,000	$50,000	$50,000	$50,000
Owners Project Management	$500,000	$500,000	$500,000	$500,000
Owners Engineer	$170,000	$170,000	$170,000	$170,000
Owners Legal Counsel	$250,000	$250,000	$250,000	$250,000
Land	$500,000	$500,000	$500,000	$500,000
Electric Transmiss on Serv ce	$50,000	$50,000	$50,000	$50,000
Site Secur ty	$50,000	$50,000	$50,000	$50,000
Spare Parts	$100,000	$100,000	$100,000	$100,000
AFUDC (KU Ownership Port on)	$150,000	$150,000	$150,000	$150,000
Contingency (15% of EPC)	$3,750,000	$4,350,000	$4,950,000	$5,663,000
Owner Cost	**$6,670,000**	**$7, 270,000**	**$7,870,000**	**$8,583,000**
Total Project Cost	**$31,670,000**	**$36,270,000**	**$40,870,000**	**$46,333,000**
Total Cost $/kW (AC)	**$4872/kW**	**$3627/kW**	**$4087/kW**	**$4633/kW**
Levelized Cost ($/MWHR)	**$226.57**	**$177.08**	**$189.38**	**$219.37**

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.**

HDR

From:	Freibert, Charlie
To:	Thompson, Paul; Voyles, John; Sinclair, David; Whelan, Chris
Cc:	Schetzel, Doug; Brunner, Bob; Schram, Chuck; Phillips, Brian; Wilson, Stuart; Depaull, Tom; Oelker, Linn; Freibert, Charlie
Subject:	Results to date from the RFP
Date:	Friday, November 02, 2012 6:52:05 PM
Attachments:	RFPresponses110212.xlsx

Paul, John, David and Chris,

27 Parties responded with multiple proposals/options (3 parties offered 2 technologies/fuels)

30 Offers of various Technologies/fuels – summary below.

CCCT offers 8
CT offers 5
Coal 9
Biomass 1
Landfill/waste gas 2
Wind 1
Solar 1
System 2
Distributed Generation 1

Offers 30

Attached is a spreadsheet overview of the responses to date.

We will keep you posted on further offers that are received late (I expect maybe 4 next week), and on the progress of the analysis by Stuart's team.

Have a great weekend!

Charlie Freibert
Director Marketing
LG&E and KU Energy LLC

Energy Services
220 West Main Street
Louisville, KY 40202
[redacted]

[redacted]

	9/7/12 RFP: Responses received 11/2/12 at 4pm EDT			
	Company	**Contact**	**Technology/Site**	**Notes**
1	Erora	Mike McGinnis	789MW CCCT	Cash Creek, Henderson KY
2	AEP	Vince Findley	700MW of Portfolio	AEP portfolio in PJM of coal and gas
3	Tenaska	Jason Behrens	250MW CT	Wolf Hills Energy, LLC Bristol VI
4	Big Rivers	Lindsay Barron	417MW Coal	Wilson Station Ohio Cnty KY
5	Quantum Utility Generation	Larry Kellerman	640MW CCCT	Choctaw, AL
6	Calpine	Mike Antonell	500MW CCCT	Morgan, AL
7	Ameren Mktg	Dennis Beutler	668MW coal	Joppa, IL
7	Ameren Mktg	Dennis Beutler	222MW CT	Joppa, IL
8	Paducah Power Sys	Rakesh Kothaka	26MW CT	Paducah KY
9	Agile Energy	Eric Lundberg	113MW Recip Gen	Muhlenberg Cnty KY
10	KMPA	Rakesh Kothaka	25MW coal	Prairie State, IL
11	Kanjee Holdings	Bob Harbour	700MW CCCT New	Murdock IL
11	Kanjee Holdings	Bob Harbour	700MW CCCT New	Louisville KY ???
12	Constellation/ Exelon	Andre Senenko	200MW fixed	MISO Hub
13	CPV	Gener Cotiangco	700MW CCCT New	Smyth Cnty VI
14	Duke Energy Ohio	Katie Kiefer	203MW coal	OVEC Gen
15	Well Head Energy Systems	Dave Weddle	100MW Distributed	LG&E/KU system
16	Energy Consulting Group	Bobby Tucker	700MW coal	Plant Washington GA
17	Solar Energy Solutions	Matt Partymiller	1MW solar PV	LG&E/KU system
18	EDP Renewable	Thomas Greer	99MW wind	Blue Canyon Windpower OK MISO
19	LS Power	Joe Gorberg	500MW CT	Bluegrass, Oldham Cnty KY
20	Sky Global Partners	Kathy Morgan	300MW CCCT new	Elk Ridge Energy Center, Bell Cnty KY near Pineville
21	Wellington Development	Steve Derby	300MW coal CFBC	East KY in PJM
22	Southern Wholesale Energy	Lance Haman	675MW CT	Green Cnty AL;
22	Southern Wholesale Energy	Lance Haman	159MW coal	Robert Scherer unit in AL

23	Santee Cooper	Mike Cool	250MW coal	Georgetown So Carolina
24	Nextera Energy	John Sullivan	50MW coal	Combo Prairie St IL and OVEC
25	Southpoint Biomass	Mark Harris	177MW wood	Lawrence Cnty Ohio
26	North American Biofuel	Bette Marvin	19.2MW landfill gas	in WI and PA
27	Southern Power Company	Tim Haskew	800MW CCCT new	LG&E/KU system
28				
29				
30				
	Summary	CCCT offers	8	
		CT offers	5	
		Coal	9	
		Biomass	1	
		Landfill/waste gas	2	
		Wind	1	
		Solar	1	
		System	2	
		Distributed Generation	1	
		Offers	30	

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RFP for Electric Energy and Capacity

June 27, 2013






RFP for energy and capacity was issued in September 2012

Response Summary

Response Type	*Number of Responses*	*Number of Proposals*
External	*29*	*68*
Self-Build - New	*3*	*3*
Self-Build - Retrofit	*4*	*4*
Energy Efficiency	*7*	*7*
Total	*43*	*82*

External Response Summary

Category	*Number of Assets*	*MWs*
Total	*35*	*11,853*
Coal	*9*	*2,734*
Gas	*17*	*7,669*
Renewable	*7*	*550*
Portfolio	*2*	*900*
New	*14*	*4,686*
Existing	*21*	*7,166*
In-State	*13*	*3,757*
Out-of-State	*22*	*8,095*

CCGT Specifications

- *Capital Cost (Green River site*, $2018, Millions):* 650
- *Max Fired/Unfired Capacity (MW):* 670/637
- *Fired/Unfired Heat Rate (btu/kWh):* 6,940/6,866

**Analysis considered locating CCGT at Green River and Brown stations. Capital cost and cost of transmission system upgrades are lower at Brown, but these costs are more than offset by value of greater operating flexibility at Green River station.*

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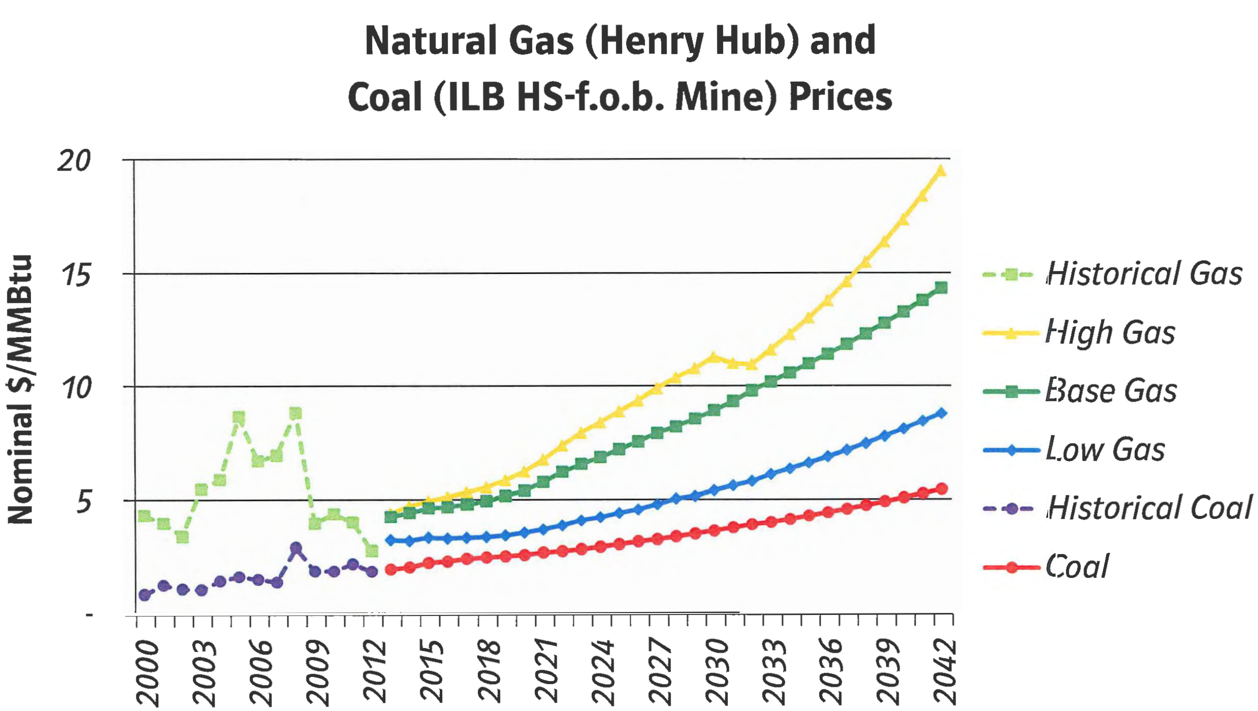
Gas Price Scenarios



Source: EIA

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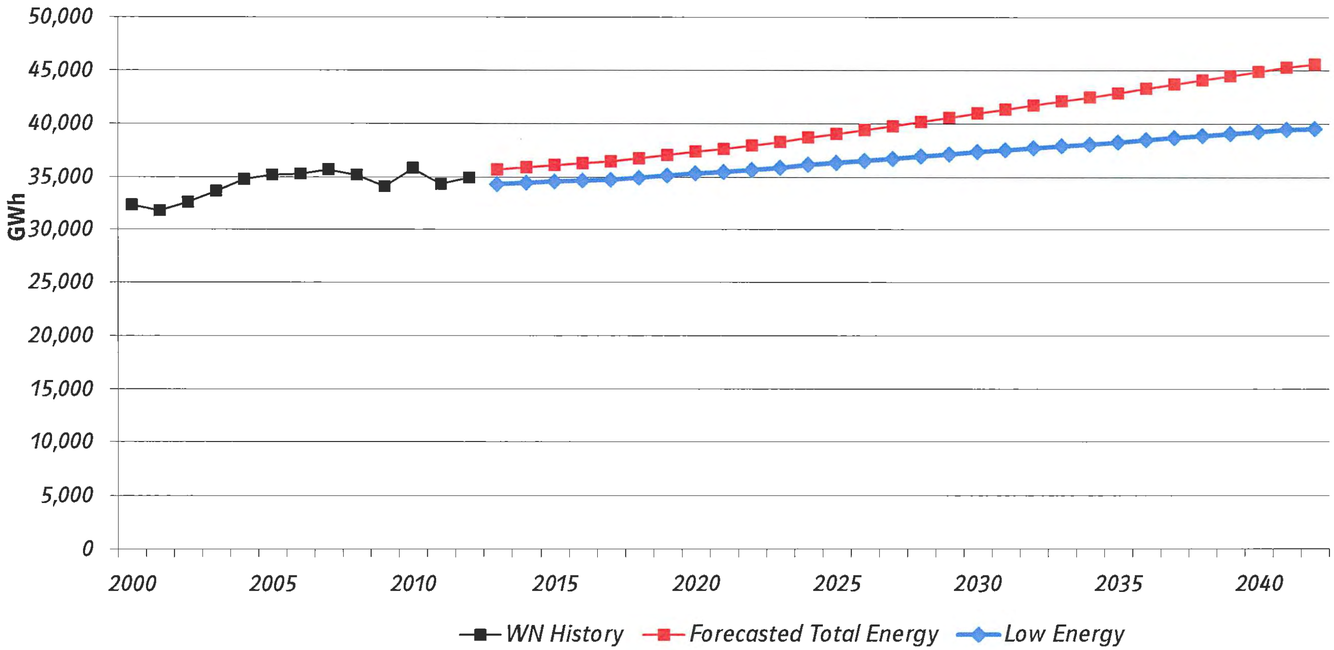
Combined Company Energy Requirements



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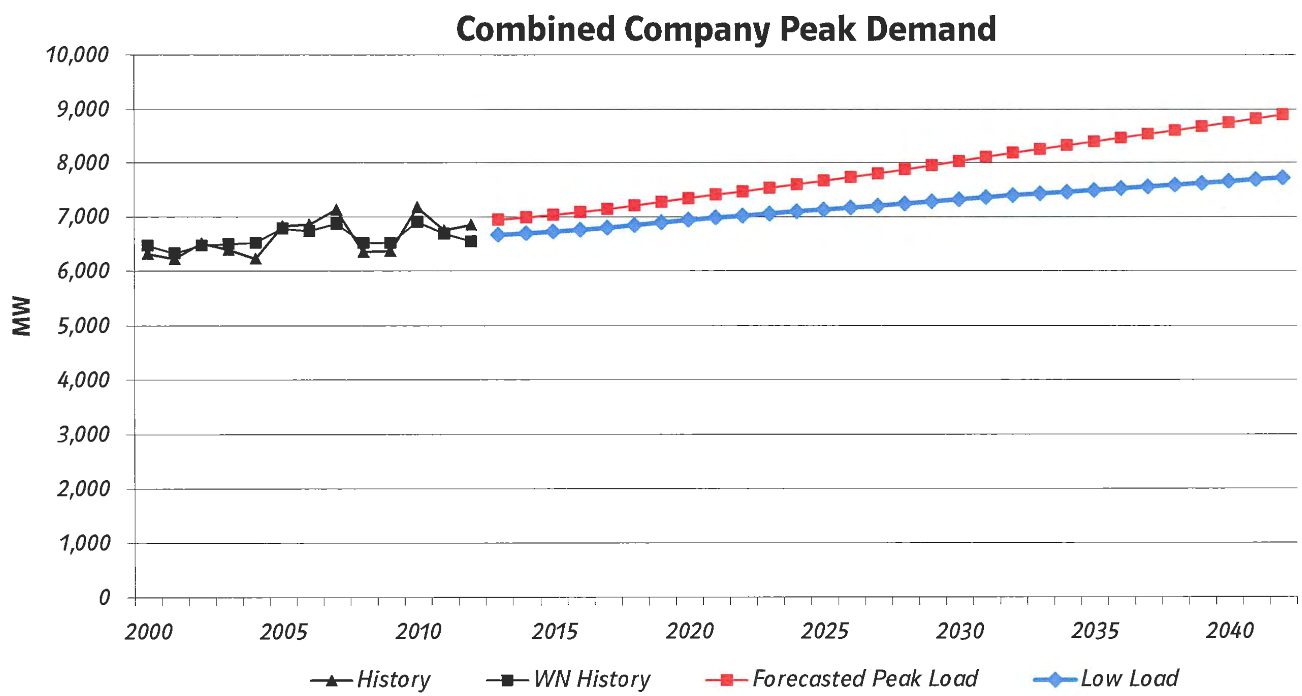
Peak Demands



* Historical peaks not adjusted for curtailments.

2016 capacity = 7,954 MW

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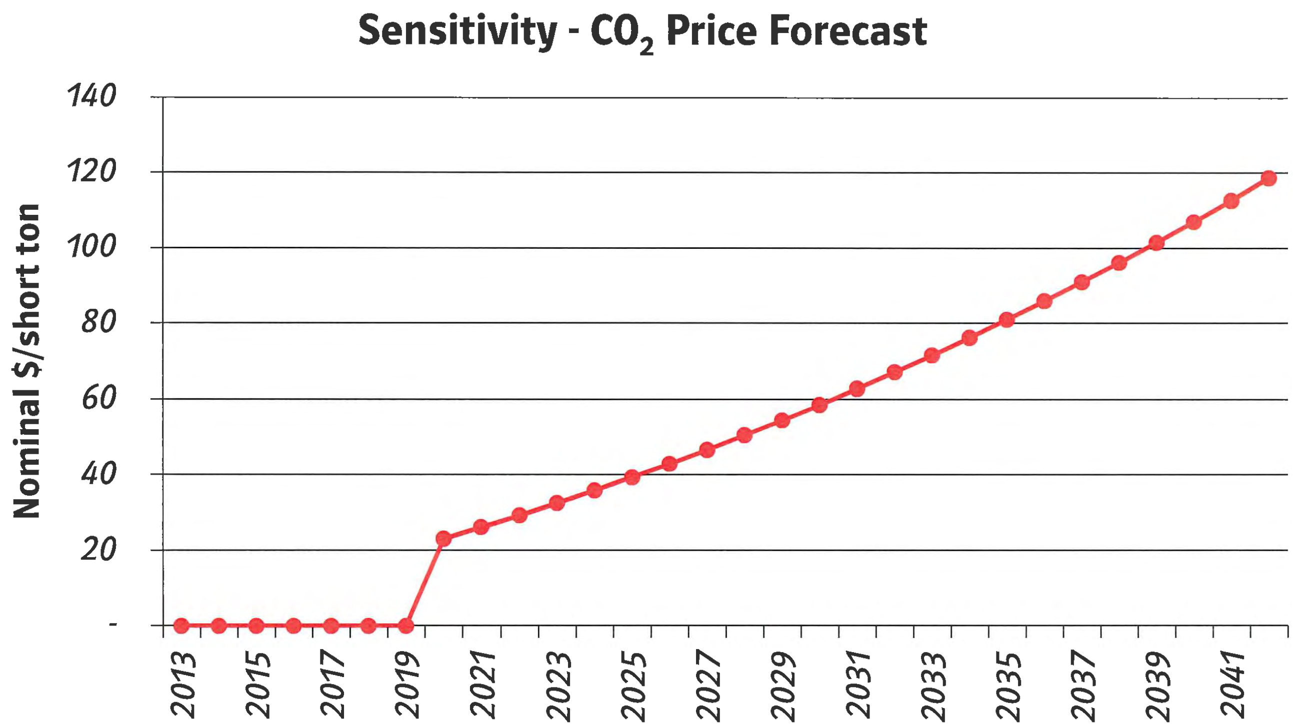
CO_2 price sensitivity starting in 2020



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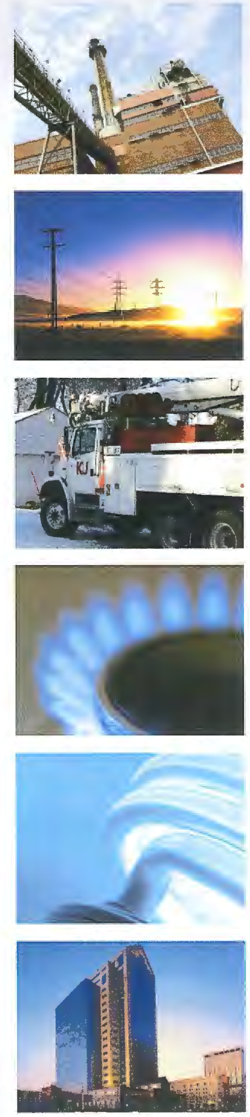
Analysis of Responses to 2012 RFP

Generation Planning & Analysis
December 18, 2012

CONFIDENTIAL



Without Brown 1 and 2, the reserve margin shortfall in 2015 is 336 MW

LG&E/KU Resource Summary – Base Load Forecast (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	7,885
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demand	137	137	137	137	137	137	137
Total Supply	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin (RM)	11.2%	10.3%	9.7%	8.1%	7.4%	6.4%	5.4%
RM Shortfall (16% RM)	336	404	452	567	627	704	783
RM Shortfall (15% RM)	265	333	380	495	554	631	709

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Phase 1 Screening Results

Group	Counterparty	Description	Levelized Cost ($/MWh)
CCCT (1X1)_5	Calpine	5 yr PPA, 250 MW	68
CCCT (1X1)_Own	LGE/KU (4 Proposals)	Self-Build, 299-379 MW	73 – 80
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	60
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	77
CCCT (2X1)_20	Khanjee (2 Proposals)	22 yr PPA, 700 MW	65 – 72
CCCT (2X1)_5	Calpine	5 yr PPA, 500 MW	68
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	59
CCCT (2X1)_Own	LGE/KU (2 Proposals)	Self-Build, 670 MW	70-71
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	71
Coal_10	Nextera	10 yr PPA, 50 MW	57
Coal_10	Big Rivers	1-15 yr PPA, 417 MW	83
Coal_5	Nextera	6 yr PPA, 30 MW	56
Coal_5	AEP	5 yr PPA, Up to 700 MW	81
Coal_5	Big Rivers	1–15 yr PPA, 417 MW	79
Coal_5	Ameren	5 yr PPA, 668 MW	61
Coal_Own	Duke	OVEC, 203 MW	91
Coal_Own	LGE/KU	Brown 1-2 Retrofit, 269 MW	69
DSM	LGE/KU (7 Proposals)	Lighting, T-stat Rebates, Windows & Doors, Mfg Homes, T-stat Pilot, Comm. New Constr., ADR	104+
RTC	KMPA	5 yr PPA, 25 MW	45
RTC	Exelon	10 yr PPA, 200 MW	53
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	133
SCCT_5	LS Power	5 yr PPA, 495 MW	249
SCCT_20	LS Power (2 Proposals)	20 yr PPA, 495 MW	269 – 271
SCCT_Own	LS Power (3 Proposals)	PPA w/ Asset Sale, 495 MW	227 – 239
Solar_Own	Solar Energy Solutions	Asset Sale, 1 – 5 MW	194
Solar_Own	LGE/KU	Self-Build, 10 MW	247
Wind	EDP Renewables (3 Proposals)	15 or 20 yr PPA, 99 – 151 MW	59 – 68

Phase 2 Analysis Methodology

- Iteration 1 focuses separately on alternatives that address the Companies' capacity shortfall in the short-term (5 years or less), medium-term (10 years), and long-term (20+ years).
- Iteration 2 focuses on the following types of alternatives:
  - *'Optimized' short-term PPA*
  - *Short-term PPA + Brown 1-2 retrofit*
  - *'Refined' long-term PPA*
- In iteration 3, proposals for smaller amounts of capacity are iteratively combined with other short-term PPAs to understand the impact of these proposals on production costs.

Phase 2 Results

	Alternative	1st LCR	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	AEP Port 350 - 2 yr, Khanjee ('17)	'21 SCT	22,522	1,082	800	234	86	64	24,788
2	Khanjee Fixed Price PPA	'21 SCT	22,537	1,082	799	234	86	52	24,791
3	Ameren Coal 3 yr 167, BR1-2	'18 2x1	22,982	1,569	53	322	251	-30	25,148
4	LS Power (2020 Sale)	'19 2x1	23,200	1,221	54	501	157	64	25,197
5	LS Power (2018 Sale)	'19 2x1	23,196	1,240	34	501	162	64	25,197
6	LS Power (2014 Sale)	'19 2x1	23,191	1,274	3	516	172	64	25,220
7	LS Power PPA, ERORA 20 yr PPA	'28 2x1	23,050	864	591	505	143	112	25,265
8	Ameren Coal PPA (334) – 5 yr	'17 SCT	23,053	1,536	166	383	143	-7	25,275
9	Ameren Coal PPA (501) – 5 yr	'19 SCT	23,015	1,493	250	366	136	30	25,290
10	Khanjee Tolling PPA	'21 SCT	23,042	1,082	799	234	86	52	25,295
11	AEP Portfolio 350 - 2 yr, ERORA PPA	'21 2x1	22,983	1,146	522	406	132	124	25,312
12	Ameren Coal 334 - 2yr	'17 2x1	23,074	1,631	73	405	146	-7	25,323
13	LS Power 20 yr PPA (2015)	'19 2x1	23,200	1,290	151	481	149	64	25,336
14	Ameren Coal 501 - 4 yr	'19 2x1	23,022	1,572	206	382	138	30	25,350
15	LS Power PPA, ERORA Sale	'28 2x1	23,028	1,372	151	506	188	112	25,356
16	Ameren Coal 501 - 3 yr	'18 2x1	23,039	1,601	159	393	142	30	25,365
17	LS Power PPA, GE 2x1 (2019)	'27 2x1	23,164	1,348	151	470	170	64	25,367
18	Ameren Coal PPA (668)	'20 2x1	22,960	1,543	333	371	135	30	25,372
19	Ameren Coal 668 5 yr	'20 2x1	22,960	1,543	333	371	135	30	25,372
20	LS Power PPA, Siemens 2x1 (2017)	'28 2x1	23,164	1,350	151	489	157	64	25,375
21	AEP Portfolio 350 - 2 yr	'17 2x1	23,090	1,631	82	405	146	21	25,376
22	Ameren Coal 501 - 2 yr	'17 2x1	23,055	1,631	110	405	146	30	25,377
23	LS Power 20 yr PPA (2014)	'19 2x1	23,201	1,311	154	495	153	64	25,379
24	LS Power PPA, ERORA 10 yr PPA	'27 2x1	23,113	1,084	421	505	145	112	25,380
25	LS Power PPA, Siemens 1x1H (2019)	'24 2x1	23,159	1,372	151	469	166	64	25,383
26	Ameren Coal 668 - 4 yr	'19 2x1	22,988	1,572	275	382	138	30	25,384
27	AEP Portfolio 400 - 2 yr	'17 2x1	23,087	1,631	94	405	146	23	25,385
28	LS Power 5 yr PPA (2015)	'19 SCT	23,183	1,493	67	430	152	64	25,389
29	Calpine 250, Exelon	'18 SCT	23,214	1,476	70	386	129	121	25,396
30	LS Power 2 CTs - 2 yr	'17 2x1	23,116	1,631	20	423	151	64	25,405

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Key Takeaways from Phase 2 Analysis

- The Khanjee fixed price PPA is the most competitive option.
- The Brown 1-2 retrofit (paired with a shorter-term PPA) is also competitive if Brown 1-2 operate through 2042.
- The LS Power sale alternatives are more favorable than the LS Power PPA alternatives.
- A short-term Ameren PPA is more competitive than the LS Power PPA proposals.
- The longer-term alternatives are generally more competitive than shorter-term alternatives.

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Several assumptions impact the valuation of the Brown 1-2 retrofit alternative

- In the base gas price scenario, coal becomes relatively less expensive than natural gas over time. Beginning in 2022, dispatch costs for Brown 1 and 2 are expected to be lower than new CCCT generation.
- Brown 1 and 2 operate through the end of the analysis period (2042). In 2013, Brown 1 and 2 will be 55 and 49 years old, respectively. In 2042, Brown 1 and 2 will be 85 and 79 years old, respectively.
- Brown 1 and 2 will require no additional environmental controls through 2042.
- No CO_2 regulations resulting in a cost for CO_2 emissions will be promulgated through 2042.

Changing key assumptions significantly impacts the valuation of Brown 1-2

	NPVRR ($M)
Difference between Best BR1-2 Retrofit Option and Best Short-Term PPA	125
Impact of Ignoring Long-term Production Cost Differences	(110)
Impact of Retiring BR1-2 in 2030	(125)
Impact of Installing SCR on BR1-2	(165)
Net	(275)

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Shortlist of External Respondents

- Initial discussions will be held with the following parties:
  - *AEP*
  - *Ameren*
  - *Big Rivers*
  - *ERORA*
  - *Khanjee*
  - *LS Power*
- Discussions may be held with the following parties (depending on the outcome of discussions with the above-mentioned parties):
  - *Calpine*
  - *Exelon*
  - *Quantum*

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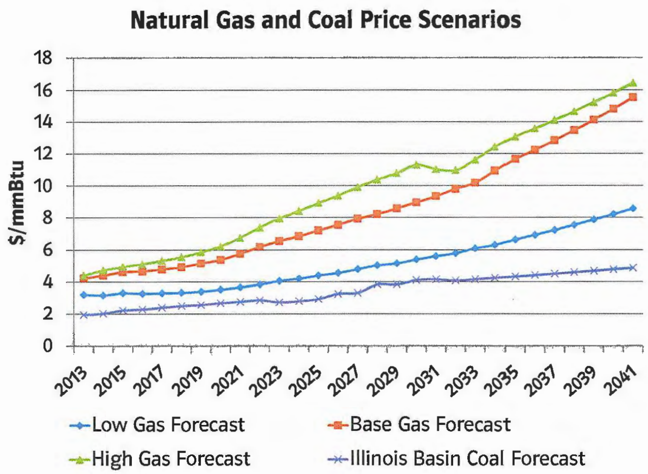
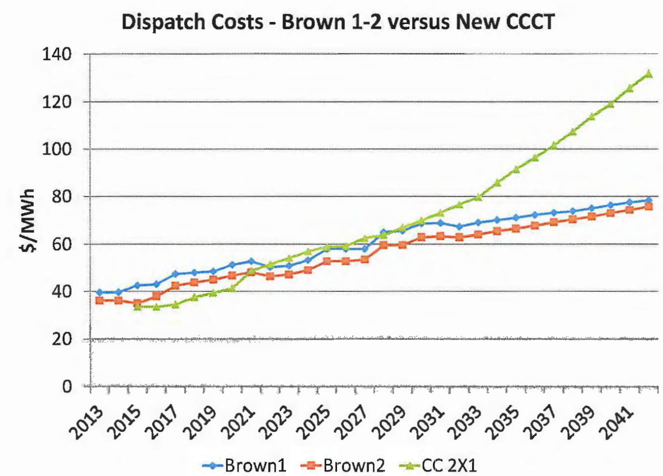
Next Steps

- Meetings with shortlisted respondents begin January 7.
- Open Questions:
  - *Long-term commodity price assumptions significantly impact this analysis. What alternative(s) has the least risk as far as long-term commodity prices are concerned?*
  - *The prospects for plant-wide averaging for MATS compliance at E.W. Brown are not certain. What alternative is most competitive in a scenario with minimal retrofit costs for Brown 1-2?*
  - *What impact do the energy efficiency alternatives have on the analysis?*
  - *What transmission considerations may impact the recommendation?*

Appendix

Coal becomes relatively less expensive than gas over time





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Purchasing the LS Power CTs is less costly than a PPA

- The difference in NPVRR between the top sale alternative and the top PPA alternative is $140 million.
  - *At the end of the PPA, new capacity must be acquired to replace the LS Power CTs. These costs account for $90 million of the $140 million difference.*
  - *The LS Power assets are priced to sell. The NPVRR of the capital costs in the sale alternative is $30 million less than the NPVRR of the capacity charges in the PPA alternative.*
  - *Differences in fixed O&M between the alternatives explain the majority of the remaining $20 million difference.*

5/1/2013

ERORA (Cash Creek Generation)

- 700 MW of 2X1 CCCT, with a guaranteed heat rate of 6,840 Btu/kWh for the first 535 MW and 8,720 Btu/kWh for the next 165 MW (duct firing)
- Guaranteed Annual Availability of 90% and Summer Season Availability of 95%
- Annual start limit – 120 starts
- Units are assumed to be available in June 2017 and will be located in Henderson, KY
- AGC is not available but can be installed at the Companies' expense
- Four options:
    - o 10 year tolling agreement at $5.55/kW-month capacity charge
    - o 20 year tolling agreement at $5.05/kW-month capacity charge
    - o Asset sale for $765 million
    - o Fully permitted 2,050 acre site for $30 million
- Liquidated Damages

  ERORA anticipates that its financial responsibility, respecting the contractual guarantees described below, will be addressed either by the issuance of a guarantee or a letter of credit from a credit-worthy entity.

    - o ERORA will pay liquidated damages to the Companies, equal to $1000/kW, capped at $20 million, for any capacity shortfall
    - o ERORA will be responsible for procurement and delivery of any fuel required in excess of the guaranteed heat rates, capped at $20 million over the term of the tolling agreement
    - o ERORA will pay liquidated damages to the Companies (within 30 days of the end of the applicable annual or summer period), equal to the pro-rata amount of the tolling charge (for that period), for failure to meet either the annual or summer availability guarantee, capped at $ 5 million in a given year
    - o ERORA will pay liquidated damages to the Companies, equal to $100,000/day, capped at $20 million, for a failure to meet the in-service date

5/1/2013

RFP Analysis Update

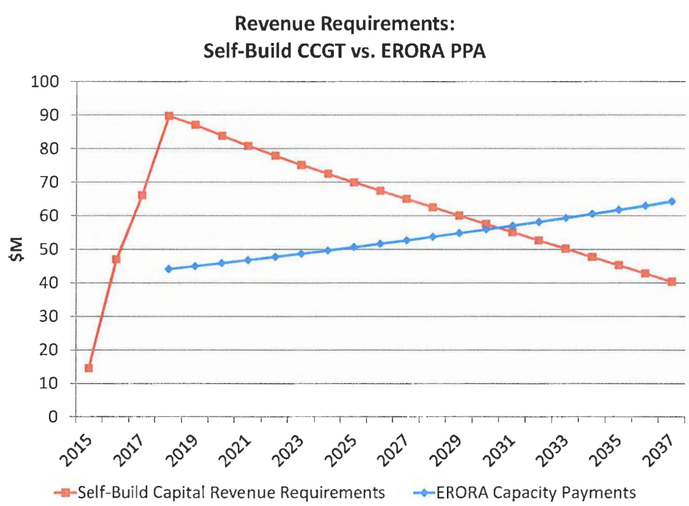
1. When we last met…
   a. CCGT options were favorable in most gas price/load/carbon scenarios.
   b. ERORA PPA and self-build CCGT were among the top CCGT options.

2. Today, this is still the case, but ERORA PPA is more competitive than before.
   a. XM ~~interconnection~~ costs are lower for the Cash Creek site than for either Brown or Green River.
      i. ~$50 million lower than Brown
      ii. ~$80 million lower than Green River
      iii. Note: ERORA unit connected to XM system via single 26-mile radial line.
   b. ERORA lowered its PPA capacity payment from $5.40/kW-month to $5.05/kW-month ($30 million PVRR impact).

3. Before considering XM networking costs and cost of imputed debt associated with PPA, self-build CCGT is more costly than ERORA PPA.

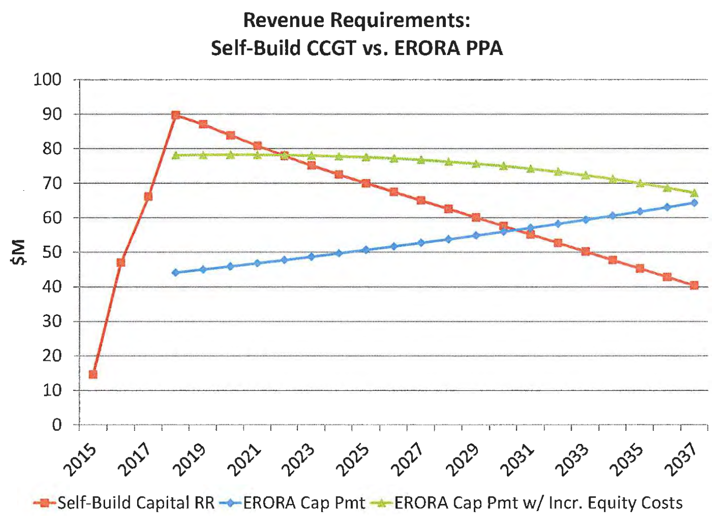
Cost Item	Average PVRR Difference over 12 Gas Price/Load/Carbon Scenarios ($M) (Self-Build CCGT vs. ERORA PPA)*
Firm Gas Transportation	-1
Fixed O&M	20
Production Costs	-102
XM Capital	80
Unit Capital/Capacity Charge	87
Total	85

*Negative values indicate that self-build CCGT is favorable to ERORA PPA.



5/1/2013

4. Cost of imputed debt…
    a. Rating agencies impute debt for utilities' PPAs.
    b. To maintain target capital structure, utilities must increase equity share of capital structure to offset imputed debt.
    c. Incremental cost of equity financing more than offsets favorability of ERORA PPA.



	Average PVRR Difference over 12 Gas Price/Load/Carbon Scenarios ($M) (Self-Build CCGT vs. ERORA PPA)*
w/o Cost of Imputed Debt	85
w/ Cost of Imputed Debt	-121

*Negative values indicate that self-build CCGT is favorable to ERORA PPA.

5. XM networking costs
    a. ERORA proposal includes cost of interconnection (via a single 26-mile radial line) to XM system.
    b. All other units in LG&E/KU system are 'networked' via multiple outlets.
    c. XM group is developing range of costs for networking ERORA unit.

5/1/2013

6. Siting considerations for self-build CCGT (Green River vs. Brown)…
    a. Costs of CCGT and XM are higher at Green River (compared to Brown).
        i. Cost of CCGT is $10 million higher at Green River if BR1-2 continue to operate.
            1. If BR1-2 are retired, cost of CCGT is $30 million higher at Green River.
        ii. Cost of XM is $30 million higher at Green River.
    b. Gas interconnection cost is higher at Green River but firm gas transportation costs are lower.
    c. If company can 'net out' during permitting for new CCGT, we assume new CCGT will not be subject to annual start limit.

7. Comparison of self-build options (PVRR, $M)

Alternative*	Year of 2nd CCGT in Mid Load Case	Mid Gas, Mid Load, Zero Carbon	Average over Six Zero Carbon Scenarios	Average over Six Mid Carbon Scenarios	Average over All Scenarios
1 - BR1-2 (Rt 2017), BR 2x1 (Jan '18), GR 2x1 SL	2021	22,092	19,926	32,969	26,447
2 - BR1-2 (Rt w/ BR 2x1), GR 2x1 (Jan '18), BR 2x1	2025	21,954	19,810	33,187	26,499
3 - BR1-2, BR 2x1 SL (Jan '18), GR 2X1 SL	2025	21,821	19,780	33,246	26,513
4 - BR1-2, GR 2x1 (Jan '18), BR 2x1 SL	2025	21,785	19,743	33,276	26,509
Alternative		**Difference from Best Case**			
1 - BR1-2 (Rt 2017), BR 2x1 (Jan '18), GR 2x1 SL	2021	307	183	0	0
2 - BR1-2 (Rt w/ BR 2x1), GR 2x1 (Jan '18), BR 2x1	2025	169	68	218	52
3 - BR1-2, BR 2x1 SL (Jan '18), GR 2X1 SL	2025	35	37	277	66
4 - BR1-2, GR 2x1 (Jan '18), BR 2x1 SL	2025	0	0	307	62

*Units with 'SL' in unit name are subject to annual 'start limit.'

8. Short-term considerations…
    a. Expect BR1-2 NALCO to be viable option (at least through 2017).
        i. Need to update BR1-2 on-going capital costs for various retirement scenarios.
    b. Based on reserve margin shortfall in 2015-17, not compelled to enter into short-term PPA at this time.

9. Next steps…
    a. Evaluate various amount of duct firing capacity to determine optimal CCGT design.
    b. Further examine potential reliability and XM cost savings associated with building 1x1 CCGTs.
        i. Initial review of 1x1 is costly.

Value varies with Key Uncertainties

Alternative	Gas	BG	BG	BG	BG	HG	HG	HG	HG	LG	LG	LG	LG
	Load	BL	BL	LL	LL	BL	BL	LL	LL	BL	BL	LL	LL
	Carbon	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC
Alternative	*Next CCGT*												
1 - PPA (2015-16) & CCGT (2017)	2021												
2 - Coal PPA (2015-19)	2019												
3 - BR1-2 Baghouse Retrofit	2018												
4 - 2015 Asset Purchase (SCCT)	2019												
5 - BR1-2 Baghouse Retrofit (Retire 2030)	2018												

Gas: Base/Mid (BG), High (HG), Low (LG)   *Load: Base (BL), Low (LL)*   *Carbon: Zero (0C), Mid (MC)*

<-Better/Worse->

- Alt #1 – Prefer CCGT in low-gas and mid-carbon scenarios
- Alt #2 – Short-term PPA viable in most scenarios; prefer coal to SCCT
- Alt #3 – Prefer BR1-2 retrofit in zero carbon and mid-high gas price scenarios
- Alt #4 – Prefer SCCT purchase in zero carbon and mid gas price scenario
- Alt #5 – BR1-2 retrofit not favorable if units don't operate through 2042

PPL companies

Capacity could be needed as early as 2015 but could be as late as 2022

Reserve Margin Over/(Under) 15% (MW)	2015	2016	2017	2018	2019	2020	2021
With Brown 1-2							
Base Load Forecast	7	(64)	(111)	(226)	(285)	(362)	(440)
Low Load Forecast	359	309	282	188	152	100	51
Without Brown 1-2							
Base Load Forecast	(265)	(333)	(380)	(495)	(554)	(631)	(709)
Low Load Forecast	87	40	13	(81)	(117)	(169)	(218)
Incremental DSM above 2012 level (reflected in the data above)	125	157	189	221	203	205	206

LG&E KU

PPL companies

RFP Analysis Update

May 13, 2013

Continued operation of Brown 1-2 defers the short-term need for capacity

Reserve Margin Over/(Under) 15% (MW)	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*
With Brown 1-2							
2013 BP Load Forecast	7	(64)	(111)	(226)	(285)	(362)	(440)

- NALCO injection for Brown 1-2 is a viable MATS compliance alternative.

Self-build CCGT is most competitive long-term option

- Self-Build CCGT (640+ MW) at Green River – Configuration (2x1, etc.) to be determined.
- LS Power (495 MW; SCCT) – PPA with asset purchase option not competitive in mid carbon scenarios.
- Big Rivers (417 MW; Coal) – PPA and asset purchase not competitive under any scenario.
- Khanjee (700 MW, CCGT) – PPA and associated project development evaluated to be too uncertain and risky.
- ERORA Asset Purchase (789 MW; CCGT) – Not competitive compared to self-build options.
- ERORA PPA (700 MW; CCGT)
  - *PPA results in need to increase share of equity financing to offset higher amount of imputed debt on balance sheet.*
  - *Cost of incremental equity financing and XM network costs make PPA not a least-cost option.*

LG&E KU
PPL companies

2018 CCGT at Green River is least-cost long-term option

PVRR ($M)

	Average PVRR over 12 Gas Price/Load/CO2 Price Scenarios*	Difference from Best Alternative
Green River CCGT (2018)	26,469	0
Brown CCGT (2018)	26,472	4
LS Power PPA w/ Asset Purchase (2020)	26,602	133
ERORA PPA (2018)**	26,612	143
Big Rivers Asset Purchase (2015)	26,890	421

*Values exclude production costs prior to 2018.

**ERORA PPA does not include XM networking costs.

LG&E KU

PPL companies

Next Steps

- Finalize analysis of optimal plant size
- Inform short-listed parties that they were not selected
- Develop "Resource Assessment" document

2012 RFP Analysis
Status Report and Next Steps

LG&E KU
PPL companies

Generation Planning & Analysis
November 30, 2012

Table of Contents

1 Summary of RFP Responses

Table 1 summarizes the number of RFP responses and proposals by response type. Several external responses include multiple proposals that refer to the same asset or asset portfolio. Table 2 contains summary statistics for the unique assets referenced in the external RFP responses.

Table 1 – Summary of RFP Responses

Response Type	Number of Responses	Number of Proposals
External	27	61
Self-Build	7	7
Retrofit	4	4
Energy Efficiency	7	7
Total	45	79

Table 2 – Summary Statistics for Assets Referenced in RFP Responses

Category	Number of 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

A detailed summary of all proposals is included in Appendix A – Detailed Summary of RFP Proposals.

2 Phase 1 Screening Analysis

In the Phase 1 Screening analysis, proposals were grouped (broadly) by technology and term. The proposals with the lowest levelized cost per megawatt-hour in each technology/term 'group' were evaluated in the next analysis Phase. These proposals are listed in Table 3.

Table 3 – Lowest Cost Responses from Phase 1 Screening Analysis

Group	Counterparty	Description	Levelized Cost ($/MWh)
CCCT (1X1)_5	Calpine	5 yr PPA, 250 MW	73
CCCT (1X1)_Own	LGE/KU (4 Options)	Self-Build, 299-379 MW	81 – 88
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	65
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	77
CCCT (2X1)_20	Khanjee (2 Options)	22 yr PPA, 700 MW	65 – 81
CCCT (2X1)_5	Calpine	5 yr PPA, 500 MW	72
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	63
CCCT (2X1)_Own	LGE/KU	Self-Build, 670 MW	78
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	79
Coal_10	Nextera	10 yr PPA, 50 MW	57
Coal_10	Big Rivers	1-15 yr PPA, 417 MW	78
Coal_10	AEP	11 yr PPA, Up to 700 MW	60
Coal_5	Nextera	6 yr PPA, 30 MW	56
Coal_5	Big Rivers	1–15 yr PPA, 417 MW	74
Coal_5	Ameren	5 yr PPA, 668 MW	58
Coal_Own	Duke	OVEC, 203 MW	82
Coal_Own	LGE/KU	Brown 1-2 Retrofit, 270 MW	72
DSM	LGE/KU (7 Options)	Lighting, T-stat Rebates, Windows & Doors, Mfg Homes, T-stat Pilot, Comm. New Constr., ADR	82+
RTC	KMPA	5 yr PPA, 25 MW	45
RTC	Exelon	10 yr PPA, 200 MW	53
SCCT_20	LS Power (2 Options)	20 yr PPA, 495 MW	282 – 284
SCCT_Own	LS Power (3 Options)	PPA w/ Asset Sale, 495 MW	249
Solar_Own	Solar Energy Solutions	Asset Sale, 1 – 5 MW	194
Solar_Own	LGE/KU	Self-Build, 10 MW	247
Wind	EDP Renewables (3 Options)	15 or 20 yr PPA, 99 – 151 MW	59 – 68

A complete summary of results from the Phase 1 Screening analysis is included in Appendix B – Phase 1 Screening Analysis Results.

3 LG&E/KU Resource Summary

After the Phase 1 Screening analysis, each alternative is evaluated using Strategist and PROSYM in the context of a generation portfolio that includes Cane Run 7 and the company's existing SCCTs and coal units (Brown 3, Mill Creek, Ghent, and Trimble County). Table 4 summarizes the Companies' capacity needs through 2021.[1]

[1] The capacity of Brown 1-2 is not included in the 'Existing Resources' line.

Table 4 – LG&E/KU Resource Summary (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Peak Reductions[2]	-137	-137	-137	-137	-137	-137	-137
Total Demand	6,903	6,954	7,010	7,077	7,144	7,212	7,281
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Total Supply	7,694	7,685	7,702	7,664	7,683	7,684	7,684
16% Reserve Requirements	8,008	8,067	8,132	8,209	8,287	8,366	8,446
Reserve Margin Shortfall	314	382	430	545	605	682	761
Reserve Margin	11.5%	10.5%	9.9%	8.3%	7.5%	6.5%	5.5%

4 Phase 2, Iteration 1 Alternatives

The responses that passed the Phase 1 Screening analysis were used to develop alternatives for the first iteration of the Phase 2 analysis. These alternatives are listed in Table 5. Each of these alternatives meets the Companies' reserve margin shortfall (see Table 4) through at least 2017. To streamline the evaluation process, this initial iteration focuses separately on alternatives that address the Companies' capacity shortfall in the short-term (5 years or less), medium-term (10 years), and long-term (20+ years). The top options in each of these categories will be evaluated further in subsequent iterations of the Phase 2 analysis.

The Phase 2, Iteration 1 alternatives were developed with the following capacity and timing considerations:

1. The self-build CCCT proposals were paired with the same LS Power proposal so the results for these alternatives would be comparable.
2. The self-build 1X1 CCCT proposals were paired with the same LS Power proposal and were assumed to be commissioned in 2020 to coincide with the first need for additional capacity (in these cases).
3. The self-build 2X1 CCCT proposals were assumed to be commissioned in 2017 so that these alternatives would be comparable to the ERORA proposals.
4. The Brown 1-2 retrofit and Duke's OVEC proposals were paired with the same Calpine proposal so that these alternatives would be comparable.
5. The Brown 1-2 retrofit and 250 MW Calpine proposals were both paired with the same LS Power proposal so that these alternatives would be comparable.

[2] Peak reductions include the impacts of interruptible loads and demand-side management programs.

?

Table 5 – Phase 2, Iteration 1 Alternatives

Term	Alt ID	Description	Delivered MWs
Short-Term	R07A	Ameren 5 yr PPA, Coal (2015)	668
	R04A	Big Rivers 3 yr PPA (2015)	407
	R06A	Calpine 5 yr PPA, 500 MW (2015)	485
	R19F	LS Power 5 yr PPA (2015)	495
	R05D	Quantum 5 yr PPA (2015)	680
Medium-Term	R02_	AEP Portfolio 11 yr PPA (2015)	700
	R04B	Big Rivers 10 yr PPA (2015)	407
	C05_	Calpine 5 yr PPA, 250 MW (2015), Exelon 10 yr PPA (2015)	438
	R19D	LS Power 20 yr PPA (2014)	495
	R19A	LS Power 20 yr PPA (2015)	495
	C08_	LS Power 20 yr PPA (2015), Calpine 5 yr PPA, 250 MW (2015)	738
Long-Term	C06_	Calpine 250 MW (2015), BR1-2 Retrofit	512
	C07_	Calpine 250 MW (2015), Duke (2013)	446
	R11E	Khanjee 22 yr PPA, Fixed Price (2015)	700
	R11F	Khanjee 22 yr PPA, Tolling (2015)	700
	R19E	LS Power (2014 Sale)	495
	R19B	LS Power (2018 Sale)	495
	R19C	LS Power (2020 Sale)	495
	C09A	LS Power 20 yr PPA (2015), BR1-2 Retrofit	764
	C09B	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2025 Retire)	764
	C09C	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2030 Retire)	764
	C10_	LS Power 20 yr PPA (2015), ERORA 10 yr PPA (2017)	1,195
	C11_	LS Power 20 yr PPA (2015), ERORA 20 yr PPA (2017)	1,195
	C17_	LS Power 20 yr PPA (2015), ERORA (2017 Sale)	1,195
	C12_	LS Power 20 yr PPA (2015), GE 1x1 F (2020)	794
	C18_	LS Power 20 yr PPA (2015), GE 2x1 (2017)	1,093
	C14_	LS Power 20 yr PPA (2015), MHI 1x1 (2020)	868
	C13_	LS Power 20 yr PPA (2015), Siemens 1x1 F (2020)	827
	C15_	LS Power 20 yr PPA (2015), Siemens 1x1 H (2020)	874
	C16_	LS Power 20 yr PPA (2015), Siemens 2x1 (2017)	1,165

5 Uncertainty in Natural Gas Prices, Load, and CO2 Regulations

To understand the impact on the analysis associated with the uncertainty in natural gas prices, native load, and potential CO2 regulations, each alternative was evaluated under three natural gas price scenarios, three native load scenarios, and 2 CO2 price scenarios (18 scenarios in all). Charts detailing these price and load scenarios are included in Appendix C – Natural Gas, Load, and CO2 Price Scenarios.

6 Phase 2, Iteration 1 Results

Table 6 contains a complete summary of the Phase 2, Iteration 1 results. Since the Phase 2 analysis will ultimately include several more iterations, these results should be considered preliminary and subject to change. In Table 6, the short-term, medium-term, and long-term alternatives are differentiated by color.

Table 6 – Phase 2, Iteration 1 Results – PRELIMINARY (NPVRR, $M)

Alternative	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
Khanjee Fixed Price PPA	22,301	1,076	799	225	81	218	24,701
LS Power (2018 Sale)	22,965	1,191	34	485	138	124	24,937
LS Power (2020 Sale)	22,968	1,171	54	485	137	124	24,939
Calpine 250, BR1-2	22,785	1,460	70	309	238	86	24,949
LS Power (2014 Sale)	22,962	1,225	3	500	140	124	24,953
LS Power PPA, BR1-2	22,859	1,222	151	396	259	89	24,978
Calpine 250, Duke (2013)	22,607	1,372	546	336	109	117	25,088
LS Power 20 yr PPA (2015)	22,965	1,240	151	466	144	124	25,091
Calpine 250, Exelon	22,959	1,448	70	366	118	166	25,128
LS Power 20 yr PPA (2014)	22,964	1,262	154	480	148	124	25,132
LS Power PPA, Siemens 1x1 H	22,935	1,294	151	466	162	124	25,133
LS Power PPA, BR1-2 (2030 Rt)	22,945	1,322	151	416	225	89	25,148
LS Power PPA, Siemens 1x1 F	22,981	1,268	151	457	167	124	25,149
LS Power PPA, ERORA 20 yr PPA	22,845	843	591	501	142	234	25,155
LS Power PPA, Siemens 2x1	22,915	1,329	151	484	156	124	25,159
LS Power PPA, GE 2x1	22,900	1,342	151	471	173	124	25,161
LS Power PPA, ERORA Sale	22,738	1,351	151	501	186	234	25,161
LS Power 5 yr PPA (2015)	22,922	1,495	54	421	145	124	25,162
AEP Portfolio 11 yr	22,530	1,342	686	301	105	200	25,164
LS Power PPA, Calpine 250	22,942	1,240	222	492	144	147	25,187
Calpine 500, 5 yr	22,880	1,495	140	408	130	141	25,194
Quantum 5 yr	22,864	1,495	149	397	130	160	25,195
Khanjee Tolling PPA	22,796	1,076	799	225	81	218	25,196
LS Power PPA, GE 1x1 F	22,957	1,334	151	461	191	124	25,219
LS Power PPA, BR1-2 (2025 Rt)	22,957	1,387	151	436	207	89	25,227
LS Power PPA, ERORA 10 yr PPA	22,884	1,063	421	500	144	222	25,233
LS Power PPA, MHI 1x1	22,942	1,374	151	474	171	124	25,236
Ameren Coal PPA	22,722	1,495	333	357	130	206	25,243
Big Rivers 3 yr	22,843	1,553	224	379	137	263	25,399
Big Rivers 10 yr	22,767	1,478	394	352	122	308	25,421

2020
2015

Short-Term Alternatives   Medium Term Alternatives   Long-Term Alternatives

The following are key takeaways from the Phase 2, Iteration 1 results:

1. Khanjee's proposal to construct a 2X1 combined-cycle plant in the LG&E/KU service territory and sell power at a fixed price is the least-cost alternative overall. Among the other proposals that include new 2X1 CCCT capacity in 2017, ERORA's 20-year PPA is the least-cost alternative.
2. The Brown 1-2 retrofit is a competitive alternative (and less costly than either Duke's OVEC proposal or the 250 MW Calpine proposal). However, if Brown 1-2 does not operate beyond 2030, the Brown 1-2 retrofit is not among the top options. A comparison of cost assumptions for the Brown 1-2 retrofit between the current analysis and the 2011 ECR filing is contained in Section 6.2.
3. Among the alternatives that include only the LS Power assets, the asset sale proposals are more economic than the PPA proposals. The expansion plans for these proposals include a 2X1 CCCT in 2020. These combinations are superior to the alternatives that pair 1X1 CCCTs with the LS Power CTs.

4. The 5-year PPA from LS Power is the least-cost alternative among the short-term alternatives (and clearly superior to the proposals from Big Rivers).[3] Excluding transmission costs, the Ameren proposal is also competitive.

6.1 Questions/Concerns Regarding Leading Alternatives

While a final list of leading alternatives cannot formally be identified at this time (given the amount of analysis that still has to be completed – see Section 7), it appears at this point that the list would include the following counterparties: LS Power, Ameren, ERORA, and Khanjee. The following questions/concerns exist for these counterparties:

1. LS Power
    a. FERC/market power concerns.
    b. The Companies requested a 5-year PPA from LS Power by November 30, but have not yet received a proposal.
2. Ameren
    a. Based on discussions with Transmission Planning, transmission costs may be significantly different for this alternative.
3. ERORA
    a. Elements of the proposal require further clarification. For example, unlike ERORA's response to the prior RFP, this proposal does not include transmission losses.
4. Khanjee
    a. No site has been formally identified.
    b. Uncertainty regarding credibility and experience developing generation projects.

6.2 Brown 1-2 Retrofit Costs

The differences in Brown 1-2 retrofit costs between the current analysis and the 2011 ECR analysis are summarized in Table 7. The current assumptions for annual capital were taken from the Companies' most recent business plan. The reduction in variable O&M is driven primarily by reductions in the assumed cost to operate the Brown 1-2 baghouse. When the 2011 Air Compliance Plan was developed, the Companies had limited operating experience with the Trimble County 2 baghouse. The updated operating expense estimates are based on almost two years of experience operating the Trimble County 2 baghouse.

Table 7 – Brown 1-2 Retrofit Costs

	2011 Air Compliance Plan	2012 RFP	Delta
Annual Capital (Levelized $M/yr)	6.5	3.5	-3.0
Baghouse/SAMM Capital (Nominal $M)	228	194	-34
Fixed O&M (Levelized $M/yr)	11.7	10.9	-0.9
Variable O&M ($/MWh)	15.34	1.98	-13.4

7 Next Steps

The following 'next steps' will be completed in subsequent Phase 2 iterations:

1. Incorporate into the analysis responses received in the last week.
2. Evaluate energy efficiency and other 'green' options.

[3] Note: The Companies requested a 5-year PPA from LS Power by November 30, but have not yet received a proposal.

3. Meet with HDR to confirm self-build cost assumptions. Ensure that comparisons to other CCCT proposals are 'apples to apples.'
4. Meet with Transmission to further discuss transmission cost assumptions. Transmission will use existing information to develop additional transmission cost estimates for the leading alternatives. Some proposals include transmission flows beyond those contemplated in the preparatory transmission studies.
5. Consider risk/uncertainty more completely.
6. Revisit cost assumptions for LS Power (PPA versus asset sale).
7. Factor reliability costs into 1X1 versus 2X1 combined cycle considerations.
8. Iteratively combine proposals for small amounts of capacity (less than 200 MW) with leading alternatives.
9. Data integrity checking.

8 Appendices

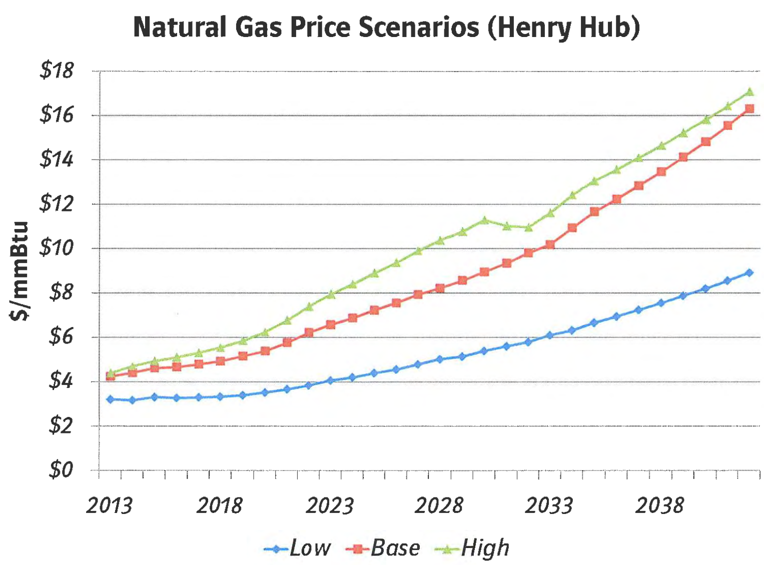
8.1 Appendix A – Detailed Summary of RFP Proposals

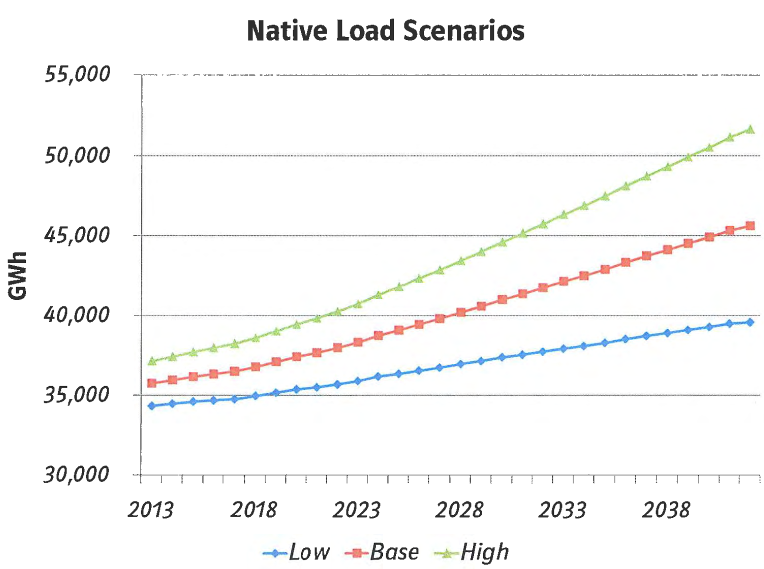
Contract Description									Capital Cost – Per Bid	Fixed Costs (FCs, Expressed as $/MW at TIP) – Per Bid				Additional Costs Incurred by LGE/KU ($2015)				Fuel/Energy Costs – Per Bid			Variable Costs – Per Bid					Additional Costs Incurred by LGE/KU ($2015)				
Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Asset Sale Price ($M)	FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M	Fixed Cost Escalator	Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M and VOM ($/MWh)	Start Cost Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu)	Variable O&M and VOM ($/MWh)	Start Cost Escalator
1A	ERORA	CCCT (2X1)_10	CCCT (2x1), GE	10 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1B	ERORA	CCCT (2X1)_20	CCCT (2x1), GE	20 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1C	ERORA	CCCT (2X1)_Own	CCCT (2x1), GE	Asset Sale, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	765						23,074		2.00%	6,705								0	264	3,019	0.36	2.00%
2	AEP	Coal_10	Portfolio	11 yr PPA, Up to 700 MW	AEP Gen Hub	1/1/2015	700	2015		147,022	0.00%			20,894			2.00%		31.91	0.00%				0.55	2.00%					
3	TPF Generation	SCCT_Own	SCCT	Asset Sale, 5 Units, 245 MW	CONSTELL PTID Node - PJM/AEP	TBD	245	2015	106					20,895	30,009	13,509	2.00%	10,650						0.55	2.00%			320	4.10	2.00%
4A	Big Rivers	Coal_5	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
4B	Big Rivers	Coal_10	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
5A	Quantum Choctaw Power	CCCT (2X1)_20	CCCT (2x1), Siemens	20-35 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		69,000 ($2015)	2.00%			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5B	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	Asset Sale, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	450	12,114 in 2015; 7,513 in 2016 esc at 2%				24,998	15,431		2.00%	7,064								0	883	3,019	0.35	2.00%
5C	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	20-35 yr PPA w/ Asset Sale Option, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	462.5 ($2015)	67,200 in 2015; 12,356 in 2016; 7,663 in 2017 esc at 2%				24,998	15,431		2.00%	7,064						1.00 in 2015; 0.35 at 2%		0	883	3,019		2.00%
5D	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		48,000 ($2015)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5E	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2016	701	2013		60,000 ($2016)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5F	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2014	701	2013		36,000 ($2014)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
6A	Calpine	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, Day-Ahead Call Option, 500 MW	Trinity/Limestone - TVA	1/1/2015	500	2015		74,160	2.30%			24,998	27,418		2.00%	7,400			25,700		1,000	2.00	2.00%					
6B	Calpine	CCCT (1X1)_5	CCCT (1x1), Siemens	5 yr PPA, Day-Ahead Call Option, 250 MW	Trinity/Limestone - TVA	1/1/2015	250	2015		74,160	2.30%			24,998	27,418		2.00%	7,500			12,850		475	2.00	2.00%					
7A	Ameren	Coal_5	Coal	5 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,496	0.00%								31.41	Schedule	7,428			2.61	Schedule					
7B	Ameren	Coal_10	Coal	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,688	Schedule								25.68	Schedule										
7C	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		83,796	Schedule				17,662				43.94	Schedule										
7D	Ameren	Coal_10	Portfolio (Coal and NG)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		131,484	Schedule								25.80	Schedule										
7E	Ameren	Coal_10	Portfolio (Coal to NG Conv.)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		87,936	Schedule				17,662				43.80	Schedule										
7F	Ameren	SCCT_5	SCCT	5 yr PPA, 5 units, 222 MW	EEI/LGE Interface	1/1/2015	222	2015		85,896	0.00%				17,662			13,366			16,900		290	1.40	Schedule					
8	Paducah Power Systems	SCCT_5	SCCT	5 yr PPA, 26 MW	LGEE-PPS1	1/1/2015	26	2015		1,825					27,200			13,090												
9A	Agile	SCCT_Own	NG Fired Recip Engine	Asset Sale, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016	157						23,268	29,800	2.00%	8,793										288	4.2	2.00%
9B	Agile	SCCT_20	NG Fired Recip Engine	20 yr Tolling Agreement, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016		157,000	0.00%	29,800	2.00%		23,268			8,793					288	4.20	2.00%					
10	KMPA	RTC	Coal, Base Load	5 yr PPA, 25 MW (RTC)	AMIL, MISO	1/1/2015	25	2015		34,255	2.00%			36,056					33.61	Schedule										
11A	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Murdock, IL - MISO	1/1/2015	746	2016						36,056	33,279				50.04 in 2017	Schedule										
11B	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279				35.13 in 2017	Schedule	0									
11C	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279			6,800			0			4.24 in 2017	Schedule					
11D	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Kentucky	1/1/2015	746	2016							23,898				44.16 in 2017	Schedule										
11E	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898				30.63 in 2017	Schedule	0									
11F	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898			6,800			0			0.55 in 2017	Schedule					
12	Exelon Generation Company	RTC	Firm Physical Energy	10 yr PPA, 200 MW	Indiana Hub - MISO	1/1/2015	200	2015						36,056					47.78	0.00%										
13	CPV Smyth Generation Co.	CCCT (2X1)_20	CCCT (2X1), Alstom	20 yr PPA, 630 MW	Smyth County, VA - PJM	6/1/2017	630	2017		132,000	0.00%	23,400		20,895	30,941			7,009			18,690		3,808	3.13	2.00%					
14A	Duke	Coal_Own	OVEC	Asset Sale in 2015, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2015	203	2015	100								2.00%		34.87	Schedule										
14B	Duke	Coal_Own	OVEC	Asset Sale in 2013, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2013	203	2013	50								2.00%		34.87	Schedule										
15	Wellhead Energy Systems	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 100 1 MW GridFox Units	LGE/KU System	1/1/2016	100	2013	99						23,898	29,800		10,000										3	4.20	
16A	Power4Georgians	RTC	Supercritical Coal	24 yr PPA, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349					32.40	1.85%				4.73	2.50%					
16B	Power4Georgians	RTC	Supercritical Coal	24 yr Tolling Agreement, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349				9,000						4.73	2.50%					
16C	Power4Georgians	RTC	Supercritical Coal	Asset Sale, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	3,030					56,349		27,673	2.50%	9,000								162,694			1.87	2.00%
17	Solar Energy Solutions	Solar_Own	Solar (PV Array)	Asset Sale, 1-5 MW	LGE/KU System	1/1/2016	1	2015	2.9							10,185	2.00%													
18A	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW	MISO/LGE Interface	1/1/2015	99	2015											50.00	3.00%										
18B	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW	MISO/LGE Interface	1/1/2016	151	2016											50.00	3.00%										
18C	EDP Renewables	Wind	Wind (As Available)	20 yr PPA, 100 MW	LGE/KU System	1/1/2016	100	2016											69.50	0.00%										
19A	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19B	LS Power	SCCT_Own	SCCT	3 yr PPA 1/1/2015, Asset Sale 2018, 495 MW	LGE Buckner Station	1/1/2015	495	2013	115	38,195	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19C	LS Power	SCCT_Own	SCCT	5 yr PPA 1/1/2015, Asset Sale 2020, 495 MW	LGE Buckner Station	1/1/2015	495	2013	105	38,195	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19D	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2014, 495 MW	LGE Buckner Station	1/1/2014	495	2013		12,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19E	LS Power	SCCT_Own	SCCT	5-mon PPA 1/1/2014, Asset Sale 2014, 495 MW	LGE Buckner Station	1/1/2014	495	2014	119	11,662	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19F	LS Power	SCCT_5	SCCT	5 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
20	Sky Global	CCCT (1X1)_10	CCCT (1X1), GE	10-20 yr PPA, 250-300 MW	KU's Pineville/Pocket North LGE	1/1/2016	250	2016		108,000	0.00%	27,000			49,005		2.00%	7,000					500							
21	Wellington	RTC	Waste Coal w/ CFBC	20 yr PPA, 112 MW	PJM West	9/1/2016	112	2012		388,014	Schedule	41,050	2.00%						61.10	Schedule										
22A	Southern Company Services	SCCT_5	SCCT	5 yr PPA, 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		45,000				56,349	25,266			12,850						4.65	0.0%					
22B	Southern Company Services	SCCT_5	SCCT	5 yr PPA (Summer Only), 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		35,000				56,349	25,266			12,850						4.65	0.0%					
22C	Southern Company Services	Coal_10	Coal	15 yr PPA, 109-159 MW	Unit GSU - SOCO	1/1/2016	159	2016		246,000	1.50%			56,349				10,400			14,136				3.5%					
23	Santee Cooper	Coal_10	Coal	7.8 yr PPA, 250 MW	Georgetown, SC	4/1/2017	250	2012		100,080	0.00%			84,038			2.00%		40	2.00%				5.00	0.0%					
24A	Nextera	Coal_5	Coal	6 yr PPA, 30 MW	Into LG&E/KU	1/1/2015	30	2015											55.00	0.96%										
24B	Nextera	Coal_10	Coal	10 yr PPA, 50 MW	Into LG&E/KU	1/1/2015	50	2015											55.00	0.96%										
25	South Point Biomass	RTC	Biomass	20 yr PPA, 165 MW	AEP/Bellefonte/Proctorville PJM	5/1/2015	165	2015						20,895					65.50	Schedule				0.55	2.00%					
26	North American BioFuels	RTC	Landfill Gas	20 yr PPA, 19 MW	WI and PA - MISO and PJM	1/1/2014	19	2013											52.00	3.00%				0.55	2.00%					
27A	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Existing LG&E/KU Site	6/1/2017	770	2012		110,520 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
27B	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Site TBD	6/1/2017	770	2012		118,680 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
28	LGE/KU	CCCT (1X1)_Own	GE CCCT (1X1) - F Class	Self-Build, 298.5 MW	Site TBD	6/1/2017	299	2015	438						21,924		2.00%	6,857								0	175	1,510	0.37	2.00%
29	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - F Class	Self-Build, 332 MW	Site TBD	6/1/2017	332	2015	420						21,924		2.00%	6,880								0	441	1,510	0.35	2.00%
30	LGE/KU	CCCT (1X1)_Own	MHI CCCT (1X1)	Self-Build, 372.7 MW	Site TBD	6/1/2017	373	2015	463						21,924		2.00%	6,813								0	633	1,510	0.34	2.00%
31	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - H Class	Self-Build, 379.4 MW	Site TBD	6/1/2017	379	2015	458						21,924		2.00%	6,613								0	687	1,510	0.33	2.00%
32	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), GE	Self-Build, 598 MW	Site TBD	6/1/2017	598	2015	609						21,924		2.00%	6,848								0	264	3,019	0.36	2.00%
33	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), Siemens	Self-Build, 670.4 MW	Site TBD	6/1/2017	670	2015	617						21,924		2.00%	6,866								0	883	3,019	0.35	2.00%
35	LGE/KU	Solar_Own	Solar (PV Array)	Self-Build, 10 MW	Site TBD	1/1/2016	10	2015	46							10,185	2.00%												0.91	2.00%
36	LGE/KU	Coal_Own	BR1-2 Retrofit	Retrofitted Coal, 270 MW	Brown Station	1/1/2015	269	2015	194									10,500						3.10 in 2016	Schedule			2,443		2.00%
37	LGE/KU	SCCT_Own	SCCT	Trimble CT Retrofit	Trimble County Station	4/1/2015	54	2015	108									10,139												2.00%
38	LGE/KU	CCCT (1X1)_Own	Steam Augmentation	Steam Augmentation for Trimble CTs	Trimble County Station	4/1/2015	1	2015	10									9,969												
39	LGE/KU	Coal_Own	Coal-to-NG Conversion	BR1-2 Coal to NG Conversion	Brown Station	4/1/2016	1	2015	10									10,000												
40A	LGE/KU	DSM	DSM	Lighting	LGE/KU System	1/1/2015	1	2015																						
40B	LGE/KU	DSM	DSM	Thermostat Rebates	LGE/KU System	1/1/2015	1	2015																						
40C	LGE/KU	DSM	DSM	Windows & Doors	LGE/KU System	1/1/2015	1	2015																						
40D	LGE/KU	DSM	DSM	Manufactured Homes	LGE/KU System	1/1/2015	1	2015																						
40E	LGE/KU	DSM	DSM	Behavioral Thermostat Pilot	LGE/KU System	1/1/2015	1	2015																						
40F	LGE/KU	DSM	DSM	Commercial New Construction	LGE/KU System	1/1/2015	1	2015																						
40G	LGE/KU	DSM	DSM	Automated Demand Response	LGE/KU System	1/1/2015	1	2015	22																					

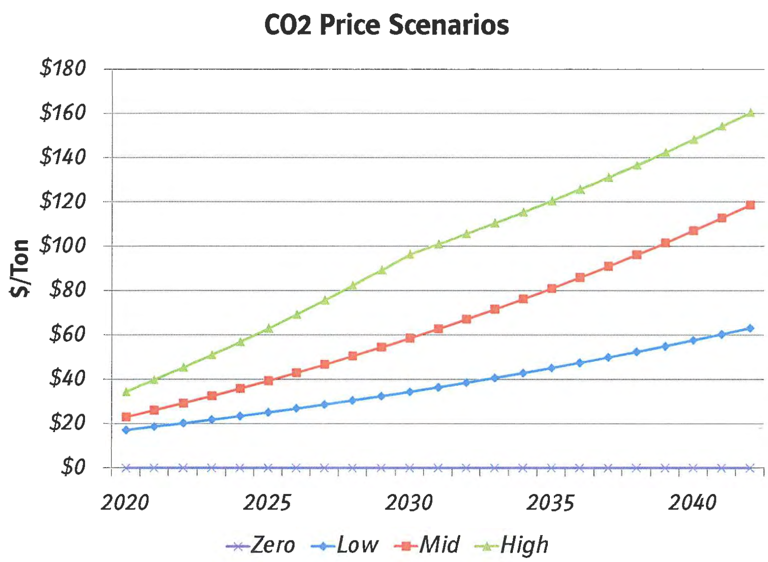
8.2 Appendix B – Phase 1 Screening Analysis Results

Class_Term	Counterparty	Description	Capital ($/kW)	Fixed O&M ($/MW-yr)	Energy Price	Total Costs	Rank
CCCT (1X1)_10	Sky Global	10-20 yr PPA, 250-300 MW	0	184,005	0	81	1
CCCT (1X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 250 MW	0	126,576	0	73	1
CCCT (1X1)_Own	LGE/KU	Steam Augmentation for Trimble CTs	1,059	0	0	275	5
CCCT (1X1)_Own	LGE/KU	Self-Build, 298.5 MW	1,468	21,924	0	88	4
CCCT (1X1)_Own	LGE/KU	Self-Build, 332 MW	1,264	21,924	0	84	3
CCCT (1X1)_Own	LGE/KU	Self-Build, 372.7 MW	1,242	21,924	0	84	2
CCCT (1X1)_Own	LGE/KU	Self-Build, 379.4 MW	1,206	21,924	0	81	1
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	0	94,389	0	65	1
CCCT (2X1)_20	CPV Smyth Generation Co.	20 yr PPA, 630 MW	0	207,236	0	100	9
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	0	94,389	0	77	2
CCCT (2X1)_20	Quantum Choctaw Power	20-35 yr PPA, 701 MW	0	106,750	0	86	5
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	82	4
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	98	8
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	65	1
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	81	3
CCCT (2X1)_20	Southern Power Company	20 yr PPA, 770 MW	0	122,026	0	89	6
CCCT (2X1)_20	Southern Power Company	20 yr PPA, 770 MW	0	129,416	0	91	7
CCCT (2X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 500 MW	0	126,576	0	72	4
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	63	2
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	65	3
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	0	40,429	0	63	1
CCCT (2X1)_Own	LGE/KU	Self-Build, 598 MW	1,018	21,924	0	79	3
CCCT (2X1)_Own	LGE/KU	Self-Build, 670.4 MW	921	21,924	0	78	1
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	1,093	23,074	0	79	2
CCCT (2X1)_Own	Quantum Choctaw Power	Asset Sale, 701 MW	642	40,429	0	82	4
CCCT (2X1)_Own	Quantum Choctaw Power	20-35 yr PPA w/ Asset Purchase Option, 701 MW	629	40,429	0	83	5
Coal_10	Nextera	10 yr PPA, 50 MW	0	0	55	57	3
Coal_10	Southern Company Services	15 yr PPA, 109-159 MW	0	302,349	0	105	9
Coal_10	Santee Cooper	7.8 yr PPA, 250 MW	0	184,118	40	82	8
Coal_10	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	78	7
Coal_10	Ameren	10 yr PPA, 668 MW	0	0	0	51	2
Coal_10	Ameren	10 yr PPA, 668 MW	0	17,662	0	67	5
Coal_10	AEP	11 yr PPA, Up to 700 MW	0	167,916	32	60	4
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	0	0	49	1
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	17,662	0	67	6
Coal_5	Nextera	6 yr PPA, 30 MW	0	0	55	56	1
Coal_5	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	74	3
Coal_5	Ameren	5 yr PPA, 668 MW	0	137,496	0	58	2
Coal_Own	LGE/KU	BR1-2 Coal to NG Conversion	10,000	0	0	120	4
Coal_Own	Duke	Asset Sale in 2015, 203 MW of OVEC	493	0	0	84	3
Coal_Own	Duke	Asset Sale in 2013, 203 MW of OVEC	246	0	0	82	2
Coal_Own	LGE/KU	Retrofitted Coal, 270 MW	721	0	0	71	1
DSM	LGE/KU	Lighting	0	0	0	202	2
DSM	LGE/KU	Thermostat Rebates	0	0	0	223	3
DSM	LGE/KU	Windows & Doors	0	0	0	637	5
DSM	LGE/KU	Manufactured Homes	0	0	0	1,043	6
DSM	LGE/KU	Behavioral Thermostat Pilot	0	0	0	252	4
DSM	LGE/KU	Commercial New Construction	0	0	0	82	1
DSM	LGE/KU	Automated Demand Response	21,899	0	0	26,253	7
RTC_20	North American BioFuels	20 yr PPA, 19 MW	0	0	52	69	4
RTC_5	KMPA	5 yr PPA, 25 MW (RTC)	0	70,311	0	45	1
RTC_20	Wellington	20 yr PPA, 112 MW	0	41,050	0	144	10
RTC_20	South Point Biomass	20 yr PPA, 165 MW	0	20,895	0	86	6
RTC_10	Exelon	10 yr PPA, 200 MW	0	36,056	48	53	2
RTC_22	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	69,335	0	70	5
RTC_22	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	23,898	0	57	3
RTC_24	Power4Georgians	24 yr PPA, 850 MW	0	444,005	32	102	8
RTC_24	Power4Georgians	24 yr Tolling Agreement, 850 MW	0	444,005	0	102	9
RTC_60	Power4Georgians	Asset Sale, 850 MW	3,565	84,022	0	88	7
SCCT_20	Agile	20 yr Tolling Agreement, 12 units, 112.9 MW	0	210,068	0	560	3
SCCT_20	LS Power	20 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	284	2
SCCT_20	LS Power	20 yr PPA starting 1/1/2014, 495 MW	0	42,524	0	282	1
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	0	29,025	0	140	1
SCCT_5	Southern Company Services	5 yr PPA, 75-675 MW	0	126,615	0	388	5
SCCT_5	Southern Company Services	5 yr PPA (Summer Only), 75-675 MW	0	116,615	0	363	4
SCCT_5	Ameren	5 yr PPA, 5 units, 222 MW	0	103,558	0	323	3
SCCT_5	LS Power	5 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	238	2
SCCT_Own	LGE/KU	Trimble CT Retrofit	2,000	0	0	433	6
SCCT_Own	Wellhead Energy Systems	Asset Sale, 100 1 MW GridFox Units	988	53,698	0	398	5
SCCT_Own	Agile	Asset Sale, 12 units, 112.9 MW	1,386	53,068	0	469	7
SCCT_Own	TPF Generation	Asset Sale, 5 Units, 245 MW	434	64,413	0	329	4
SCCT_Own	LS Power	3 yr PPA 1/2015, Asset Sale in 2017, 495 MW	232	34,724	0	249	2
SCCT_Own	LS Power	5 yr PPA 1/2015, Asset Sale in 2019, 495 MW	212	34,724	0	252	3
SCCT_Own	LS Power	5-mon PPA 1/2014, Asset Sale in 2014, 495 MW	240	34,724	0	240	1
Solar_Own	Solar Energy Solutions	Asset Sale, 1-5 MW	2,932	10,185	0	194	1
Solar_Own	LGE/KU	Self-Build, 10 MW	4,633	10,185	0	247	2
Wind_15	EDP Renewables	15 or 20 yr PPA, 99 MW	0	0	50	60	2
Wind_20	EDP Renewables	20 yr PPA, 100 MW	0	0	70	68	3
Wind_15	EDP Renewables	15 yr PPA, 151.2 MW	0	0	50	59	1

8.3 Appendix C – Natural Gas, Load, and CO2 Price Scenarios







Note: The Phase 2, Iteration 1 analysis considered the Zero and Mid CO2 price scenarios only.

2012 RFP Analysis
Status Report and Next Steps

PPL companies

Generation Planning & Analysis
December 7, 2012

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1 Summary of RFP Responses

Table 1 summarizes the number of RFP responses and proposals by response type. Several external responses include multiple proposals that refer to the same asset or asset portfolio. Table 2 contains summary statistics for the unique assets referenced in the external RFP responses.

Table 1 – Summary of RFP Responses

Response Type	Number of Responses	Number of Proposals
External	29	68
Self-Build	8	8
Retrofit	4	4
Energy Efficiency	7	7
Total	48	87

Table 2 – Summary Statistics for Assets Referenced in External RFP Responses

Category	Number of Assets	MWs
Total	35	11,853
Coal	9	2,734
Gas	17	7,669
Renewable[1]	7	550
Portfolio	2	900
New	14	4,686
Existing	21	7,166
In-State	13	3,757
Out-of-State	22	8,095

A detailed summary of all proposals is included in Appendix A – Detailed Summary of RFP Proposals.

2 Phase 1 Screening Analysis

In the Phase 1 Screening analysis, proposals were grouped (broadly) by technology and term. The proposals with the lowest levelized cost per megawatt-hour in each technology/term 'group' were evaluated in the next analysis Phase. These proposals are listed in Table 3.

[1] MW total for renewable assets is not considered firm capacity.

Table 3 – Lowest Cost Responses from Phase 1 Screening Analysis

Group	Counterparty	Description	Levelized Cost ($/MWh)
CCCT (1X1)_5	Calpine	5 yr PPA, 250 MW	73
CCCT (1X1)_Own	LGE/KU (4 Proposals)	Self-Build, 299-379 MW	81 – 88
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	65
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	77
CCCT (2X1)_20	Khanjee (2 Proposals)	22 yr PPA, 700 MW	65 – 81
CCCT (2X1)_5	Calpine	5 yr PPA, 500 MW	72
CCCT (2X1)_5	Quantum Choctaw Power	5 yr PPA, 701 MW	63
CCCT (2X1)_Own	LGE/KU (2 Proposals)	Self-Build, 670 MW	78
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	79
Coal_10	Nextera	10 yr PPA, 50 MW	57
Coal_10	Big Rivers	1-15 yr PPA, 417 MW	78
Coal_10	AEP	11 yr PPA, Up to 700 MW	60
Coal_5	Nextera	6 yr PPA, 30 MW	57
Coal_5	Big Rivers	1–15 yr PPA, 417 MW	78
Coal_5	Ameren	5 yr PPA, 668 MW	60
Coal_Own	Duke	OVEC, 203 MW	82
Coal_Own	LGE/KU	Brown 1-2 Retrofit, 269 MW	71
DSM	LGE/KU (7 Proposals)	Lighting, T-stat Rebates, Windows & Doors, Mfg Homes, T-stat Pilot, Comm. New Constr., ADR	104+
RTC	KMPA	5 yr PPA, 25 MW	45
RTC	Exelon	10 yr PPA, 200 MW	53
SCCT_5	Paducah Power Systems	5 yr PPA, 26 MW	140
SCCT_5	LS Power	5 yr PPA, 495 MW	238
SCCT_20	LS Power (2 Proposals)	20 yr PPA, 495 MW	282 – 284
SCCT_Own	LS Power (3 Proposals)	PPA w/ Asset Sale, 495 MW	240 – 252
Solar_Own	Solar Energy Solutions	Asset Sale, 1 – 5 MW	194
Solar_Own	LGE/KU	Self-Build, 10 MW	247
Wind	EDP Renewables (3 Proposals)	15 or 20 yr PPA, 99 – 151 MW	59 – 68

A complete summary of results from the Phase 1 Screening analysis is included in Appendix B – Phase 1 Screening Analysis Results.

3 LG&E/KU Resource Summary

After the Phase 1 Screening analysis, each alternative is evaluated using Strategist and PROSYM in the context of a generation portfolio that includes Cane Run 7 and the company's existing SCCTs and coal units (Brown 3, Mill Creek, Ghent, and Trimble County). Table 4 summarizes the Companies' capacity needs through 2021.[2]

Table 4 – LG&E/KU Resource Summary (MW)

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,260	7,241	7,276	7,339	7,431	7,532	7,556
Energy Efficiency/DSM	-220	-150	-129	-125	-149	-182	-138
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demand	137	137	137	137	137	137	137
Total Supply	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin (RM)	11.2%	10.3%	9.7%	8.1%	7.4%	6.4%	5.4%
RM Shortfall (16% RM)	336	404	452	567	627	704	783
RM Shortfall (15% RM)	265	333	380	495	554	631	709
RM Shortfall (14% RM)	195	262	309	423	481	557	635

4 Long-Term Capacity Resources

Strategist is used to develop resource expansion plans for meeting the company's forecasted energy requirements. Alternatives with greater capacity may have higher initial costs but they will defer the need (and associated costs) for long-term capacity resources (LCRs). The following resources are included as LCRs in Strategist:

1. SCCT (Siemens F Class)
2. 2X1 CCCT (Siemens F Class)
3. 1X1 CCCT (Siemens H Class)

5 Phase 2, Iteration 1 Alternatives

The responses that passed the Phase 1 Screening analysis were used to develop alternatives for the first iteration of the Phase 2 analysis. These alternatives are listed in Table 5. Each of these alternatives meets the Companies' reserve margin shortfall (see Table 4) through at least 2017. To streamline the evaluation process, this initial iteration focuses separately on alternatives that address the Companies' capacity shortfall in the short-term (5 years or less), medium-term (10 years), and long-term (20+ years). The top options in each of these categories will be evaluated further in subsequent iterations of the Phase 2 analysis.

The Phase 2, Iteration 1 alternatives were developed with the following capacity and timing considerations:

1. The self-build CCCT proposals were paired with the same 20-year LS Power PPA proposal so the results for these alternatives would be comparable.

[2] The capacity of Brown 1-2 is not included in the 'Existing Resources' line.

2. The self-build 1X1 CCCT proposals (which were paired with the same LS Power proposal) were assumed to be commissioned in 2020 to coincide with the first need for additional capacity (in these cases).
3. The self-build 2X1 CCCT proposals were assumed to be commissioned in 2017 so that these alternatives would be comparable to the ERORA proposals. The GE self-build 2X1 CCCT was also assumed to be commissioned in 2020 so that this alternative would be comparable to the self-build 1X1 CCCT proposals and any of the 20-year LS Power PPA proposals that include a Siemens 2X1 CCCT as the first LCR in their expansion plans.
4. The Brown 1-2 retrofit and Duke's OVEC proposals were paired with the same Calpine proposal so that these alternatives would be comparable.
5. The Brown 1-2 retrofit and 250 MW Calpine proposals were both paired with the same LS Power proposal so that these alternatives would be comparable.

Table 5 – Phase 2, Iteration 1 Alternatives

Term	Alt ID	Description	Delivered MWs
Short-Term	R04A	Big Rivers 5 yr PPA (2015)	407
	R05D	Quantum 5 yr PPA (2015)	680
	R06A	Calpine 5 yr PPA, 500 MW (2015)	485
	R07A	Ameren 5 yr PPA, 668 MW (Coal, 2015)	668
	R07G	Ameren 5 yr PPA, 334 MW (Coal, 2015)	334
	R07J	Ameren 5 yr PPA, 501 MW (Coal, 2015)	501
	R19F	LS Power 5 yr PPA (495 MW, 2015)	495
	R19G	LS Power 5 yr PPA (330 MW, 2015)	330
Medium-Term	C05_	Calpine 5 yr PPA, 250 MW (2015), Exelon 10 yr PPA (2015)	438
	R02A	AEP Portfolio 11 yr PPA (2015)	700
	R02B	AEP Portfolio 11 yr PPA (2015)	350
	R02C	AEP Portfolio 11 yr PPA (2015)	500
	R04B	Big Rivers 10 yr PPA (2015)	407
Long-Term	C06_	Calpine 250 MW (2015), BR1-2 Retrofit	512
	C07A	Calpine 250 MW (2015), Duke (2015)	446
	C07B	Calpine 250 MW (2015), Duke (2015 Sale, 2030 Retire)	446
	C08_	LS Power 20 yr PPA (2015), Calpine 5 yr PPA, 250 MW (2015)	738
	C09A	LS Power 20 yr PPA (2015), BR1-2 Retrofit	764
	C09B	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2025 Retire)	764
	C09C	LS Power 20 yr PPA (2015), BR1-2 Retrofit (2030 Retire)	764
	C09D	LS Power 20 yr PPA (2015), BR1-2 Retrofit w/ SCR	764
	C10_	LS Power 20 yr PPA (2015), ERORA 10 yr PPA (2017)	1,195
	C11_	LS Power 20 yr PPA (2015), ERORA 20 yr PPA (2017)	1,195
	C12_	LS Power 20 yr PPA (2015), GE 1x1 F (2019)	794
	C13_	LS Power 20 yr PPA (2015), Siemens 1x1 F (2019)	827
	C14_	LS Power 20 yr PPA (2015), MHI 1x1 (2019)	868
	C15_	LS Power 20 yr PPA (2015), Siemens 1x1 H (2019)	874
	C16_	LS Power 20 yr PPA (2015), Siemens 2x1 (2017)	1,165
	C17_	LS Power 20 yr PPA (2015), ERORA (2017 Sale)	1,195
	C18A	LS Power 20 yr PPA (2015), GE 2x1 (2017)	1,093
	C18B	LS Power 20 yr PPA (2015), GE 2x1 (2019)	1,093
	C19A	LS Power 5 yr PPA (495 MW, 2015), BR1-2	764
	C19B	LS Power 5 yr PPA (330 MW, 2015), BR1-2	599
	R11E	Khanjee 22 yr PPA, Fixed Price (2015)	700
	R11F	Khanjee 22 yr PPA, Tolling (2015)	700
	R19A	LS Power 20 yr PPA (2015)	495
	R19B	LS Power (2018 Sale)	495
	R19C	LS Power (2020 Sale)	495
	R19D	LS Power 20 yr PPA (2014)	495
	R19E	LS Power (2014 Sale)	495

6 Uncertainty in Natural Gas Prices, Load, and CO2 Regulations

To understand the impact on the analysis associated with the uncertainty in natural gas prices, native load, and potential CO2 regulations, each alternative was evaluated under three natural gas price scenarios, three native load scenarios, and 2 CO2 price scenarios (18 scenarios in all). Charts detailing these price and load scenarios are included in Appendix C – Natural Gas, Load, and CO2 Price Scenarios.

7 Phase 2, Iteration 1 Results - PRELIMINARY

Table 6 contains a complete summary of the Phase 2, Iteration 1 results. Since the Phase 2 analysis will ultimately include several more iterations, these results should be considered preliminary and subject to change. In Table 6, the short-term, medium-term, and long-term alternatives are differentiated by color.

Table 6 – Phase 2, Iteration 1 Results (NPVRR, $M, Base Case Assumptions, No Purchases) – PRELIMINARY[3]

	Alternative	Production Cost	Capital	Capacity Charge	Firm Gas Transport	Fixed O&M	Trans	Grand Total
1	Khanjee Fixed Price PPA	22,544	1,021	799	217	75	218	24,875
2	LS Power 5 yr PPA - 2 CTs, BR1-2	23,050	1,451	44	327	248	89	25,210
3	Calpine 250, BR1-2	23,012	1,480	70	320	242	86	25,210
4	LS Power PPA, BR1-2	23,111	1,214	151	396	259	89	25,220
5	LS Power (2020 Sale)	23,202	1,200	54	496	156	124	25,232
6	LS Power (2018 Sale)	23,199	1,219	34	496	161	124	25,232
7	LS Power (2014 Sale)	23,194	1,253	3	510	171	124	25,255
8	LS Power 5 yr PPA (2015), BR1-2	23,050	1,451	67	348	254	89	25,258
9	AEP Portfolio 11 yr (700)	22,790	1,264	686	287	97	200	25,324
10	LS Power PPA, GE 2x1 (2019)	23,175	1,283	151	452	164	124	25,349
11	LS Power PPA, ERORA 20 yr PPA	23,050	843	591	501	142	234	25,361
12	LS Power 5 yr PPA (2015)	23,191	1,432	67	413	141	124	25,368
13	LS Power 5 yr PPA (2015) - 2CTs	23,172	1,475	44	410	144	124	25,369
14	LS Power PPA (2015)	23,201	1,269	151	477	148	124	25,370
15	LS Power PPA, Siemens 1x1H (2019)	23,171	1,315	151	454	155	124	25,370
16	Calpine 250, Duke (2015)	22,857	1,443	70	347	540	117	25,376
17	AEP Portfolio 11 yr (350)	22,923	1,484	343	355	124	147	25,376
18	Khanjee Tolling PPA	23,050	1,021	799	217	75	218	25,380
19	Calpine 500, 5 yr	23,143	1,432	140	400	125	141	25,381
20	LS Power PPA, Siemens 1x1F (2019)	23,212	1,287	151	447	162	124	25,384
21	LS Power PPA, BR1-2 (2030 Rt)	23,190	1,313	151	416	225	89	25,384
22	Ameren Coal PPA (501)	23,023	1,432	250	349	125	206	25,385
23	AEP Portfolio 11 yr (500)	22,856	1,424	490	332	116	170	25,387
24	LS Power PPA, GE 2x1 (2017)	23,137	1,342	151	471	173	124	25,398
25	Calpine 250, Exelon	23,220	1,439	70	378	126	166	25,400
26	Ameren Coal PPA (334)	23,061	1,475	166	367	132	206	25,407
27	LS Power PPA, Siemens 2x1 (2017)	23,165	1,329	151	484	156	124	25,409
28	LS Power PPA (2014)	23,202	1,290	154	491	152	124	25,412
29	LS Power PPA, BR1-2 (SCR)	23,114	1,377	151	402	284	89	25,417
30	LS Power PPA, Calpine 250	23,191	1,240	222	492	144	147	25,436
31	LS Power PPA, ERORA Sale	23,028	1,351	151	501	186	234	25,451
32	LS Power PPA, GE 1x1 F (2019)	23,193	1,355	151	452	183	124	25,458
33	LS Power PPA, ERORA 10 yr PPA	23,114	1,063	421	500	144	222	25,463
34	LS Power PPA, BR1-2 (2025 Rt)	23,202	1,378	151	436	207	89	25,464
35	LS Power PPA, MHI 1x1 (2019)	23,177	1,395	151	462	164	124	25,473
36	Quantum 5 yr	23,111	1,522	149	407	133	160	25,482
37	Big Rivers 5 yr	23,109	1,439	224	352	127	263	25,514
38	Ameren Coal PPA (668)	22,961	1,522	333	366	133	206	25,522
39	Calpine 250, Duke (2015, 2030 Rt)	22,996	1,554	70	371	439	117	25,547
40	Big Rivers 10 yr	23,014	1,478	394	352	122	308	25,668

Short-Term Alternatives   Medium Term Alternatives   Long-Term Alternatives

The following are key takeaways from the Phase 2, Iteration 1 results:

[3] References to LS Power PPA (with no additional qualifiers) pertain to the 20-year PPA beginning in 2015.

1. Khanjee's proposal to construct a 2X1 combined-cycle plant in the LG&E/KU service territory and sell power at a fixed price is the least-cost alternative overall. Among the other proposals that include new 2X1 CCCT capacity in 2017, ERORA's 20-year PPA is the least-cost alternative.
2. The Brown 1-2 retrofit is a competitive alternative (and less costly than either Duke's OVEC proposal or the 250 MW Calpine proposal). However, if Brown 1-2 does not operate beyond 2030, the Brown 1-2 retrofit is not among the top options. A comparison of cost assumptions for the Brown 1-2 retrofit between the current analysis and the 2011 ECR filing is contained in Section 7.2.
3. Among the alternatives that include only the LS Power assets, the asset sale proposals are more economic than the PPA proposals. The expansion plans for these proposals include a 2X1 CCCT in 2019. These combinations are superior to the alternatives that pair 1X1 CCCTs with the LS Power CTs.
4. The 5-year PPA from LS Power is the least-cost alternative among the short-term alternatives (and clearly superior to the proposals from Big Rivers).[4] Excluding transmission costs, the Ameren proposal is also competitive.

7.1 Questions/Concerns Regarding Leading Alternatives

While a final list of leading alternatives cannot formally be identified at this time (given the amount of analysis that still has to be completed – see Section 8), it appears at this point that the list would include the following counterparties: LS Power, Ameren, ERORA, AEP, Quantum, Calpine, Exelon, and Khanjee. The following is a list of questions/concerns:

1. LS Power
   a. FERC/market power concerns.
2. Ameren
   a. Based on discussions with Transmission Planning, transmission costs may be significantly different for this alternative.
3. ERORA
   a. Elements of the proposal require further clarification. For example, unlike ERORA's response to the prior RFP, this proposal does not include transmission losses.
4. Khanjee
   a. No site has been formally identified.
   b. Uncertainty regarding whether LG&E/KU would be responsible for firm gas transportation costs.
   c. Uncertainty regarding credibility and experience developing generation projects.

7.2 Brown 1-2 Retrofit Costs

The differences in Brown 1-2 retrofit costs between the current analysis and the 2011 ECR analysis are summarized in Table 7. The current assumptions for annual capital were taken from the Companies' most recent business plan. The reduction in variable O&M is driven primarily by reductions in the assumed cost to operate the Brown 1-2 baghouse. When the 2011 Air Compliance Plan was developed, the Companies had limited operating experience with the Trimble County 2 baghouse. The updated operating expense estimates are based on almost two years of experience operating the Trimble County 2 baghouse.

[4] Note: The Companies requested a 5-year PPA from LS Power by November 30, but have not yet received a proposal.

Table 7 – Brown 1-2 Retrofit Costs

	2011 Air Compliance Plan	2012 RFP	Delta
Annual Capital (Levelized $M/yr)	6.5	3.5	-3.0
Baghouse/SAMM Capital (Nominal $M)	228	194	-34
Fixed O&M (Levelized $M/yr)	11.7	10.9	-0.9
Variable O&M ($/MWh)	15.34	1.98	-13.4

8 Next Steps

The following 'next steps' will be completed in subsequent Phase 2 iterations:

1. Incorporate into the analysis responses received in the last week.
2. Evaluate energy efficiency and other 'green' options.
3. Meet with HDR to confirm self-build cost assumptions. Ensure that comparisons to other CCCT proposals are 'apples to apples.'
4. Meet with Transmission to further discuss transmission cost assumptions. Transmission will use existing information to develop additional transmission cost estimates for the leading alternatives. Some proposals include transmission flows beyond those contemplated in the preparatory transmission studies.
5. Consider risk/uncertainty more completely.
6. Revisit cost assumptions for LS Power (PPA versus asset sale).
7. Factor reliability costs into 1X1 versus 2X1 combined cycle considerations.
8. Iteratively combine proposals for small amounts of capacity (less than 200 MW) with leading alternatives.
9. Data integrity checking.

9 Appendices

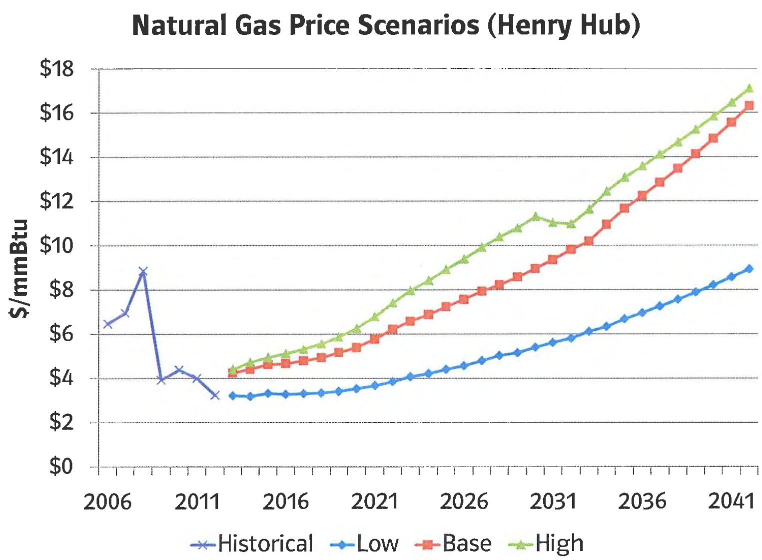
9.1 Appendix A – Detailed Summary of RFP Proposals

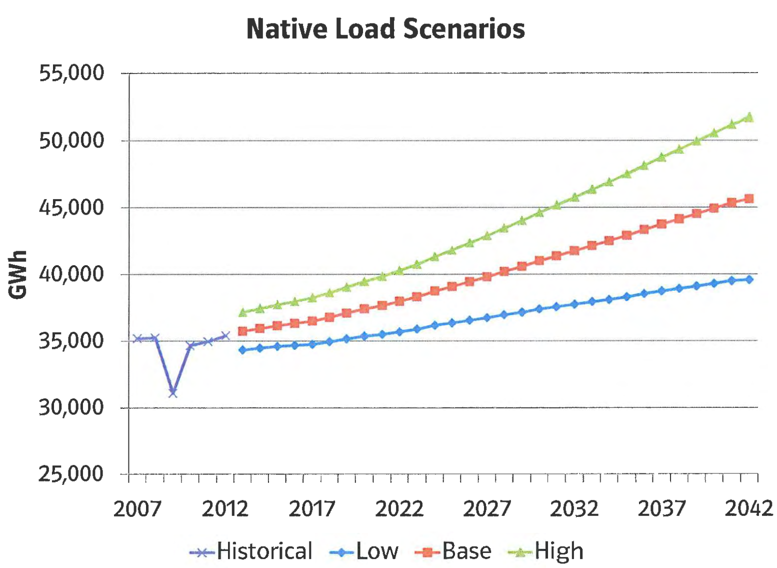
Contract Description									Capital Cost	Fixed Costs (FCs, Expressed as $/MW at TIP)								Fuel/Energy Costs			Variable Costs									
									Per Bid	Per Bid				Additional Costs Incurred by LGE/KU ($2015)				Per Bid			Per Bid					Additional Costs Incurred by LGE/KU ($2015)				
Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Asset Sale Price ($M)	FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M	Fixed Cost Escalator	Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator	Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu)	Variable O&M ($/MWh)	Start Cost and VOM Escalator
1A	ERORA	CCCT (2X1)_10	CCCT (2x1), GE	10 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1B	ERORA	CCCT (2X1)_20	CCCT (2x1), GE	20 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016		64,800	2.00%	6,515	2.00%		23,074		2.00%	6,705			20,000/strt or 680/hr			1.70	2.00%					
1C	ERORA	CCCT (2X1)_Own	CCCT (2x1), GE	Asset Sale, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	765						23,074		2.00%	6,705								0	264	3,019	0.36	2.00%
2	AEP	Coal_10	Portfolio	11 yr PPA, Up to 700 MW	AEP Gen Hub	1/1/2015	700	2015		147,022	0.00%			20,894			2.00%		31.91	0.00%				0.55	2.00%					
3	TPF Generation	SCCT_Own	SCCT	Asset Sale, 5 Units, 245 MW	CONSTELL PTID Node - PJM/AEP	TBD	245	2015	106					20,895	30,009	13,509	2.00%	10,650						0.55	2.00%			320	4.10	2.00%
4A	Big Rivers	Coal_5	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
4B	Big Rivers	Coal_10	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015		145,647	1.00%			36,056			2.00%	11,029			88,391			2.85	2.00%					
5A	Quantum Choctaw Power	CCCT (2X1)_20	CCCT (2x1), Siemens	20-35 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		69,000 ($2015)	2.00%			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5B	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	Asset Sale, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2015	450	12,114 in 2015; 7,513 in 2016 esc at 2%				24,998	15,431		2.00%	7,064								0	883	3,019	0.35	2.00%
5C	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	20-35 yr PPA w/ Asset Sale Option, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	462.5 ($2015)	67,200 in 2015; 12,356 in 2016; 7,663 in 2017 esc at 2%				24,998	15,431		2.00%	7,064						1.00 in 2015; 0.35 at 2%		0	883	3,019		2.00%
5D	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013		48,000 ($2015)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5E	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2016	701	2013		60,000 ($2016)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
5F	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2014	701	2013		36,000 ($2014)	Schedule			24,998	15,431		2.00%	7,064			23,900/strt or 800/hr			1.00	2.50%					
6A	Calpine	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, Day-Ahead Call Option, 500 MW	Trinity/Limestone - TVA	1/1/2015	500	2015		74,160	2.30%			24,998	27,418		2.00%	7,400			25,700		1,000	2.00	2.00%					
6B	Calpine	CCCT (1X1)_5	CCCT (1x1), Siemens	5 yr PPA, Day-Ahead Call Option, 250 MW	Trinity/Limestone - TVA	1/1/2015	250	2015		74,160	2.30%			24,998	27,418		2.00%	7,500			12,850		475	2.00	2.00%					
7A	Ameren	Coal_5	Coal	5 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,496	0.00%								31.41	Schedule	7,428			2.61	Schedule					
7B	Ameren	Coal_10	Coal	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		137,688	Schedule								25.68	Schedule										
7C	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015		83,796	Schedule				17,662				43.94	Schedule										
7D	Ameren	Coal_10	Portfolio (Coal and NG)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		131,484	Schedule								25.80	Schedule										
7E	Ameren	Coal_10	Portfolio (Coal to NG Conv.)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015		87,936	Schedule				17,662				43.80	Schedule										
7F	Ameren	SCCT_5	SCCT	5 yr PPA, 5 units, 222 MW	EEI/LGE Interface	1/1/2015	222	2015		85,896	0.00%				17,662			13,366			16,900		290	1.40	Schedule					
7G	Ameren	Coal_5	Coal	5 yr PPA, 334 MW	EEI/LGE Interface	1/1/2015	334	2015		137,496	0.00%							1,000			13,900									
7H	Ameren	Coal_10	Coal	10 yr PPA, 334 MW	EEI/LGE Interface	1/1/2015	334	2015										1,000												
7I	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 334 MW	EEI/LGE Interface	1/1/2015	334	2015	10.8						17,662			1,000												
7J	Ameren	Coal_5	Coal	5 yr PPA, 501 MW	EEI/LGE Interface	1/1/2015	501	2015		137,496	0.00%							1,000			20,850									
8	Paducah Power Systems	SCCT_5	SCCT	5 yr PPA, 26 MW	LGEE-PPS1	1/1/2015	26	2015		1,825					27,200			13,090												
9A	Agile	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016	157						23,268	29,800	2.00%	8,793										288	4.2	2.00%
9B	Agile	SCCT_20	NG-Fired Recip Engine	20 yr Tolling Agreement, 12 units, 112.9 MW	KU Sub in Muhlenberg Co	6/1/2016	112.9	2016		157,000	0.00%	29,800	2.00%		23,268			8,793					288	4.20	2.00%					
10	KMPA	RTC	Coal, Base Load	5 yr PPA, 25 MW (RTC)	AMIL, MISO	1/1/2015	25	2015		34,255	2.00%			36,056					33.61	Schedule										
11A	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Murdock, IL - MISO	1/1/2015	746	2016						36,056	33,279				50.04 in 2017	Schedule										
11B	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279				35.13 in 2017	Schedule	0									
11C	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016		111,000 in 2017	Schedule			36,056	33,279			6,800			0			4.24 in 2017	Schedule					
11D	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Kentucky	1/1/2015	746	2016							23,898				44.16 in 2017	Schedule										
11E	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898				30.63 in 2017	Schedule	0									
11F	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016		100,800 in 2017	Schedule				23,898			6,800			0			0.55 in 2017	Schedule					
12	Exelon Generation Company	RTC	Firm Physical Energy	10 yr PPA, 200 MW	Indiana Hub - MISO	1/1/2015	200	2015						36,056					47.78	0.00%										
13	CPV Smyth Generation Co.	CCCT (2X1)_20	CCCT (2X1), Alstom	20 yr PPA, 630 MW	Smyth County, VA - PJM	6/1/2017	630	2017		132,000	0.00%	23,400		20,895	30,941			7,009			18,690		3,808	3.13	2.00%					
14A	Duke	Coal_Own	OVEC	Asset Sale in 2015, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2015	203	2015	100								2.00%		34.87	Schedule										
14B	Duke	Coal_Own	OVEC	Asset Sale in 2013, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2013	203	2013	50								2.00%		34.87	Schedule										
15	Wellhead Energy Systems	SCCT_Own	NG-Fired Recip Engine	Asset Sale, 100 1 MW GridFox Units	LGE/KU System	1/1/2016	100	2013	99						23,898	29,800		10,000										3	4.20	
16A	Power4Georgians	RTC	Supercritical Coal	24 yr PPA, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349					32.40	1.85%				4.73	2.50%					
16B	Power4Georgians	RTC	Supercritical Coal	24 yr Tolling Agreement, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019		359,983	0.00%	27,673	2.50%	56,349				9,000						4.73	2.50%					
16C	Power4Georgians	RTC	Supercritical Coal	Asset Sale, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	3,030					56,349		27,673	2.50%	9,000								162,694			1.87	2.00%
17	Solar Energy Solutions	Solar_Own	Solar (PV Array)	Asset Sale, 1-5 MW	LGE/KU System	1/1/2016	1	2015	2.9							10,185	2.00%													
18A	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW	MISO/LGE Interface	1/1/2015	99	2015											50.00	3.00%										
18B	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW	MISO/LGE Interface	1/1/2016	151	2016											50.00	3.00%										
18C	EDP Renewables	Wind	Wind (As Available)	20 yr PPA, 100 MW	LGE/KU System	1/1/2016	100	2016											69.50	0.00%										
19A	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19B	LS Power	SCCT_Own	SCCT	3 yr PPA 1/1/2015, Asset Sale 2018, 495 MW	LGE Buckner Station	1/1/2015	495	2013	115	38,195	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19C	LS Power	SCCT_Own	SCCT	5 yr PPA 1/1/2015, Asset Sale 2020, 495 MW	LGE Buckner Station	1/1/2015	495	2013	105	38,195	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19D	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2014, 495 MW	LGE Buckner Station	1/1/2014	495	2013		12,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
19E	LS Power	SCCT_Own	SCCT	5-mon PPA 1/1/2014, Asset Sale 2014, 495 MW	LGE Buckner Station	1/1/2014	495	2014	119	11,662	Schedule				34,724		2.00%	10,900			25,500			0.62	2.5%					
19F	LS Power	SCCT_5	SCCT	5 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013		30,000	Schedule	7,800	2.50%		34,724		2.00%	10,900			25,500			0.62	2.5%					
20	Sky Global	CCCT (1X1)_10	CCCT (1X1), GE	10-20 yr PPA, 250-300 MW	KU's Pineville/Pocket North LGE	1/1/2016	250	2016		108,000	0.00%	27,000			49,005		2.00%	7,000					500							
21	Wellington	RTC	Waste Coal w/ CFBC	20 yr PPA, 112 MW	PJM West	9/1/2016	112	2012		388,014	Schedule	41,050	2.00%						61.10	Schedule										
22A	Southern Company Services	SCCT_5	SCCT	5 yr PPA, 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		45,000				56,349	25,266			12,850						4.65	0.0%					
22B	Southern Company Services	SCCT_5	SCCT	5 yr PPA (Summer Only), 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015		35,000				56,349	25,266			12,850						4.65	0.0%					
22C	Southern Company Services	Coal_10	Coal	15 yr PPA, 109-159 MW	Unit GSU - SOCO	1/1/2016	159	2016		246,000	1.50%			56,349				10,400			14,136				3.5%					
23	Santee Cooper	Coal_10	Coal	7.8 yr PPA, 250 MW	Georgetown, SC	4/1/2017	250	2012		100,080	0.00%			84,038			2.00%		40	2.00%				5.00	0.0%					
24A	Nextera	Coal_5	Coal	6 yr PPA, 30 MW	Into LG&E/KU	1/1/2015	30	2015											55.00	0.96%										
24B	Nextera	Coal_10	Coal	10 yr PPA, 50 MW	Into LG&E/KU	1/1/2015	50	2015											55.00	0.96%										
25	South Point Biomass	RTC	Biomass	20 yr PPA, 165 MW	AEP/Bellefonte/Proctorville PJM	5/1/2015	165	2015						20,895					65.50	Schedule				0.55	2.00%					
26	North American BioFuels	RTC	Landfill Gas	20 yr PPA, 19 MW	WI and PA - MISO and PJM	1/1/2014	19	2013											52.00	3.00%				0.55	2.00%					
27A	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Existing LG&E/KU Site	6/1/2017	770	2012		110,520 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
27B	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Site TBD	6/1/2017	770	2012		118,680 ($2017)	1.50%				21,924			7,250			42,000	1,275		0.80	2.00%					
41A	Union Power Partners	CCCT (2X1)_Own	CCCT (2X1), GE	Asset Sale end 2014, 500 MW	Entergy AK XM at the El Dorado su	1/1/2015	500	2015	298					24,998	22,111		2.00%	7,085								0	264	3,019	0.36	0.02
41B	Union Power Partners	CCCT (2X1)_10	CCCT (2X1), GE	20 Yr PPA	Entergy AK XM at the El Dorado su	1/1/2015	500	2015		91,200	0.00%			24,998	22,111		2.00%	7,100			0	1,038		1.06	2.00%					
42	Energy Development, Inc	RTC	Landfill Gas	20 yr PPA, 14.4 MW	Kentucky	1/1/2015	14	2015											62	2.00%				0.55	2.00%					
28	LGE/KU	CCCT (1X1)_Own	GE CCCT (1X1) - F Class	Self-Build, 298.5 MW	Site TBD	6/1/2017	299	2015	438						21,924		2.00%	6,857								0	175	1,510	0.37	2.00%
29	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - F Class	Self-Build, 332 MW	Site TBD	6/1/2017	332	2015	420						21,924		2.00%	6,880								0	441	1,510	0.35	2.00%
30	LGE/KU	CCCT (1X1)_Own	MHI CCCT (1X1)	Self-Build, 372.7 MW	Site TBD	6/1/2017	373	2015	463						21,924		2.00%	6,813								0	633	1,510	0.34	2.00%
31	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - H Class	Self-Build, 379.4 MW	Site TBD	6/1/2017	379	2015	458						21,924		2.00%	6,613								0	687	1,510	0.33	2.00%
32	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), GE	Self-Build, 598 MW	Site TBD	6/1/2017	598	2015	609						21,924		2.00%	6,848								0	264	3,019	0.36	2.00%
33	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), Siemens	Self-Build, 670.4 MW	Site TBD	6/1/2017	670	2015	617						21,924		2.00%	6,866								0	883	3,019	0.35	2.00%
35	LGE/KU	Solar_Own	Solar (PV Array)	Self-Build, 10 MW	Site TBD	1/1/2016	10	2015	46							10,185	2.00%												0.91	2.00%
36	LGE/KU	Coal_Own	BR1-2 Retrofit	Retrofitted Coal, 270 MW	Brown Station	1/1/2015	269	2015	194									10,500						3.10 in 2016	Schedule			2,443		2.00%
37	LGE/KU	SCCT_Own	SCCT	Trimble CT Retrofit	Trimble County Station	4/1/2015	54	2015	108									10,139												2.00%
38	LGE/KU	CCCT (1X1)_Own	Steam Augmentation	Steam Augmentation for Trimble CTs	Trimble County Station	4/1/2015	1	2015	10									9,969												
39	LGE/KU	Coal_Own	Coal-to-NG Conversion	BR1-2 Coal to NG Conversion	Brown Station	4/1/2016	1	2015	10									10,000												
40A	LGE/KU	DSM	DSM	Lighting	LGE/KU System	1/1/2015	1	2015																						
40B	LGE/KU	DSM	DSM	Thermostat Rebates	LGE/KU System	1/1/2015	1	2015																						
40C	LGE/KU	DSM	DSM	Windows & Doors	LGE/KU System	1/1/2015	1	2015																						
40D	LGE/KU	DSM	DSM	Manufactured Homes	LGE/KU System	1/1/2015	1	2015																						
40E	LGE/KU	DSM	DSM	Behavioral Thermostat Pilot	LGE/KU System	1/1/2015	1	2015																						
40F	LGE/KU	DSM	DSM	Commercial New Construction	LGE/KU System	1/1/2015	1	2015																						
40G	LGE/KU	DSM	DSM	Automated Demand Response	LGE/KU System	1/1/2015	1	2015	22																					

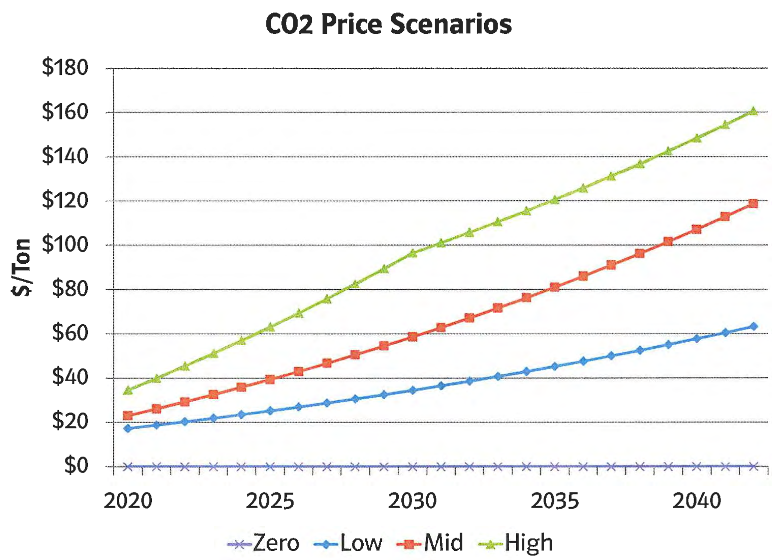
9.2 Appendix B – Phase 1 Screening Analysis Results

Class_Term	Counterparty	Description	Capital ($/kW)	Fixed O&M ($/MW-yr)	Energy Price	Total Costs	Pass
CCCT (1X1)_10	Sky Global	10-20 yr PPA, 250-300 MW	0	184,005	0	81	☐
CCCT (1X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 250 MW	0	126,576	0	73	✓
CCCT (1X1)_Own	LGE/KU	Steam Augmentation for Trimble CTs	1,059	0	0	275	☐
CCCT (1X1)_Own	LGE/KU	Self-Build, 298.5 MW	1,468	21,924	0	88	✓
CCCT (1X1)_Own	LGE/KU	Self-Build, 332 MW	1,264	21,924	0	84	✓
CCCT (1X1)_Own	LGE/KU	Self-Build, 372.7 MW	1,242	21,924	0	84	✓
CCCT (1X1)_Own	LGE/KU	Self-Build, 379.4 MW	1,206	21,924	0	81	✓
CCCT (2X1)_10	Union Power Partners	20 Yr PPA	0	137,832	0	79	
CCCT (2X1)_10	ERORA	10 yr PPA, 700 MW	0	94,389	0	65	✓
CCCT (2X1)_20	CPV Smyth	20 yr PPA, 630 MW	0	207,236	0	100	☐
CCCT (2X1)_20	ERORA	20 yr PPA, 700 MW	0	94,389	0	77	✓
CCCT (2X1)_20	Quantum Choctaw	20-35 yr PPA, 701 MW	0	106,750	0	86	☐
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	82	☐
CCCT (2X1)_20	Khanjee	22 yr PPA	0	69,335	0	98	☐
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	65	✓
CCCT (2X1)_20	Khanjee	22 yr PPA	0	23,898	0	81	✓
CCCT (2X1)_20	Southern Power Co.	20 yr PPA, 770 MW	0	122,026	0	89	☐
CCCT (2X1)_20	Southern Power Co.	20 yr PPA, 770 MW	0	129,416	0	91	☐
CCCT (2X1)_5	Calpine	5 yr PPA, Day-Ahead Call Option, 500 MW	0	126,576	0	72	✓
CCCT (2X1)_5	Quantum Choctaw	5 yr PPA, 701 MW	0	40,429	0	63	✓
CCCT (2X1)_5	Quantum Choctaw	5 yr PPA, 701 MW	0	40,429	0	65	
CCCT (2X1)_5	Quantum Choctaw	5 yr PPA, 701 MW	0	40,429	0	61	
CCCT (2X1)_Own	Union Power Partners	Asset Sale end 2014, 500 MW	596	46,632	0	83	☐
CCCT (2X1)_Own	LGE/KU	Self-Build, 598 MW	1,018	21,924	0	79	✓
CCCT (2X1)_Own	LGE/KU	Self-Build, 670.4 MW	921	21,924	0	78	✓
CCCT (2X1)_Own	ERORA	Asset Sale, 700 MW	1,093	23,074	0	79	✓
CCCT (2X1)_Own	Quantum Choctaw	Asset Sale, 701 MW	642	40,429	0	82	☐
CCCT (2X1)_Own	Quantum Choctaw	20-35 yr PPA w/ Asset Sale Option, 701 MW	629	40,429	0	83	☐
Coal_10	Nextera	10 yr PPA, 50 MW	0	0	55	57	✓
Coal_10	Southern Co. Services	15 yr PPA, 109-159 MW	0	302,349	0	122	
Coal_10	Santee Cooper	7.8 yr PPA, 250 MW	0	184,118	40	95	
Coal_10	Ameren	10 yr PPA, 334 MW	0	0	0	58	
Coal_10	Ameren	10 yr PPA, 334 MW	32	17,662	0	72	
Coal_10	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	91	✓
Coal_10	Ameren	10 yr PPA, 668 MW	0	0	0	60	
Coal_10	Ameren	10 yr PPA, 668 MW	67	17,662	0	74	
Coal_10	AEP	11 yr PPA, Up to 700 MW	0	167,916	32	71	✓
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	0	0	58	
Coal_10	Ameren	10 yr PPA, Up to 700 MW	0	17,662	0	73	
Coal_5	Nextera	6 yr PPA, 30 MW	0	0	55	56	✓
Coal_5	Ameren	5 yr PPA, 334 MW	0	137,496	0	67	✓
Coal_5	Big Rivers	1-15 yr PPA, Wilson Station, 417 MW	0	181,703	0	87	✓
Coal_5	Ameren	5 yr PPA, 501 MW	0	137,496	0	67	✓
Coal_5	Ameren	5 yr PPA, 668 MW	0	137,496	0	67	✓
Coal_Own	Duke	Asset Sale in 2015, 203 MW of OVEC	493	0	0	99	✓
Coal_Own	Duke	Asset Sale in 2013, 203 MW of OVEC	246	0	0	95	
Coal_Own	LGE/KU	Retrofitted Coal, 270 MW	721	0	0	78	✓
Coal_Own	LGE/KU	BR1-2 Coal to NG Conversion	173	23,898	0	103	
DSM	LGE/KU	Lighting	0	0	0	270	✓
DSM	LGE/KU	Thermostat Rebates	0	0	0	279	✓
DSM	LGE/KU	Windows & Doors	0	0	0	828	✓
DSM	LGE/KU	Manufactured Homes	0	0	0	1,397	✓
DSM	LGE/KU	Behavioral Thermostat Pilot	0	0	0	383	✓
DSM	LGE/KU	Commercial New Construction	0	0	0	104	✓
DSM	LGE/KU	Automated Demand Response	21,899	0	0	27,473	✓
RTC	Energy Development, Inc	20 yr PPA, 14.4 MW	0	0	62	65	
RTC	North American BioFuels	20 yr PPA, 19 MW	0	0	52	58	
RTC	KMPA	5 yr PPA, 25 MW (RTC)	0	70,311	0	45	✓
RTC	Wellington	20 yr PPA, 112 MW	0	41,050	0	114	
RTC	South Point Biomass	20 yr PPA, 165 MW	0	20,895	0	73	
RTC	Exelon Generation	10 yr PPA, 200 MW	0	36,056	48	53	✓
RTC	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	69,335	0	59	
RTC	Khanjee	22 yr PPA, Fixed Price w/ Min Take (85% CF)	0	23,898	0	49	
RTC	Power4Georgians	24 yr PPA, 850 MW	0	444,005	32	97	
RTC	Power4Georgians	24 yr Tolling Agreement, 850 MW	0	444,005	0	97	
RTC	Power4Georgians	Asset Sale, 850 MW	3,565	84,022	0	81	
SCCT_20	Agile	20 yr Tolling Agreement, 12 units, 112.9 MW	0	210,068	0	560	☐
SCCT_20	LS Power	20 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	284	✓
SCCT_20	LS Power	20 yr PPA starting 1/1/2014, 495 MW	0	42,524	0	282	✓
SCCT_5	Paducah Power Sys.	5 yr PPA, 26 MW	0	29,025	0	140	✓
SCCT_5	Southern Co. Services	5 yr PPA, 75-675 MW	0	126,615	0	388	
SCCT_5	Southern Co. Services	5 yr PPA (Summer Only), 75-675 MW	0	116,615	0	363	
SCCT_5	Ameren	5 yr PPA, 5 units, 222 MW	0	103,558	0	323	
SCCT_5	LS Power	5 yr PPA starting 1/1/2015, 495 MW	0	42,524	0	255	✓
SCCT_Own	LGE/KU	Trimble CT Retrofit	2,000	0	0	433	☐
SCCT_Own	Wellhead Energy Sys.	Asset Sale, 100 1 MW GridFox Units	988	53,698	0	398	☐
SCCT_Own	Agile	Asset Sale, 12 units, 112.9 MW	1,386	53,068	0	469	☐
SCCT_Own	LGE/KU	Self-Build, 206 MW	840	23,898	0	318	☐
SCCT_Own	TPF Generation	Asset Sale, 5 Units, 245 MW	434	64,413	0	329	☐
SCCT_Own	LS Power	3 yr PPA 1/2015, Asset Sale end 2017, 495 MW	232	34,724	0	249	✓
SCCT_Own	LS Power	5 yr PPA 1/2015, Asset Sale end 2019, 495 MW	212	34,724	0	252	✓
SCCT_Own	LS Power	5-mon PPA 1/2014, Asset Sale in 2014, 495 MW	240	34,724	0	240	✓
Solar_Own	Solar Energy Solutions	Asset Sale, 1-5 MW	2,932	10,185	0	194	✓
Solar_Own	LGE/KU	Self-Build, 10 MW	4,633	10,185	0	247	✓
Wind	EDP Renewables	15 or 20 yr PPA, 99 MW	0	0	50	60	✓
Wind	EDP Renewables	20 yr PPA, 100 MW	0	0	70	68	✓
Wind	EDP Renewables	15 yr PPA, 151.2 MW	0	0	50	59	✓

9.3 Appendix C – Natural Gas, Load, and CO2 Price Scenarios







Note: The Phase 2, Iteration 1 analysis considered the Zero and Mid CO_2 price scenarios only.

RFP Status

- Transmission Analysis
  - Errora network connection costs - ~~[illegible]~~ this week
  - ST options - DC & Ameren - - this week
  - Brown & GR sites w/ CCGT - end of march
- BREC - ~~[illegible]~~
- Finalizing self build costs for different CCGT configurations & BR vs. GR site
- Nucla testing looks promising for B1&2 will continue through summer
- Optimized size & location analysis by end of may
- Sept/Oct filing w/ PSC for CCN - 2018 CCGT Selfbuild
- BREC - offered $500m ≈ new CCGT cost w/ our middle gas price
  - No future environmental risk
  - no CO2 risk w/ CCGT
  - Adj for CO2 using longer life (LYF = 2024) + 15% FCR = $276m
  - MCJ ≈ $250m on new FGD & baghouse
  - Might be willing to take for free
  - PSC involved - BREC called

Brown 1-2 Baghouse Retrofit Analysis

LG&E KU

PPL companies

Generation Planning & Analysis
March 2013

Table of Contents

1 Executive Summary

In the 2011 ECR Plan filing, LG&E and KU (the "Companies") proposed to retrofit Brown 1-2 with a fabric filter baghouse ("baghouse") to comply with EPA regulations. Because of the marginal economics of this decision compared to retiring the units, the Companies ultimately agreed with interveners to revisit the Brown 1-2 baghouse retrofit decision – at the earliest – on July 1, 2013.

Table 1 summarizes the Companies' reserve margin ("RM") shortfall with and without Brown 1-2 beginning in 2015. With Brown 1-2, the Companies will be short 64 MW in 2015. Without Brown 1-2, the Companies will be short 336 MW in 2015.

Table 1 – Reserve Margin Shortfall (MW)

	2015	2016	2017	2018	2019	2020	2021
RM Shortfall (16% RM) w/ BR1-2	(64)	(135)	(183)	(298)	(358)	(435)	(514)
RM Shortfall (16% RM) w/o BR1-2	(336)	(404)	(452	(567)	(627)	(704)	(783)

Several key inputs to the Brown 1-2 baghouse retrofit decision have changed since the 2011 ECR Plan filing:

1. Capital and operating cost assumptions for the baghouse have decreased. The updated operating cost assumptions are based on the Companies' experience operating the Trimble County 2 baghouse.
2. The outlook for natural gas prices is lower by approximately \$3/mmBtu. This reduces the generation cost of a combined cycle gas turbine ("CCGT"), the likely replacement for Brown 1-2, by approximately \$21/MWh.
3. The risk of CO_2 regulations is increasing. While no federal legislation mandating a cap-and-trade scheme or carbon tax has advanced, the EPA is expected to propose CO_2 regulations for existing power plants.

In the updated analysis, the Companies evaluated the Brown 1-2 retire/retrofit decision under three gas price scenarios, two load scenarios, and two CO_2 price scenarios. The differences in present value revenue requirements ("PVRR") between the "Brown 1-2 retirement" and "Brown 1-2 retrofit" alternatives are summarized in Table 2. Compared to the Brown 1-2 retirement alternative, the PVRR of the Brown 1-2 retrofit alternative ranges from approximately \$300 million lower (i.e., favorable) to approximately \$700 million higher (i.e., unfavorable). If all scenarios are assumed to be equally probable, the Brown 1-2 retrofit alternative is on average \$170 million *unfavorable* to the Brown 1-2 retirement alternative. The Brown 1-2 retrofit alternative is not the least-cost alternative in any mid CO_2 price scenario or any scenario with low natural gas prices. In the base gas, zero CO_2 price scenarios, the favorability of the Brown 1-2 retrofit alternative is the result of two key assumptions:

1. Brown 1 and 2 will operate through the end of the analysis period in 2042.
2. Brown 1 and 2 will require no additional environmental controls through 2042.

If either of these assumptions is not realized, the Brown 1-2 retrofit alternative is not least-cost in the base gas price scenarios. The impacts of lower gas prices and the increasing risk of CO_2 regulations more than offset the impact of lower baghouse capital and operating expenses. The merits of the baghouse retrofit alternative today are unfavorable compared to the evaluation in the 2011 ECR Plan filing.

Table 2 – Brown 1-2 Retire/Retrofit Analysis Results ($2013, $M)

	Scenario (Gas/Load/CO_2)			**PVRR Difference[1] (Brown 1-2 Retirement Less Retrofit Brown 1-2)***
1	Base Gas	Base Load	Zero CO_2	55
2			Mid CO_2	(337)
3		Low Load	Zero CO_2	100
4			Mid CO_2	(305)
5	High Gas	Base Load	Zero CO_2	281
6			Mid CO_2	(125)
7		Low Load	Zero CO_2	124
8			Mid CO_2	(194)
9	Low Gas	Base Load	Zero CO_2	(222)
10			Mid CO_2	(681)
11		Low Load	Zero CO_2	(243)
12			Mid CO_2	(481)

*Positive values indicate that the Brown 1-2 retrofit is favorable to retirement.

Based on this analysis, it is recommended that the Companies do not proceed with the installation of a baghouse on Brown 1-2. However, a decision to retire Brown 1-2 has not been reached, as the Companies are currently testing a fuel additive for Brown 1-2 that may enable the units to comply with EPA regulations.

[1] PVRR differences reflect differences in operating revenue requirements beginning in 2018 and all differences in capital revenue requirements (see discussion in Section 4.1). Further updates to transmission cost estimates may result in changes to these values, but will not affect the recommendation.

2 LG&E/KU Resource Summary and Brown 1-2 Retrofit Alternatives

If the Companies do not retrofit Brown 1-2 with any mercury control technology, they must be retired by April 16, 2015 to comply with the EPA's Mercury and Air Toxic Standards ("MATS" or "Utility MACT" rule). Depending on whether Brown 1-2 are retired, the Companies will be 64-336 MW short of a 16% reserve margin in 2015 (see Table 3). The Companies optimal reserve margin range is 15-17%. For planning purposes, the Companies target the middle of this range (16%).

Table 3 – LG&E/KU Resource Summary

	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,426	7,509	7,597	7,696	7,746	7,815	7,885
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,040	7,091	7,147	7,214	7,282	7,350	7,418
Existing Resources[2]	7,814	7,802	7,819	7,781	7,800	7,801	7,801
Firm Purchases (OVEC)	152	152	152	152	152	152	152
Curtailable Demands	137	137	137	137	137	137	137
Total Supply w/ Brown 1-2 (BR1-2)	8,103	8,091	8,108	8,070	8,089	8,091	8,091
Brown 1-2[3]	272	269	269	269	269	269	269
Total Supply w/o Brown 1-2 (BR1-2)	7,831	7,822	7,839	7,801	7,820	7,822	7,822
Reserve Margin ("RM") w/ BR1-2	15.1%	14.1%	13.4%	11.9%	11.1%	10.1%	9.1%
Reserve Margin ("RM") w/o BR1-2	11.2%	10.3%	9.7%	8.1%	7.4%	6.4%	5.4%
RM Shortfall (16% RM) w/ BR1-2*	(64)	(135)	(183)	(298)	(358)	(435)	(514)
RM Shortfall (16% RM) w/o BR1-2*	(336)	(404)	(452	(567)	(627)	(704)	(783)
RM Shortfall (15% RM) w/ BR1-2*	7	(64)	(111)	(226)	(285)	(362)	(440)
RM Shortfall (15% RM) w/o BR1-2*	(265)	(333)	(380)	(495)	(554)	(631)	(709)

*Negative values reflect reserve margin shortfalls.

Two alternatives exist for retrofitting Brown 1-2 to comply with the MATS:

1. Install a fabric filter baghouse ("baghouse").
2. Utilize a fuel additive that bonds with the mercury in the fuel during combustion. Tests are underway at the Brown Station to understand the viability of this alternative.

The baghouse alternative has a much higher capital cost than the fuel additive alternative. This analysis is limited to evaluating the merits of the baghouse alternative.

[2] 'Existing Resources' include Cane Run 7 and Brown 1-2.
[3] 3 MW derate beginning in 2016 reflects the addition of a baghouse.

3 Updated Input Assumptions

The baghouse alternative was originally evaluated in the 2011 ECR Plan analysis. Since that analysis, several key input assumptions have changed:

1. The estimated capital cost for the Brown 1-2 baghouse has decreased by $34 million (from $228 million to $194 million).
2. The operating cost assumptions for the Brown 1-2 baghouse have decreased by approximately $13 per megawatt-hour. When the 2011 Air Compliance Plan was developed, the Companies had limited operating experience with the Trimble County 2 baghouse. The updated operating expense estimates are based on almost two years of experience operating the Trimble County 2 baghouse.
3. The outlook for natural gas prices is lower by approximately $3/mmBtu. This reduces the generation cost of a CCGT, the likely replacement for Brown 1-2, by approximately $21/MWh.
4. The risk of CO_2 regulations is increasing. While no federal legislation mandating a cap-and-trade scheme or carbon tax has advanced, the EPA is expected to propose CO_2 regulations for existing power plants.

4 Brown 1-2 Baghouse Analysis

4.1 Summary of Alternatives

To evaluate the Brown 1-2 baghouse retrofit alternative, the Companies compared the costs of installing a baghouse at Brown 1-2 to the costs of retiring Brown 1-2 and replacing the capacity. The Brown 1-2 baghouse retrofit and Brown 1-2 retirement alternatives are summarized in more detail in Table 4. In both alternatives, a 2X1 CCGT is constructed in 2018.[4] The differences in cost between the alternatives are driven by the longer-term implications of retrofitting Brown 1-2 (e.g., retiring Brown 1-2 accelerates the need for additional generating capacity commissioned after 2018; retrofitting Brown 1-2 results in a higher weighting of coal generation in the Companies' generating portfolio). For this reason, with the exception of the difference in capital costs related to the baghouse, the difference in present value of revenue requirements ("PVRR") between the two alternatives is driven by cost differences beginning in 2018. Prior to 2018, the analysis assumes that replacement capacity and energy can be acquired for Brown 1-2 at a cost not materially different than that of retaining and operating Brown 1-2. Retaining Brown 1-2, the projected reserve margin shortfall is 64 MW in 2015, increasing to 183 MW in 2017. For both alternatives, the analysis assumes similar costs for meeting this shortfall.

[4] The earliest that replacement capacity can be constructed is 2018.

Table 4 – Summary of Alternatives

Alternative	Description
Brown 1-2 Baghouse Retrofit	• 4/2016: Retrofit Brown 1-2 with fabric filter baghouse. • 2015-2017: Purchase capacity and energy to meet 64-135 MW RM shortfall. • 1/2018: Build 2X1 CCGT.
Brown 1-2 Retirement	• 2015-2017: Retire Brown 1-2 in 2015 and purchase replacement capacity OR operate Brown 1-2 with fuel additive. • 2015-2017: Purchase capacity and energy to meet 64-135 MW RM shortfall. • 1/2018: Build 2X1 CCGT. ← Build in 2018 in retire case

4.2 Analysis Methodology

To understand the impact on the analysis associated with the uncertainty in natural gas prices, native load, and potential CO_2 regulations, each alternative was evaluated under three natural gas price scenarios, two native load scenarios, and two CO_2 price scenarios (12 scenarios in all). Charts detailing the price and load scenarios are included in *Appendix A – Natural Gas, Load, and CO2 Price Scenarios*.

For each alternative and each 'gas price-native load-CO_2 price' scenario, Strategist was used to develop a least-cost resource expansion plan for meeting the Companies' forecasted energy requirements. Then, detailed production costs were computed for each alternative and associated expansion plan using PROSYM. The analysis period was 30 years (2013-2042).

If Brown 1-2 are retired, the Brown Station's on-going capital, fixed O&M, landfill costs, and costs for complying with the EPA's effluent guidelines will be impacted. In addition, the Companies' transmission plan will be impacted. The analysis considers all of these cost impacts in addition to impacts to expansion plans and production costs.

must be compared to cost of baghouse

4.3 Analysis Results

If Brown 1-2 are retired, the Companies' need for generating capacity beyond 2018 will be accelerated, resulting in a higher-cost expansion plan. In the base load scenario, retrofitting Brown 1-2 (and retaining their 269 MW of capacity for the longer-term) defers the need for additional generating capacity by four years. In the low load scenario, retrofitting Brown 1-2 defers the need for additional generating capacity by eight years. The table in *Appendix B – Brown 1-2 Retire/Retrofit Analysis Results* lists the first generating resource ("1st long-term generating resource" or "1st LGR") that is added after 2018 for each of the 12 'gas price-load-CO2 price' scenarios.

Table 5 compares the two alternatives under each of the 12 'gas price-load-CO_2 price' scenarios. The PVRR values include operating revenue requirements beginning in 2018 and all capital revenue requirements. A complete summary of the analysis results are contained in *Appendix B – Brown 1-2 Retire/Retrofit Analysis Results*. The following conclusions can be drawn from these results:

1. Compared to the Brown 1-2 retirement alternative, the PVRR of the Brown 1-2 baghouse retrofit alternative ranges from approximately $300 million lower (i.e., favorable) to approximately $700 million higher (i.e., unfavorable). If all scenarios are assumed to be equally probable, the Brown 1-2 retrofit alternative is on average $170 million *unfavorable* to the Brown 1-2 retirement alternative.

2. The Brown 1-2 baghouse retrofit alternative is not the least-cost alternative in any mid CO_2 price scenario or any scenario with low natural gas prices.
3. In the zero CO_2 price scenarios, the Brown 1-2 baghouse retrofit alternative is the least-cost alternative in the base and high gas price scenarios.

Table 5 – Analysis Results ($2013, $M)

	Scenario (Gas/Load/CO_2)[5]			Total PVRR		PVRR Difference[6]
				Brown 1-2 Retrofit	Brown 1-2 Retirement	(Retire Less Retrofit)
1	BG	BL	0C	21,628	21,573	55
2			MC	35,340	35,677	(337)
3		LL	0C	18,866	18,766	100
4			MC	32,179	32,485	(305)
5	HG	BL	0C	22,760	22,479	281
6			MC	37,631	37,756	(125)
7		LL	0C	19,504	19,380	124
8			MC	33,790	33,984	(194)
9	LG	BL	0C	18,553	18,775	(222)
10			MC	30,195	30,876	(681)
11		LL	0C	16,450	16,693	(243)
12			MC	28,161	28,642	(481)

In the base gas, zero CO_2 price scenarios, the PVRR of the Brown 1-2 baghouse retrofit alternative is $55-100 million favorable to the Brown 1-2 retirement alternative. Two assumptions drive this difference:

1. Brown 1 and 2 operate through the end of the analysis period (2042).
2. Brown 1 and 2 will require no additional environmental controls through 2042.

In 2013, Brown 1 and 2 will be 56 and 50 years old, respectively. In 2042, Brown 1 and 2 will be 85 and 79 years old, respectively (see Table 6). If Brown 1-2 do not operate beyond 2030, the PVRR of the Brown 1-2 baghouse retrofit alternative is increased (i.e., becomes less favorable) by approximately $160 million in the base load scenario and $300 in the low load scenario. If SCR is needed for Brown 1-2 in 2025, the cost of the Brown 1-2 retrofit is increased by approximately $110 million. Furthermore, if SCR is needed before 2025, the cost impact is greater.

Clearly, if any one of these assumptions is not realized, the Brown 1-2 baghouse retrofit alternative is not least-cost in the base gas scenarios. Furthermore, if Brown 1-2 do not operate beyond 2030, the retrofit alternative is favored only in the high gas, base load, zero CO_2 price scenario. The impacts of lower gas prices and the increasing risk of CO_2 regulations more than offset the impact of lower baghouse capital and operating expenses.

[5] Gas: Base/Mid (BG), High (HG), Low (LG); Load: Base (BL), Low (LL); CO_2: Zero (0C), Mid (MC).
[6] Further updates to transmission cost estimates may result in changes to these values, but will not affect the recommendation.

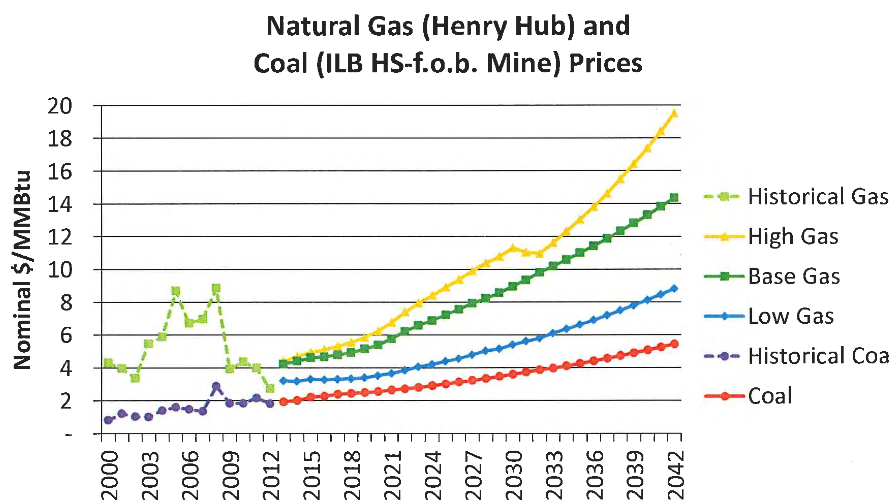
Table 6 – Age of Brown 1 and 2 (years)

Year	Brown 1	Brown 2
2013	56	50
2025	68	62
2030	73	67
2035	78	72
2042	85	79

5 Conclusion

Based on this analysis, it is recommended that the Companies do not proceed with the installation of a baghouse on Brown 1-2. However, a decision to retire Brown 1-2 has not been reached, as the Companies are currently testing a fuel additive for Brown 1-2 that may enable the units to comply with EPA regulations.

6 Appendix A – Natural Gas, Load, and CO_2 Price Scenarios



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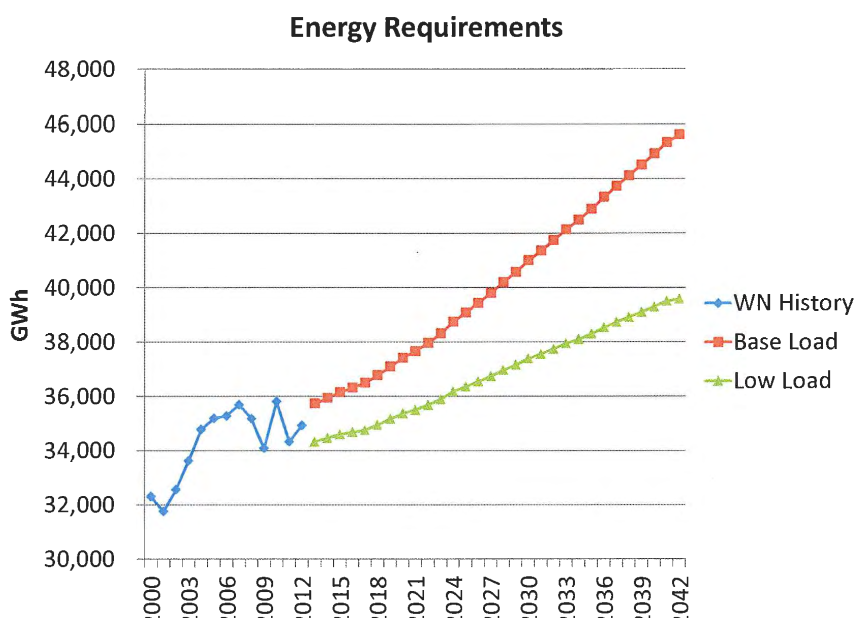
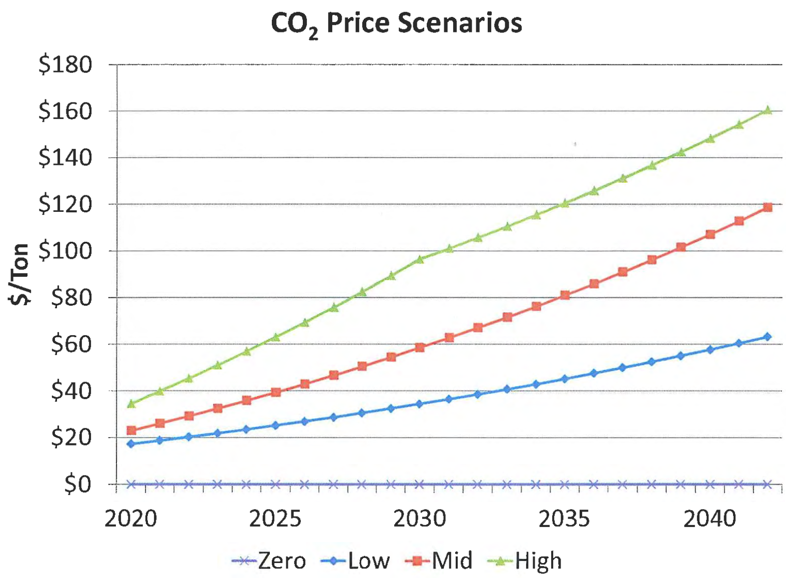




Note: The analysis considered the Zero and Mid CO_2 price scenarios only.

7 Appendix B – Brown 1-2 Retire/Retrofit Analysis Results

	Scenario (Gas/Load/ CO_2)[7]			Case	1st LGR	Production Costs	Capital	Firm Gas Transport	Fixed O&M	Trans Impact[8]	Total Cost
1	BG	BL	0C	Brown 1-2 Retire	'21 SCT	19,485	1,554	381	143	64	21,628
				Brown 1-2 Retrofit	'25 SCT	19,379	1,623	325	246	0	21,573
				Difference		106	(69)	56	(102)	64	55
2			MC	Brown 1-2 Retire	'21 2x1	32,987	1,733	402	154	64	35,340
				Brown 1-2 Retrofit	'25 2x1	33,380	1,714	336	248	0	35,677
				Difference		(393)	19	67	(94)	64	(337)
3		LL	0C	Brown 1-2 Retire	'32 2x1	17,531	959	227	87	64	18,866
				Brown 1-2 Retrofit	'40 SCT	17,460	935	175	196	0	18,766
				Difference		70	23	51	(109)	64	100
4			MC	Brown 1-2 Retire	'32 1x1	30,869	950	209	87	64	32,179
				Brown 1-2 Retrofit	'40 2x1	31,087	1,016	183	198	0	32,485
				Difference		(219)	(66)	27	(111)	64	(305)
5	HG	BL	0C	Brown 1-2 Retire	'21 2x1	20,426	1,715	401	153	64	22,760
				Brown 1-2 Retrofit	'25 2x1	20,210	1,688	333	247	0	22,479
				Difference		216	26	69	(94)	64	281
6			MC	Brown 1-2 Retire	'21 2x1	35,298	1,715	401	153	64	37,631
				Brown 1-2 Retrofit	'25 2x1	35,488	1,688	333	247	0	37,756
				Difference		(190)	26	69	(94)	64	(125)
7		LL	0C	Brown 1-2 Retire	'32 1x1	18,193	950	209	87	64	19,504
				Brown 1-2 Retrofit	'40 1x1	18,021	983	178	197	0	19,380
				Difference		172	(33)	31	(110)	64	124
8			MC	Brown 1-2 Retire	'32 1x1	32,479	950	209	87	64	33,790
				Brown 1-2 Retrofit	'40 2x1	32,586	1,016	183	198	0	33,984
				Difference		(107)	(66)	27	(111)	64	(194)
9	LG	BL	0C	Brown 1-2 Retire	'21 2x1	16,309	1,630	398	151	64	18,553
				Brown 1-2 Retrofit	'25 2x1	16,548	1,649	331	246	0	18,775
				Difference		(239)	(19)	67	(95)	64	(222)
10			MC	Brown 1-2 Retire	'21 2x1	27,841	1,733	402	154	64	30,195
				Brown 1-2 Retrofit	'25 2x1	28,578	1,714	336	248	0	30,876
				Difference		(736)	19	67	(94)	64	(681)
11		LL	0C	Brown 1-2 Retire	'32 SCT	15,330	778	195	83	64	16,450
				Brown 1-2 Retrofit	'40 SCT	15,387	935	175	196	0	16,693
				Difference		(57)	(157)	20	(113)	64	(243)
12			MC	Brown 1-2 Retire	'32 1x1	26,850	950	209	87	64	28,161
				Brown 1-2 Retrofit	'40 2x1	27,244	1,016	183	198	0	28,642
				Difference		(395)	(66)	27	(111)	64	(481)

Brown 1-2 Retirement has Lower PVRR   Brown 1-2 Baghouse Retrofit has Lower PVRR

[7] Gas: Base/Mid (BG), High (HG), Low (LG); Load: Base (BL), Low (LL); CO_2: Zero (0C), Mid (MC).
[8] Further updates to transmission cost estimates may result in changes to these values, but will not affect the recommendation.

Note: The '1st LGR' column in the previous table indicates the LGR that is added after the 2018 CCGT. Production Costs include the production costs for the alternatives being evaluated, the LGRs, and the units in the Companies' existing generation portfolio. Capital, Firm Gas Transport, and Fixed O&M include costs for the alternatives being evaluated and the LGRs. Transmission Impact ("Trans Impact") is the PVRR impact of each alternative on the Companies' 2013 transmission plan. The PVRR values include operating revenue requirements (i.e., Production Costs, Firm Gas Transport, and Fixed O&M revenue requirements) beginning in 2018 and all capital and transmission revenue requirements.

DRAFT 3/25/2013

Letters to RFP Respondents

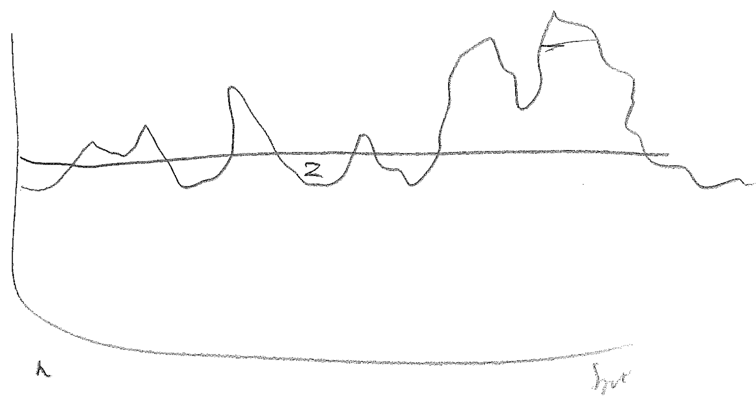
A. Parties that did not make the short-list (Agile, Calpine, CPV Smyth Generation Co., Duke, EDP Renewables, Energy Development, Inc., Exelon Generation Company, KMPA, Nextera, North American Biofuels, Paducah Power Systems, Power4Georgians, Quantum Choctaw Power, Santee Cooper, Sky Global, Elk Ridge Energy Center, Solar Energy Solutions, South Point Biomass, Southern Company Services, Southern Power Company, TPF Generation, Union Power Partners, Wellhead Energy Systems, Wellington)
    a. Distribution: Week of 4/8
        i. Need to update Phase 2 analysis with updated XM costs to make sure short list of respondents doesn't change.
    b. Content
        i. We do not anticipate further consideration of your response.

B. Ameren and LS Power — Call?, Done next to let [illegible] know our value is [illegible] – partially [illegible]?
    a. Distribution: Week of 4/8
    b. Content
        i. Analysis is on-going.
        ii. You are one of the top two respondents.
        iii. Optimal way forward depends on the results of ongoing emissions testing taking place on two of our existing units.
        iv. We should know more by early May.
        v. Will get back to you then.

C. Big Rivers
    a. Distribution: Week of 4/8 – Run [illegible] draft by Perry, Paul Sam. Done next to call?
    b. Content
        i. 'Thanks but no thanks' theme but with enough information to clearly demonstrate extent to which we exhaustively considered their proposals.
            1. Summary of process.
            2. Ways we considered Wilson PPA.
            3. Concerns regarding sale.
            4. Bid is not least-cost.

D. Other short-listed respondents (AEP, ERORA, Khanjee)
    a. Distribution: Week of 4/8
    b. Content
        i. We do not anticipate further consideration of your offer.

News media statement – "still evaluating – 2-3 month delay"? →
→ Political stakeholders – KPSC, others?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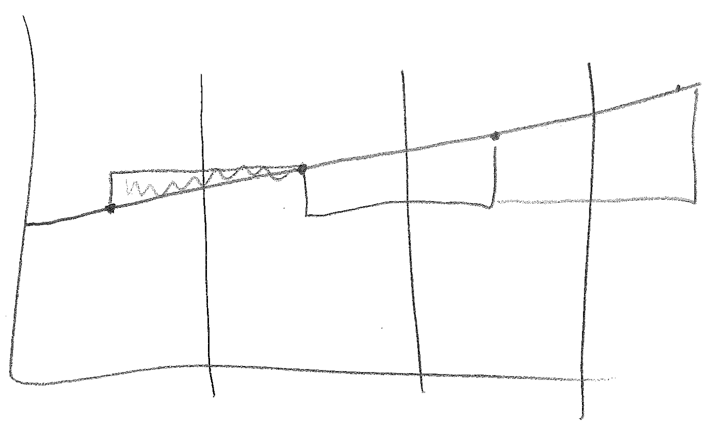

2018 CCGT Project Schedule Overview

Major Activity	Tasks	Issues/Risks	Begin Date	End Date	Lead Personnel
Regulatory I-land updt tu KBC per SRP	1. File Generation CPCN 2. File Transmission CPCN 3. Receive Gen & Trans CPCN rate case [illegible] 6-30-14	• Transmission CPCN may create opportunities for delay (see Political Outreach below). • Should timing of filing be accelerated to reduce COD risk?	8/13 3/14	11/13 5/14 11/14	Staton, Sturgeon, Sinclair, Voyles
Environmental	1. Siting Study 2. Cumulative Environmental Assessment 3. File Air Permit Application 4. Receive Air Permit	• This will be 1st PSD CO2 permit in KY	7/13 7/13 7/13	9/13 9/13 11/13 11/14	Winkler Winkler Revlett
Site Development & Construction	1. Geotechnical study 2. Wetlands study 3. Conceptual design 4. EPC bid package 5. EPC bids 6. EPC short-list 7. EPC best & final 8. EPC negotiations 9. LNTP 10. FNTP 11. Back feed power 12. Raw water available	• Cost and timeline risk due to increasing number of CCGTs being developed in US.	5/13 6/13 5/13 8/13 1/14 5/14 7/14 9/14 NA NA	6/13 7/13 7/13 12/13 5/14 7/14 8/14 12/14 1/15 3/15 12/16 12/16	Lively, Schetzel Lively, Winkler Lively Lively Lively Lively, Schetzel Lively, Schetzel Schetzel, Lively Lively Lively Balmer Lively

Major Activity	Tasks	Issues/Risks	Begin Date	End Date	Lead Personnel
	13. Fuel available 14. Testing 15. COD		 5/17 	5/17 12/17 1/18	Brunner Lively, Troost Lively
Real Estate & Right-of-Way	1. Plant site land acquisition 2. Trans ROW optioning 3. Trans ROW acquisition 4. Trans eminent domain (if needed) 5. Pipeline ROW optioning 6. Pipeline ROW acquisition 7. Pipeline eminent domain (if needed)	• In general, the risk of ROW acquisition for gas & transmission increases project risk • Development must finalize land need • Timing on transmission ROW allows 1 year for construction • Texas Gas may build pipeline which would shift ED to Federal process.	? 3/14 11/14 5/15 9/13 11/14 5/15	? 11/14 5/16 5/16 10/14 4/15 5/16	Cockerill Cockerill Dimas
Transmission Interconnection & Upgrades	1. System Impact Study 2. Facilities studies 3. LGI Agreement 4. Route studies & final route 5. PtP service for testing 6. NITS service for full plant output		5/13 12/13 5/13 11/13 12/13 12/13	10/13 5/14 5/14 3/14 5/17 11/17	Schetzel Schetzel Balmer Balmer Brunner Brunner

Major Activity	Tasks	Issues/Risks	Begin Date	End Date	Lead Personnel
Gas Transportation	1. Pipeline routing study & selection 2. Pipeline Build/Buy analysis & decision TGT IOC cert 3. Gas transport contract	• Owning pipeline provides better optionality for future interconnection with ANR for reliability & price protection with TGT • After CPCN & air permit approval	5/13 7/13 7/13	8/13 9/13 12/14	Ryan Sinclair Sinclair
Political Outreach	1. Develop plan to support project 2. Inform local political leaders of GR site selection	• This be done to support site, pipeline, and trans ROW acquisition	5/13 ?	7/13 ?	Siemens
Finance	1. Obtain approval for project costs in 2014 BP		5/13	12/13	Blake
Human Resources	1. Inform GR staff of project 2. Operations staff available for training 3. Staff ready for operations	• Timing of this as it relates to political and regulatory communications	? 1/17 12/17	? 12/17 12/17	Troost
Public Communications	1. Develop project communications plan	• Need to consider political, regulatory, customer, and employee issues	5/13	7/13	Whelan

Chronological Timeline of Major Events

May 2013

Begin SIS
File supplemental LGI request
Begin pipeline routing study
Begin geotechnical survey
Begin developing project communications plan
Begin developing political outreach plan

June 2013

Begin wetlands survey
Complete geotechnical survey

July 2013

Complete conceptual design
Begin CEA and siting study
Begin work on air permit application
Complete wetlands study
Complete project communications plan
Complete political outreach plan
Begin contract discussions with TGT

August 2013

Pipeline route selection
Begin preparing EPC bid package

September 2013

Pipeline build/buy decision
Siting study complete
CEA complete
Pipeline ROW optioning

October 2013

Complete SIS

November 2013

File CCN application
File air permit application
Begin transmission route study

December 2013

Complete EPC bid package
Begin facility study
Request PtP transmission service for testing
Request NITS for COD
Project capital approved in 2014 BP

January 2014

Issue EPC bid package

March 2014

Select transmission route
SIS complete
Start optioning transmission ROW
Begin preparing transmission CPCN

May 2014

Complete facility study
EPC bids due
File transmission CPCN application

July 2014

Sign LGIA
EPC short list

August 2014

Best & Final bid due

September 2014

Begin EPC negotiations

November 2014

Generation CCN order
Transmission CCN order
Start transmission ROW acquisition
Start pipeline ROW acquisition
Final air permit

December 2014

Execute gas transport agreement
EPC award

January 2015

Limited Notice to Proceed

March 2015

Final Notice to Proceed

May 2015

Finish transmission ROW acquisition absent eminent domain
Finish pipeline ROW acquisition absent eminent domain
File ED To acquire transmission & pipeline ROW

May 2016

All ROW available to construct

December 2016

Back feed power
Raw water available

January 2017

Operations staff available for training

May 2017

Fuel available
PtP transmission available
Full Electric export available
Unit testing begins

NITS available	November 2017
Target COD	
	January 2018
Guaranteed COD	

1. CRT clause ←
2. Interim report? - MJ
3. Any major ~~[illegible]~~ routing issues?
4. Smallscale Solar, Energy Efficiency?
5. Existing Documents - set together
6. Vendor Conversations, document

Owner's Cost for 2018 NGCC
BOT Costs to be Confirmed in Due Diligence

	Self Build	BOT	Notes
Project Development	6,500	1,000	Spec dev. & Contract Negotiations
Trans Line Relocation	1,750	-	Brown
Trans Inter. Facilities	5,500	-	Confirm W/TO and Erorra
NG Pipe Interconnection	14,250	-	Brown
NG Frim Transport Start up	6,750	-	Confirm if in BOT Price
Construction Power	750	-	Confirm if in BOT Price
Owner's Operators prior to COD	2,340	2,340	
Owner's Project Management	5,300	2,650	
Owner's Engineer	1,900	950	
Owners Legal Counsel	1,300	800	
Operator Training	225	225	
Pt to Pt for Testing	4,000	-	Confirm if in BOT Price
Net Testing Fuel/VO&M/Power	(1,799)		Fuel at $4.5/MMBTU, $36/MWH
Site Security	50	-	
Operating Spares	10,000	10,000	Confirm if in BOT Price
Office Furniture	350	350	Confirm if in BOT Price
Kitchen Furniture	130	130	Confirm if in BOT Price
Lab Equipment & Furniture	350	350	Confirm if in BOT Price
Locker Room Furniture	180	180	Confirm if in BOT Price
Workshop Tools & Equipment	1,800	1,800	Confirm if in BOT Price
IT / Telecommuniction Infrastructure	250	250	
NERC Cyber Security	1,000	1,000	
Property Tax During Construction	1,750	-	
AFUDC	5,500	-	
Total Owners Indirects	70,126	22,025	
LTSA	3,460	12,700	for Siemens F or $12,700 for GE F5
Total Non EPC	73,586	34,725	

EPC Scope Items

Raw Water Clarifier	2,500	Necessary for Future 316b compliance
BFP Building	600	
Aux Boiler	1,623	
Aux Boiler Building	440	
HRSG Penthouse	1,000	
HRSG Elevator	750	
HRSG Cycling Design	2,000	
Electrical Switchgear Building	500	
Spare Cooling Tower Cell	500	
Cooling Tower Fan VFD	400	
Auxiliary Cooling Water Pump	120	Typical IPP uses main CWP off-line
CW/BFP/Cond Pump Flow Margin	100	
BFP Hydraulic Coupling	300	
Condensate Polisher	1,200	
Shell & Tube CCCW Heat Exchanger	1,000	Plate & Frame typical IPP design
Condenser Cleanliness Factor - 85%	500	
Incremental Demin Tank Capacity	300	Typical IPP employs 12 hour storage
CTG Non Standard Options	1,000	IPP typically accept OEM standard
CTG Fast Start Upgrade (Purge Credit)	300	
Redundant CTG Static Start	400	Typical IPP employs common SFC
Storm Shelter Rated Control Room	400	
FM Global Recommendations	400	Typical IPP builds to NFPA Code only
Incremental Warehouse Capacity	300	Typical IPP builds min. size warehouse
Emergency Diesel Generator	200	
GSU Transformer Margin (5%)	500	
UAT Transformer Margin (20%)	250	
Steam Turbine Generator Breaker	500	
Tefzel Cable Insulation/Jacket	300	Typical IPP employs XLPE/PVC
Redundant Protective Relaying	100	Typical IPP overlaps zones only
Two Year Warranty vs. 1 Year from SC	2,000	1 Year Standard
EPC Direct Cost	20,483	
Construction Indirects	2,458	
Project Indirects	1376	
EPC Contingency and profit	2432	
Expected increase in BOT Scope	$ 26,749	

Comparable Gas Pipeline Service?

4/12/2013

1. XM costs have changed.
2. ERORA looks better.
    a. ERORA sale is approximately $60 million favorable.
        i. ERORA XM: ~$20 million favorable (before: ~$50 million unfavorable)
        ii. ERORA sale price has always been ~$50 million lower.
        iii. ERORA gas transportation is ~$10 million higher.
    b. ERORA PPA is $4-40 million favorable.
3. XM costs of building at GR versus BR will be higher. $\Delta \approx 25m$
4. Need to develop new cases for ERORA.

[illegible]

Process Background
[illegible]

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Meeting Future Capacity Needs in a World of Uncertainty

January 29, 2013

Lot to cover ~~[illegible]~~ Spent a lot of time for discussion but I can schedule a follow-up meeting with this group or subgroup - decide at end

The focus is not on numbers
Trying to organize the data around risk + uncertainties

Key uncertainties related to future resources

- *Capacity needs beginning in 2015 caused by existing retirement plans and load growth*
- *Downside load growth risk driven by continuing national and global economic challenges (new load forecast by June)*
- *Future natural gas prices*
- *Potential environmental regulations on CO2 and fracking*
- *Availability of CCGT resources: self-build and 3rd party alternatives might not be doable by 2017*
- *Future of Brown 1&2 – existing and future regulations and future coal/gas price spread*

– Upside would be on existing path to solve, (Construct CCG as soon as possible.

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Capacity could be needed as early as 2015 but could be as late as 2022

(This is the "problem" we are trying to solve)
— along with energy —

shaded = short

Reserve Margin Over/(Under) 15% (MW)	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*
With Brown 1-2							
Base Load Forecast	7	(64)	(111)	(226)	(285)	(362)	(440)
Low Load Forecast	359	309	282	188	152	100	51
Without Brown 1-2							
Base Load Forecast	(265)	(333)	(380)	(495)	(554)	(631)	(709)
Low Load Forecast	87	40	13	(81)	(117)	(169)	(218)
Incremental DSM above 2012 level (reflected in the data above)	*125*	*157*	*189*	*221*	*203*	*205*	*206*

in this time
some more
Ameren US Power
CCGT
some more

261 MW Today

January 29, 2013

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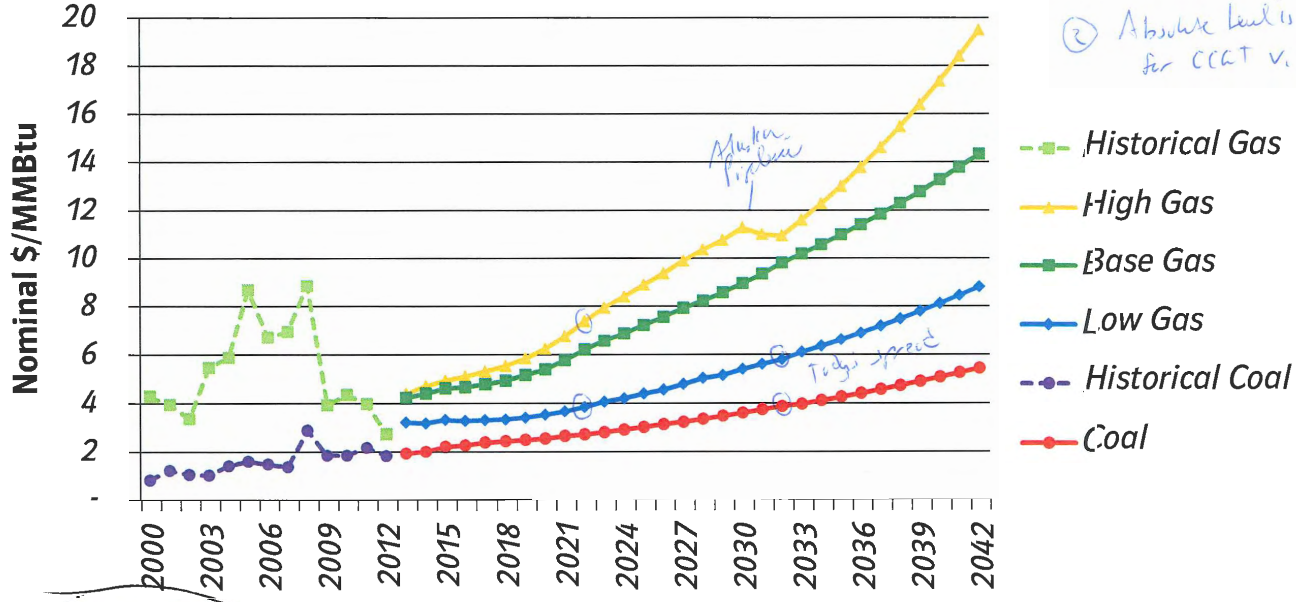
Attachment to Response to KIUC Question No. 1-6
Page 497 of 543
Sinclair

Wide range of possible future gas prices

① Spread between coal + gas is crucial for B1&2

② Absolute level is important for CCGT v. SCCT

Natural Gas (Henry Hub) and Coal (ILB HS-f.o.b. Mine) Prices



Source: EIA

Gas = ~$3.50 Today
10 years out – $4.00 + $7.00

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Alternative strategies to address capacity need

- *Key Question – Do we need to commit to a long-term resource now?*
  - *The Companies have a history of long-term commitments*
  - *Options could be valuable given major uncertainties*
  - *Most long-term solutions are not available until 2017 at the earliest so short-term capacity could still be needed*
- *Alternatives:*
  - *Short term approach enables better information on key uncertainties*
  - *Long-term approach that works best given possible outcomes for key uncertainties*

Short-term v. Long-term strategies

Approach	Pros	Cons	Risks
Short-term eg. Downward CCN?	• *Better information on Key Uncertainties* • *Could be lower cost in short-term* • *Could be easier regulatory process* • *Potentially capture future technology improvements*	• *Could pay a premium in the long-run* • *Justification of transmission upgrades absent LT system benefits* Eg - LT Pur ≈ $64 m NPVRR over Base Arrow 300 - 80 500 = $40 m	• *Pass on viable LT resource* • *Could create ability for future regulatory second guessing* • *Key Uncertainties remain largely unresolved* Possibly less than LT option opportunity cost v. real cost
Long-term	• *Consistent with past practice* • *Lock-in future capacity costs & technology*	• *Give up some future resource flexibility to address Key Uncertainties* • *Forego technology improvements*	• *Key uncertainties are resolved adverse to resource choice* • *Regulatory second guessing*

AEP out –
not what we thought

Alternatives to address short-term needs

- *LS Power (495 MW)*
  - — *Can defer capacity need until at least 2019 at relatively low cost*
  - — *Keeps these units economically viable and creates future optionality (asset purchase, future PPA)* doing no deal increases probability that they go away
- *Ameren (334-501 MW)*
  - — *Sourced from Joppa*
  - — *Based on current environmental compliance plan, Joppa may not be viable beyond 2019*
- *Purchase firm transmission and source energy from the market* (PJM & MISO appear to have adequate capacity ~~past~~ 2015
  - — *Probably do not want do this for more than 200 MW (~ 2% of reserve margin)*
- *Retrofit Brown 1&2 (272 MW) with FGD additive technology (Nalco)*
  - could be LT as well
  - gets us through Summer 2015
  - operation could be limited to ~~Summer or~~ when BR 3 is operating (summer & winter)

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Alternatives to address long-term needs

- *LS Power (495 MW) – PPA w/ or w/o purchase option*
  - *Available in 2015*
  - *FERC approval of purchase remains uncertain*
  - *Long-term v. multiple short-term PPAs*
- 2017? *ERORA (700 MW greenfield CCGT) – PPA or Purchase* transmission questions!
- *Khanjee (700 MW greenfield CCGT) – PPA*
- Not competitive *Big Rivers (417 MW from Wilson) – PPA or Purchase*
  - *Available in 2015* - ~~Very expensive~~ Proposal not well developed - Asking us to solve their problem - rather than solving ours - lots of work - RUS, etc. approval process.
- 2017? *Self-build (600-700 MW CCGT)*
  - *Still evaluating site specific costs at Brown and Green River* (Need to get our costs down)
- *Retrofit Brown 1&2 (272 MW)*
  - *Baghouse v. FGD additive (Nalco)*

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LT Capex is just extension of current cycle – nothing special
B1 – 85% in 2042
B2 – 79% in 2042

CR – 46-53 when retire
2008 DRP Aggressive Green

Future of Brown 1&2 remains in doubt

- *How long will units operate even with proposed upgrades?*
- *Increasing risk of CO_2 regulations on existing units* (EEI – maybe this fall, Dragged
- *Future Gas/Coal spread that will support baghouse retrofit* – need B-to-be better
- *Baghouse progress payments in 2013 ($12.4 million)* – next slide
- *Major capital planned in 2013-14 (~$14 million)* – would eliminate w/some other adder if going to retire
- *Nalco test results* – could create optionality for the future
- *What has changed since December 2011 KPSC settlement?*
  - (+) — *Baghouse capital costs decreased by $34 million (from $228 to $194)*
  - (+) — *Baghouse operating costs decreased by $13/MWH (from $15 to $2)*
  - (–) — *Long-term view of gas prices is lower by ~$3/mmBtu (~$21/MWh for CCGT)*
  - (–) — *Increasing risk of CO2 regulations* – key issue ~~the~~ last time, harder to defend in current environment ("elections have consequences")
  - — *SCR installation risk is about the same*
- *Economic justification of baghouses may be closer than in 2011*

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Baghouse progress payments begin to mount

Baghouse Cumulative Progress Payments
$(000)

2013	BR1	BR2	Total
Apr	430	485	915
May	859	971	1,830
Jun	1,633	1,845	3,478
Jul	1,633	1,845	3,478
Aug	3,695	4,175	7,870
Sep	5,242	5,923	11,165
Oct	5,242	5,923	11,165
Nov	5,242	5,923	11,165
Dec	5,843	6,603	12,446

Orient

Value varies with Key Uncertainties

Heavy weighting on this case last time (CIN + ECK)

Not ~~deciding now~~ deciding now

deciding now

ranked

Alternative	Next CCGT												
	Gas	BG	BG	BG	BG	HG	HG	HG	HG	LG	LG	LG	LG
	Load	BL	BL	LL	LL	BL	BL	LL	LL	BL	BL	LL	LL
	Carbon	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC
1 - PPA (2015-16) & CCGT (2017)	2021												
2 - Coal PPA (2015-19)	2019												
3 - BR1-2 Baghouse Retrofit	2018												
4 - 2015 Asset Purchase (SCCT)	2019												
5 - BR1-2 Baghouse Retrofit (Retire 2030)	2018												

Gas: Base/Mid (BG), High (HG), Low (LG) Load: Base (BL), Low (LL) Carbon: Zero (0C), Mid (MC)

<-Better/Worse->

- *Alt #1 – Prefer CCGT in low-gas and mid-carbon scenarios* Start w/ #2 3/then in 2020 + end 7.8% (Siegel = SC)
- *Alt #2 – Short-term PPA viable in most scenarios; prefer coal to SCCT* (BH+L in the way out) Ameren LS Power
- *Alt #3 – Prefer BR1-2 retrofit in zero carbon and mid-high gas price scenarios*
- *Alt #4 – Prefer SCCT purchase in zero carbon and mid gas price scenario* HG + LL Favor CCGT
- *Alt #5 – BR1-2 retrofit not favorable if units don't operate through 2042*

You always end up w/a CCGT - just when?

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Path Forward

- *February*
  - — *Finalize bids from ERORA, LS Power, and Ameren* (we also need to decide what we would prefer from them.
  - — *Provide detailed due diligence questions to Khanjee and Big Rivers* – down for KBSC
  - — *Finalize self-build costs* (and location – linked to BR 1+2)
- *March*
  - — *Make decision on Brown 1&2 baghouse retrofit* – start spending money on Baghouse – influence, value of ocean alternative – high risk solution
  - — *Assess potential of Nalco process for Brown 1&2*
  - — *Finalize financial and risk analysis*
  - — *Recommend alternative(s) for future capacity*

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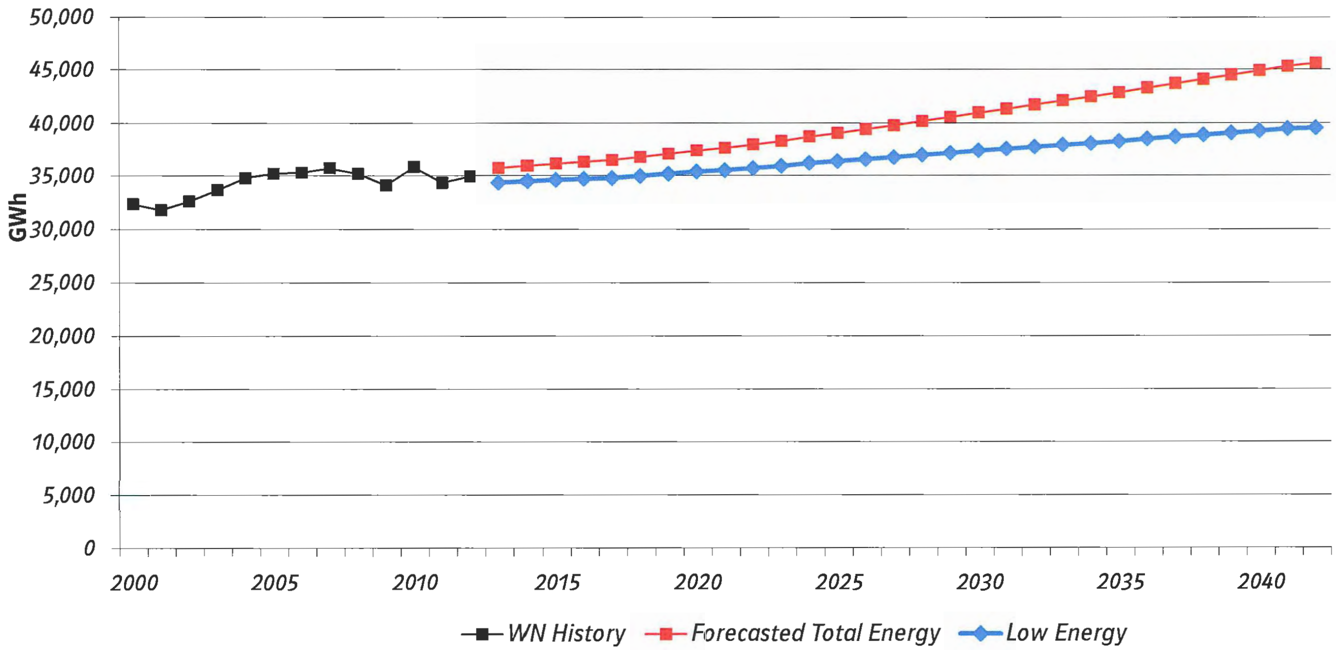
Appendix

Combined Company Energy Requirements



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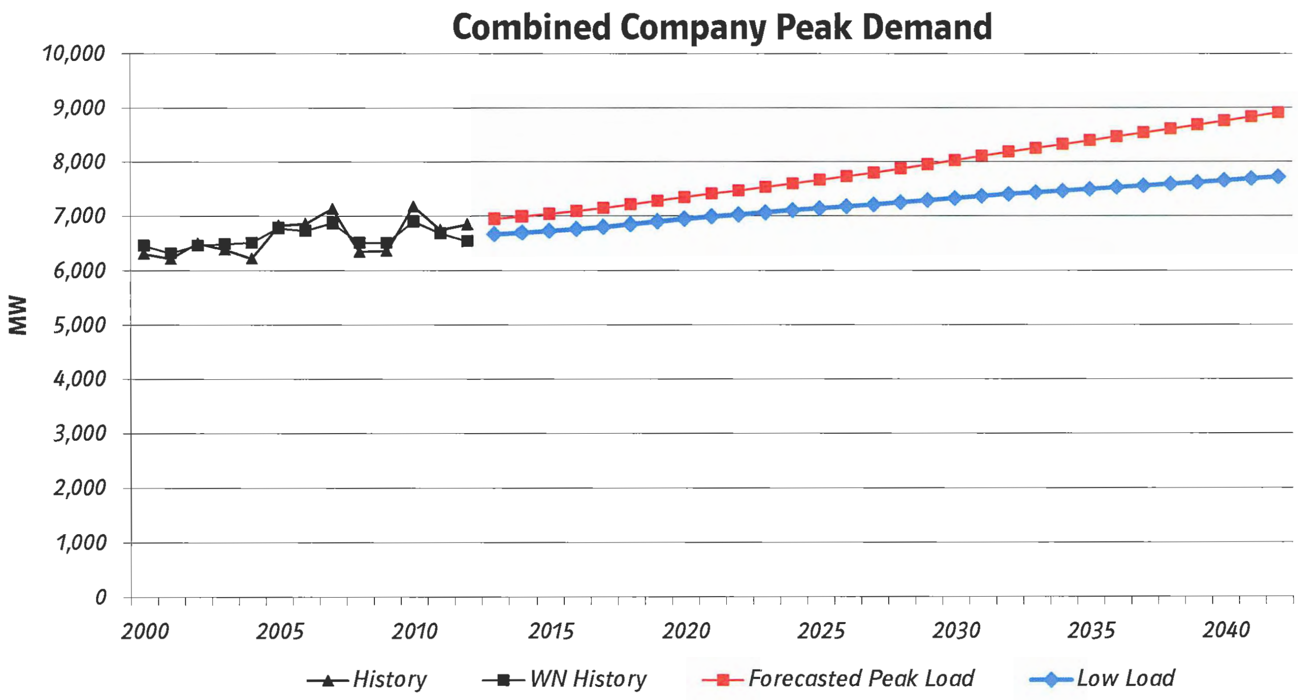
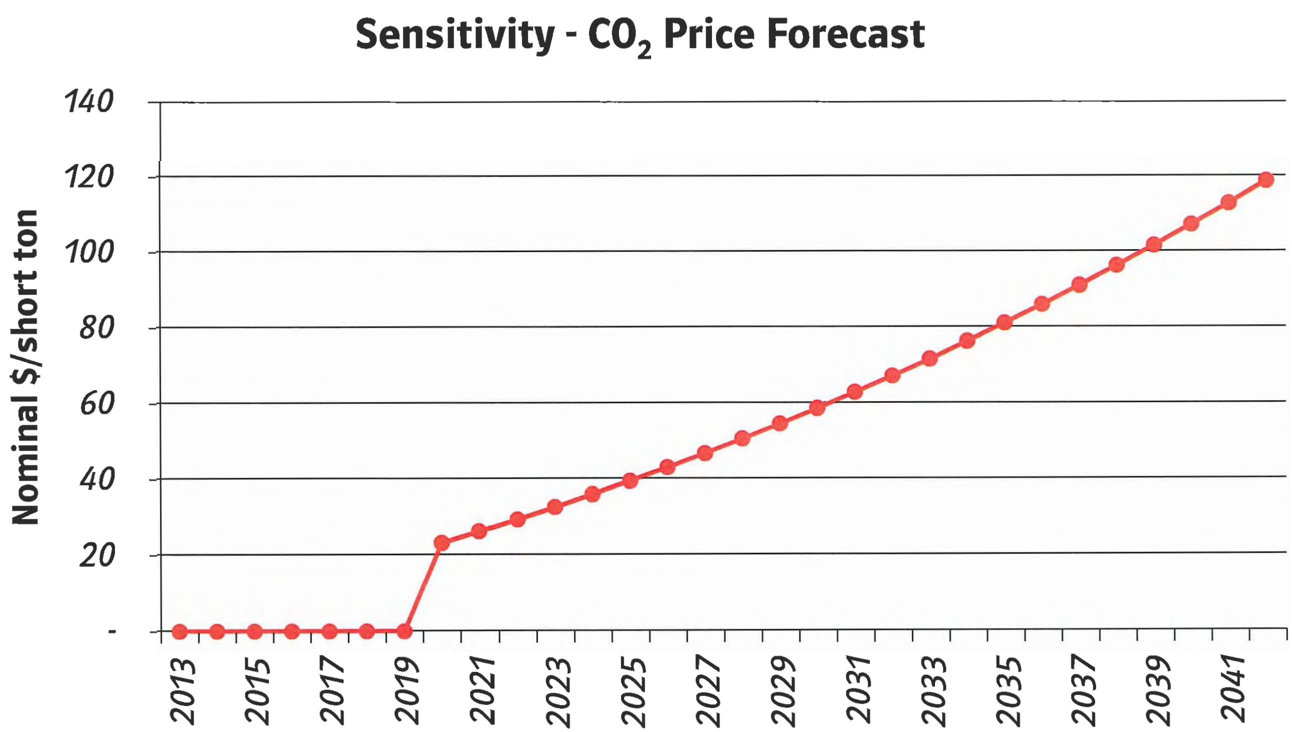
Peak Demands



** Historical peaks not adjusted for curtailments.*

CO_2 price sensitivity starting in 2020



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Background write-up
CCGT economic results
analysis - technology choice

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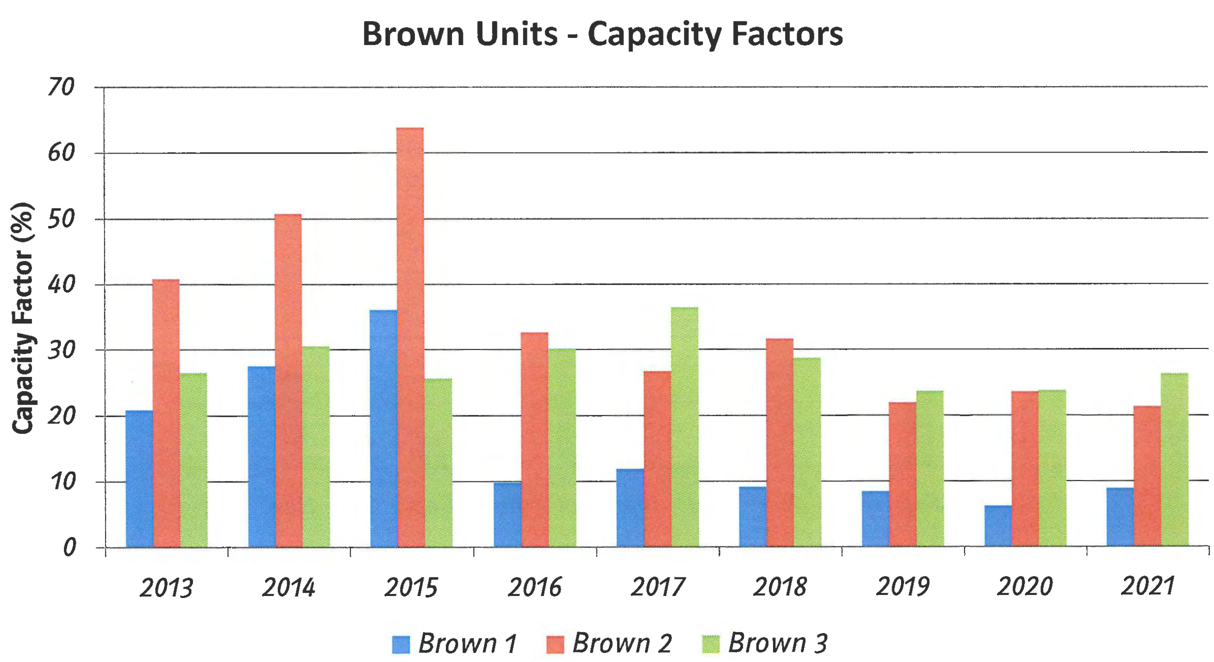
RFP Update

February 18, 2013

Questions still to be answered

- *Final decision on Brown baghouses*
- *Refined transmission costs, including:*
  - *Network cost for Erora*
  - *Short term PPA sources/capacity*
  - *Brown site transmission cost*
- *Brown 1&2 Nalco test results*
- *Economic implications of Nalco at Brown 1&2*
  - *Nalco costs of $6/MWh could minimize capacity factors, affecting other O&M and capital plans*
  - *Potential for retiring Brown 1 and retaining Brown 2?*
- *Consider moving forward assuming 2018 CCGT at Brown?*
  - *Determine best short term PPA solution based on BR 1&2 decision*

Brown 1 dispatch may be limited if Nalco results in higher O&M costs



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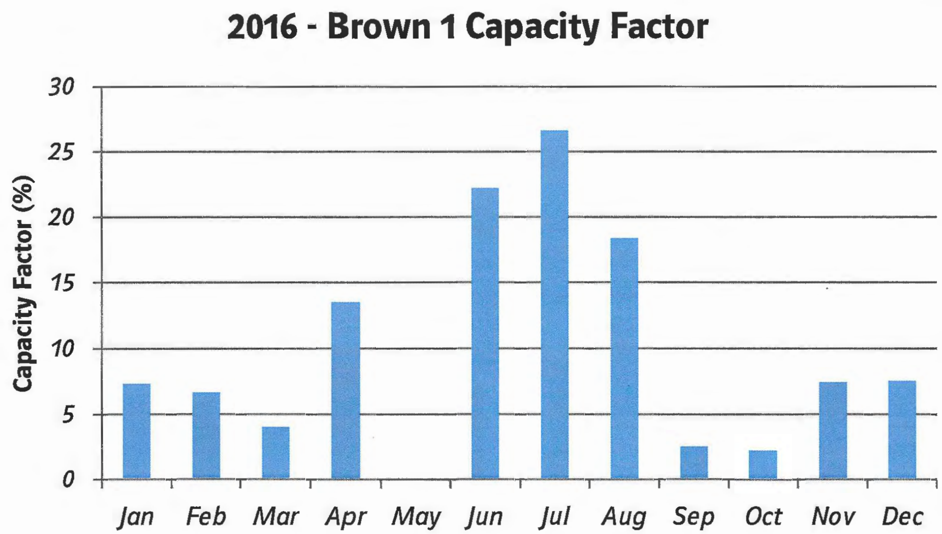
Brown 1 could have very limited dispatch outside of summer months



Brown 1 2016 - Percent of Operating Hours at Generation Level

Month	1	2	3	4	5	6	7	8	9	10	11	12
Offline	78%	80%	88%	60%	100%	37%	25%	50%	93%	94%	78%	78%
Min Load	22%	20%	12%	40%	0%	61%	74%	47%	7%	6%	22%	22%
> Min Load	0%	0%	0%	0%	0%	2%	2%	3%	0%	0%	0%	0%

What is known regardless of Brown decision?

- *CCGT is least cost resource in 2018-2020 timeframe*
  - *Even with Brown 1&2, over 200 MW is needed to reach a 15% RM in 2018 with base load case*
  - *Energy savings outweigh lumpy capacity addition*

- *Short-term PPA is still needed, covering at least 2015-2017*
  - *Capacity amount will vary based on Brown 1&2 decision*

- *LS Power is not a long-term preferred option*
  - *Ranks highly only in base load/base gas/no carbon case*

Potential short term PPAs with 2018 CCGT

- *Less capacity from two sources may minimize transmission costs*
- *Without Brown 1&2*
  - *— 167 or 334 MW from Ameren + 165 MW from LS Power*
- *With Brown 1&2*
  - *— 167 MW from Ameren or 165 MW from LS Power*
- *With Brown 2 only (retiring 106 MW Brown 1)*
  - *— 167 MW from Ameren + 165 MW from LS Power*

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Benefits of decision on Brown 1&2 baghouses

- *Eliminates need to renegotiate baghouse progress payments*
- *More time for Nalco evaluation*
- *Still enables early 2018 CCGT*
- *Fall CCGT CCN filing benefits from refreshed information and developments*
  - *New load forecast*
  - *DSM Potential Study close to completion*
  - *GHG regulations/proposals potentially taking shape*

Path Forward (unchanged from Jan 29)

- *February*
  - — *Finalize bids from ERORA, LS Power, and Ameren*
  - — *Provide detailed due diligence questions to Khanjee and Big Rivers*
  - — *Finalize self-build costs*

- *March*
  - — *Make decision on Brown 1&2 baghouse retrofit*
  - — *Assess potential of Nalco process for Brown 1&2*
  - — *Finalize financial and risk analysis*
  - — *Recommend alternative(s) for future capacity*

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Appendix

Capacity could be needed as early as 2015 but could be as late as 2022

Reserve Margin Over/(Under) 15% (MW)	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*
With Brown 1-2							
Base Load Forecast	7	(64)	(111)	(226)	(285)	(362)	(440)
Low Load Forecast	359	309	282	188	152	100	51
Without Brown 1-2							
Base Load Forecast	(265)	(333)	(380)	(495)	(554)	(631)	(709)
Low Load Forecast	87	40	13	(81)	(117)	(169)	(218)
Without Brown 1							
Base Load Forecast	(159)	(227)	(274)	(389)	(448)	(525)	(603)
Low Load Forecast	193	146	119	25	(11)	(63)	(112)

Value varies with Key Uncertainties

Alternative	Gas	BG	BG	BG	BG	HG	HG	HG	HG	LG	LG	LG	LG
	Load	BL	BL	LL	LL	BL	BL	LL	LL	BL	BL	LL	LL
	Carbon	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC
	Next CCGT												
1 - PPA (2015-16) & CCGT (2017)	2021												
2 - Coal PPA (2015-19)	2019												
3 - BR1-2 Baghouse Retrofit	2018												
4 - 2015 Asset Purchase (SCCT)	2019												
5 - BR1-2 Baghouse Retrofit (Retire 2030)	2018												

Gas: Base/Mid (BG), High (HG), Low (LG) *Load: Base (BL), Low (LL)* *Carbon: Zero (0C), Mid (MC)*

<-Better/Worse->

- *Alt #1 – Prefer CCGT in low-gas and mid-carbon scenarios*
- *Alt #2 – Short-term PPA viable in most scenarios; prefer coal to SCCT*
- *Alt #3 – Prefer BR1-2 retrofit in zero carbon and mid-high gas price scenarios*
- *Alt #4 – Prefer SCCT purchase in zero carbon and mid gas price scenario*
- *Alt #5 – BR1-2 retrofit not favorable if units don't operate through 2042*

PPL companies

Sinclair, David

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

$000s in 2013$

Rank	Alternative	Avg NPVRR - All Cases	Diff from Best
1	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	31,461,412	0
2	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,477,935	16,524
3	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	31,478,253	16,842
4	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	31,480,542	19,130
5	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	31,483,507	22,095
6	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	31,487,889	26,478
7	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	31,491,948	30,536
8	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	31,493,277	31,866
9	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	31,494,596	33,184
10	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	31,495,211	33,799
11	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	31,495,331	33,919
12	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	31,496,569	35,158
13	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,502,358	40,946
14	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	31,509,317	47,906
15	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	31,512,597	51,185
16	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,517,783	56,372
17	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	31,519,623	58,211
18	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	31,520,354	58,942
19	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,545,084	83,673
20	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,574,389	112,978
21	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	31,578,006	116,594
22	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	31,590,372	128,960
23	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,615,870	154,458
24	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	31,621,181	159,770
25	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	31,645,457	184,046
26	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	31,947,057	485,645
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	32,144,975	683,563

6-18-13

Rank	Alternative	$000s in 2013$ Avg NPVRR - Zero Carbon	Diff from Best
1	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,557,696	0
2	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,623,617	65,921
3	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	24,718,159	160,463
4	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	24,719,147	161,451
5	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,724,459	166,763
6	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	24,727,587	169,892
7	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	24,730,971	173,275
8	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	24,731,977	174,281
9	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,740,983	183,287
10	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,741,301	183,605
11	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,743,589	185,893
12	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	24,748,004	190,309
13	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	24,750,936	193,241
14	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	24,755,030	197,335
15	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,756,325	198,629
16	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	24,757,643	199,947
17	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,758,258	200,562
18	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,765,405	207,709
19	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,772,365	214,669
20	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,780,831	223,135
21	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	24,783,401	225,705
22	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	24,803,728	246,032
23	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,808,484	250,788
24	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,837,789	280,093
25	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	24,851,149	293,453
26	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,879,195	321,499
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	24,958,577	400,881

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$000s in 2013$

Rank	Alternative	Avg NPVRR - Mid Carbon	Diff from Best
1	Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	38,198,364	0
2	Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,214,888	16,524
3	Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,215,206	16,842
4	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	38,217,494	19,130
5	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	38,224,842	26,478
6	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	38,230,230	31,866
7	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,231,548	33,184
8	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,232,164	33,799
9	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,239,310	40,946
10	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	38,246,270	47,906
11	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	38,247,867	49,503
12	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,254,736	56,372
13	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	38,256,308	57,944
14	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	38,257,306	58,942
15	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	38,259,691	61,327
16	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	38,261,162	62,797
17	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	38,277,189	78,824
18	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,281,685	83,320
19	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	38,284,215	85,850
20	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,310,990	112,626
21	Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,352,546	154,181
22	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	38,377,016	178,652
23	LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	38,391,214	192,850
24	LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,598,315	399,951
25	LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,667,297	468,933
26	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	39,175,956	977,591
27	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	39,331,372	1,133,008

Nominal Revenue Requirement Differences ($000s, 2013$)

6/18/2013

	Base Gas				High Gas				Low Gas			
Year	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18) vs. Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)		LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20) vs. Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)		Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18) vs. Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)		LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20) vs. Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)		Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18) vs. Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)		LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20) vs. Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	
2013	Transmission NPV 14,163		-7,556		14,163		-7,556		14,163		-7,556	
2014	0		0		0		0		0		0	
2015	14,550		0		14,554		0		14,578		0	
2016	45,122	149	3,046		45,139		5,610	65	45,359		-60	
2017	49,244		7,236	45	49,082	178	9,589		49,311	32	1,164	15
2018	29,742		14,960		43,322		21,385		-28,630		4,612	
2019	10,692		19,953		26,297		28,743		-48,526	savings	9,452	
2020	-9,201		0		-9,354		0		-9,326		0	
2021	-9,708		0		-9,577		0		-9,846		0	
2022	-9,255		0		-9,177		0		-9,475		0	
2023	-9,137		0		-8,844		0		-9,161		0	
2024	-8,845		0		-8,510		0		-8,578		0	
2025	-8,382		0		-7,784		0		-8,052		0	
2026	-8,570		0		-8,132		0		-8,895		0	
2027	-6,634		0		-9,497		0		-8,663		0	
2028	-8,399		0		-7,096		0		-8,432		0	
2029	-8,205		0		-8,704		0		-8,036		0	
2030	-6,833		0		-7,267		0		-8,577		0	
2031	-7,603		0		-6,752		0		-7,403		0	
2032	-6,118		0		-8,610		0		-6,083		0	
2033	-6,877		0		-5,421		0		-11,537		0	
2034	-9,343		0		-1,932		0		-6,311		0	
2035	-7,114		0		-7,559		0		-5,480		0	
2036	32,095		0		30,852		0		27,931		0	
2037	-12,779		0		-10,400		0		-20,034		0	
2038	-48,054		0		-47,838		0		-48,699		0	
2039	-2,774		0		-2,084		0		-3,388		0	
2040	-2,295		0		-4,505		0		-3,144		0	
2041	-7,059		0		-2,774		0		-10,617		0	
2042	-1,735		0		-3,712		0		2,384		0	

6-18-13

Alternative	Average NPVRR ($000s, 2013$)			Rank			Difference from Best		
	0C	MC	All Cases	0C	MC	Avg	0C	MC	Avg
LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	24,727,587	38,256,308	31,491,948	6	13	7	169,892	57,944	30,536
LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	24,750,936	38,224,842	31,487,889	13	5	6	193,241	26,478	26,478
LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,743,589	38,217,494	31,480,542	11	4	4	185,893	19,130	19,130
Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	24,719,147	38,247,867	31,483,507	4	11	5	161,451	49,503	22,095
Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,741,301	38,215,206	31,478,253	10	3	3	183,605	16,842	16,842
Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,724,459	38,198,364	31,461,412	5	1	1	166,763	0	0
LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	24,748,004	38,277,189	31,512,597	12	17	15	190,309	78,824	51,185
LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,772,365	38,246,270	31,509,317	19	10	14	214,669	47,906	47,906
LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,765,405	38,239,310	31,502,358	18	9	13	207,709	40,946	40,946
LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,623,617	38,667,297	31,645,457	2	25	25	65,921	468,933	184,046
Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	24,731,977	38,261,162	31,496,569	8	16	12	174,281	62,797	35,158
Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,756,325	38,230,230	31,493,277	15	6	8	198,629	31,866	31,866
Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,740,983	38,214,888	31,477,935	9	2	2	183,287	16,524	16,524
Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,879,195	38,352,546	31,615,870	26	21	23	321,499	154,181	154,458
Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	24,958,577	39,331,372	32,144,975	27	27	27	400,881	1,133,008	683,563
Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,837,789	38,310,990	31,574,389	24	20	20	280,093	112,626	112,978
Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	24,718,159	39,175,956	31,947,057	3	26	26	160,463	977,591	485,645
LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	24,851,149	38,391,214	31,621,181	25	23	24	293,453	192,850	159,770
LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,557,696	38,598,315	31,578,006	1	24	21	0	399,951	116,594
LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,808,484	38,281,685	31,545,084	23	18	19	250,788	83,320	83,673
Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	24,730,971	38,259,691	31,495,331	7	15	11	173,275	61,327	33,919
Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,758,258	38,232,164	31,495,211	17	8	10	200,562	33,799	33,799
Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	24,757,643	38,231,548	31,494,596	16	7	9	199,947	33,184	33,184
Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	24,755,030	38,284,215	31,519,623	14	19	17	197,335	85,850	58,211
Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	24,783,401	38,257,306	31,520,354	21	14	18	225,705	58,942	58,942
Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,780,831	38,254,736	31,517,783	20	12	16	223,135	56,372	56,372
LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	24,803,728	38,377,016	31,590,372	22	22	22	246,032	178,652	128,960

Rankings

6/18/2013

Gas Price	BG				HG				LG					
Load	BL		LL		BL		LL		BL		LL			
Carbon	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC	0C	MC	Avg	Mode
LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	9	14	9	14	9	17	8	16	4	4	4	4	9	4
LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	13	6	14	6	19	9	20	9	1	2	1	1	8	1
LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	7	3	6	2	15	5	14	3	10	10	6	6	7	6
Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	6	13	5	13	5	13	6	13	3	1	3	3	7	13
Ameren 1 Unit (2016-2017), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	8	4	11	4	14	4	16	5	2	3	2	2	6	4
Ameren 1 Unit (2016-2017), 2 Units (2018-2019); BR 2x1 constrained CCGT (Jan '20)	4	1	4	1	8	1	10	1	5	6	5	5	4	1
LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	17	18	16	18	12	20	11	19	12	12	12	12	15	12
LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	20	11	20	10	22	12	22	11	11	11	9	9	14	11
LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	16	9	15	7	20	10	18	7	14	15	14	14	13	14
LS Power 3 CTs (2016-2019), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	2	25	2	25	3	25	3	25	21	25	25	25	17	25
Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	11	16	12	17	6	14	7	15	9	8	11	11	11	11
Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	14	7	18	9	16	6	17	6	8	9	10	10	11	9
Ameren 2 Units (2016-2019), BR 2x1 constrained CCGT (Jan '20)	5	2	8	3	10	2	13	2	13	13	13	13	8	13
Wilson (2016-2019), BR 2x1 constrained CCGT (Jan '20)	26	22	27	21	26	22	26	22	25	22	24	22	24	22
Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	25	27	26	27	4	27	4	27	27	27	27	27	23	27
Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24	20	25	20	23	15	25	18	24	21	22	20	21	20
Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	3	26	3	26	1	26	1	26	26	26	26	26	18	26
LS Power 1 CT (2016-17); ERORA PPA (2018-2037)	22	23	24	23	27	24	27	24	23	23	23	21	24	23
LS Power 1 CT (2016-17), 2 CTs (2018-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	1	24	1	24	2	21	2	23	18	24	21	24	15	24
LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	23	17	23	15	24	18	24	14	20	19	19	19	20	19
Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	10	15	10	16	7	16	9	17	7	5	8	8	11	10
Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	15	8	17	8	18	8	21	10	6	7	7	7	11	8
Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	12	5	13	5	13	3	15	4	17	17	15	15	11	15
Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	18	19	19	19	11	19	12	20	15	14	17	16	17	19
Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	21	12	22	12	21	11	23	12	16	16	16	17	17	12
Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	19	10	21	11	17	7	19	8	19	18	18	18	15	19
LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	27	21	7	22	25	23	5	21	22	20	20	23	20	21

2 year only (2018 GR) Amerson is preferable to LJ by $8m

Coleman Asset purchase saves $1m in No CO_2 v Amerson / 2018 GR
but costs $900+m w/ CO_2

LJ Asset purchase is what makes it best in No CO_2 world but
we are unlikely to know that for certain by 2020

Amerson only w/ CO_2 - best to defer to 2020 + PPA for 1 or 2 units

Coleman	LJ
4	5
16	14
	Amer
4	1
4	2

Coleman PPA better than LJ for 4 year PPA but not 2 year PPA

Coleman is $17m > Amerson in 2020 case w/ 1+2 unit deal
but tied in 2 unit deal

~~Operational flexibility does not affect GR v. BA capital costs~~

Next Steps – GP [illegible] case + assumptions [illegible] w/ [illegible]
- [illegible] Δ's w/ [illegible] + LGE/KU
- Answer proposal on 1 + 2 unit deal for 4 years
- run [illegible] w/ [illegible] + 1x1 case
- may need to talk to [illegible] about 4 year [illegible] billing

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Black box of [illegible] – difficult to analyze
- [illegible] on GP for [illegible] costs

2 [illegible] – need time for GP + [illegible] to review
- [illegible] [illegible]

LJ + [illegible] info

GasPrice	Low Gas
Load	Base Load
CO2	Zero Carbon

Total Cost Delta

Year	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20) vs. LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20) vs. LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)
2012	0	0
2013	0	51,913
2014	0	0
2015	-12,793	-12,793
2016	-38,092	-38,043
2017	-39,586	-40,482
2018	23,980	20,654
2019	39,180	32,793
2020	5,965	5,965
2021	5,782	5,782
2022	5,173	5,173
2023	4,712	4,712
2024	4,203	4,203
2025	3,834	3,834
2026	3,248	3,248
2027	2,999	2,999
2028	2,651	2,651
2029	2,867	2,867
2030	2,234	2,234
2031	1,948	1,948
2032	2,158	2,158
2033	1,975	1,975
2034	1,744	1,744
2035	1,799	1,799
2036	-6,871	-6,871
2037	1,761	1,761
2038	8,430	8,430
2039	1,030	1,030
2040	600	600
2041	359	359
2042	752	752
Total	32,041	73,394

+66 -156 -27

GasPrice Mid Gas
Load Base Load
CO2 Zero Carbon

Total Cost Delta		
Year	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20) vs. LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20) vs. LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)
2012	0	0
2013	0	51,913
2014	0	0
2015	-12,768	-12,768
2016	-38,205	-40,709
2017	-38,877	-44,449
2018	-10,663	-21,455
2019	6,258	-7,225
2020	7,024	7,024
2021	7,477	7,477
2022	8,921	8,921
2023	7,941	7,941
2024	6,919	6,919
2025	6,611	6,611
2026	5,585	5,585
2027	5,912	5,912
2028	5,188	5,188
2029	5,017	5,017
2030	4,387	4,387
2031	4,328	4,328
2032	3,635	3,635
2033	4,209	4,209
2034	3,783	3,783
2035	4,133	4,133
2036	-5,338	-5,338
2037	3,578	3,578
2038	11,332	11,332
2039	3,945	3,945
2040	3,497	3,497
2041	2,438	2,438
2042	2,663	2,663
Total	18,928	38,490

-4
-95

GasPrice	High Gas
Load	Base Load
CO2	Zero Carbon

Total Cost Delta

Year	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20) vs. LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20) vs. LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)
2012	0	0
2013	0	51,913
2014	0	0
2015	-12,772	-12,772
2016	-38,212	-42,824
2017	-38,867	-46,251
2018	-15,825	-31,252
2019	1,653	-17,770
2020	9,407	9,407
2021	8,854	8,854
2022	9,286	9,286
2023	9,235	9,235
2024	8,420	8,420
2025	9,880	9,880
2026	9,772	9,772
2027	8,091	8,091
2028	9,108	9,108
2029	8,326	8,326
2030	7,657	7,657
2031	6,764	6,764
2032	5,171	5,171
2033	6,390	6,390
2034	6,759	6,759
2035	6,592	6,592
2036	-3,982	-3,982
2037	4,854	4,854
2038	13,713	13,713
2039	5,757	5,757
2040	5,081	5,081
2041	4,531	4,531
2042	5,053	5,053
Total	60,697	65,763

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- 2018 unit is a good decision – Least-cost in 4 of 12 cases (all are low gas cases) and never worse than 8th.
- Delaying next unit until 2020 is lowest cost in 4 of 12 cases (all involve carbon and base or high gas prices).
- Building in 2018 is lower in cost than 2020 unit in 8 of 12 cases (all zero carbon cases and low gas cases).
- Building 2018 CCGT reduces average PVRR by $10.3 million over 2020 unit – very close.
- Delaying next unit until 2020 could reduce revenue requirements through 2019.
    - "Renting" LS Power capacity in the short-term is cheaper than initial rate impact of CWIP and Plant in Service/depreciation associated with building in 2018 (lower revenue requirements by ~$90 million in 2015 – 2018). LS v GR Lev Cud
    - Even with Low Gas Prices, not enough energy savings to offset early year construction revenue requirements compared to PPA costs.

- Qualitative benefits of 2018
    - Allows "netting out" for air permit.
    - Increases high efficiency gas-fired capacity in the fleet sooner.
    - Creates jobs in western KY sooner (construction and permanent).
    - Implements long-term capacity solution sooner.
    - Increases ability to reduce CO2 emissions sooner.

- Qualitative benefits of delaying until 2020
    - Because we are making no long-term decision, Big Rivers and Erora should be less of an issue
    - "Renting" LS Power is consistent with prior strategy of owning but without the regulatory risk and downside carbon (prefer CCGT with carbon regulations).
    - Allows time to complete and operate CR7, thus potentially reducing technology risk
    - Short-term customer experience enhancement (due to lower revenue requirements) offset by slightly higher annual revenue requirements from 2020 onward. (Note that the breakeven date for 2018 v 2020 is around 2035).
    - LS Power PPA is a non-event from environmentalist's perspective.
    - Allows more time to see how carbon regulations and load growth develop (reduces excess capacity argument).

- PVRR of delaying via LS Power is $25 million better than Ameren on average
    - Transmission upgrades required for Ameren - $50 million PVRR

JF LS Seg ok to 1 + 2 [illegible] [illegible]

JF2 LS Seg 1 [illegible] 2018

JF LS Sg 3 [illegible] [illegible] 2019 2018

or talk to [illegible]

6/5/2013

Rank	Alternative	Base Gas Base Load Zero Carbon	Base Gas Base Load Medium Carbon	Base Gas Low Load Zero Carbon	Base Gas Low Load Medium Carbon	High Gas Base Load Zero Carbon	High Gas Base Load Medium Carbon	High Gas Low Load Zero Carbon	High Gas Low Load Medium Carbon	Low Gas Base Load Zero Carbon	Low Gas Base Load Medium Carbon	Low Gas Low Load Zero Carbon	Low Gas Low Load Medium Carbon	Average NPVRR Zero Carbon	Average NPVRR Medium Carbon	Average NPVRR All Cases
1	LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	5	5	6	6	7	8	7	7	1	1	1	1	5	3	1
2	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	7	1	7	1	9	1	13	1	5	4	4	4	7	1	2
3	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	9	2	9	2	14	4	23	4	2	2	2	2	8	2	3
4	LS Power 2 CTs (2016-17); GR 2x1 CCGT (Jan '18)	8	9	8	9	8	10	8	10	3	3	3	3	6	7	4
5	LS Power 2 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	11	4	10	3	15	5	20	3	7	6	6	6	9	4	5
6	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	10	3	11	4	11	2	17	2	10	9	8	8	10	5	6
7	LS Power 2 CTs (2016-18); BR 2x1 constrained CCGT (Jan '19)	12	6	12	5	16	6	28	6	6	5	5	5	11	6	7
8	Ameren 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	13	7	13	7	13	3	25	5	13	12	12	12	13	8	8
9	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	14	8	16	8	17	7	29	8	8	7	7	7	14	9	9
10	Ameren 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	16	10	18	10	18	9	30	9	11	10	10	10	16	10	10
11	Ameren 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	15	11	14	11	10	12	11	11	9	8	9	9	12	11	11
12	Ameren 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	17	12	17	12	12	13	15	12	12	11	11	11	15	12	12
13	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 1x1 constrained CCGT (Jan '22)	4	27	2	28	6	11	4	27	4	20	24	28	3	27	13
14	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	21	15	15	16	19	19	9	16	15	13	13	15	18	14	14
15	LS Power 1 CT (2016-17), 2 CTs (2018); BR 1x1 constrained CCGT (Jan '19)	23	13	21	15	24	16	14	14	16	14	14	16	20	15	15
16	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 1x1 constrained CCGT (Jan '20)	24	14	20	14	23	15	12	13	19	16	16	18	21	16	16
17	LS Power 2 CTs (2016-17); GR 1x1 CCGT (Jan '18)	22	20	19	20	20	25	10	22	18	15	15	17	19	18	17
18	Wilson (2016-19); BR 2x1 constrained CCGT (Jan '20)	20	16	32	13	21	14	32	20	23	25	26	14	28	13	18
19	LS Power 1 CT (2016-17); ERORA PPA (2018-37)	19	26	26	17	22	17	33	24	17	24	18	13	22	17	19
20	LS Power 2 CTs (2016-18); BR 1x1 constrained CCGT (Jan '19)	26	18	23	19	29	23	21	18	20	17	17	19	23	19	20
21	LS Power 3 CTs (2016-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	3	29	2	28	5	21	4	27	14	29	24	28	4	29	21
22	LS Power 2 CTs (2016-19); BR 1x1 constrained CCGT (Jan '20)	27	19	22	18	28	22	19	17	21	18	19	20	24	20	22
23	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 1x1 constrained CCGT (Jan '20)	25	17	24	21	25	18	16	15	24	21	21	22	25	21	23
24	Ameren 1 Unit (2016-17), 2 Units (2018); BR 1x1 constrained CCGT (Jan '19)	28	21	27	22	30	24	26	21	22	19	20	21	26	22	24
25	Ameren 2 Units (2016-19); BR 1x1 constrained CCGT (Jan '20)	29	22	29	23	27	20	22	19	27	27	27	26	29	23	25
26	Ameren 2 Units (2016-18); BR 1x1 constrained CCGT (Jan '19)	31	23	31	24	32	26	27	23	25	23	23	24	30	24	26
27	Ameren 1 Unit (2016-17); GR 1x1 CCGT (Jan '18)	30	24	28	25	26	28	18	25	26	22	22	23	27	25	27
28	Ameren 2 Units (2016-17); GR 1x1 CCGT (Jan '18)	32	25	30	26	31	29	24	26	28	26	28	25	31	26	28
29	Coleman Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	1	30	1	31	2	27	1	29	29	30	29	32	1	30	29
30	Coleman Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	2	31	4	30	1	30	2	31	31	31	31	30	2	31	30
31	Wilson (2016-19); BR 1x1 constrained CCGT (Jan '20)	33	28	33	27	33	31	31	30	30	28	30	27	33	28	31
32	Wilson Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	6	32	5	33	4	32	3	32	32	32	32	33	17	32	32
33	Wilson Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	18	33	25	32	3	33	6	33	33	33	33	31	32	33	33

ST v LT

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NPVRR ($000) in 2013 $

Rank	Alternative	Base Gas Base Load Zero Carbon	Base Gas Base Load Medium Carbon	Base Gas Low Load Zero Carbon	Base Gas Low Load Medium Carbon	High Gas Base Load Zero Carbon	High Gas Base Load Medium Carbon	High Gas Low Load Zero Carbon	High Gas Low Load Medium Carbon	Low Gas Base Load Zero Carbon	Low Gas Base Load Medium Carbon	Low Gas Low Load Zero Carbon	Low Gas Low Load Medium Carbon	Average NPVRR Zero Carbon	Average NPVRR Medium Carbon	Average NPVRR All Cases	Versus Least Cost Option
1	LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	26,838,605	40,803,755	23,720,501	37,359,736	27,880,000	42,949,570	24,384,767	38,912,099	23,745,252	35,795,356	21,399,949	33,320,882	24,661,512	38,190,233	31,425,873	0
2	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	26,857,534	40,770,971	23,736,741	37,319,233	27,940,698	42,905,085	24,455,327	38,860,378	23,777,294	35,833,817	21,427,808	33,349,349	24,699,234	38,173,139	31,436,186	10,314
3	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	26,871,198	40,784,634	23,755,180	37,337,673	27,962,012	42,926,399	24,481,251	38,886,301	23,757,583	35,814,108	21,412,258	33,333,799	24,706,580	38,180,486	31,443,533	17,660
4	LS Power 2 CTs (2016-17); GR 2x1 CCGT (Jan '18)	26,861,365	40,823,906	23,741,506	37,381,062	27,900,245	42,969,879	24,405,038	38,932,683	23,762,985	35,818,373	21,420,443	33,340,783	24,681,930	38,211,114	31,446,522	20,650
5	LS Power 2 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,879,756	40,793,193	23,758,540	37,341,033	27,963,272	42,927,659	24,476,853	38,881,904	23,798,908	35,855,432	21,448,966	33,370,507	24,721,049	38,194,955	31,458,002	32,129
6	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	26,877,095	40,790,532	23,763,913	37,346,406	27,945,763	42,910,151	24,469,383	38,874,434	23,818,646	35,875,168	21,471,960	33,393,500	24,724,460	38,198,365	31,461,413	35,540
7	LS Power 2 CTs (2016-18); BR 2x1 constrained CCGT (Jan '19)	26,893,032	40,806,469	23,776,593	37,359,085	27,984,199	42,948,586	24,502,390	38,907,440	23,778,810	35,835,334	21,433,028	33,354,569	24,728,009	38,201,914	31,464,961	39,089
8	Ameren 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,893,444	40,806,881	23,782,687	37,365,180	27,956,692	42,921,079	24,482,954	38,888,004	23,837,289	35,893,811	21,492,839	33,414,379	24,740,984	38,214,889	31,477,937	52,064
9	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	26,902,066	40,815,503	23,790,779	37,373,272	27,984,325	42,948,713	24,508,252	38,913,302	23,803,146	35,859,670	21,459,243	33,380,784	24,741,302	38,215,207	31,478,255	52,382
10	Ameren 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	26,916,915	40,830,352	23,808,054	37,390,546	27,993,754	42,958,141	24,520,323	38,925,373	23,820,290	35,876,813	21,478,622	33,400,163	24,756,326	38,230,231	31,493,279	67,406
11	Ameren 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	26,904,507	40,869,656	23,788,230	37,427,464	27,941,873	43,011,443	24,449,042	38,976,374	23,818,032	35,868,136	21,473,022	33,393,955	24,729,118	38,257,838	31,493,478	67,605
12	Ameren 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	26,918,930	40,881,472	23,804,054	37,443,611	27,948,118	43,017,751	24,459,082	38,986,728	23,830,681	35,886,069	21,490,826	33,411,166	24,741,949	38,271,133	31,506,541	80,668
13	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 1x1 constrained CCGT (Jan '22)	26,755,452	41,036,432	23,542,752	37,935,333	27,753,120	42,998,026	24,162,891	39,085,686	23,774,345	36,013,950	21,640,902	34,071,384	24,604,910	38,523,469	31,564,189	138,317
14	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	27,113,353	40,946,501	23,789,809	37,576,789	28,069,381	43,099,083	24,407,083	39,011,853	23,927,645	35,947,993	21,561,046	33,725,831	24,811,386	38,384,675	31,598,031	172,158
15	LS Power 1 CT (2016-17), 2 CTs (2018); BR 1x1 constrained CCGT (Jan '19)	27,135,985	40,945,368	23,821,934	37,572,460	28,117,885	43,094,504	24,457,348	39,001,667	23,936,792	35,962,208	21,571,430	33,733,646	24,840,229	38,384,976	31,612,602	186,730
16	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 1x1 constrained CCGT (Jan '20)	27,136,894	40,946,278	23,820,021	37,570,547	28,115,753	43,092,371	24,453,092	38,997,411	23,953,123	35,978,539	21,587,244	33,749,460	24,844,355	38,389,101	31,616,728	190,855
17	LS Power 2 CTs (2016-17); GR 1x1 CCGT (Jan '18)	27,135,730	40,969,999	23,812,164	37,597,696	28,093,169	43,121,751	24,428,770	39,029,961	23,946,864	35,970,711	21,582,187	33,742,611	24,833,147	38,405,455	31,619,301	193,428
18	Wilson (2016-19); BR 2x1 constrained CCGT (Jan '20)	27,035,496	40,948,350	23,924,836	37,507,037	28,094,317	43,060,666	24,623,370	39,028,418	23,986,679	36,038,197	21,641,373	33,563,507	24,884,345	38,357,696	31,621,021	195,148
19	LS Power 1 CT (2016-17); ERORA PPA (2018-37)	26,956,449	41,034,583	23,848,592	37,590,117	28,099,044	43,096,497	24,659,866	39,071,412	23,937,334	36,033,637	21,605,616	33,521,048	24,851,150	38,391,216	31,621,183	195,310
20	LS Power 2 CTs (2016-18); BR 1x1 constrained CCGT (Jan '19)	27,157,820	40,967,203	23,843,346	37,593,872	28,140,072	43,116,691	24,478,486	39,022,805	23,958,019	35,983,435	21,592,200	33,754,416	24,861,657	38,406,404	31,634,030	208,158
21	LS Power 3 CTs (2016-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	26,705,535	41,293,379	23,542,752	37,935,333	27,726,344	43,112,487	24,162,891	39,085,686	23,910,026	36,452,258	21,640,902	34,071,384	24,614,742	38,658,421	31,636,581	210,709
22	LS Power 2 CTs (2016-19); BR 1x1 constrained CCGT (Jan '20)	27,159,116	40,968,500	23,841,821	37,592,347	28,138,327	43,114,946	24,474,618	39,018,936	23,974,737	36,000,153	21,608,401	33,770,617	24,866,170	38,410,917	31,638,543	212,671
23	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 1x1 constrained CCGT (Jan '20)	27,156,455	40,965,839	23,847,194	37,597,720	28,120,818	43,097,438	24,467,148	39,011,467	23,994,474	36,019,890	21,631,395	33,793,611	24,869,581	38,414,328	31,641,954	216,081
24	Ameren 1 Unit (2016-17), 2 Units (2018); BR 1x1 constrained CCGT (Jan '19)	27,166,853	40,976,237	23,857,533	37,608,059	28,140,198	43,116,817	24,484,348	39,028,667	23,982,355	36,007,770	21,618,414	33,780,630	24,874,950	38,419,697	31,647,323	221,451
25	Ameren 2 Units (2016-19); BR 1x1 constrained CCGT (Jan '20)	27,172,805	40,982,188	23,865,968	37,616,494	28,131,747	43,108,366	24,480,719	39,025,037	24,013,118	36,038,533	21,652,274	33,814,489	24,886,105	38,430,851	31,658,478	232,606
26	Ameren 2 Units (2016-18); BR 1x1 constrained CCGT (Jan '19)	27,181,703	40,991,086	23,874,807	37,625,333	28,149,627	43,126,246	24,496,419	39,040,738	23,999,498	36,024,913	21,637,793	33,800,009	24,889,975	38,434,721	31,662,348	236,475
27	Ameren 1 Unit (2016-17); GR 1x1 CCGT (Jan '18)	27,179,254	41,012,402	23,857,537	37,644,518	28,131,255	43,160,957	24,471,359	39,076,129	24,000,425	36,020,773	21,634,119	33,798,904	24,878,992	38,452,281	31,665,636	239,763
28	Ameren 2 Units (2016-17); GR 1x1 CCGT (Jan '18)	27,193,295	41,027,565	23,874,713	37,660,244	28,141,041	43,169,623	24,482,814	39,084,006	24,014,560	36,038,408	21,652,570	33,812,994	24,893,166	38,465,473	31,679,319	253,447
29	Coleman Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	26,537,762	41,377,184	23,406,316	38,097,819	27,375,403	43,135,371	23,742,942	39,089,798	24,038,362	36,985,223	21,770,040	34,884,069	24,478,471	38,928,244	31,703,357	277,485
30	Coleman Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	26,658,591	41,454,928	23,556,892	38,045,045	27,372,975	43,201,734	24,024,518	39,195,277	24,165,244	37,093,841	21,846,836	34,613,804	24,604,176	38,934,105	31,769,140	343,268
31	Wilson (2016-19); BR 1x1 constrained CCGT (Jan '20)	27,314,034	41,120,106	24,007,336	37,758,783	28,267,705	43,245,754	24,620,932	39,167,926	24,160,982	36,182,992	21,800,193	33,966,797	25,028,530	38,573,726	31,801,128	375,256
32	Wilson Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	26,850,012	41,603,937	23,715,196	38,280,562	27,675,509	43,366,013	24,097,729	39,322,703	24,307,062	37,266,398	22,039,088	35,088,143	24,780,766	39,154,626	31,967,696	541,823
33	Wilson Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	26,935,932	41,685,453	23,848,376	38,243,815	27,675,101	43,432,898	24,361,365	39,430,479	24,435,263	37,383,298	22,116,409	34,853,151	24,895,408	39,171,516	32,033,462	607,589

Attorney-Client Work Product – RFP Update June 7, 2013

Average NPVRR across all cases (Base/Low Load; High/Med/Low Gas Price; Zero/Medium Carbon)

Rank	Alternative	*NPVRR ($000) in 2013 $* Average NPVRR All Cases	Versus Least Cost Option
1	LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	31,425,873	0
2	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	31,436,186	10,314
3	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	31,443,533	17,660
4	LS Power 2 CTs (2016-17); GR 2x1 CCGT (Jan '18)	31,446,522	20,650
5	LS Power 2 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,458,002	32,129
6	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	31,461,413	35,540
7	LS Power 2 CTs (2016-18); BR 2x1 constrained CCGT (Jan '19)	31,464,961	39,089
8	Ameren 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,477,937	52,064
9	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	31,478,255	52,382
10	Ameren 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	31,493,279	67,406
11	Ameren 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	31,493,478	67,605
12	Ameren 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	31,506,541	80,668
13	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 1x1 constrained CCGT (Jan '22)	31,564,189	138,317
14	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	31,598,031	172,158
15	LS Power 1 CT (2016-17), 2 CTs (2018); BR 1x1 constrained CCGT (Jan '19)	31,612,602	186,730
16	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 1x1 constrained CCGT (Jan '20)	31,616,728	190,855
17	LS Power 2 CTs (2016-17); GR 1x1 CCGT (Jan '18)	31,619,301	193,428
18	Wilson (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,621,021	195,148
19	LS Power 1 CT (2016-17); ERORA PPA (2018-37)	31,621,183	195,310
20	LS Power 2 CTs (2016-18); BR 1x1 constrained CCGT (Jan '19)	31,634,030	208,158
21	LS Power 3 CTs (2016-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	31,636,581	210,709
22	LS Power 2 CTs (2016-19); BR 1x1 constrained CCGT (Jan '20)	31,638,543	212,671
23	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 1x1 constrained CCGT (Jan '20)	31,641,954	216,081
24	Ameren 1 Unit (2016-17), 2 Units (2018); BR 1x1 constrained CCGT (Jan '19)	31,647,323	221,451
25	Ameren 2 Units (2016-19); BR 1x1 constrained CCGT (Jan '20)	31,658,478	232,606
26	Ameren 2 Units (2016-18); BR 1x1 constrained CCGT (Jan '19)	31,662,348	236,475
27	Ameren 1 Unit (2016-17); GR 1x1 CCGT (Jan '18)	31,665,636	239,763
28	Ameren 2 Units (2016-17); GR 1x1 CCGT (Jan '18)	31,679,319	253,447
29	Coleman Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	31,703,357	277,485
30	Coleman Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	31,769,140	343,268
31	Wilson (2016-19); BR 1x1 constrained CCGT (Jan '20)	31,801,128	375,256
32	Wilson Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	31,967,696	541,823
33	Wilson Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	32,033,462	607,589

Attorney-Client Work Product – RFP Update June 7, 2013

Single Case: Base Load; Medium Gas Price; Zero Carbon

Rank	Alternative	*NPVRR ($000) in 2013 $* Medium Gas Base Load Zero Carbon	Versus Least Cost Option
1	Coleman Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	26,537,762	0
2	Coleman Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	26,658,591	120,829
3	LS Power 3 CTs (2016-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	26,705,535	167,773
4	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 1x1 constrained CCGT (Jan '22)	26,755,452	217,690
5	LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	26,838,605	300,843
6	Wilson Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	26,850,012	312,250
7	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	26,857,534	319,772
8	LS Power 2 CTs (2016-17); GR 2x1 CCGT (Jan '18)	26,861,365	323,603
9	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	26,871,198	333,436
10	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	26,877,095	339,333
11	LS Power 2 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,879,756	341,994
12	LS Power 2 CTs (2016-18); BR 2x1 constrained CCGT (Jan '19)	26,893,032	355,270
13	Ameren 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	26,893,444	355,682
14	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	26,902,066	364,304
15	Ameren 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	26,904,507	366,745
16	Ameren 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	26,916,915	379,153
17	Ameren 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	26,918,930	381,168
18	Wilson Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	26,935,932	398,170
19	LS Power 1 CT (2016-17); ERORA PPA (2018-37)	26,956,449	418,687
20	Wilson (2016-19); BR 2x1 constrained CCGT (Jan '20)	27,035,496	497,734
21	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	27,113,353	575,591
22	LS Power 2 CTs (2016-17); GR 1x1 CCGT (Jan '18)	27,135,730	597,968
23	LS Power 1 CT (2016-17), 2 CTs (2018); BR 1x1 constrained CCGT (Jan '19)	27,135,985	598,223
24	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 1x1 constrained CCGT (Jan '20)	27,136,894	599,132
25	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 1x1 constrained CCGT (Jan '20)	27,156,455	618,693
26	LS Power 2 CTs (2016-18); BR 1x1 constrained CCGT (Jan '19)	27,157,820	620,058
27	LS Power 2 CTs (2016-19); BR 1x1 constrained CCGT (Jan '20)	27,159,116	621,354
28	Ameren 1 Unit (2016-17), 2 Units (2018); BR 1x1 constrained CCGT (Jan '19)	27,166,853	629,091
29	Ameren 2 Units (2016-19); BR 1x1 constrained CCGT (Jan '20)	27,172,805	635,043
30	Ameren 1 Unit (2016-17); GR 1x1 CCGT (Jan '18)	27,179,254	641,492
31	Ameren 2 Units (2016-18); BR 1x1 constrained CCGT (Jan '19)	27,181,703	643,941
32	Ameren 2 Units (2016-17); GR 1x1 CCGT (Jan '18)	27,193,295	655,533
33	Wilson (2016-19); BR 1x1 constrained CCGT (Jan '20)	27,314,034	776,272

Attorney-Client Work Product – RFP Update June 7, 2013

Average of all zero carbon cases (Base/Low Load; High/Med/Low Gas Price; Zero Carbon)

Rank	Alternative	*NPVRR ($000) in 2013 $* Average NPVRR Zero Carbon	Versus Least Cost Option
1	Coleman Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	24,478,471	0
2	Coleman Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	24,604,176	125,705
3	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 1x1 constrained CCGT (Jan '22)	24,604,910	126,440
4	LS Power 3 CTs (2016-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	24,614,742	136,271
5	LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	24,661,512	183,042
6	LS Power 2 CTs (2016-17); GR 2x1 CCGT (Jan '18)	24,681,930	203,460
7	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	24,699,234	220,763
8	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	24,706,580	228,110
9	LS Power 2 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,721,049	242,578
10	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	24,724,460	245,989
11	LS Power 2 CTs (2016-18); BR 2x1 constrained CCGT (Jan '19)	24,728,009	249,538
12	Ameren 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	24,729,118	250,647
13	Ameren 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,740,984	262,513
14	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,741,302	262,831
15	Ameren 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	24,741,949	263,478
16	Ameren 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	24,756,326	277,856
17	Wilson Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	24,780,766	302,295
18	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	24,811,386	332,915
19	LS Power 2 CTs (2016-17); GR 1x1 CCGT (Jan '18)	24,833,147	354,677
20	LS Power 1 CT (2016-17), 2 CTs (2018); BR 1x1 constrained CCGT (Jan '19)	24,840,229	361,758
21	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 1x1 constrained CCGT (Jan '20)	24,844,355	365,884
22	LS Power 1 CT (2016-17); ERORA PPA (2018-37)	24,851,150	372,679
23	LS Power 2 CTs (2016-18); BR 1x1 constrained CCGT (Jan '19)	24,861,657	383,186
24	LS Power 2 CTs (2016-19); BR 1x1 constrained CCGT (Jan '20)	24,866,170	387,699
25	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 1x1 constrained CCGT (Jan '20)	24,869,581	391,110
26	Ameren 1 Unit (2016-17), 2 Units (2018); BR 1x1 constrained CCGT (Jan '19)	24,874,950	396,479
27	Ameren 1 Unit (2016-17); GR 1x1 CCGT (Jan '18)	24,878,992	400,521
28	Wilson (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,884,345	405,874
29	Ameren 2 Units (2016-19); BR 1x1 constrained CCGT (Jan '20)	24,886,105	407,634
30	Ameren 2 Units (2016-18); BR 1x1 constrained CCGT (Jan '19)	24,889,975	411,504
31	Ameren 2 Units (2016-17); GR 1x1 CCGT (Jan '18)	24,893,166	414,695
32	Wilson Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	24,895,408	416,937
33	Wilson (2016-19); BR 1x1 constrained CCGT (Jan '20)	25,028,530	550,060

Average of all medium carbon cases (Base/Low Load; High/Med/Low Gas Price; Medium Carbon)

		NPVRR ($000) in 2013 $	
Rank	**Alternative**	**Average NPVRR Medium Carbon**	**Versus Least Cost Option**
1	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,173,139	0
2	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	38,180,486	7,347
3	LS Power 1 CT (2016-17); GR 2x1 CCGT (Jan '18)	38,190,233	17,094
4	LS Power 2 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,194,955	21,816
5	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,198,365	25,226
6	LS Power 2 CTs (2016-18); BR 2x1 constrained CCGT (Jan '19)	38,201,914	28,775
7	LS Power 2 CTs (2016-17); GR 2x1 CCGT (Jan '18)	38,211,114	37,976
8	Ameren 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,214,889	41,750
9	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,215,207	42,069
10	Ameren 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	38,230,231	57,093
11	Ameren 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	38,257,838	84,699
12	Ameren 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	38,271,133	97,994
13	Wilson (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,357,696	184,557
14	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	38,384,675	211,536
15	LS Power 1 CT (2016-17), 2 CTs (2018); BR 1x1 constrained CCGT (Jan '19)	38,384,976	211,837
16	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 1x1 constrained CCGT (Jan '20)	38,389,101	215,962
17	LS Power 1 CT (2016-17); ERORA PPA (2018-37)	38,391,216	218,077
18	LS Power 2 CTs (2016-17); GR 1x1 CCGT (Jan '18)	38,405,455	232,316
19	LS Power 2 CTs (2016-18); BR 1x1 constrained CCGT (Jan '19)	38,406,404	233,265
20	LS Power 2 CTs (2016-19); BR 1x1 constrained CCGT (Jan '20)	38,410,917	237,778
21	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 1x1 constrained CCGT (Jan '20)	38,414,328	241,189
22	Ameren 1 Unit (2016-17), 2 Units (2018); BR 1x1 constrained CCGT (Jan '19)	38,419,697	246,558
23	Ameren 2 Units (2016-19); BR 1x1 constrained CCGT (Jan '20)	38,430,851	257,712
24	Ameren 2 Units (2016-18); BR 1x1 constrained CCGT (Jan '19)	38,434,721	261,582
25	Ameren 1 Unit (2016-17); GR 1x1 CCGT (Jan '18)	38,452,281	279,142
26	Ameren 2 Units (2016-17); GR 1x1 CCGT (Jan '18)	38,465,473	292,335
27	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 1x1 constrained CCGT (Jan '22)	38,523,469	350,330
28	Wilson (2016-19); BR 1x1 constrained CCGT (Jan '20)	38,573,726	400,588
29	LS Power 3 CTs (2016-19); LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,658,421	485,282
30	Coleman Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	38,928,244	755,105
31	Coleman Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	38,934,105	760,966
32	Wilson Asset Purchase (2016 no add env or XM); BR 2x1 constrained CCGT (Jan '21)	39,154,626	981,487
33	Wilson Asset Purchase (2016 no add env or XM); BR 1x1 constrained CCGT (Jan '21)	39,171,516	998,377

Agenda for RFP Status Meeting

September 23, 2013

Issues to be Resolved

1. Site
2. Technology (2x1 v 1x1)
3. High level communications plan

Analysis Review (Schram)

1. Recap of Revenue Requirement analysis for Brown and Green River
2. Recap of Revenue Requirement analysis of 2x1 and 1x1 CCGT

Discussion of qualitative site issues for Brown and Green River (Voyles)

CCN Overview (Sinclair)

1. Need Demonstration
2. GHG regulation risk
3. New DSM
4. Solar project

Other Regulatory filings

1. DSM by February 2014
2. IRP in April 2014
3. Rate case mid 2014

Communications Plan

1. RFP respondents
2. Media / Public at large
3. PSC
4. Politicians
5. Other stakeholders

Potential Solar Project for 2013 CCN Filing

Option 1 – Traditional Rate Base

- 10 MW solar farm located between Louisville & Lexington
- Requires approximately 200 acres
- Total project cost is approximately $40 million
- Owned 50/50 by LG&E and KU
- Only proceed if approved by KPSC
- Need to develop justification (e.g., least-cost, pilot to understand integration issues, hedge against gas prices or CO2)

Option 2 – Customer Choice

- Model after Berea customer leasing program
    - LG&E/KU builds and owns asset
    - Customers lease a panel (235 watts / panel) for 25 years for upfront payment of $750
    - Lease is transferable to any customer in their service territory
    - Utility has a buy-back option
    - Customer gets energy credit on monthly bill for their share of the amount of energy produced at the site (not per panel)
    - Berea retains REC rights
    - First 60 panels sold in 4 days
- Site could be same as Option #1 or perhaps Louisville Zoo (need to consider Lexington site as well for KU customers)
- May need to include a monthly administration fee to cover plant O&M
- Only proceed if enough customers sign up so limited need for justification