From:	Thompson, Paul
To:	Bowling, Ralph
Cc:	Sinclair, David
Subject:	FW: Supply Chain
Date:	Thursday, April 04, 2013 2:45:14 PM

Ralph, can you give me data on BR 1 & 2 per Farr request… last few years data. Want to provide info on reliability of each of them, too.

Thanks.

Paul

From: Farr, Paul [PPL]
Sent: Thursday, April 04, 2013 2:31 PM
To: Thompson, Paul
Cc: Rives, Brad; Blake, Kent
Subject: RE: Supply Chain

Paul, thanks and it makes sense to me. The guys at LS haven't reached out for quite a while, so it makes sense they see another option. What type of capacity factor do we have these days on Br 1 and 2?

From: Thompson, Paul [redacted]
Sent: Thursday, April 04, 2013 1:24 PM
To: Farr, Paul
Cc: Rives, Stephen B; Blake, Kent W
Subject: RE: Supply Chain

Paul,

On the RFP status, we are making our way to a conclusion. We have some internal meetings yet here in early April and then plan to go public likely very late April or in May – which of course will be coordinated with all internal parties involved. Rough conclusions at this point include:

1. Not going to move forward with baghouse at Br 1 and 2 (will be getting implicit agreement from KPSC on April 24 when we have regularly scheduled meeting with them on ECR projects)
2. Likely to be able to use sorbent injection at Br 1 and 2 to allow for use of units for extended period of time (several years) although perhaps with limiting operation conditions (still subject to more testing thru mid summer)
3. Self build CCGT at either the Brown site or more likely the Green River site for a 2018 commercial operation date is the least cost approach
4. Limited power purchase agreement from either the LS Power CTs or from EEI Joppa stations (based upon transmission requests, it looks like EKPC may be entering into a 10 year PPA with LS Power from the CTs in LaGrange – this would take out that PPA option for us).

Let me know if you have any questions.

Thanks.

Paul T.

From: Sinclair, David
To: Rives, Brad
Cc: Thompson, Paul
Subject: FW: Solar Project Revenue Requirements (RR)
Date: Wednesday, October 02, 2013 5:52:20 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, CO2 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:	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: Sinclair, David
To: Thompson, Paul
Cc: Schram, Chuck; Wilson, Stuart; Heun, Jeff; Schetzel, Doug; Voyles, John; Straight, Scott
Subject: RE: Solar Cost Comparison
Date: Monday, December 16, 2013 4:44:25 PM
Attachments: 000000003002001259.pdf
RE 10 MW Solar Project.msg

Paul,

The $20 million was based on the lower end $2.00 / watt estimate from Burns and McDonnell (see attached email) because we already had the land. I've also attached an EPRI report (see Figure 4) that shows 2016 solar projects worldwide estimated to cost around $1.40 /watt dc ($2012) ($1.80/ watt ac) with US projects estimated to currently be costing between $2.00 and $2.50 /watt dc ($2.60 to $3.25 / watt ac). Below is a quote from the report:

Utility-scale (1-MW+) system installation costs vary in different markets. For example, in the U.S., most best-in-class projects are going in the ground at $2-$2.50/Wdc, and as low as $1.75/Wdc (for 5 MW+ projects). These higher prices are due to higher permitting/interconnection, transactional, and equipment costs. Also, prices are being upwardly affected by U.S. developers claiming higher 'developer fees' than their cohorts in Europe. In Japan, meanwhile, prices are higher because the country is currently supporting an over-subsidized boom market.

Comparing the US to worldwide pricing, US projects are around 45% (2.25/1.55) more expensive currently. If that holds and we use EPRI's 2016 worldwide price, then one could expect a 2016 US project to be around $2.60 /watt ac ($1.80 x 1.45) assuming the gap doesn't narrow. Note that the $2.60 is similar the Burns and McDonnell number with land. I can't tell if the EPRI data includes land or not.

Thanks
David

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
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Douglas Schetzel
Director Business Development
LG&E and KU Energy, LLC
[redacted]

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Solar PV Market Update

June 2013 Volume 6: Q2 2013

Editor's Note

Welcome to the second edition of EPRI's quarterly Solar PV Market Update for 2013. As with prior publications, this Update explores front line economic, policy, and technology trends that are occurring throughout the PV segment. It first examines recent upheaval in the PV inverter landscape, marked by equipment oversupply, falling revenues, shifting market and product demand, and industry consolidation. Next, it provides a breakdown of latest PV system component and system pricing data, offering insight into some of the factors driving price point movements. And finally, it highlights integrated solar module-and-rack systems that are designed to reduce both material and labor costs in the residential and commercial rooftop market spaces.

Please let us know how we can improve upon this issue. As always, we welcome your general comments as well as your suggestions for future content coverage.

Sincerely,

The EPRI Solar Generation (P187), Integration of Distributed Renewables (P174), and Renewable Energy Economics and Technology Status (P84) Program Teams

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Market Landscape

Pricing Pressure and Shakeout Catch Up to the PV Inverter Segment

The $7 billion PV inverter marketplace is undergoing an extreme makeover. Although sales are booming, pricing pressures that have dogged other segments of the solar supply chain have caught up to inverter manufacturers, triggering drastic reductions in product prices, collapsing once healthy margins, and prompting a wave of industry consolidation. Due primarily to product oversupply and the emergence of lower-cost Chinese options, average prices have fallen by approximately 15% for residential inverters, by 20% for commercial inverters, and by 50% for utility-scale inverters over the past 16 months. The pricing volatility has left both upstarts and established firms scrambling. Some have become victims of a broad shakeout, while others have reloaded, executing redirected business strategies that, in some cases, have involved merger and acquisition.

Thus far in 2013, the inverter landscape appears to be in a continued state of flux. Although movements in price have generally moderated in recent months, industry players are still adapting to new market realities. Among them: shifts in regional and product segment demand, local barriers to entry, rising bankability and reliability requirements, growing desire for advanced grid integration functionality, and ever lower price point expectations. Amidst this backdrop, electric utilities and other project investors are well-positioned to reap the benefits of an increasingly favorable buying environment—one that is likely to remain rosy for the foreseeable future as inverter prices continue to slide and commercially available technologies improve.

Inverter Market and Pricing Shifts

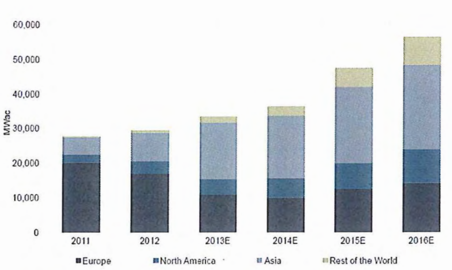
Despite growth in volume sales, double-digit percentage reductions to inverter prices across all product segments have led to diminishing gross revenues for suppliers. Definitive shifts in market and product demand are among the key causal factors affecting the health of today's bloated inverter sector.

For one, identified high growth markets are moving away from historically supportive European feed-in tariff (FIT) markets that have primarily accommodated residential string and commercial inverters. In their place, markets in Asia (particularly China and India), South America, parts of the U.S., and regions of Africa are expanding that emphasize high-power products used for utility-scale projects. These larger, 3-phase inverters have experienced the greatest reduction in price, in turn, more significantly cutting into supplier profit margins. Meanwhile, core expanding markets in China, Japan, and North America have erected certification barriers that are complicating market entry by foreign suppliers. And finally, low cost manufacturers located primarily in China are placing across-the-board pressure on equipment pricing perhaps at the expense of quality assurance.

Figure 1 shows the historical and expected geographic diffusion of inverter market demand, while Figure 2 illustrates the historical and projected movement in product demand. Asia is clearly the big growth market, with North America also demonstrating steady gains. Inverter demand in Europe, meanwhile, is anticipated to temporarily slow, before rebounding in 2014. Meantime, residential and commercial systems are ceding market share to utility-scale systems (>500 kW), with all segments anticipated to post growth in 2014 and beyond.

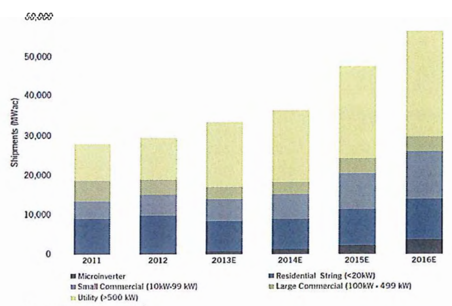
continued on page 2

continued from page 1



Source: GTM Research

Figure 1. Global PV Inverter Shipments by Region, 2011-2016E



Source: GTM Research

Figure 2. Global PV Inverter Shipments by Inverter Size, 2011-2016E

To a lesser extent, the commercial emergence of module-level power electronics, such as microinverters and power optimizers, is also impacting product demand choices while posing a challenge to industry incumbents. Although still relatively small in market heft, the segment has experienced exponential growth—installations have risen from 51 MW in 2009 to over 785 MW in 2012[1, 2]—prompting some of the more established firms, such as SMA and Power-One, to develop their own suite of products or to investigate acquisition and partnership opportunities for developing OEM and white-label offerings.

But of broader consequence to the overarching industry's health is the emergence of low cost Chinese manufacturers; their proliferation is beginning to highlight prominent regional cost differences. For example, according to GTM Research, the cost of a 500-kW inverter made in China is over 50% cheaper than a comparable unit manufactured in the U.S. The main reasons: containment, supply chain, and testing. Because central inverters in China are typically housed in containers, rather than outdoors as is usually the case in the U.S., their costs associated with weather, cleaning, and cooling are much lower. Meanwhile, procurement costs in China are substantially below those in America. And lastly, China's more lenient standards surrounding certification and testing to various grid support functions are helping to keep manufacturing costs at bay (potentially at the expense of quality control).

The increasing number of lower-cost Chinese products is raising concerns about cost versus reliability tradeoffs. Indeed, per Figure 3, dramatic price drops since 2011, particularly in the commercial and utility inverter segments, are forcing manufacturers to make hard decisions about availability and cost considerations. In addition, suppliers are being confronted by calls for the introduction of advanced grid integration features like fault ride-through, reactive power control, and remote curtailment that introduce greater cost.

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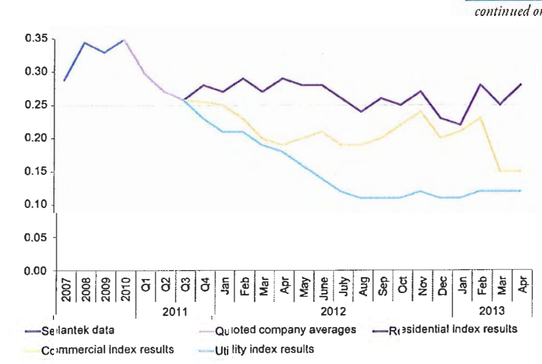

Notes: Annual data 2007 – 2010 from Selantek. Data Q1 – Q3 2011 is an average of inverter average selling prices (ASPs) for quoted companies. Inverter Price Index results are for October 2011 to April 2013. Bloomberg New Energy Finance defines the different segment sizes as: residential 0-20kW, commercial 20-1000kW and utility 1000kW+.

Source: Bloomberg New Energy Finance

Figure 3. Inverter prices, 2007–April 2013 ($/Wac)

[1] Enphase, SolarEdge and Tigo account for over 93% of the total market share of shipments and installations in the module-level power electronics space.

[2] As of the end of 2012, over $550 million in private venture capital had been raised by microinverter and distributed optimization product manufacturers.

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Looking ahead, some industry analysts expect blended average inverter selling prices to fall by 10% annually over the next few years—from \$0.22/W in 2012 to \$0.14/W in 2016. It remains to be seen how many companies will be able to meet this bar. With the expected further transition to more price-sensitive markets and a subsequent further diminishing of product margins, some suppliers may be well served emphasizing sales of non-hardware offerings, such as EPC, O&M, and other after-sales services (see sidebar "Inverter After-Sales Services: A Market Opportunity with Questions").

Industry Shakeout & Consolidation

The combination of global product oversupply and a contracted addressable market is causing industry-wide consolidation and contraction. To compensate for large revenue declines, the sector has instituted heavy layoffs, perhaps none more symbolic than the 1,000 announced by market leader SMA in May to counteract a greater than 50% reduction in 2012 profits.[3] Furthermore, as depicted in Table 1 on page 4, a number of companies have simply been unable to compete, either going belly up or divesting themselves of their inverter assets. Others—particularly the more established players—have made strategic acquisitions to remain competitive in the more geographically and product diffuse inverter market place.

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Inverter After-Sales Services: A Market Opportunity with Questions

As margins from hardware sales shrink, inverter manufacturers may be increasingly well served to bolster their after-sales service plan offerings to shore up revenues. These services—which encompass inverter maintenance and repairs typically covered under warranty—are often required by banks and investors to receive project financing. But shifting customer attitudes about O&M appear to offer an opportunity for charging premiums for greater coverage. Results from a recent IMS Research PV inverter survey, for example, indicate that respondents rank both inverter warranty and service higher than product price competitiveness.[4]

Today's fairly robust after-sales services market accounts for roughly \$850 million. But an expected increase in larger capacity inverters used in utility-scale solar installations, along with greater project owner sensitivity around system uptimes, has the potential to double the global market to \$1.7 billion by 2017.[5] Inverter manufacturers may choose to serve this developing market need for more rapid inverter repair and diagnosis by either supporting an internal workforce or entering into partnerships with third-party providers to build a distributed service network.

Still, buyers beware: warranties and service offerings are only as good as the companies that back them. The high profile bankruptcy of Satcon—once among the leading commercial- and utility-scale inverter suppliers in North America—is a case in point. The company's insolvency calls its standard 5-year warranty (extendable up to 20 years in 5 year increments), preventative maintenance plan, and uptime guarantee into question. Satcon initially pledged to continue to honor its warranties and provide post-sales service and support during its bankruptcy proceedings. But uncertainties have since reemerged as the company's assets have been sold off (Great Wall Energy was given approval in June 2013 to purchase Satcon's assets). Some former Satcon employees are reportedly creating regional offshoot companies to provide troubleshooting and repairs for the thousands of existing Satcon projects in the field.[6] Their success and status is, however, unclear.

No doubt, inverter company failures will continue to occur. A major challenge: how to structure increasingly important post-hardware sales service plans that protect project owners and investors from market casualty?

Note: EPRI and Sandia National Labs are jointly spearheading the development of standards and protocols to define common requirements, needs, and expectations surrounding PV operations and maintenance (O&M). The multi-year effort is a response to the growing importance conferred upon PV system O&M and consequent calls to establish guidelines that protect both buyers and sellers. Three sets of guidelines are currently being developed for broad industry use, many of which are relevant to inverters and their upkeep: O&M Definitions, O&M Best Practices, and Design and Installation for O&M Optimization. Contact EPRI's [Nadav Enbar] if you would like to participate in this effort.

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3 SMA employs ~5,500 employees worldwide, 4,500 of whom work in Germany.

4 Results from the IMS Research survey, titled "PV Inverter Customer Survey - World – 2013," published in January 2013, were based on responses from a broad range of PV industry participants, including distributors, installers, integrators, and others with purchasing authority.

5 According to IMS Research, 26% of three-phase inverters—typically used in utility-scale solar installations—were sold with a service plan in 2012. The firm forecasts that sales of such service plans will increase to 34% by 2017.

6 Any third-party O&M provider for existing Satcon inverters will likely need access to the company's spare-part supply chain. PV systems are often designed around a particular inverter model, which makes swapping out failed Satcon components with competitors' products impractical.

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Table 1. Recent Activities in the Inverter Marketplace

Company	Activity	Notes
ABB	Acquisition - Power-One	Acquiring Power-One for ~$1 billion to become #2 PV inverter supplier in the world. Transaction expected to close in 2H13. ABB generally gains greater access to markets in the Americas, and makes inroads into residential/commercial markets (particularly in Europe), enabling it to move beyond its traditional utility-scale focus.
Advanced Energy	Acquisition - REFUsol	Purchased string inverter maker REFUsol--and its suite of 3-phase, 8kW to 24kW devices--for $77 million in Apr. 2013. AE becomes #3 player in the PV inverter market; hopes to leverage the acquisition to more quickly access emerging markets in India, Asia, the Mediterranean, and Eastern Europe.
eIQ and Azuray Technologies	Market Exit	Doors reportedly closed at the two module-level power electronics firms due to increasing market/price competition, niche offering, and volume shortfalls.
Lehner Agrar	Acquisition - Oelmaier Technology	Bought Germany-based inverter producer Oelmaier for an undisclosed sum during liquidation proceedings in Nov. 2012. Lehner Agrar, an agricultural technology provider, expanding into the field of electrical engineering.
mutares AG	Acquisition - Diehl Controls	Purchased Diehl Controls' PV business unit in early 2013 with an eye toward strategic partnership. Diehl Controls to continue to manufacture its inverter line and serve as OEM while Mutares leverages its sales channels.
Pairan	Insolvency	Filed for bankruptcy in mid-2012. One of multiple medium-sized German solar companies to go under in the last 24 months.
Satcon	Insolvency	Declared Chapter 11 bankruptcy protection in Oct. 2013. After failing to find a buyer, the company was forced to liquidate in early 2013, raising questions about the warranty and upkeep of its numerous commercially operating inverters in the field.
Siemens	Divestment	Exiting the solar business citing weakening demand. Once among the largest inverter manufacturers, production halted in May 2013. Customer service of existing hardware reportedly unaffected.
SMA	Majority stake position in Jiangsu Zeversolar New Energy	Purchased majority 72.5% stake of the Chinese inverter maker for $52.5 million in Dec. 2012. The acquisition positions SMA, the market leader in the space, to capture a bigger slice of the growing Chinese market.

Notes: The top three inverter firms—SMA, Power-One, and Advanced Energy—now represent an over 50% share of the world's inverter market.

Bankruptcy has touched an assortment of companies: earlier stage companies in the less mature module-level power electronics, such as eIQ and Azuray Technologies; more established European-based medium-size inverter manufacturers, such as Pairan; and industry stalwarts like Satcon. Other industry participants such as Siemens have dropped out of the space altogether, judging it to be unprofitable. And incumbents ABB, Advanced Energy, and SMA, among others, have recently made significant acquisitions to shore up their market positions.

Looking ahead, the state of the inverter landscape is likely to elicit further M&A activity as smaller, less capitalized companies increasingly seek out a corporate parent. Further insolvency and divestment is also anticipated, principally among European and low-cost Asian manufacturers unable to access available markets and/or prove field reliability. Ultimately, industry analysts expect the inverter space to contract over the next year or two, with much of the small-to-medium-sized competition being weeded out, before the industry regains equilibrium and average selling prices (ASPs) stabilize.

Cost Corner

Solar PV Pricing Highlights: 1H2013

Global solar PV pricing continues to fluctuate, more perceptibly for some system component areas than others. The oscillation in market prices is based on a host of local and international dynamics—including availability of supply, policy landscape distinctions, the threat or imposition of trade tariffs, and market rates for electricity. Table 2 provides recent price point changes that have occurred between Q1 and Q2 of 2013. Unless otherwise noted, it depicts average price points for major PV system inputs as well as the overall systems themselves, sold in Dec. 2012/Jan. 2013 and in May 2013.

For a variety of reasons, average prices for many of the raw materials and equipment that comprise a PV system slightly increased over the first half of 2013, perhaps presaging the beginnings of the industry's long awaited rebound in pricing. It remains to be seen, however, if the identified price rises will be temporary blips or have longer-term impacts. Industry consolidation and multilateral trade disputes represent the main factors driving the variability in prices, and the segment's overall supply-demand imbalance.

Table 2. Average PV System Component and System Pricing

PV Component/System	Dec 2012/Jan 2013	May 2013
Polysilicon price	$16/kg	$17/kg
5" Monocrystalline wafers	$0.71 each	$0.78 each
6" Monocrystalline wafers	$1.16 each	$1.23 each
6" Multicrystalline wafers	N/A	$0.92 each
Multicrystalline cells	$0.38/W	$0.42/W
Monocrystalline cells	$0.44/W	$0.49/W
Multicrystalline modules*	$0.83/W	$0.84/W
Monocrystalline modules*	$0.85/W	$0.93/W
CdTe modules*	$0.72/W	$0.71/W
a-Si modules*	$0.61/W	$0.51/W**
Inverters - residential (0-20 kW)†	$0.23/Wac	$0.28/Wac
Inverters - commercial (20-1,000 kW)†	$0.20/Wac	$0.17/Wac
Inverters - utility-scale (1,000 kW+)†	$0.11/Wac	$0.12/Wac
PV System - US residential	$5.86/W^	$4.93/W^^
PV System - US commercial-scale	$4.64/W^	$3.92/W^^
PV System - US utility-scale	$2.27/W	$2.14/W^^
PV System - US national average	$4.45/W^	$3.37/W^^
PV System - Germany residential rooftop (up to 10 kW without tax)	$2.32/W	N/A
PV System - Germany utility-scale	$1.59/W	N/A
PV System - Global average	$3.10/W	N/A

Notes:
All prices approximate, weighted averages.
U.S. residential system prices ranged from <$3/W to ~$8/W and often fell in the $4/W range in 1Q13. Prices for commercial systems ranged between $2.50/W and $8/W. Utility prices were highly variable based on size, technology, fixed/tracking choices, and other factors. The relatively slight decline in price for U.S. utility-scale PV systems is related to the disproportionate number of smaller projects that came on-line in 1Q13 vs. 4Q12.
** All module prices for the first buyer, inventoried panel prices are significantly lower. Data for CIGS unavailable.*
*** as of April 2013*
^ as of 1Q12
^^ as of 1Q13
† Excludes warranty and VAT
Sources: GTM Research/SEIA, NREL, Lawrence Berkeley National Lab, BNEF, European Photovoltaic Industry Assn (EPIA), BSW Solar

Incipient trade disputes primarily between China, the U.S., and Europe are, for example, inflating polysilicon spot prices. Simultaneously, producers are either cutting or shutting down polysilicon production, thus easing oversupply. The rise in poly spot prices is expected to continue, potentially reaching $25/kg by year's end, as a result of escalating trade wars and also due to necessary market correction—spot prices, which hovered just below $16/kg in 2012, are basically unsustainable for the majority of manufacturers.[7] Correspondingly, wafer prices have increased by 7-10% during the first half of 2013 due mainly to a winnowing of supply.[8] Large wafer makers are now reportedly procuring bigger orders, placing greater pressure on smaller companies to remain economically competitive while guaranteeing product quality.

Cell prices are also on the rise largely as a result of consolidation, lowering inventories, and rising utilization rates (i.e., the amount of production provided from market-ready capacity along the value chain).[9] Much of the segment's consolidation is being driven by China's evolving attitude toward domestic lending. (China produces 44 GW of the world's 65 GW of cell capacity.) Chinese banks are, for example, now

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7 Costs for many polysilicon manufacturers are typically 50%-100% higher than current spot prices.
8 There is roughly 48 GW of fully commissioned crystalline silicon wafer manufacturing capacity currently available worldwide; 37 GW of existing supply resides in China.
9 The top 10 c-Si cell manufacturers—with a total capacity of 18.4 GW—had an average utilization rate of 71%. The top 10 c-Si cell manufacturers, by production, are: Yingli, JA Solar, Suntech, Motech, Jinko Solar, Trina Solar, Canadian Solar, Gintech, Hareon Solar, and SunPower.

continued from page 5

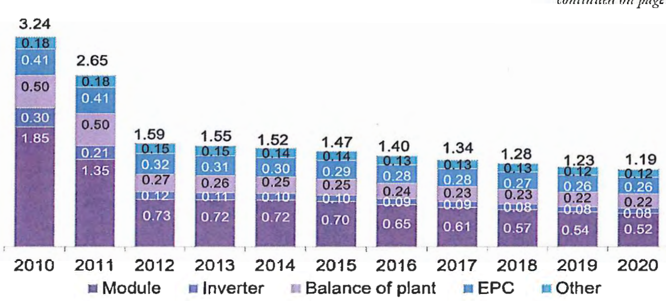
more vigilantly qualifying loans to firms along the PV supply chain. In tandem, the government is reportedly developing entry requirements to help take unneeded capacity out of the market. These standards—which will dictate capacity, efficiency, pipeline, and other benchmarks—are intended to provide banks with guidance when making PV-related investment decisions. As a result, small cell companies (and other Chinese-based outfits along the supply chain) manufacturing undifferentiated and/or uncompetitive products are expected to shut down, helping to better calibrate overall market supply with demand.

Most modules—excepting those composed of amorphous silicon (a-Si), which are unlikely to remain a viable standalone commercial product for much longer—are also experiencing price increases. The main reason: trade tariffs.[10] For example, recently imposed provisional anti-dumping duties issued by the European Commission on Chinese solar panels, cells, and wafers—averaging 47.6%, and ranging from 37.3%-67.9%, on more than 100 companies—are affecting Chinese module imports to the EU.[11] Consequently, module deal prices, particularly for monocrystalline, are on the upswing in Europe given the absence of cheap Chinese modules. Similar dynamics, though to a lesser extent, are afoot in the United States, which has also imposed duties on Chinese product. (See PV Market Update, Vol. 5 [3002000683] for a recap on the state of worldwide PV trade disputes.) All told, the instituted tariffs appear to be having a near-term effect on module pricing by penalizing depressed Chinese products. (Roughly 43 GW of the world's 60 GW of fully commissioned c-Si module capacity is produced in China.) However, loopholes and ongoing negotiations are likely to lessen their longer term impact. Bloomberg New Energy Finance forecasts that c-Si module prices will stabilize at $0.70-0.75/W by end 2013.[12]

Meanwhile, the inverter segment, which has been experiencing major upheaval during the last 12-24 months, appears to be settling down. Over the course of 2012, average residential inverter prices fell 15%, by 20% for the commercial inverter segment, and by 50% for utility-scale inverters. The difficult pricing environment prompted a number of exits and bankruptcies, claiming the likes of industry stalwart Satcon, among others, and has since triggered a fair amount of acquisition activity. Major purchases by Advanced Energy (REFUsol) and ABB (Power-One) indicate the sector's maturation as suppliers increasingly look for deep pocketed parent companies to help them compete in the increasingly ruthless inverter marketplace.[13]

Thus far in 2013, inverter prices continue to slide for commercial inverters, but have stabilized for utility-scale inverters, partially due to increased demand for larger, next generation model sizes. Meanwhile, residential systems, which have seen an uptick in demand due in part to the growing popularity of solar leasing models, have witnessed a notable bump in prices. In general, industry analysts expect inverter price fluctuations to moderate going forward and for more steady downward movement to ensue.

continued on page 9



Notes: Data collected and triangulated from project developer and installer documents for projects based largely in European countries (Germany, Italy, Romania, and UK).
All metrics are in $/Wdc.
Elements embedded in the "Other" category include finance arrangement, permitting, paperwork, and contingency.
Utility-scale (1-MW+) system installation costs vary in different markets. For example, in the U.S., most best-in-class projects are going in the ground at $2-$2.50/Wdc, and as low as $1.75/Wdc (for 5 MW+ projects). These higher prices are due to higher permitting/interconnection, transactional, and equipment costs. Also, prices are being upwardly affected by U.S. developers claiming higher 'developer fees' than their cohorts in Europe. In Japan, meanwhile, prices are higher because the country is currently supporting an over-subsidized boom market.
Source: Bloomberg New Energy Finance

Figure 4. Fixed-Axis Utility-Scale PV Price CAPEX Forecast, 2010-2020 (2012 $/Wdc)

10 Module prices are, of course, also affected by supply chain dynamics (i.e., module prices are impacted by movements in price for polysilicon feedstock, wafers, and cells).

11 The EC plans to issue a final decision on anti-dumping duties, covering a five-year period, by December 2013. It is also examining potential anti-subsidy penalties on Chinese solar products. Meantime, to avoid a full-blown trade war, the EU, China, and the U.S. are seeking a negotiated solution in which China would agree to sell product at a minimum floor price.

12 Price points will, however, be lower on the spot market and in large project deals.

13 The top three inverter firms—SMA, Power-One, and Advanced Energy—now represent an over 50% share of the world's inverter market.

continued from page 6

Finally, on the heels of significant drops in 2010, 2011, and 2012, PV system prices appear to have tempered. Figure 4 offers one take on the trajectory of prices for utility-scale systems. Note: The figure's data is conveyed in $/Wdc and that, more generally, system pricing is highly variable based on geography, local market terms, and other factors. Suffice to say, installation prices are falling—and will likely continue to fall—as bureaucratic red tape is reduced, installation is further streamlined, and advances in equipment manufacture and deployment are realized. Today, some German EPCs claim they can build a large-scale PV system for $1.05/W, though with almost no margin.[14]

It remains to be seen how much further the PV industry can sustainably reduce pricing in the near term. But current pricing is beginning to translate to lower, more competitive purchase contracts, which will likely strengthen demand. For example, in the U.S., First Solar recently received approval from the New Mexico Public Regulation Commission to sell solar generation from a 50-MW plant to El Paso Electric for $0.0579/kWh. And "parity projects," in which the output produced by deployed PV systems is being sold at grid-competitive rates without subsidy, are popping up in increasing numbers in places like Australia, Brazil, Chile, Spain, South Africa, and parts of the United States.

Technology Spotlight

Integrated Solar Racking

A Brief Backgrounder

Innovative solar PV racking systems, designed to reduce both material and labor costs, are proliferating in the residential and commercial rooftop market spaces. Packaged as integrated module-and-rack systems, these alternative racking approaches potentially offer a faster, less expensive means for installing solar PV than traditional methods by decreasing parts count, lowering system weight, and simplifying assembly.

As the moniker implies, integrated systems are typically preassembled offsite and arrive at a project location ready to install. Although there are various design approaches—including ballast to forgo or minimize physical rooftop attachment, rail-free installation, and techniques that eliminate the clamping together of the module and rack during installation—on-site labor often entails lifting the systems via crane to the rooftop, appropriate placement of the system about the roof surface, and wiring.

The expanding array of product offerings in this area, many of which have been commercially released in the last several years, is an outgrowth of wide-ranging efforts to reduce balance-of-system (BOS) costs—effectively all of the upfront system costs with the exception of those associated with the module. Historically, BOS costs have represented roughly half of system costs for most of the past 30 years. But with the precipitous drop in module selling prices over the last 3-4 years, BOS now accounts for over half of a typical PV system's installed cost.[15,16] Among the larger constituent costs within the BOS category: mounting and racking, which generally accounts for between 5% and 10% of a fixed system's overall install costs. (Costs for tracking systems contribute approximately twice as much.)

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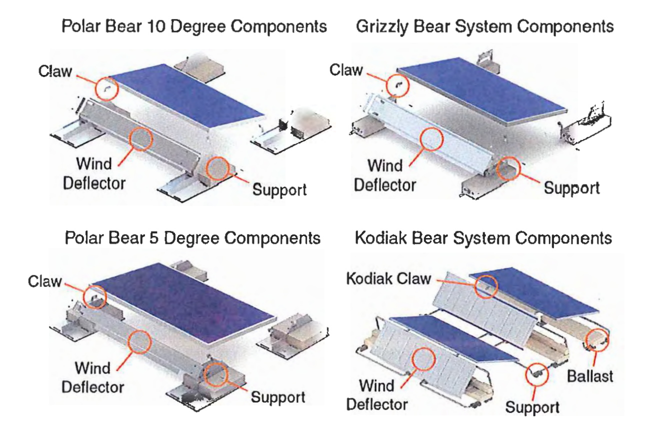

Source: PanelClaw

Figure 5. PanelClaw Ballasted Rooftop System

[14] This claim is rendered moot if import duties on Chinese products dramatically increase component prices.

[15] "Hard" and "soft" BOS component costs relate to a project's "first cost" (i.e., $/W price tag). BOS hard costs encompass the labor required for PV plant construction and commissioning, as well as the capital equipment associated with a PV plant: primarily the racking, power electronics, communication and monitoring, and wiring. "Soft" costs surround project management-, compliance-, and other non-capital equipment-related activities, including permitting and interconnection; project design; conformity with safety, building, and electric codes; and workforce development and training. Historically, BOS hardware costs have comprised 33-40%, while soft costs—owner's costs, contingency, AFUDC, and engineering/facility fees—have made up the remaining 10-20% of non-module related costs.

[16] According to GTM Research, modules selling prices have declined by 82% since 2009—from $3.50/W to ~$0.60/W.

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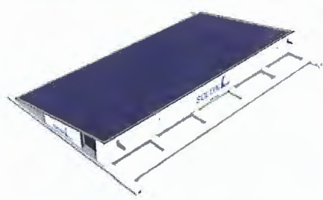
Table 3. Integrated Solar Racking Companies and Products

Company	Product Name(s)	Notes
PanelClaw	Grizzly Bear and Polar Bear flat roof mount solutions with integrated and flexible ballast	Unanchored products use ballast to weigh down the racking and modules instead of attaching them directly to the roof. Installation Rate Guarantee offered.
SOLON	SOLquick System	Pre-assembled product integrates a frameless module to a wood composite rack. Can accommodate multiple module manufacturers.
SunPower	T5 and T10 Solar Roof Tiles	Interlocking system secures roof tiles and enables rapid installation. A lightweight polymer further protects the roof and eliminates the need for electrical grounding.
Zep Solar	ZS series for shingle, tile, metal, corrugated, and other roof types	Rail-free technology incorporates the panel into the racking hardware via a custom grooved frame known as the "Zep Groove." Product licensed to panel vendors.

A Sampling of Market Players

Table 3 provides a snapshot of a select number of integrated solar racking manufacturers and their associated products. The table's profiled companies are a representative sample of the diversity of design approaches that are now commercially available. For example, PanelClaw offers an integrated solar racking system that contains built-in ballast weighting into its lighter-weight design. Devised for flat or nearly flat roofs, the company's largely unanchored products use weight to hold down the racking and modules instead of attaching them directly to the site surface and, in turn, avoid potential rooftop complications or damage from penetration. As a result, the time and complexity of installation can be reduced and costs lowered. PanelClaw, in fact, backs up its claims by offering an Installation Rate Guarantee certifying the time required to install its flat roof products.

SOLON manufactures the SOLquick integrated laminate and racking system for large commercial rooftops that are designed to support systems of 100 kW and higher. In contrast to traditional approaches that clamp the module to the rack on site, SOLON's SOLquick product rolls out of the factory preassembled, with a frameless module designated as a laminate—basically a traditional module without the aluminum frame—already affixed to a wood composite rack.[17] Although the company typically uses its own laminates with its SOLquick product, the racking system has the flexibility to accommodate other models. In addition, the entire system comes with a 25-year performance and 10-year product warranty. Company officials assert that 15 modules, totaling 4,200 Watts can be installed per man-hour.



Source: SOLON

Figure 6. SOLON SOLquick Unit

Meanwhile, SunPower produces T5 and T10 Solar Roof Tiles, which come pre-assembled in an integrated, all-in-one pre-engineered unit that includes the panel, frame, and mounting system. Built around the company's 24%-efficient Maxeon® solar cell technology, the company's Solar Roof Tiles, which are angled at 5- or 10-degree tilts, interlock together securely for rapid installation and can produce more total energy by area than any other roof tile solar panel system on the market today. Like PanelClaw, SunPower's commercial solar rooftop racking

Source: SunPower

Figure 7. SunPower T5 Solar Roof Tile Installation

products are self-ballasted and in turn help preserve rooftop integrity. In addition, a lightweight polymer material helps further protect the roof and eliminates the need for electrical grounding. All told, SunPower avers that workers can install up to ten T5 modules, equating to 3,200 W, per man-hour.[18]

Zep Solar has created a rail-free technology that effectively incorporates the panel into the racking hardware via a custom grooved frame known as the "Zep Groove." Essentially, the firm's mounting and grounding hardware lock into the panel groove design to form secure module units. In using the module frame as the structural and mounting element, Zep Solar's technology platform is reportedly able to accelerate installations by

continued on page 9

[17] The SOLquick rack is composed of a non-metallic substructure made from Fibrex, a wood polymer with a PVC coating.
[18] Each SunPower module is about 320 W and has efficiency greater than 20%.

continued from page 8

Source: Zep Solar

Figure 8. Zep Solar Roof Mount

4-5x versus rail-based systems through streamlined logistics, reduced labor handling, and auto-grounding. (The resulting savings are a big reason why the company is a favorite of large residential rooftop installers SolarCity and Vivint Solar.) But the company's real innovation may well be that it licenses its grooved module frame design to a number of panel vendors who then adapt their products to Zep-compatible versions. That standardization, which reduces the overarching design and deployment effort, is likely to prove advantageous in the highly competitive racking market. Later this year, the company plans to release a ballasted, rail-free, commercial flat-roof product.

Outstanding Questions

Although integrated solar racking is growing in popularity, competitors have raised questions about the products' merits. Among the challenges posited: Constrained module choice, limited suitability for different rooftop situations, increased shipping costs, greater crane operation requirements, and wind loading concerns (for ballasted systems).

The biggest advantage of non-integrated systems over their integrated cousins is that they are "module-agnostic;" they ultimately provide customers with the flexibility to invest in their preferred module technology (based on cost, bankability, quality, etc.). Many argue that this optionality is of greater importance to customers than the reduced installation and cost savings proffered by integrated systems. However, new integrated racking designs are emerging that enable them to work with a broader array of panels. For example, SOLON's SOLquick system has been designed to integrate with any unframed solar laminate the company internally qualifies as both cost-effective and of adequate quality. And Zep Solar's racking platform is compatible with a growing number of modules, including those manufactured by Yingli, Sharp, Trina, Canadian Solar, Hanwha, and Suniva.[19]

Non-integrated systems also tend to be appropriate for a greater variety of rooftop (~80%) conditions. Integrated models are, meanwhile, ideal for flat rooftops, but their application is slowly extending to other contexts. SunPower, for instance, claims that its Solar Roof Tiles are compatible with all roof membranes and flexible enough to adapt to virtually any flat or low-slope roof.

Separately, shipping can be more costly for integrated systems given that they cannot be packed as tightly as non-integrated products. And, on a related note, increased time may be necessary to crane lift palettes containing integrated systems to a rooftop given packaging designs. But some manufacturers, such as PanelClaw, seem to refute these assertions (or at least infer that material and installation savings outweigh potentially increased costs) by agreeing to cover the freight costs of their rooftop products and offering an Installation Rate Guarantee.

Finally, wind loading concerns have arisen as ballasted systems (both integrated and non-integrated) have gained market traction and the frequency of extreme weather events has increased. To assuage these concerns, a number of manufacturers now provide "wind and seismic stamps" for their flat-roof products that assure their fitness for multiple environments.

EPRI's Take

The steady commercial release of novel integrated rooftop solar racking products, each embedded with innovative design and deployment features, is a response to growing demand in the residential and commercial distributed PV markets. Demand is projected to significantly rise in these segments, both in absolute terms and as a percentage of market share, due to lowering barriers to entry. Faced with the dual pressures of further diminishing system costs and preserving margin, solar racking companies are offering differentiated products that aim to streamline and simplify the installation process. For electric utilities, especially those that plan to invest in third-party leasing vehicles or that intend to pursue distributed PV ownership, the financial upsides presented by these racking solutions are worth noting.

To be sure, integrated racking products available today have both advantages and disadvantages; they are no slam dunk. While they offer economies-of-scale design and installation savings with lower potential for misconfiguration, the systems are not appropriate for every rooftop setting. Also, some non-integrated racking products have made significant strides and are now relatively comparable in cost and benefit. But integrated racking approaches do offer broad promise for further parts and process consolidation. Ultimately, standardization—pursued by both integrated and non-integrated racking players, and enabled by emerging regulations—will be the key to lowering cost-per-Watt installation metrics.

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[19] According to Zep Solar, SolarEdge, Enphase, and Tigo all make power electronics that are also compatible with Zep's technology platform.

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EPRI Resources

Nadav Enbar, *Sr. Project Manager, Power Delivery & Utilization, EPRI*
[redacted]

Travis Coleman, *Project Manager, Environment and Renewable Energy, EPRI*
[redacted]

Clarence Lyons, *Project Manager, Environment and Renewable Energy, EPRI*
[redacted]

Integration of Distributed Renewables (Program 174)

Solar Generation (Program 187)

Renewable Energy Economics and Technology Status (Program 84)

3002001259 June 2013

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800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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


RFP 2013

CONFIDENTIAL ATTORNEY-CLIENT WORKPRODUCT July 24, 2013

Status of RFP Analysis

Financial Analysis

- Transmission analysis was fine-tuned for PPA options and self-build timing/location.
    - No more analysis to be performed.
- 4-year PPA with Ameren and deferring long-term resource to 2020 is on average the least-cost resource decision in a carbon constrained world.
- Significant transmission upgrades make LS Power PPA uneconomic.

  ≥ $35 mm to have unconstrained

  only $3.40 avg. gas case then have LS Power cheaper
- Deferring CCGT until 2020 reduces revenue requirements by $105 NPVRR from 2015-19.
- Should a PPA with Ameren not materialize, building a CCGT at Brown by 2018 is the next preferred option.
    - Brown site continues to be cheaper than Green River.
    - Large number of start/stops for CCGT is not required in a carbon constrained world.
- Green River site is $25.5 million (NPVRR) more than Brown.
- Lowest cost BREC option is 3-year Coleman PPA.
    - $56 million NPVRR more than least-cost option.
    - $26 million NPVRR more than 2018 Brown CCGT.

Ameren PPA Issues

- Uncertainty related to relief from Illinois' Multi-pollutant Standard ("MPS") and impact on Dynegy transaction.
    - Dynegy expected to file application with Illinois Pollution Control Board ("IPCB") within weeks.
        - Expect quick response from IPCB if Dynegy must wait until after acquiring assets.
    - If IPCB approves application then Dynegy transaction expected to close before year-end.
    - Ameren willing to do PPA assuming no transaction with Dynegy.
    - LGE/KU will require "ability to walk away" date by early 2014 if MPS contingency is not waived by Ameren. Initial position will be November 1, 2013.
        - This allows LGE/KU to move forward with CPCN filing for a summer 2018 CCGT.
- Ameren and LGE/KU are in general agreement on non-binding term sheet except for:
    - "Ability to walk away" date (see above).
    - Capacity price
        - Ameren has moved once in response to LGE/KU first counter so we plan on countering one more time.
- Troutman Sanders producing first draft of PPA – not shared with Ameren yet.
- Expect to be able to complete definitive documents by September 1 assuming both sides work hard.

Next Steps

- Finalize non-binding term-sheet with Ameren.
- Internal review of PPA and share with Ameren.
- Complete analysis write-up in anticipation of late September KPSC filing.
- LGE/KU authorization – Award Recommendation ($126 million in capacity payments) needs approval of IC and LKE Board.

Todd, Karen

From:	Sinclair, David
Sent:	Friday, September 20, 2013 4:31 PM
To:	Thompson, Paul; Bowling, Ralph; Malloy, John; Jessee, Tom; Blake, Kent; Rives, Brad; Reynolds, Gerald; Whelan, Chris; Siemens, George; Staton, Ed; Schetzel, Doug; Voyles, John
Cc:	Balmer, Chris; Wilson, Stuart; Schram, Chuck; Freibert, Charlie; Brunner, Bob; Freibert, David
Subject:	RE: RFP decision; Site Location; CPCN Outline

All,

Attached is the agenda for the above meeting on Monday.

Thanks
David

Agenda for RFP Status Meeting ...

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)

① Environmental Permitting ; Operating Flexibility
② Slightly more jobs (union) at GR
③ TMN & Variability of Grid
→ Generation in West ky ??
→ very uncertain.
④ TLR 5 in west — already experienced
⑤ ⊕ GR can get to another pipeline (13 more miles)
⊖ 11 mile pipeline gets to Tex Gas, which could be too much concentration.
⑥ ⊖ GR would pick up Coal-friendly opposition at GR.
⑦ System Impact Study — shows
⑧ Diversity of Generation Siting

CCN Overview (Sinclair)

1. Need Demonstration
2. GHG regulation risk
3. New DSM
4. Solar project

Other Regulatory filings

June EPA

1. DSM by February 2014
2. IRP in April 2014
3. Rate case mid 2014 ECR

Communications Plan

10/3

1. RFP respondents
2. Media / Public at large Thom
3. PSC
4. Politicians
5. Other stakeholders

Employees

Public Action for Development
① Gas Pipeline
② Queue for TMN
③ Landowner.

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Table 1 – 2018 NGCC (Green River vs. Brown, PVRR, $M)

Alternative	Prod Cost	Capital	Cap Charge	FGT	FOM	XM Capital	Total	Delta
Avg of all scenarios								
GR 2x1 NGCC 2018	29,581	1,154	36	249	97	169	31,284	0
BR 2x1 NGCC 2018	29,613	1,142	36	255	97	144	31,287	2
Avg of all mid-carbon scenarios								
BR 2x1 NGCC 2018	36,315	1,172	36	259	98	144	38,023	0
GR 2x1 NGCC 2018	36,311	1,184	36	252	98	169	38,049	26
Avg of all zero carbon scenarios								
GR 2x1 NGCC 2018	22,851	1,124	36	245	95	169	24,520	0
BR 2x1 NGCC 2018	22,911	1,112	36	252	95	144	24,550	30

Table 2 – NGCC Configuration & Class Comparison

Configuration and Class	Capacity (MW)	Range (MW)	PVRR Delta ($M)
2x1 F Class	670	600-700	0
Two 1x1 F Class	660	600-700	43
2x1 H Class	760	700-800	0
Two 1x1 H Class	760	700-800	63

Table 3 – NGCC Capital Costs (Green River vs. Brown, $M, $2018)

Configuration and Class	Green River	Brown	Delta (GR vs. BR)
2x1 F Class	650	640	10
1x1 F Class	438	428	10
Two 1x1 F Class	700	690	10

7/23/2013

RFP Rankings - Mid-Carbon Scenario

$000s in 2013$

Rank	Alternative	Avg NPVRR - Mid Carbon	Diff from Best
1	Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,172,392	0
2	Ameren 2 Units (2016-19), BR 2x1 constrained CCGT (Jan '20)	38,185,261	12,869
3	Ameren 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,192,283	19,891
4	Ameren 1 Unit (2016-17), BR 2x1 CCGT (Jan '18)	38,202,222	29,830
5	Ameren 2 Units (2016-18), BR 2x1 constrained CCGT (Jan '19)	38,203,776	31,384
6	Ameren 1 Unit (2016-19) and LS Power 1 CT (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,212,296	39,904
7	LS Power 1 CT (2016-19) and Ameren 1 Unit (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,217,575	45,183
8	LS Power 1 CT (2016-19) and Ameren 1 Unit (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,223,887	51,495
9	LS Power 1 CT (2016-17), 2 CTs (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,225,579	53,187
10	Ameren 1 Unit (2016-17), GR 2x1 CCGT (Jan '18)	38,227,771	55,379
11	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,228,366	55,974
12	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,232,030	59,638
13	Ameren 2 Units (2016-17), GR 2x1 CCGT (Jan '18)	38,237,906	65,514
14	LS Power 2 CTs (2016-19), BR 2x1 constrained CCGT (Jan '20)	38,239,178	66,786
15	LS Power 1 CT (2016-17), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	38,240,182	67,790
16	Coleman 1 Unit (2016-17), GR 2x1 CCGT (Jan '18)	38,240,311	67,919
17	LS Power 1 CT (2016-17), BR 2x1 CCGT (Jan '18)	38,246,655	74,263
18	Coleman 2 Units (2016-18), BR 2x1 constrained CCGT (Jan '19)	38,251,264	78,872
19	LS Power 2 CTs (2016-18), BR 2x1 constrained CCGT (Jan '19)	38,253,429	81,037
20	Coleman 2 Units (2016-19), BR 2x1 constrained CCGT (Jan '20)	38,256,332	83,940
21	Coleman 2 Units (2016-17), GR 2x1 CCGT (Jan '18)	38,262,021	89,630
22	LS Power 3 CTs (2016-19), BR 2x1 constrained CCGT (Jan '20)	38,265,882	93,490
23	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	38,272,204	99,812
24	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	38,284,933	112,541
25	Coleman (2016-19), BR 2x1 constrained CCGT (Jan '20)	38,306,175	133,783
26	Wilson (2016-19), BR 2x1 constrained CCGT (Jan '20)	38,353,937	181,545
27	LS Power 1 CT (2016-17), GR 1x1 CCGT (Jan '18)	38,362,744	190,352
28	Ameren 1 Unit (2016-17), ERORA PPA (2018-37)	38,382,729	210,337
29	LS Power 1 CT (2016-17), ERORA PPA (2018-37)	38,431,898	259,506
30	LS Power 1 CT (2016-17), 2 CTs (2018-19), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,620,524	448,132
31	LS Power 3 CTs (2016-19), LS Power Asset Purchase (Jan '20); BR 2x1 constrained CCGT (Jan '22)	38,689,748	517,356
32	Coleman Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	39,166,430	994,038
33	Wilson Asset Purchase (2016), BR 2x1 constrained CCGT (Jan '21)	39,332,948	1,160,556

NPVRR ($2013, $000s)

7/23/2013

	Year	ProdCost	Capital	CapCharge	FGT	FOM	XMCap	Total
Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	2015	1,004,694	117	0	0	3,637	0	1,008,448
	2016	1,000,839	369	20,262	0	8,050	1,138	1,030,658
	2017	984,135	13,221	18,327	0	11,359	2,001	1,029,044
	2018	937,079	38,492	33,067	0	6,953	2,019	1,017,610
	2019	904,236	49,935	29,742	0	6,652	2,761	993,325
	Total	**4,830,983**	**102,133**	**101,399**	**0**	**36,651**	**7,918**	**5,079,084**
Ameren 1 Unit (2016-17), BR 2x1 CCGT (Jan '18)	2015	1,004,647	12,750	0	0	3,637	0	1,021,034
	2016	1,000,798	38,361	18,841	0	8,050	24	1,066,074
	2017	983,998	51,659	16,946	0	11,359	989	1,064,951
	2018	942,294	67,171	0	11,245	10,723	3,940	1,035,372
	2019	909,650	61,707	0	10,745	10,255	4,653	997,008
	Total	**4,841,386**	**231,648**	**35,787**	**21,989**	**44,024**	**9,605**	**5,184,439**
Ameren 1 Unit (2016-17), BR 2x1 CCGT (Jan '18)	2015	-47	12,633	0	0	0	0	12,586
vs.	2016	-41	37,992	-1,421	0	0	-1,113	35,416
Ameren 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	2017	-137	38,438	-1,381	0	0	-1,012	35,907
	2018	5,215	28,679	-33,067	11,245	3,770	1,921	17,762
	2019	5,414	11,772	-29,742	10,745	3,602	1,892	3,683
	Total	**10,403**	**129,514**	**-65,611**	**21,989**	**7,373**	**1,687**	**105,355**

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Option 1 – Focus on Ameren

- MPS contingency creates big uncertainty
  - Sale to Dynegy not likely to close until November
  - Process with IL environmental regulators could take significant time
- Ameren accepted the bulk of LGE/KU counter except for capacity price. They did come off their offer by $1.9 million per unit per year.

Option 2 –Focus on LS Power

- Only $19 million greater than Ameren (based on 6/18 values)
- Firm gas costs makes up the bulk of the difference
  - Evaluating the amount of flexibility needed given rest of gas fleet
- May need to give up "purchase option"

Option 3 – Negotiate simultaneously with both but for a 1 unit deal for all for years 300 MW

- One unit from each meets 2018-19 capacity needs.
- Assuming we get LS Power deal done this limits exposure should Dynegy not get MPS transferred. May be able to go back to LS Power for a second unit.
- Reducing capacity in 2018-19 from each source reduces transmission availability risk.
- Creates excess capacity in 2016 and 2017.
- More expensive than LS Power-only deal (assuming no optimization of gas transportation).

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- Capital cost for Green River location is about $31 million NPVRR more expensive than Brown location.
    - Site costs are $12 million NPVRR greater.
    - Transmission upgrades are about $ 19 million greater.

- Potential for greater operational flexibility at Green River related to environmental permitting for site with retired coal units offsets higher capital costs for a 2018 build.

- 2018 CCGT can be supported but it is not the lowest cost option at the present time.

- Delaying CCGT until 2020 is lowest cost option based on the average of all cases and the average of the CO2 cases.
    - Best deferral option is Ameren 1 unit 167 MW (2016-17) and 2 units 334 MW (2018-19).
    - Second best is Ameren 2 units 334 MW (2016-19).
        - LS Power 1 CT (2016-17) and 2 CTs (2018-19) is only $2.5 million NPVRR more.

- CO2 cases are most critical because there is no way to assure that there will never be CO2 costs in the future.
    - Future CO2 risk (combined with uncertain FERC approval) makes it highly unlikely that we would ever exercise option to purchase LS Power units.
    - Purchase of Coleman is only $1 million NPVRR better than building CCGT in 2018 assuming there are never any CO2 costs but is $928 million NPVRR worse in CO2 scenarios.
    - 2018 CCGT is only $5 million NPVRR better than best Ameren 2020 deferral option (see above) with no CO2 (ever) but is $49 million worse in CO2 scenarios.

- Delaying next unit until 2020 could reduce revenue requirements through 2019.
    - Revenue requirements of short-term capacity (with added equity cost) is lower cost than initial rate impact of CWIP and Plant in Service/depreciation associated with building in 2018.
    - Even with Low Gas Prices, not enough energy savings to offset early year construction revenue requirements compared to PPA costs.

- Qualitative benefits of 2018
    - Greater potential to "net 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 (by reducing energy coming from coal units).

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- Qualitative benefits of delaying until 2020
    - Because we are making no long-term decision, Big Rivers and Erora should be less of a political issue.
    - A transaction with LS Power is consistent with prior resource strategy 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.
    - A PPA is likely a non-event from environmentalist's perspective.
    - Allows more time to see how carbon regulations and load growth develop (reduces excess capacity argument).
    - Better matches expected capacity need – less of a lumpy addition issue.

- Qualitative negatives of a transaction with Ameren or LS Power
    - Ameren is an out of state coal resource – why not BREC?
    - LS Power is gas – why not BREC coal?

- Next steps
    - Generation Planning and Transmission Planning compare analysis and assumptions to ensure complete understanding
    - Marked-up counter proposal to Ameren
    - Response from LS Power
    - LMP data on Coleman and MISO/LGEE

Nominal Revenue Requirement Differences ($000s, 2013$) 6/18/2013

Year	Base Gas: 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)	Base Gas: 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)	High Gas: 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)	High Gas: 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)	Low Gas: 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)	Low Gas: 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	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	3,046	45,139	5,610	45,359	-60
2017	49,244	7,236	49,082	9,589	49,311	1,164
2018	29,742	14,960	43,322	21,385	-28,630	4,612
2019	10,692	19,953	26,297	28,743	-48,526	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

	Average NPVRR ($000s, 2013$)			Rank			Difference from Best		
Alternative	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

4-15-13

$000s in 2013$

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

6-15-13

Rank	Alternative	Avg NPVRR - Mid Carbon	Diff from Best
		$000s in 2013$	
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

Rank	Alternative	Avg NPVRR - All Cases ($000s in 2013$)	Diff from Best ($000s in 2013$)
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	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,479,501	18,090
5	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	31,480,542	19,130
6	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	31,483,507	22,095
7	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	31,487,889	26,478
8	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	31,491,948	30,536
9	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	31,493,277	31,866
10	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	31,494,596	33,184
11	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	31,495,211	33,799
12	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	31,495,331	33,919
13	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	31,496,569	35,158
14	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	31,502,358	40,946
15	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	31,509,317	47,906
16	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	31,512,597	51,185
17	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,517,783	56,372
18	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	31,519,623	58,211
19	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	31,520,354	58,942
20	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	31,545,084	83,673
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

		$000s in 2013$	
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	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,216,102	17,738
5	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	38,217,494	19,130
6	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	38,224,842	26,478
7	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	38,230,230	31,866
8	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	38,231,548	33,184
9	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	38,232,164	33,799
10	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	38,239,310	40,946
11	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	38,246,270	47,906
12	Ameren 1 Unit (2016-2017), GR 2x1 CCGT (Jan '18)	38,247,867	49,503
13	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,254,736	56,372
14	LS Power 1 CT (2016-17), GR 2x1 CCGT (Jan '18)	38,256,308	57,944
15	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	38,257,306	58,942
16	Coleman 1 Unit (2016-17); GR 2x1 CCGT (Jan '18)	38,259,691	61,327
17	Ameren 2 Units (2016-2017), GR 2x1 CCGT (Jan '18)	38,261,162	62,797
18	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	38,277,189	78,824
19	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	38,281,685	83,320
20	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	38,284,215	85,850
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

		$000s in 2013$	
Rank	Alternative	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	Coleman (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,742,901	185,205
12	LS Power 1 CT (2016-2017), 2 CTs (2018-2019); BR 2x1 constrained CCGT (Jan '20)	24,743,589	185,893
13	LS Power 2 CTs (2016-17), GR 2x1 CCGT (Jan '18)	24,748,004	190,309
14	LS Power 1 CT (2016-2017), 2 CTs (2018); BR 2x1 constrained CCGT (Jan '19)	24,750,936	193,241
15	Coleman 2 Units (2016-17); GR 2x1 CCGT (Jan '18)	24,755,030	197,335
16	Ameren 2 Units (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,756,325	198,629
17	Coleman 1 Unit (2016-17), 2 Units (2018-19); BR 2x1 constrained CCGT (Jan '20)	24,757,643	199,947
18	Coleman 1 Unit (2016-17), 2 Units (2018); BR 2x1 constrained CCGT (Jan '19)	24,758,258	200,562
19	LS Power 2 CTs (2016-2019), BR 2x1 constrained CCGT (Jan '20)	24,765,405	207,709
20	LS Power 2 CTs (2016-2018), BR 2x1 constrained CCGT (Jan '19)	24,772,365	214,669
21	Coleman 2 Units (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,780,831	223,135
22	Coleman 2 Units (2016-18); BR 2x1 constrained CCGT (Jan '19)	24,783,401	225,705
23	LS Power 1 CT (2016-17); GR 1x1 CCGT (Jan '18)	24,803,728	246,032
24	LS Power 3 CTs (2016-19); BR 2x1 constrained CCGT (Jan '20)	24,808,484	250,788
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

	Average NPVRR ($000s, 2013$)			Rank			Difference from Best		
Alternative	**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	14	8	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	14	6	7	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	12	5	5	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	12	6	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	13	18	16	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	20	11	15	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	19	10	14	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	17	13	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	16	7	9	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)	24,742,901	38,216,102	31,479,501	11	4	4	185,205	17,738	18,090
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	24	19	20	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	16	12	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	18	9	11	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	17	8	10	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	15	20	18	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	22	15	19	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	21	13	17	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	23	22	22	246,032	178,652	128,960

Todd, Karen

From: Sinclair, David
Sent: Wednesday, June 12, 2013 8:58 AM
To: Thompson, Paul
Subject: FW: NPVRR Cost Delta RFP Cases
Attachments: 20130611_MSF_P4I1_NPVRRCostDelta_RFPCases_DSinclair.xlsx

From: Farhat, Monica
Sent: Tuesday, June 11, 2013 4:03 PM
To: Sinclair, David
Subject: NPVRR Cost Delta RFP Cases

David,

Attached is the file that you requested.

Thanks,
Monica

Year	Mid Gas Forecast	Low Gas Forecast	High Gas Forecast
2013	4.24	3.22	4.40
2014	4.41	3.18	4.72
2015	4.62	3.32	4.94
2016	4.67	3.28	5.11
2017	4.79	3.31	5.32
2018	4.93	3.34	5.55
2019	5.16	3.41	5.86
2020	5.39	3.53	6.25
2021	5.77	3.67	6.78
2022	6.22	3.85	7.40
2023	6.58	4.07	7.95
2024	6.88	4.21	8.41
2025	7.23	4.40	8.91
2026	7.56	4.56	9.38
2027	7.93	4.79	9.91
2028	8.22	5.03	10.38
2029	8.57	5.15	10.78
2030	8.95	5.40	11.30
2031	9.35	5.61	11.03
2032	9.81	5.80	10.97
2033	10.19	6.11	11.62
2034	10.58	6.36	12.31
2035	10.99	6.63	13.04
2036	11.42	6.90	13.81
2037	11.86	7.19	14.63
2038	12.32	7.49	15.50
2039	12.80	7.80	16.41
2040	13.30	8.12	17.39
2041	13.81	8.46	18.42
2042	14.35	8.81	19.51

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

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

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

	Capital (2018 $M)	NPVRR Capital (2013 $M)[2]	NPVRR Transmission Capital (2013 $M)	Total NPVRR Delta
2x1 CCCT at Brown[1]	640	701	169	
2x1 CCCT at Green River	650	713	188	
	-11	-12	-19	-31

[1] BR1 and BR2 coal units continue to operate

[2] Capital NPVRR in (2013-2042)

Todd, Karen

From:	Sinclair, David
Sent:	Wednesday, June 12, 2013 8:57 AM
To:	Thompson, Paul
Subject:	FW: RFP Cases- NPVRR and Rank
Attachments:	20130611_MSF_NPVRR&Rank_RFPCases_DSinclair.xlsx

From: Farhat, Monica
Sent: Tuesday, June 11, 2013 8:26 AM
To: Sinclair, David
Subject: RFP Cases- NPVRR and Rank

David,

Attached is the file that you requested.

Thanks,
Monica

6/5/2013

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

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

Average NPVRR across all cases (Base/Low Load; High/Med/Low Gas Price; Zero/Medium Carbon)

		NPVRR ($000) in 2013 $	
Rank	Alternative	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

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

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

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

PWT

Attorney-Client Privileged Work Product DRAFT May 24, 2013

1. Focus only on need for capacity and energy
    a. Existing capacity, DSM, and need.
    b. Any short term needs will be dealt with in a timely manner.
        i. Short term offers have been fully evaluated.

DSM study included.

2. RFP
    a. RFP for up to 700 MW of capacity and energy issued in September 2012 with bids due by early November.
        i. Summarize parties and responses, including self-build options (any detailed lists in app)

3. RFP evaluation for this decision, including assumptions/key inputs
    a. Offers evaluated under multiple load, gas price, and carbon scenarios.
        i. Given EPA announcements about CO2 regulations, Company deemed it prudent to evaluate CO2 risk.
        ii. Multiple forms of potential CO2 regulations, but the price of emissions (Synapse source) used as proxy for CO2 regulations.
        iii. EIA source of gas prices. In addition to a variety of gas price futures, the ranges also cover typical variations in month to month commodity prices likely to be encountered during the RFP evaluation period.
4. RFP process
    a. Phase I screening description (further lists in appendix).
    b. Describe follow-on steps to arrive at short list.
    c. Short listed offers.

5. Big Rivers Wilson (PPA and Asset Sale) and recent Coleman offer (received May 22)
    a. Description of offers for BREC's regional, existing resources.
    b. Wilson
        i. Not least cost under any scenarios.
        ii. Potential risk of further environmental controls, including new FGD at Wilson.
        iii. Transmission networking cost estimated at $170 million (NPVRR).
    c. Coleman – (offer received May 22)
        i. [Evaluation underway]
        ii. Transmission networking cost estimated at (TBD).
    d. Approval hurdles include FERC and RUS. Transmission issues to be resolved include disconnection from MISO (or paying MISO drive-out charges), any required MISO approvals, and integration with LG&E/KU BA.

6. Erora
    a. Description of offer
    b. Connection of unit via proposed 26 mile radial 345kV line is not consistent with other LG&E/KU generating units.
        i. Further transmission construction cost of $70-$90 million (NPVRR) necessary to network Erora to LG&E/KU transmission system.

7. LS Power
    a. Bluegrass simple cycle CTs favorable only in limited (non-carbon) scenarios.
    b. Most favorable case for Bluegrass requires exercising purchase option in PPA; ability to complete deal is uncertain based on FERC market power screens.

8. Self-build at GR
    a. Company has two existing sites that are most favorable for CCGT development – Green River and Brown.
    b. Green River enables opportunity for unit start flexibility due to netting out for emissions due to GR3-4 retirement.
    c. Option to build a future unit at Brown site not precluded by using GR site first
    d. Electric transmission and gas pipeline ROW requirements under review.
    e. Unit size and configuration evaluation
        i. Reliability costs are affected by target reserve margin; fewer and larger units in the system may lead to higher reserve margin targets.
        ii. 2x1 units assumed to be at least 640 MW.
        iii. Two 1x1 units built sequentially require re-mobilization of construction resources.
        iv. Two 1x1 units built concurrently may lower reliability cost.
        v. Note economies of scale and efficiencies of various configurations.

9. RFP results – 2x1 CCGT at GR is least cost alternative
    a. Larger amount of CCGT capacity supports lower cost energy production offsetting higher total CAPEX..
    b. Particularly valuable in CO2 scenarios.

5/24/2013

2012 RFP Analysis – Document Summary

The analysis of responses to the 2012 RFP for electric energy and capacity started in November 2012 and is ongoing. Table 1 and Table 2 list documents produced or received during this period related to the RFP analysis.

Table 1 – Documents Produced for Internal Discussions

Meeting Date	Audience	Document	Meeting Purpose
11/30/2012	PWT and Project Team	• 2012 RFP Analysis – Status Report and Next Steps (.doc)	Present initial findings to PWT and project team.
12/18/2012	PWT and Selected Officers	• Analysis of Responses to 2012 RFP (.ppt) • 2012 RFP Analysis – Status Report and Next Steps (.doc)	Review and approve list of shortlisted respondents.
12/20/2012	File	• Executive Summary of Phase 2 RFP Analysis (.doc)	N/A
1/25/2013	PWT and Selected Officers	• Meeting Future Capacity Needs in a Worlds of Uncertainty (.ppt)	Review presentation for 1/29 meeting with officers.
1/29/2013	Officers	• Meeting Future Capacity Needs in a World of Uncertainty (.ppt)	Discuss general alternatives (and associated risks) for meeting future energy and capacity needs.
1/30/2013	Brown Station Managers	• RFP Update (.ppt)	Update Brown Station managers on Brown Station analysis.
2/18/2013	PWT and Selected Officers	• RFP Update (.ppt)	Discuss key issues/decisions related to RFP analysis and BR1-2 baghouse decision.
3/18/2013	VAS and Selected Officers	• Brown 1-2 Baghouse Retrofit Decision (.ppt)	Present recommendation to not install baghouses on Brown 1-2.
3/25/2013	PWT, Selected Officers, and Legal	• Brown 1-2 Baghouse Retrofit Analysis (.doc; A-C Work Product)	N/A
3/27/2013	File	• Considerations for Siting Future CCGTs at Brown or Green River Stations (.doc)	N/A
5/1/2013	PWT and Selected Officers	• RFP Analysis Update (.doc) • Selected Slides for 5/1 RFP Update Presentation (.ppt)	Present recommendation to build CCGT.
5/13/2013	Officers	• RFP Analysis Update (.ppt) • 2018 CCGT Project Schedule Overview (.doc)	Present recommendation to build CCGT; discuss CCGT project schedule.
5/13/2013	KWB	• RFP Analysis Update (.doc)	N/A
5/21/2013	VAS and Advisory Board of Directors	• RFP for Electric Energy and Capacity	Discuss RFP considerations with Advisory Board of Directors.

5/24/2013

Table 2 – Documents Related to Discussions with Shortlisted Parties

Meeting Date	Audience	Document
1/10/2013	Ameren	• RFP Shortlist Questions – Ameren (.doc) • Ameren Response (.doc) • Meeting minutes (.doc) • Written correspondence
1/11/2013	ERORA	• RFP Shortlist Questions – ERORA (.doc) • ERORA Response (.pdf) • Meeting minutes (.doc) • Written correspondence
1/11/2013	Big Rivers	• RFP Shortlist Questions – Big Rivers (.doc) • Big Rivers Responses (Bound Presentation and Interconnection Agrmt) • Meeting minutes (.doc) • Written correspondence
1/14/2013	LS Power	• RFP Shortlist Questions – LS Power (.doc) • LS Power Responses (.pdf) • Meeting minutes (.doc) • Written correspondence
1/17/2013	AEP	• RFP Shortlist Questions – AEP (.doc) • AEP Response (.pdf) • Meeting minutes (.doc) • Written correspondence
1/22/2013	Khanjee	• RFP Shortlist Questions – Khanjee (.doc) • Khanjee Response (.doc) • Meeting minutes (.doc) • Written correspondence

Imputed Debt — Arbough / Rating Agency
Transmission — Data/Runs w/ Tmn. — Only Summary to Stuart

PWT

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 ____

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.

Please consider if Big Rivers would be willing offer a tolling agreement for the Coleman station instead of a lease arrangement. If so, would Big Rivers consider a tolling agreement for less than all three of the Coleman units?

5/24/2013

5/24/2013 Email from Charlie Freibert to Bob Berry (Big Rivers)

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.

Please consider if Big Rivers would be willing offer a tolling agreement for the Coleman station instead of a lease arrangement. If so, would Big Rivers consider a tolling agreement for less than all three of the Coleman units?

Please see the attachment for our standard RFP data form, which includes a complete list of questions and data requirements regarding your Coleman proposal. We look forward to your complete response by May 31 so we can fully evaluate your proposal.

??

2018 CCGT Project Schedule Overview

Filing

6/14 Filing of the Next Rate Case

Major Activity	Tasks	Issues/Risks	Begin Date	End Date	Lead Personnel
Regulatory	1. File Generation CPCN 2. File Transmission CPCN 3. Receive Gen & Trans CPCN	• 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		5/13	8/13	Ryan
	2. Pipeline Build/Buy analysis & decision	• Owning pipeline provides better optionality for future interconnection with ANR for reliability & price protection with TGT	7/13	9/13	Sinclair
	3. Gas transport contract	• After CPCN & air permit approval	7/13	12/14	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

Notify Bidders

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 7/13
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

November 2017

NITS available

Target COD

January 2018

Guaranteed COD

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.*

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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.

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Next Steps

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

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Todd, Karen

Subject:	RFP Status
Location:	14 South Video
Start:	Wed 5/1/2013 9:30 AM
End:	Wed 5/1/2013 11:00 AM
Recurrence:	(none)
Meeting Status:	Accepted
Organizer:	Sinclair, David
Required Attendees:	Thompson, Paul; Wilson, Stuart; Schetzel, Doug; Freibert, Charlie; Schram, Chuck; Balmer, Chris; Bowling, Ralph; Voyles, John; Brunner, Bob; Jessee, Tom; LGEC14 South/Video (Cap 18)

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.

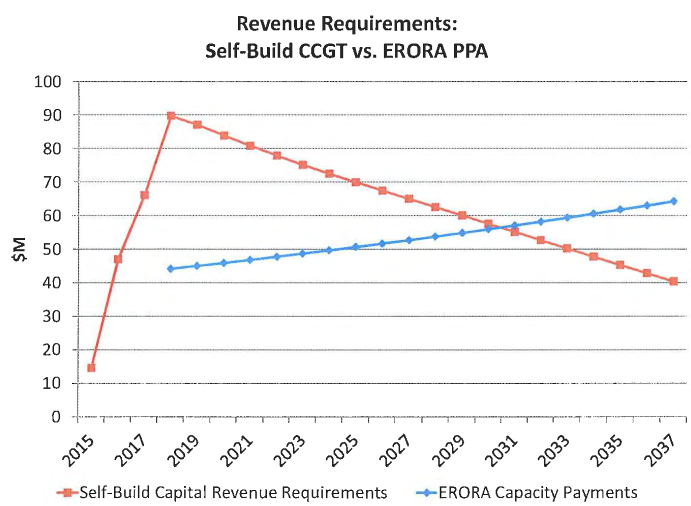
2. Today, this is still the case, but ERORA PPA is more competitive than before.
    a. XM interconnection costs are lower for the Cash Creek site than for either Brown or Green River.
        i. ~$50 million lower than Brown
        ii. ~$80 million lower than Green River
        iii. Note: ERORA unit 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 Thru 2025 ish

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

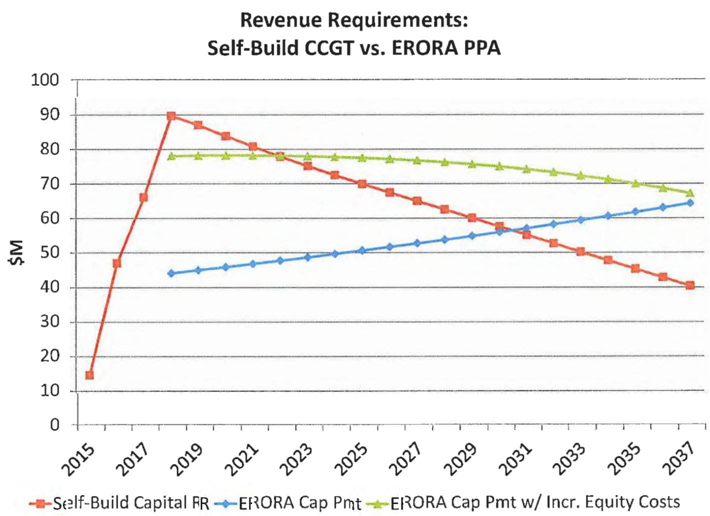
Cost Item	Average PVRR Difference over 12 Gas Price/Load/Carbon Scenarios ($M) (Self-Build CCGT vs. ERORA PPA)*
Firm Gas Transportation	-1
Fixed O&M	20
Production Costs	-102
XM Capital	80
Unit Capital/Capacity Charge	87
Total	85

*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.

Nominal Capital Cost.

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* — Nets out — Have Limits	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.

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:
    - 10 year tolling agreement at $5.55/kW-month capacity charge
    - 20 year tolling agreement at $5.05/kW-month capacity charge
    - Asset sale for $765 million
    - 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.

    - ERORA will pay liquidated damages to the Companies, equal to $1000/kW, capped at $20 million, for any capacity shortfall
    - 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
    - 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
    - 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

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	Yellow	Green	Yellow	Green	Yellow	Green	Yellow	Green	Green	Green	Green	Green
2 - Coal PPA (2015-19)	2019	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow	Yellow
3 - BR1-2 Baghouse Retrofit	2018	Green	Red	Green	Red	Green	Red	Green	Red	Red	Red	Red	Red
4 - 2015 Asset Purchase (SCCT)	2019	Green	Red	Green	Red	Yellow	Red	Yellow	Red	Red	Red	Red	Red
5 - BR1-2 Baghouse Retrofit (Retire 2030)	2018	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red	Red

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

Green | Yellow | Red
<-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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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

PRIVILEGED AND CONFIDENTIAL
ATTORNEY-CLIENT COMMUNICATION
WORK PRODUCT

April 22, 2013

RFP Plan - BREC Communications and Considerations

1. BREC responded to RFP with offer to sell the 417 MW Wilson station for $500 million

2. Potential environmental costs are significant
   a. New FGD cost estimated at $250 million
   b. Potential CO_2 costs could reduce value by another $250 million

3. Wilson offer is not competitive with other alternatives considering the potential costs above

4. Communication with other short-listed unsuccessful bidders will consist of phone call and follow-up letter
   a. Bidders will be advised that their proposal was not least cost
   b. No details will be provided on other lower cost alternatives

Todd, Karen

Subject:	Wilson Proposal (Sinclair & PWT)
Location:	PWT's conf. room
Start:	Thu 3/7/2013 9:30 AM
End:	Thu 3/7/2013 10:00 AM
Recurrence:	(none)
Meeting Status:	Meeting organizer
Organizer:	Thompson, Paul
Required Attendees:	Sinclair, David

Bailey

≈ $72/mwh on 30 yr levelized basis

$276 mm if get money back in 10 yrs.

MC 3 FGD/Baghouse analogy ⇒ $250 mm

SCR ?
CCR ?
others ?

No Tran Cost

∴ if gave it to us, then ok

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	
	CCCT	Big Rivers
2012	2.9781	3.0397
2013	4.4630	2.5131
~~2014~~	~~4.6406~~	~~2.5599~~
2015	4.8600	2.5532
2016	4.9123	2.6405
2017	5.0377	2.7908
2018	5.1839	2.8749
2019	5.4243	2.9379
2020	5.6646	3.0007
2021	6.0617	3.1399
2022	6.5319	3.2175
2023	6.9080	3.3255
2024	7.2215	3.4639
2025	7.5872	3.6020
2026	7.9321	3.7551
2027	8.3187	3.8772
2028	8.6217	4.0297
2029	8.9874	4.1973
2030	9.3844	4.3645
2031	9.8024	4.5467
2032	10.2831	4.7286
2033	10.6802	4.8487
2034	11.0926	5.0335
2035	11.5210	5.2252
2036	11.9660	5.4239
2037	12.4283	5.6298
2038	12.9084	5.8434
2039	13.4072	6.0647
2040	13.9252	6.2942
2041	14.4634	6.5320
2042	15.0224	6.7786

2.4%	Capital Escalation Rate
2.0%	O&M Escalation Rate
6.75%	Discount Rate
2042	Year Wilson is Retired

2015 $

	Units	CCCT	Big Rivers
Capital Cost	$M	590	500
Max Capacity	MW	670	417
Capital Cost	$/kW	881	1,199
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%	10%
Levelized Cost			
Fuel	$/MWh	51.95	38.33
VOM	$/MWh	1.94	3.28
Firm Gas	$/MWh	3.80	0.00
FOM	$/MWh	1.59	11.88
Capital	$/MWh	12.99	17.11
Total	$/MWh	72.27	70.59
Levelized Fuel Cost	$/MMBtu	7.53	3.67

	$/MMBtu	
	CCCT	Big Rivers
2012	2.9781	3.0397
2013	4.4630	2.5131
2014	4.6406	2.5599
2015	4.8600	2.5532
2016	4.9123	2.6405
2017	5.0377	2.7908
2018	5.1839	2.8749
2019	5.4243	2.9379
2020	5.6646	3.0007
2021	6.0617	3.1399
2022	6.5319	3.2175
2023	6.9080	3.3255
2024	7.2215	3.4639
2025	7.5872	3.6020
2026	7.9321	3.7551
2027	8.3187	3.8772
2028	8.6217	4.0297
2029	8.9874	4.1973
2030	9.3844	4.3645
2031	9.8024	4.5467
2032	10.2831	4.7286
2033	10.6802	4.8487
2034	11.0926	5.0335
2035	11.5210	5.2252
2036	11.9660	5.4239
2037	12.4283	5.6298
2038	12.9084	5.8434
2039	13.4072	6.0647
2040	13.9252	6.2942
2041	14.4634	6.5320
2042	15.0224	6.7786

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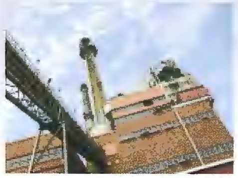
RFP Update

February 18, 2013

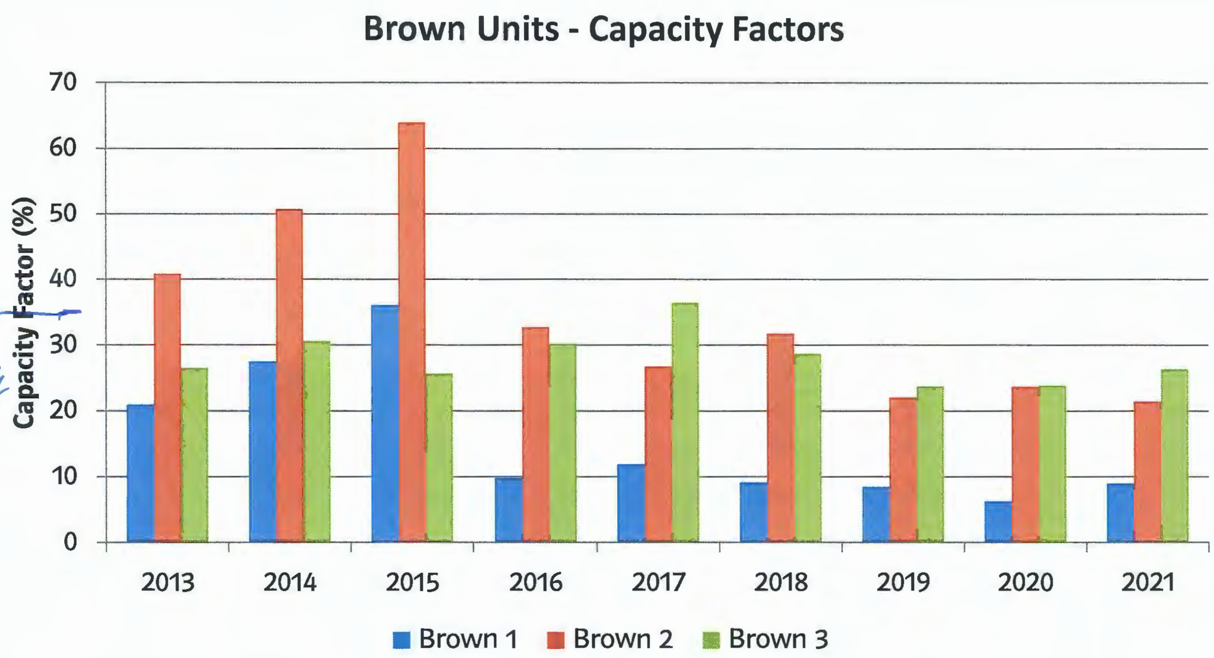





Questions still to be answered

- 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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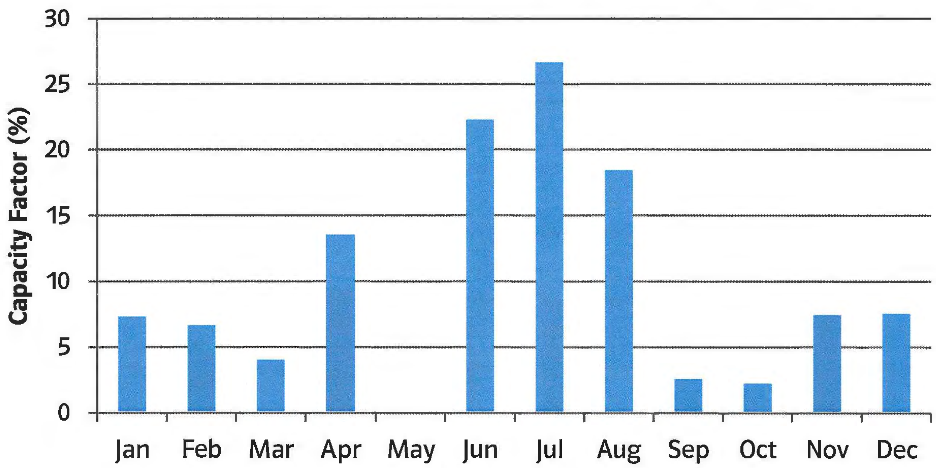
Brown 1 could have very limited dispatch outside of summer months

2016 - Brown 1 Capacity Factor



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*

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)

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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
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- Alt #5 – BR1-2 retrofit not favorable if units don't operate through 2042

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Todd, Karen

From: Sinclair, David
Sent: Monday, February 04, 2013 9:29 AM
To: Staffieri, Vic; Thompson, Paul; Rives, Brad; Blake, Kent; Reynolds, Gerald; Pottinger, Paula; Hermann, Chris
Subject: Materials for Feb 5 Meeting

All,

Attached are the 2 presentations I will cover at your Feb 5 meeting. Many of you have already seen the RFP presentation. It is the same one we discussed last Tuesday.

Thanks,
David

20130205 PJM Price Impacts Fi... 20130129_RFP Status Final 1-29...

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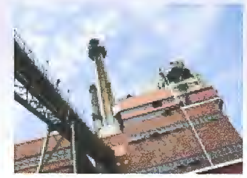

Meeting Future Capacity Needs in a World of Uncertainty

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*

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

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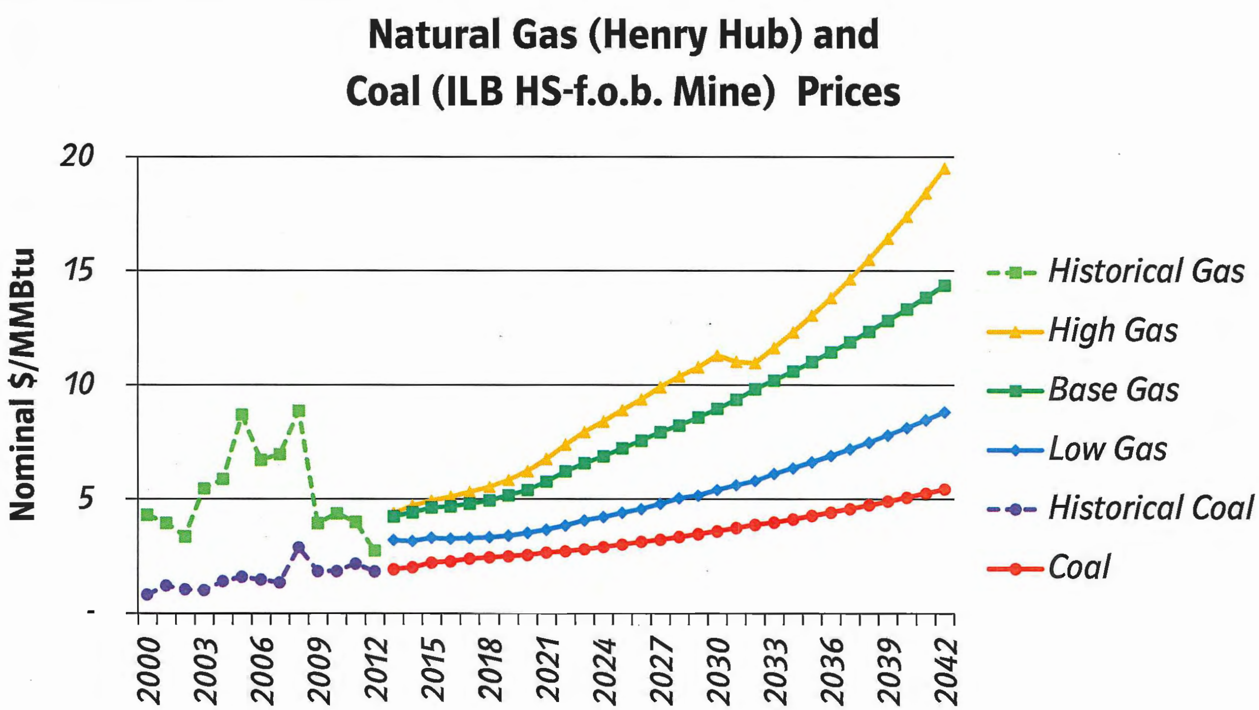
Incremental DSM above 2012 level (reflected in the data above)	*125*	*157*	*189*	*221*	*203*	*205*	*206*

Wide range of possible future gas prices



Source: EIA

January 29, 2013

LG&E KU PPL companies

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*
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PPL companies

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PPL companies

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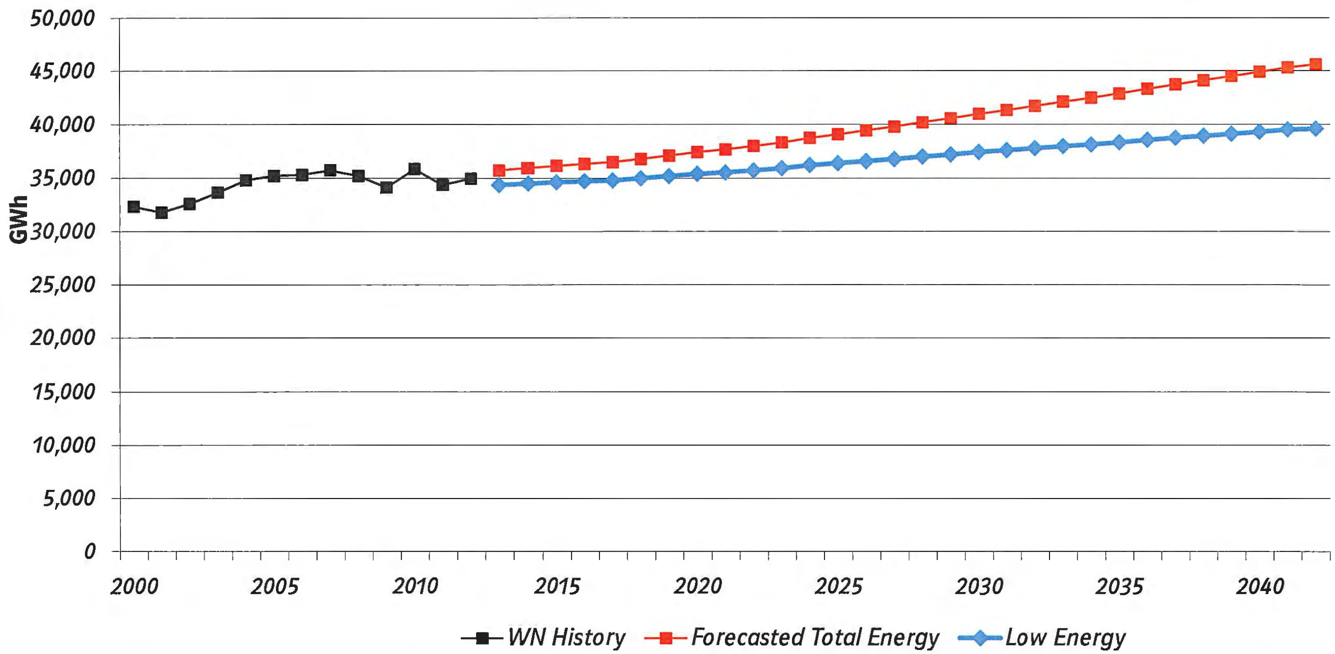
Combined Company Energy Requirements



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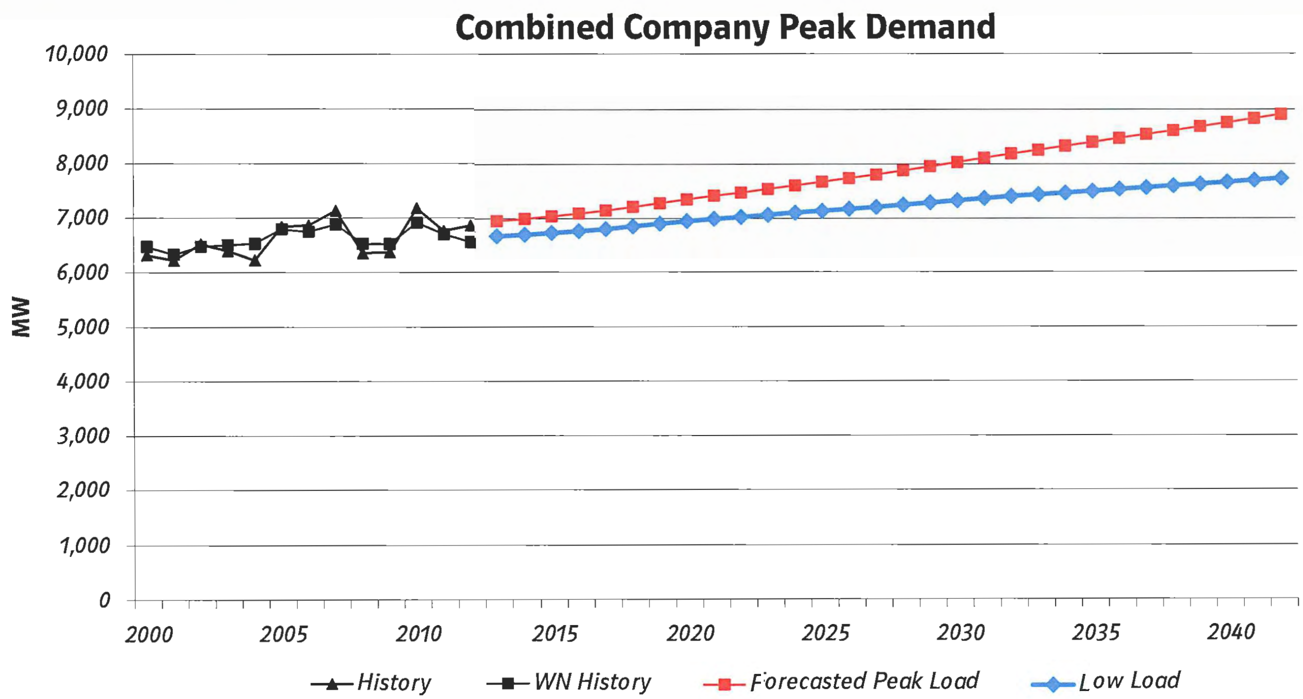

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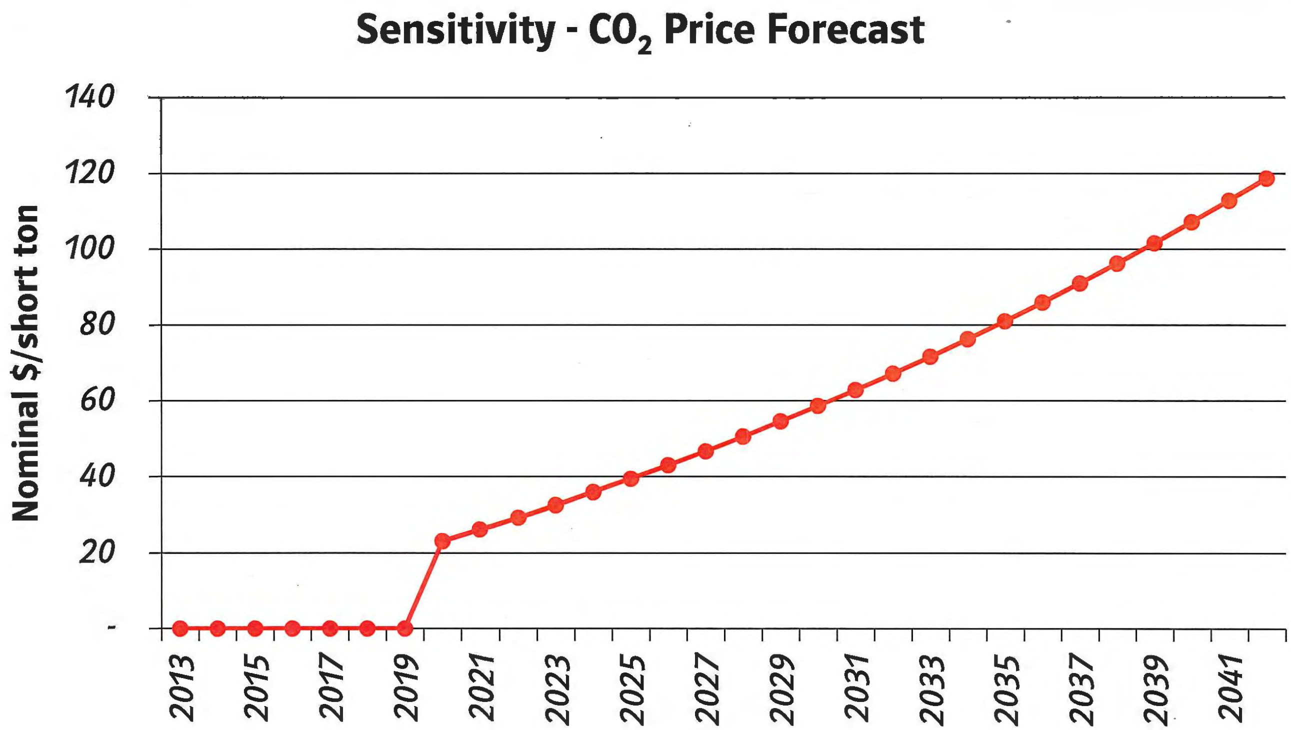
PPL companies

CO_2 price sensitivity starting in 2020



PPL companies

PJM Electricity Prices - Impacts of Gas Prices and Capacity Retirements

February 5, 2013

Higher PJM electricity prices are possible

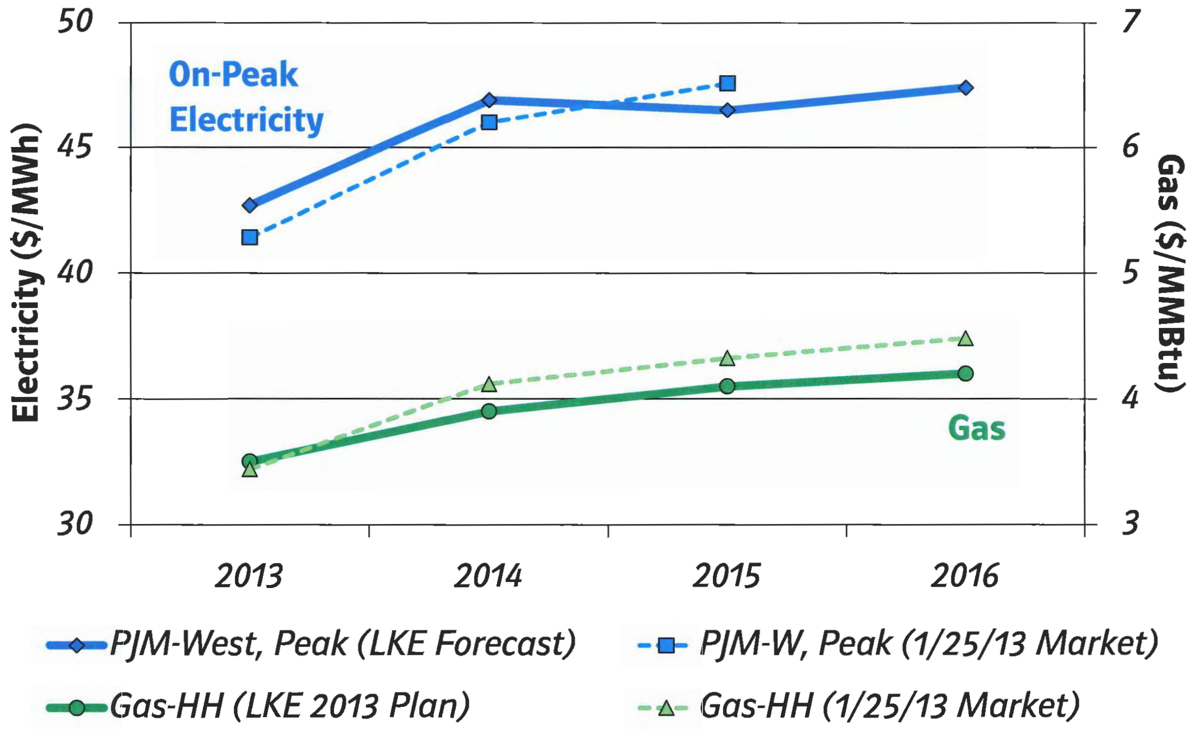
- *Higher gas prices*

- *Lower reserve margin*
  - *Announced coal retirements currently exceed announced new capacity*

- *If target reserve margin is maintained, prices will likely remain stable absent higher gas prices*

PPL companies

Electricity prices expected to increase along with natural gas prices



PPL companies

PPL's gas price scenarios may be optimistic

- *PPL's Business Plan forecast mirrors market through 2015; higher in 2016+*
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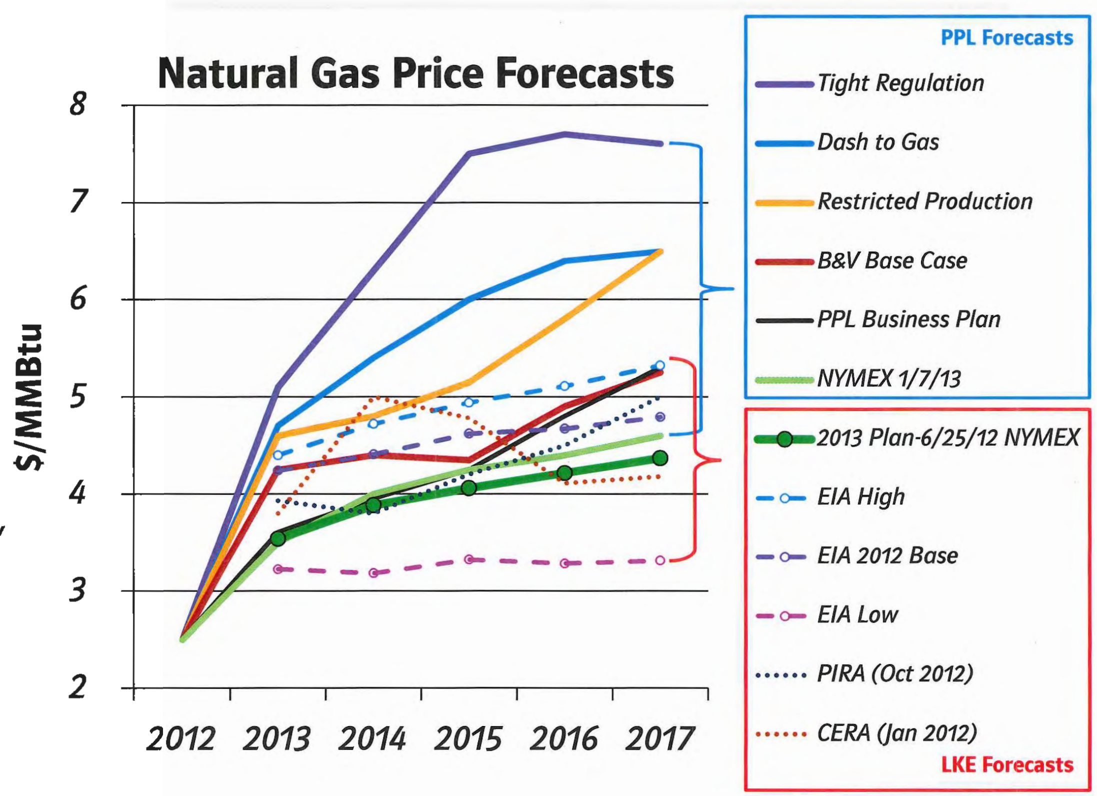

LG&E KU

PPL companies

Attachment to Response to KIUC Question No. 1-6
Page 115 of 232
Thompson

Lower reserve margins will have little impact on energy prices

- *PJM's 2012 planning reserve margin was 31%.*
- *By 2016, reserve margin drops to 16.7% with announced retirements/new units and total demand response.*
  - *Includes 10 GW load growth and 16.5 GW coal retirements offset by 6 GW new CCGTs and 3.5 GW new demand response.*
- *Almost all of the 2012-2016 increase in energy prices seems to be due to the increase in gas prices.*
- *Additional coal retirements replaced by CCGTs would lower energy prices due to improved heat rates.*
- *In PJM's 2012 capacity auction, prices increased from $86/MW-day (31 $/kW-year) in 2012 to $150/MW-day ($55/kW-year) in 2015.*

LG&E KU
PPL companies

Conclusions

- *Only higher natural gas prices will move PJM electricity prices materially higher in a way that benefits remaining coal units - just as in the past.*

- *Simply retiring more coal and building more CCGTs doesn't seem to move energy prices as long as gas remains in the $4/MMBtu range (which translates to $28/MWh for a CCGT).*

PPL companies

LG&E KU

PPL companies

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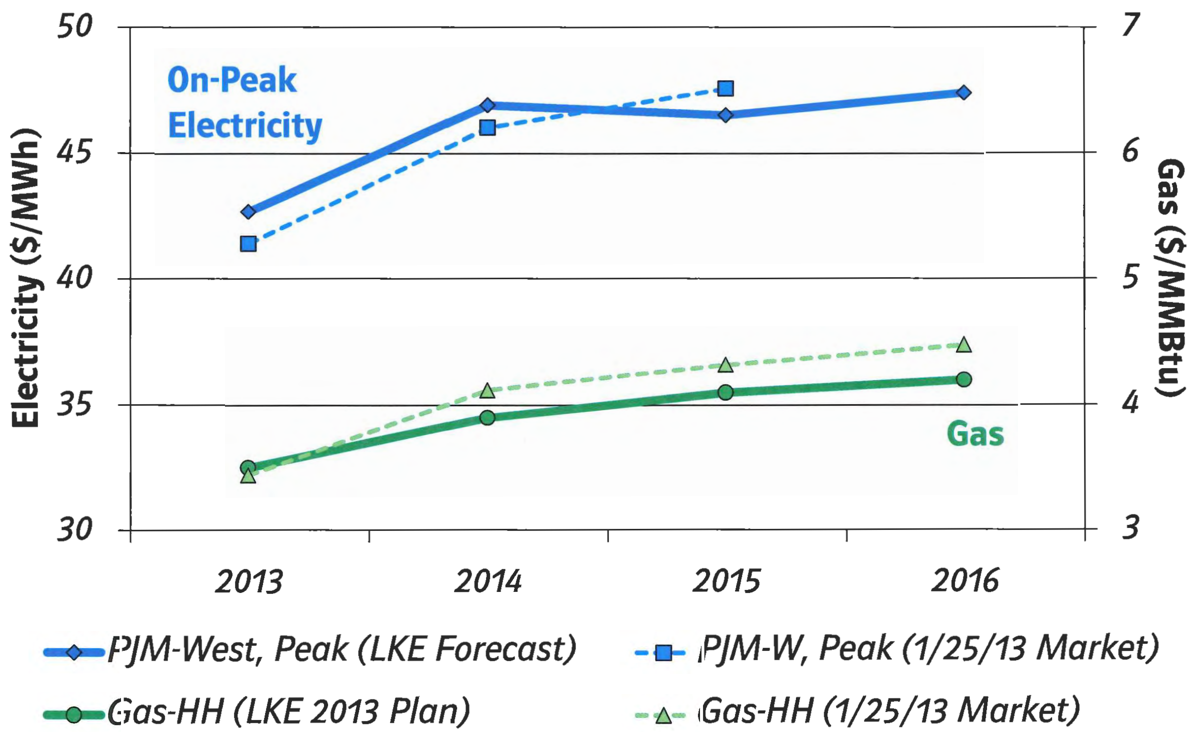

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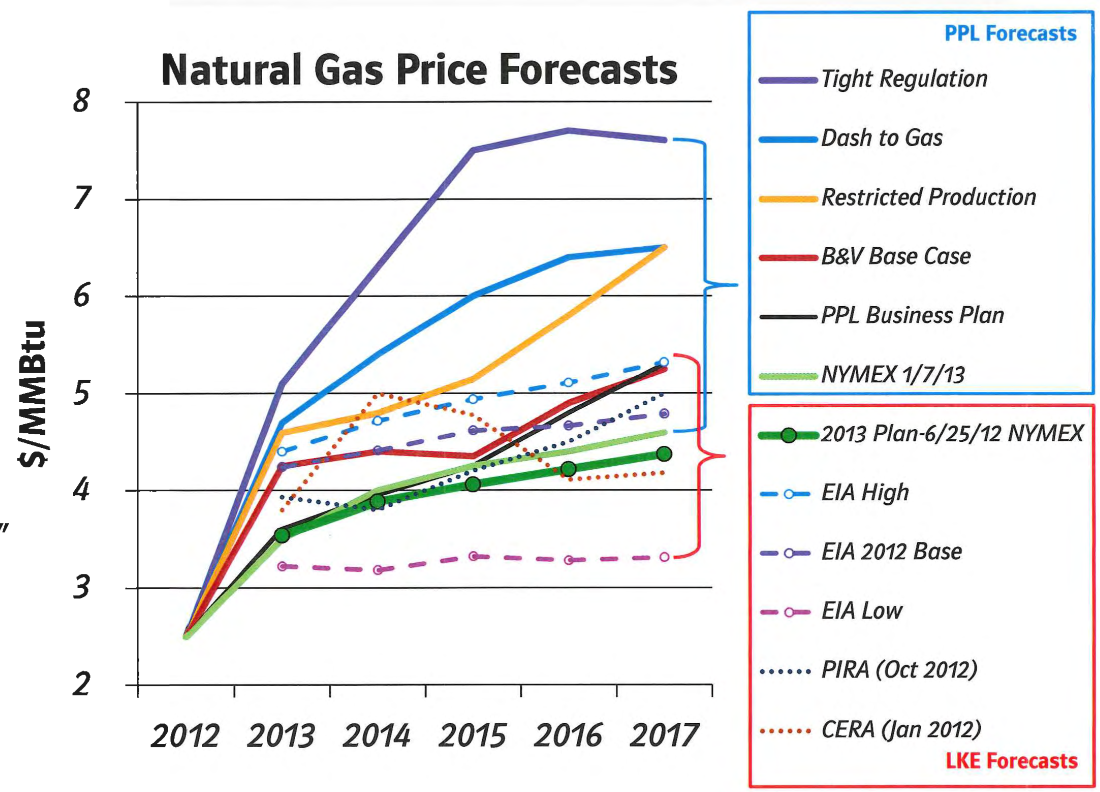

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PPL companies

Meeting Future Capacity Needs in a World of Uncertainty

January 29, 2013






Key uncertainties related to future resources

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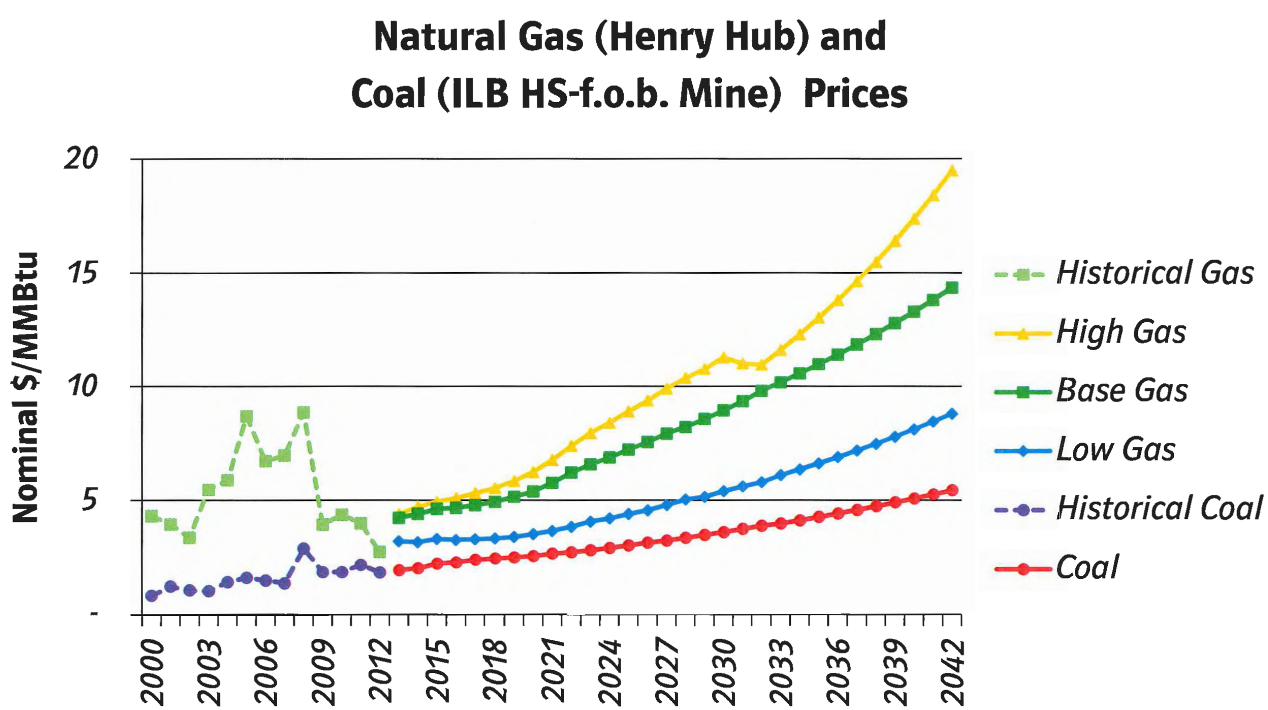

Source: EIA

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PPL companies

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LG&E KU
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PPL companies

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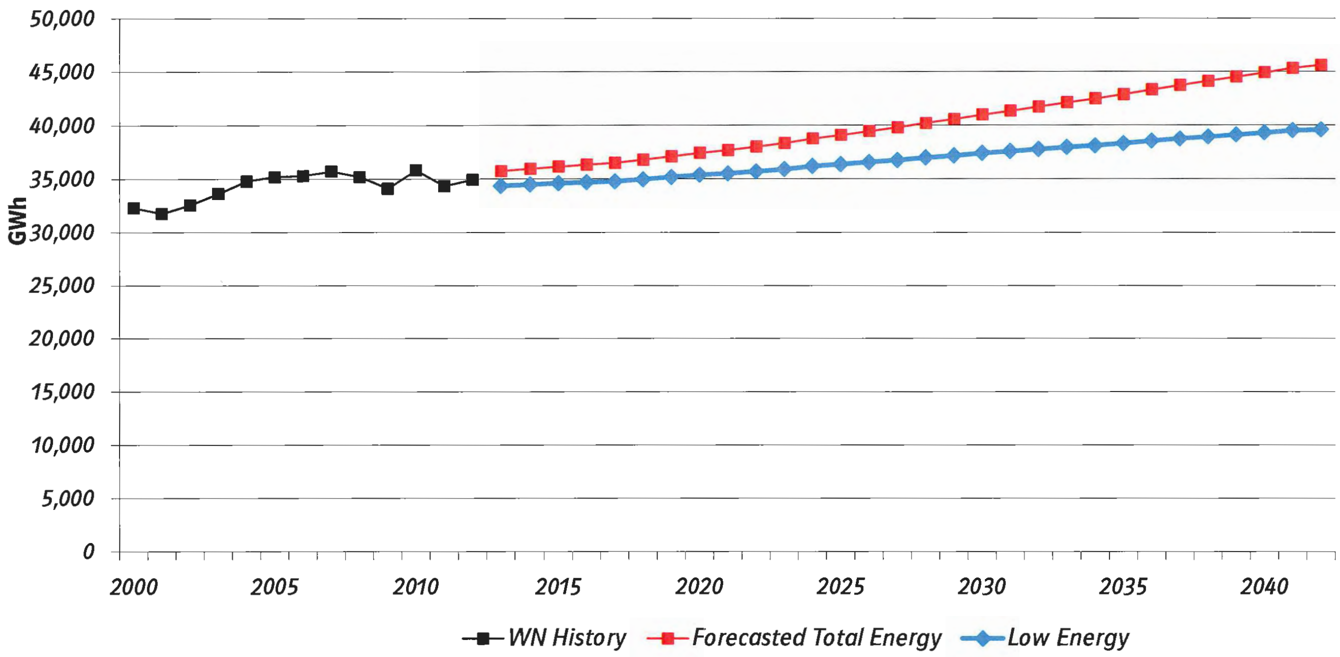

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PPL companies

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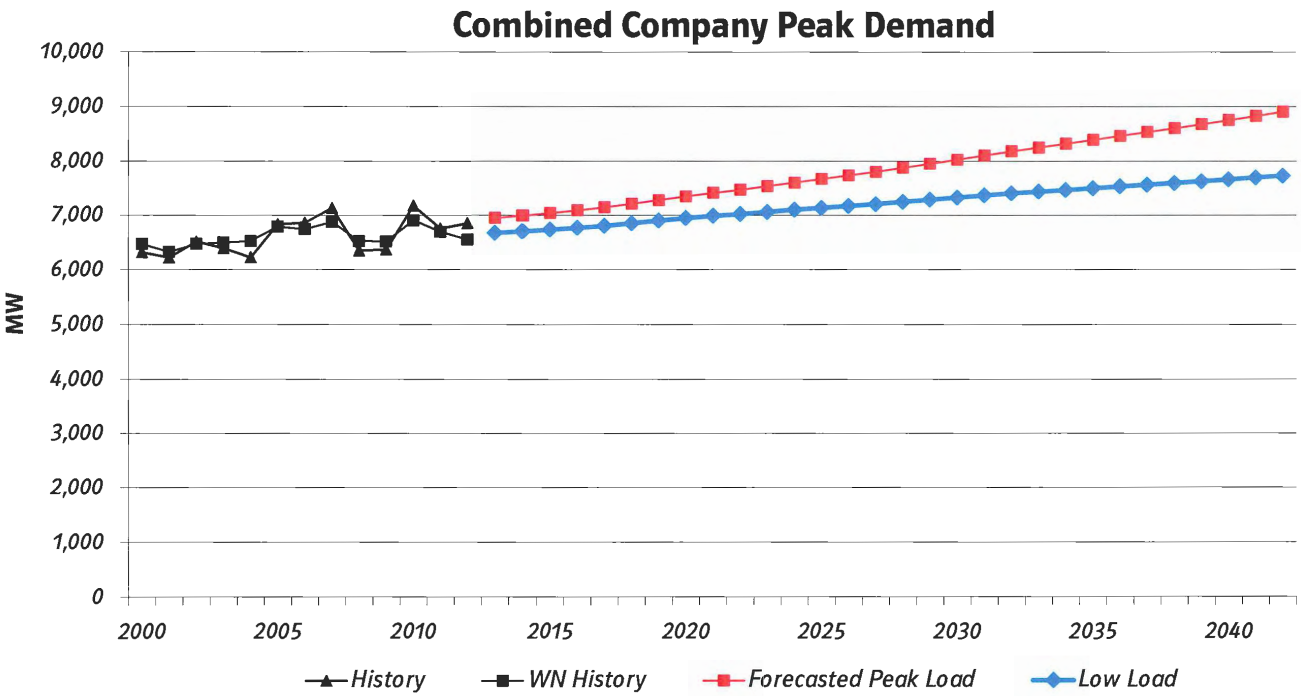

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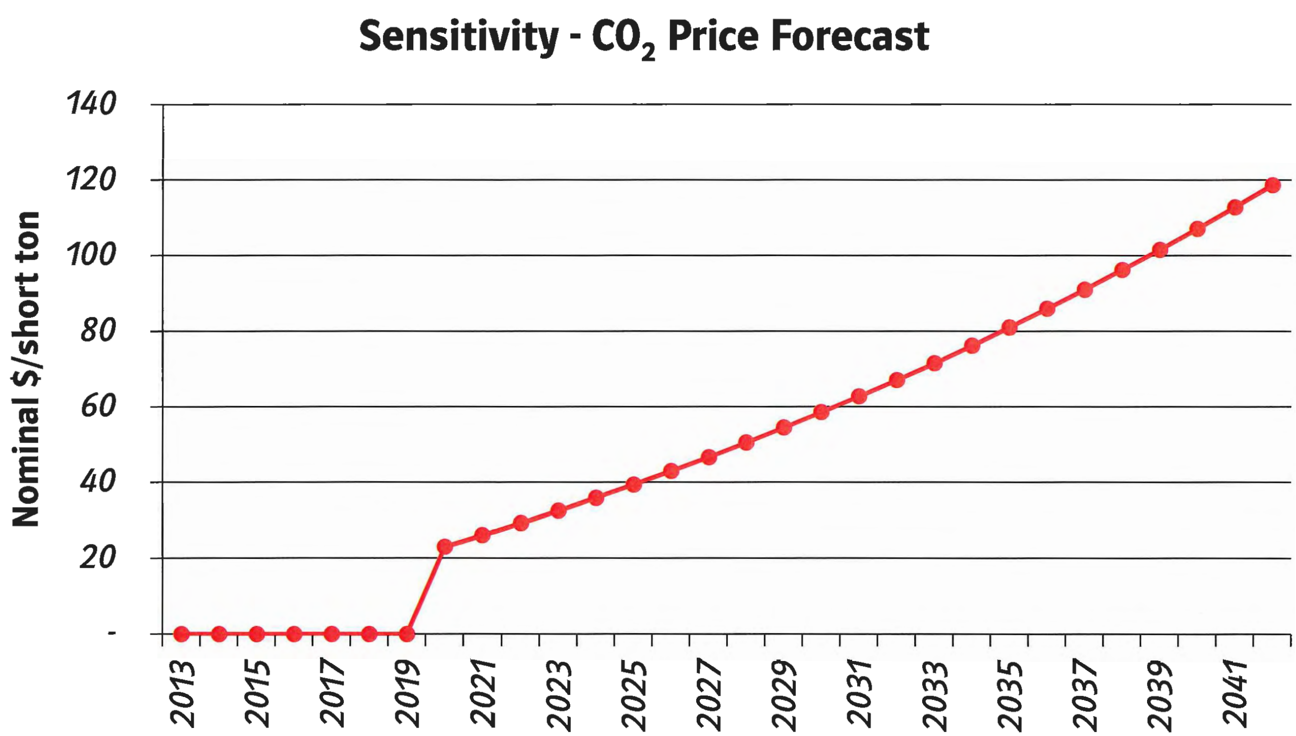

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- OVEC
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PPL companies

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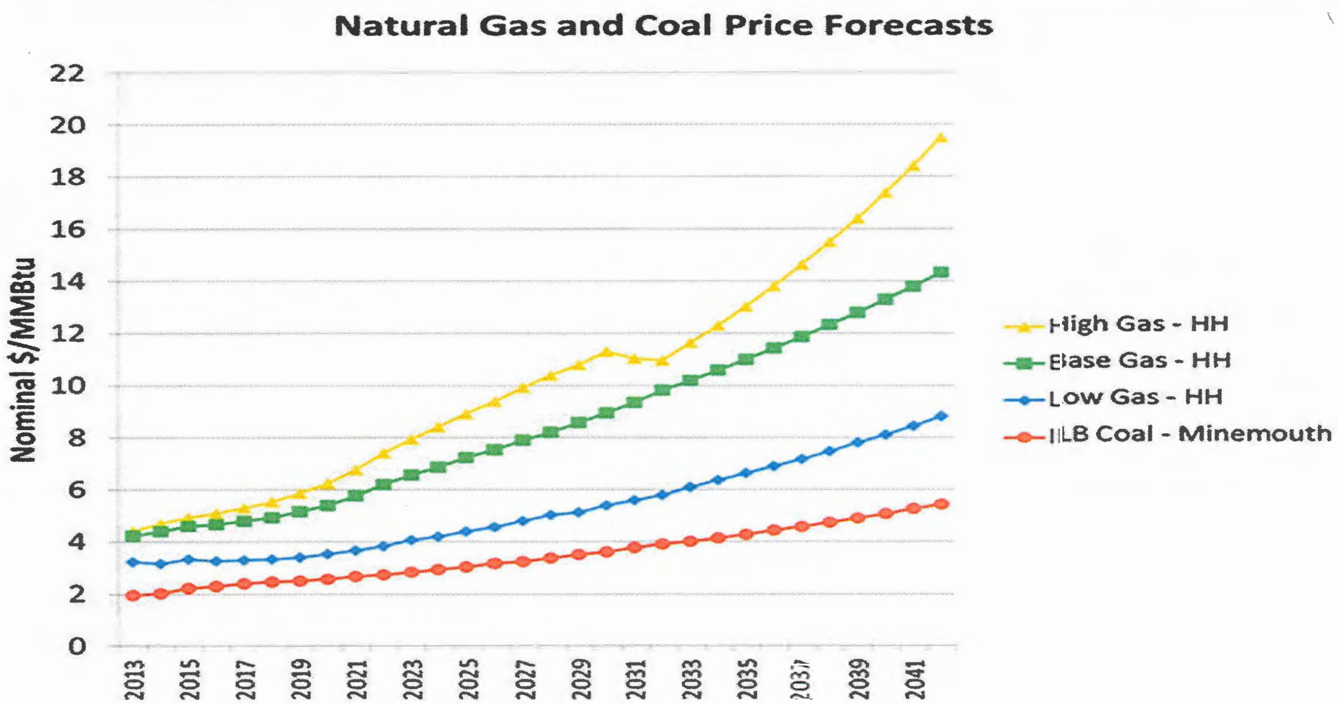

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LG&E KU PPL companies

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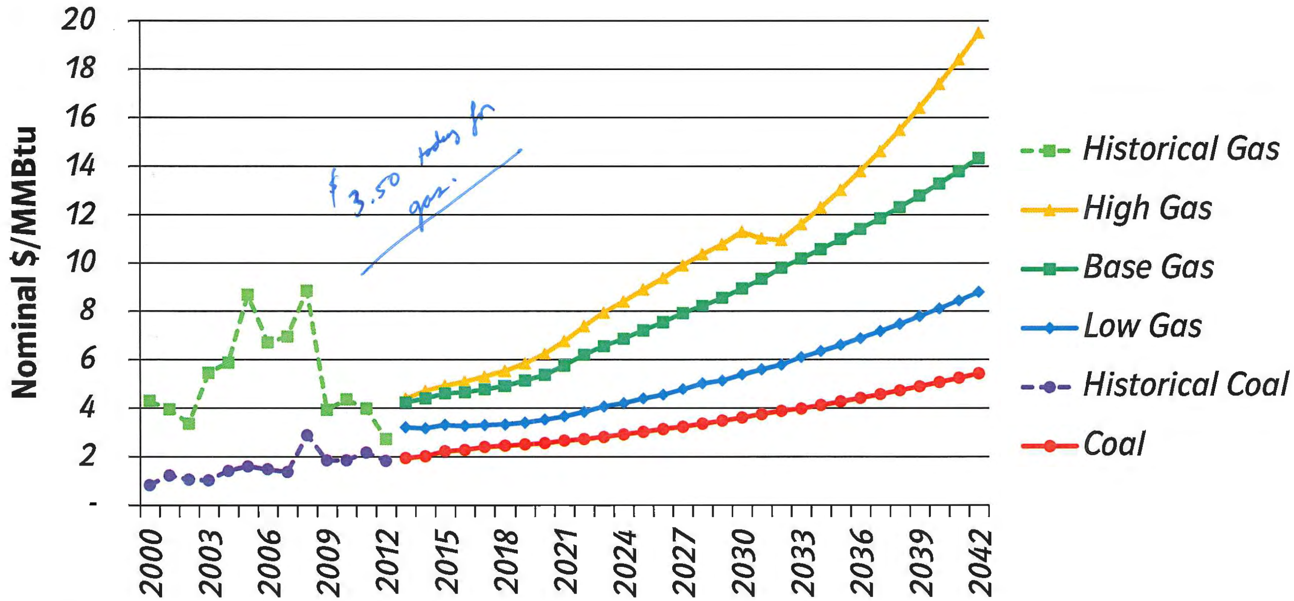
- *Future natural gas prices*
- *Potential environmental regulations on CO2 and fracking*
- *Availability of CCGT resources: self-build and 3rd party alternatives might not be doable by 2017*
- *Future of Brown 1&2 – existing and future regulations and future coal/gas price spread*

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*

Wide range of possible future gas prices



January 29, 2013

4

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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)*

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

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*

Reliability Risk that comes into play w/ energy by wire

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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*

PPL companies

Appendix

- Business Model
  - Political
- Diversity of Fuel
- EES / Conflict
- Renewables

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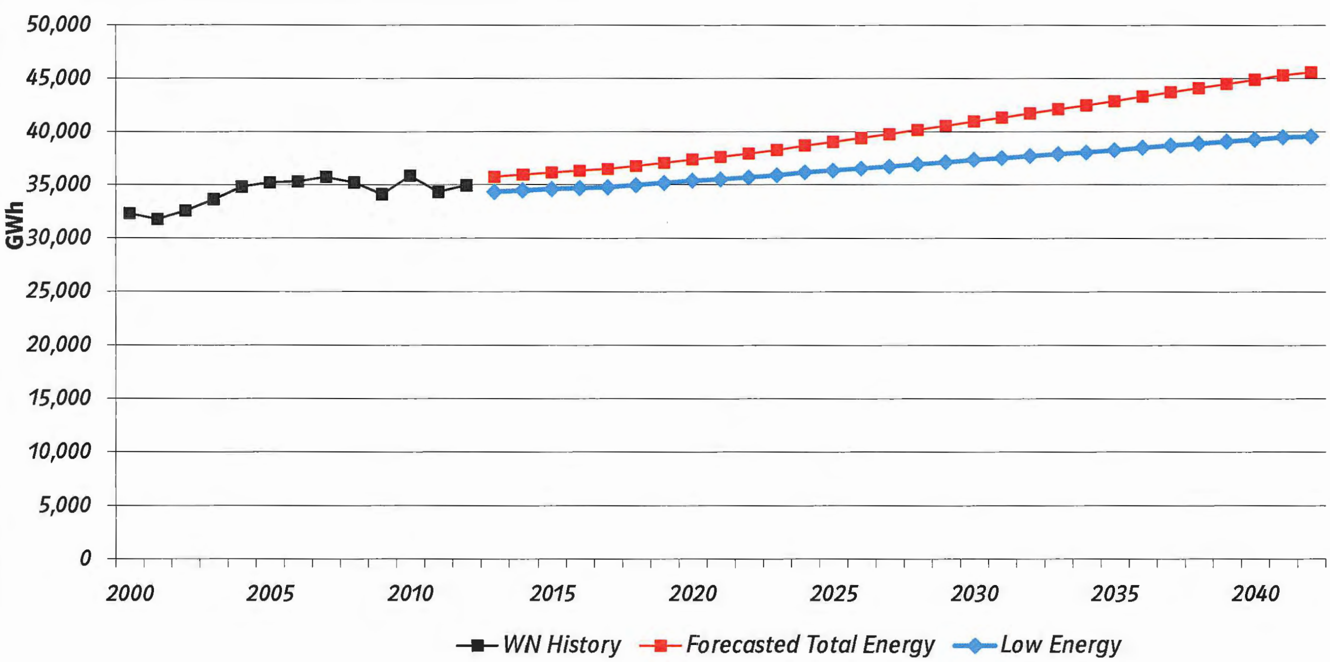
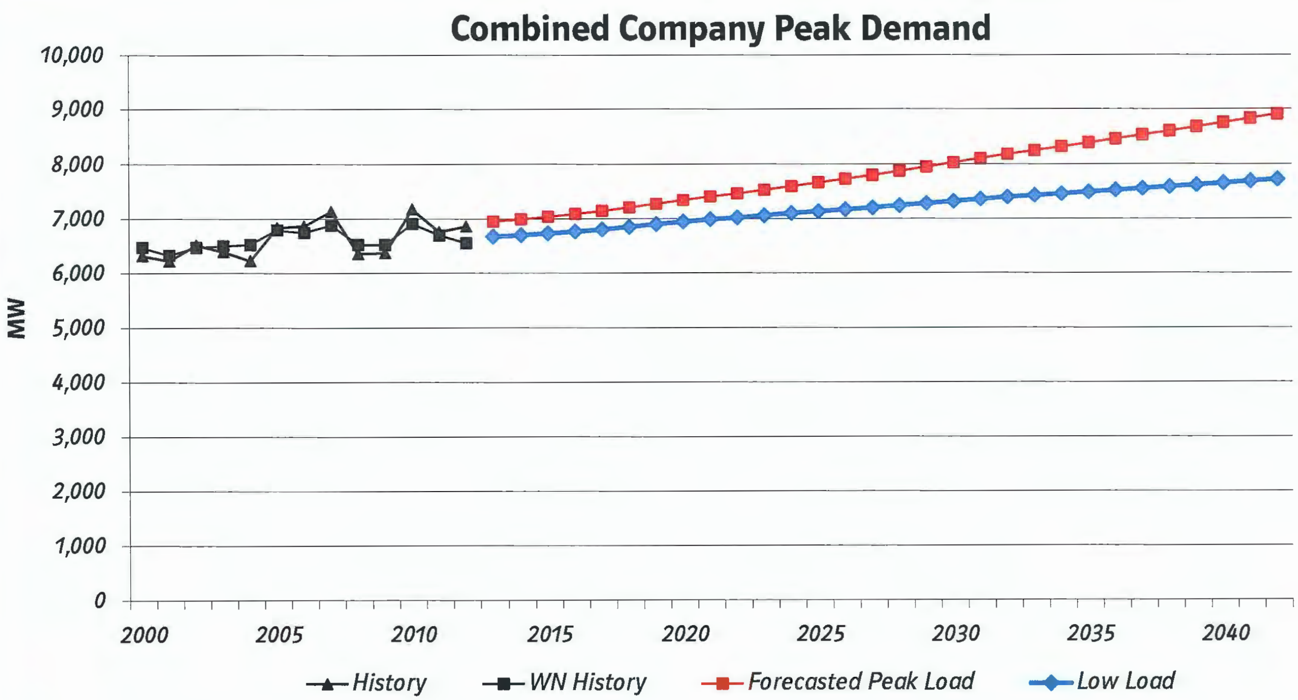
Combined Company Energy Requirements



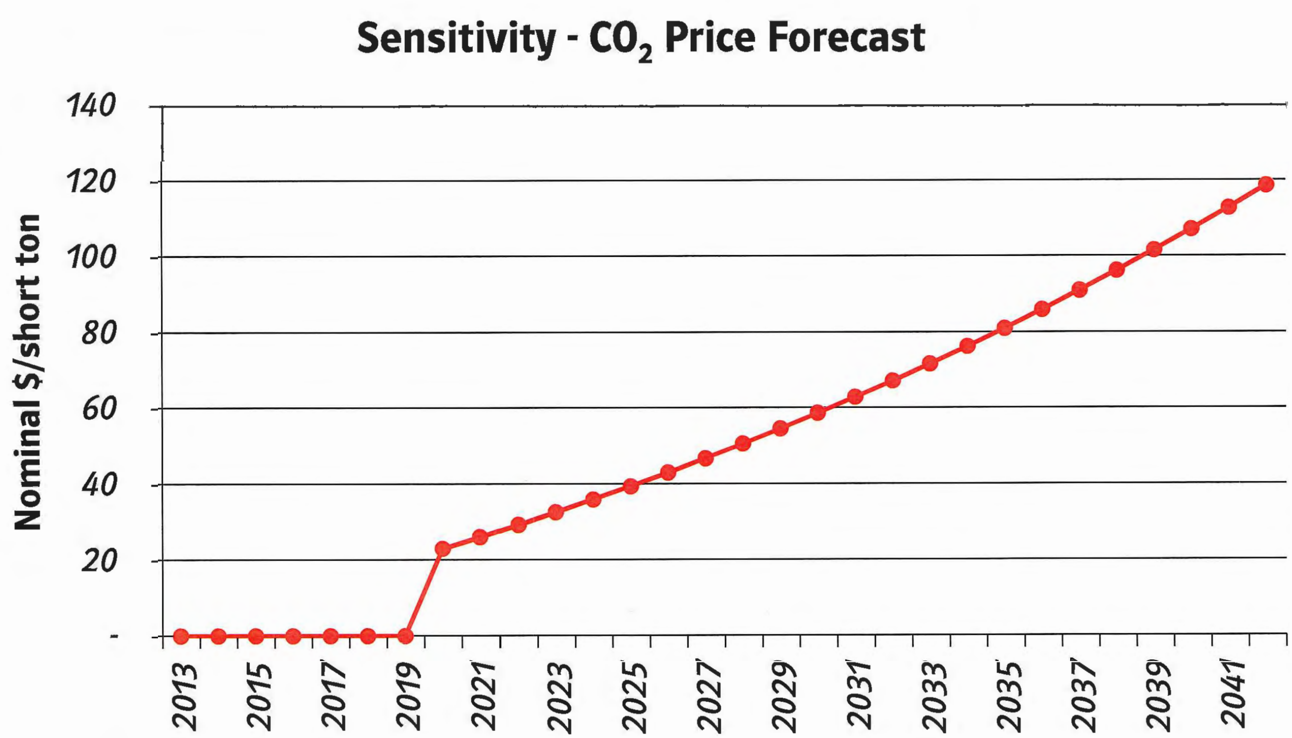
PPL companies

Peak Demands



** Historical peaks not adjusted for curtailments.*

CO_2 price sensitivity starting in 2020



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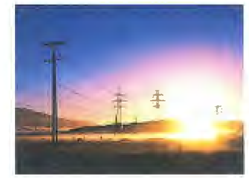
Analysis of Responses to 2012 RFP

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

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

Next Build $mm   Just RFP   Exp Plan + RFP   Fixed + Capital   Definition – Base Case

	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) Siemens	'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.

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 Δ

	$M
Difference between Best BR1-2 Retrofit Option and Best Short-Term PPA	$175 ~125
Impact of Ignoring Long-Term Production Costs after 2024	($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*

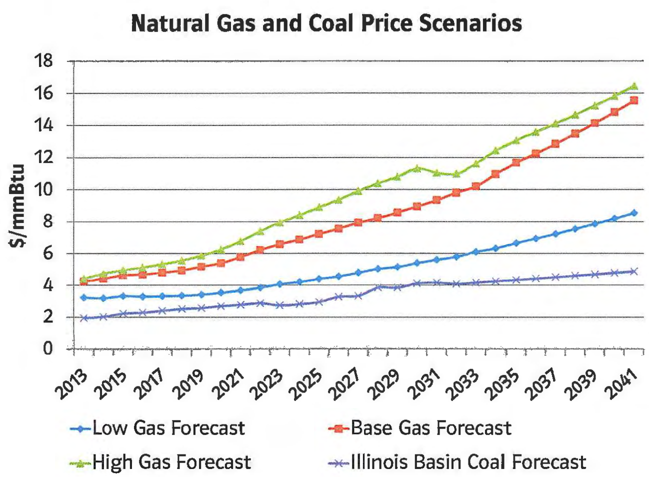
Next Steps

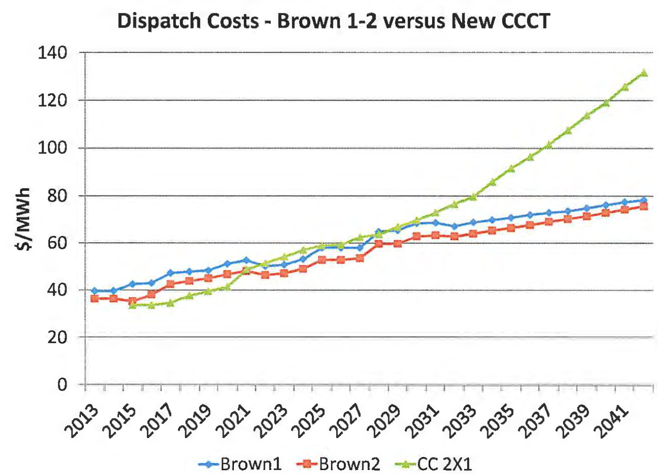
- Meetings with shortlisted respondents begin January 7.
- Open Questions:
  - *Long-term commodity price assumptions significantly impact this analysis. What alternative(s) has the least risk as far as long-term commodity prices are concerned?*
  - *The prospects for plant-wide averaging for MATS compliance 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?*

Attachment to Response to KIUC Question No. 1-6
Page 177 of 232
Thompson

Appendix

Coal becomes relatively less expensive than gas over time





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.*

Todd, Karen

Subject:	RFP Analysis
Location:	PWT's Conference Room
Start:	Tue 12/18/2012 8:30 AM
End:	Tue 12/18/2012 9:30 AM
Recurrence:	(none)
Meeting Status:	Meeting organizer
Organizer:	Thompson, Paul
Required Attendees:	Wilson, Stuart; Sinclair, David; Schetzel, Doug; Freibert, Charlie; Schram, Chuck; Balmer, Chris
Optional Attendees:	Bowling, Ralph; Voyles, John; Brunner, Bob; Staton, Ed

Updating to include additional attendees.

David Sinclair will call [redacted]

☐ Regulatory
Financial
Legal

Todd, Karen

From:	Wilson, Stuart
Sent:	Tuesday, December 18, 2012 4:15 PM
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
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

December 18, 2012

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 $12.3/kW-month, 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 a capacity price of $13.1/kW-month starting in 2016, firm gas transport, and VO&M. Heat rate is 8,793 Btu/kWh.
   - Asset sale price is $156.5 million in 2016
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
   - 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/kW-month
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
   - Located in Decatur, Alabama
   - Costs include capacity price of $6.2/kW-month, fuel, start charges, and VO&M
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

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- Assumed to be available June 2017
- Heat rates range between 6,600 Btu/kWh and 6,900 Btu/kWh

7. **CCCT 2X1 Self Build (LGE/KU)**
   - 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. **Trimble County CT 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%
       - Capital costs of $108 million for 102 MW upgrade in April 2015
       - Upgraded heat rate estimated at 9,969 Btu/kWh compared to current heat rate of 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 Smyth County, VA
   - Assumed to be available June 2017
   - Capacity charge quoted is $11.0/kW-month
10. **Demand Side Management/Energy Efficiency (LGE/KU)**
    - DSM options include Lighting, Thermostat Rebates, Windows & Doors, Manufactured Homes, Behavioral Thermostat Pilot, Commercial New Construction and Automated Demand Response programs
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
12. **EDP Renewables**
    - 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%

December 18, 2012

  - 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 landfill gas generation at 4 different sites in Kentucky
    - Costs include energy cost of $62/MWh starting in 2015 and escalating at 2% and VO&M
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
    - Three options:
      - 10 or 20 year tolling agreement at $5.4/kW-month capacity charge
      - Asset sale for $765 million
      - Fully permitted 2,050 acre site for $30 million
15. **E.W. Brown Units 1 & 2 Retrofit (LGE/KU)**
    - Baghouse required for environmental compliance
    - Capital cost of baghouse is $194 million 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
    - Additional costs would include firm gas transport
17. **Exelon Generating Company**
    - 10 year PPA for 200 MW of round the clock energy
    - Energy price quoted is $47.78/MWh (no escalation)
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 $9.3/kW-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 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

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  - Fixed price of $30.63/MWh and capacity charge of $8.4/kW-month 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 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

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 $2.9/kW-month capacity charge, and energy price of $33.61/MWh starting in 2015
20. **LS Power (Bluegrass Generation Station)**
    - 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
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 landfill gas generation from sites located in Wisconsin and Pennsylvania
    - Costs include energy cost of $52/MWh starting in 2014 and escalating at 3% and VO&M
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 $0.2/kW-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 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%

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    - 24 year tolling agreement with fixed capacity charge of $30.0/kW-month and heat rate of 9,000 Btu/kWh
    - Asset sale for $3.03 billion

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)
    - Three options:
        - 20-35 year tolling agreement with capacity charge of $5.8/kW-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 $4.0/kW-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
    - Costs include capacity charge of $8.4/kW-month, energy price based on 105% of average operating cost, and VO&M
27. **Sky Global**
    - 10 to 20 year tolling agreement beginning January 2016 for 250-300 MW of 1x1 CCCT generation located in Pineville, KY
    - Capacity charge quoted is $9.0/kW-month
    - Estimated heat rate between 7000-7500 Btu/kWh
28. **Solar Energy Solutions**
    - 1-5 MW PV asset sale for $2.9 million per MW assumed to be available beginning 2015
29. **Solar PV Array Self Build (LGE/KU)**
    - 10 MW PV capacity for $4.6 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 biomass generation located in Lawrence, OH
    - Costs include energy cost of $65.50/MWh starting in 2015 and VO&M
31. **Southern Company Services**
    - Three options:
        - 5 year tolling agreement beginning in January 2015 for 75-675 MW of SCCT 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 tolling agreement beginning in January 2016 for 109-159 MW of coal generation located in Juliette, GA. Costs include capacity cost of $20.5/kW-month, heat rate of 10,400 Btu/kWh, and start costs.

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32. **Southern Power Company**
    - Two options for 20 year tolling agreement starting in June 2017 for 770 MW of 2x1 CCCT generation with a guaranteed heat rate of 7,250 Btu/kWh:
        - 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.
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
        - 10 year tolling agreement. Costs include $7.6/kW-month capacity charge, heat rate of 7,100 Btu/kWh, start costs, and VO&M.
34. **Wellhead Energy Systems**
    - Asset sale of 100 1 MW GridFox natural gas reciprocating engines for $98.8 million in January 2016
35. **Wellington**
    - 20 year PPA starting in September 2016 for 112 MW of round the clock waste coal generation located in Green County, PA
    - Costs include capacity cost of $28.2/kW-month escalating at 2% and energy price of $61.10/MWh starting in 2016

Note: Start date is assumed to be 1/1/2015 unless otherwise stated

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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 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)

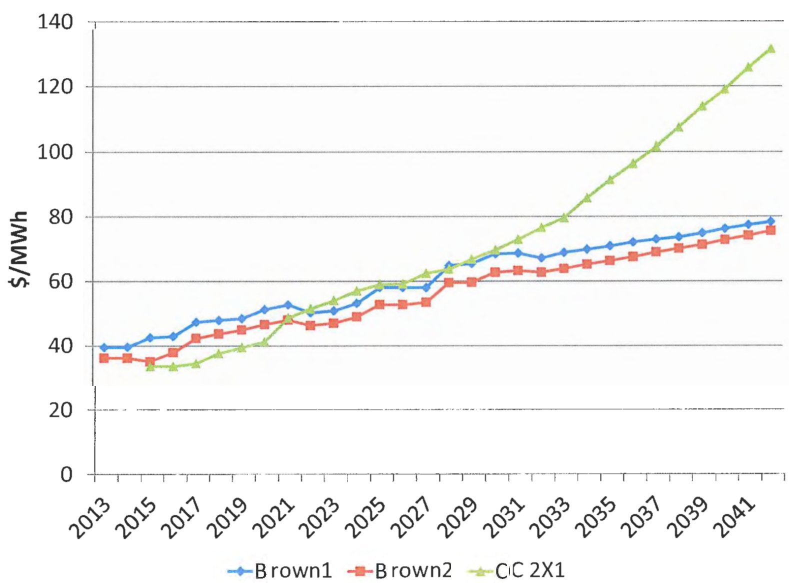


Table 11 – Age of Brown 1 and 2 (years)

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: Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Capital Cost, Per Bid: Asset Sale Price ($M)	Fixed Costs (FCs, Expressed as $/MW at TIP), Per Bid: FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	Additional Costs Incurred by LGE/KU ($2015): LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M	Fixed Cost Escalator	Fuel/Energy Costs, Per Bid: Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Variable Costs, Per Bid: Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator	Additional Costs Incurred by LGE/KU ($2015): Start Cost ($/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	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%								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)

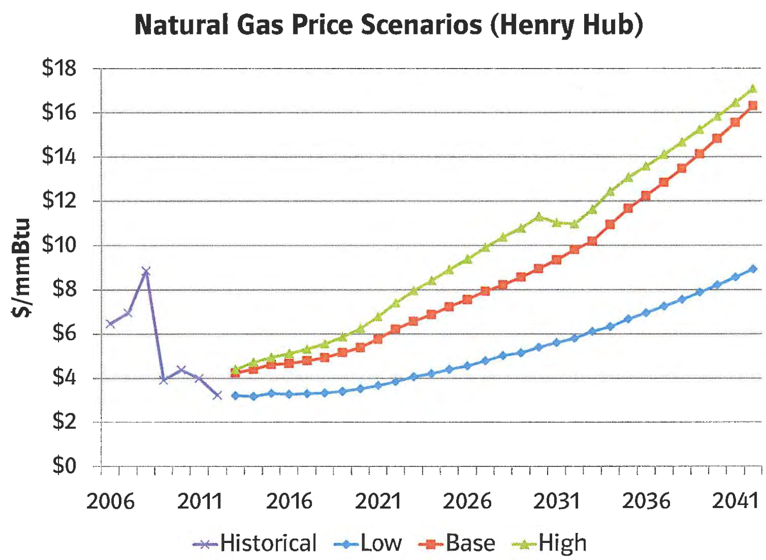
Table 17 – LG&E/KU Resource Summary – High Load Forecast (MW)

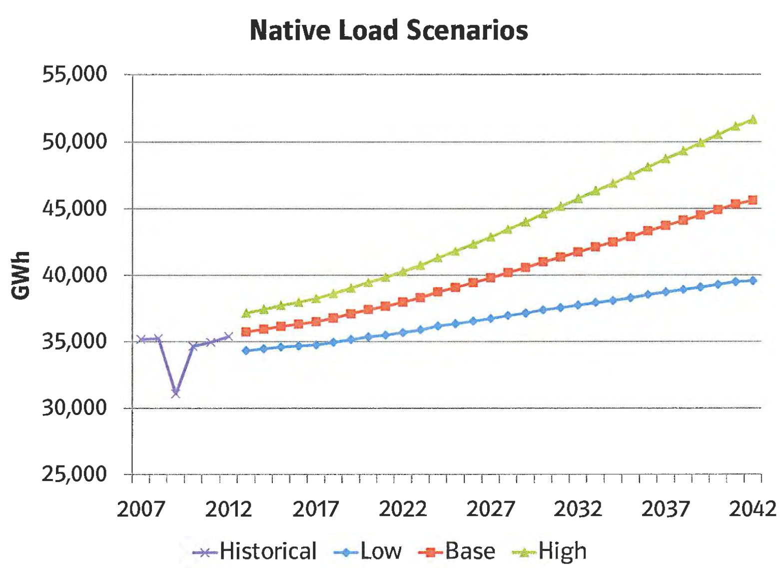
	2015	2016	2017	2018	2019	2020	2021
Forecasted Peak Load	7,733	7,833	7,940	8,056	8,125	8,218	8,312
Energy Efficiency/DSM	-386	-418	-450	-482	-464	-466	-467
Net Peak Load	7,347	7,415	7,490	7,574	7,661	7,752	7,845
Existing Resources	7,542	7,533	7,550	7,512	7,531	7,532	7,532
Firm Purchases (OVEC)	152	152	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.

Todd, Karen

From: Wilson, Stuart
Sent: Friday, November 30, 2012 11:50 AM
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
Attachments: 20121130_Phase2StatusReportandNextSteps_0060.docx

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.

2042

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 ≤5 | Medium Term Alternatives 6-19 | Long-Term Alternatives >20

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: Response	Counterparty	Class	Technology	Description	XM Interconnect Point (TIP)	Contract Start Date	Capacity @ TIP	Base Year for Quote	Capital Cost (Per Bid): Asset Sale Price ($M)
1A	ERORA	CCCT (2X1)_10	CCCT (2x1), GE	10 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	
1B	ERORA	CCCT (2X1)_20	CCCT (2x1), GE	20 yr PPA, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	
1C	ERORA	CCCT (2X1)_Own	CCCT (2x1), GE	Asset Sale, 700 MW	Davies Cty - LGE	1/1/2016	700	2016	765
2	AEP	Coal_10	Portfolio	11 yr PPA, Up to 700 MW	AEP Gen Hub	1/1/2015	700	2015	
3	TPF Generation	SCCT_Own	SCCT	Asset Sale, 5 Units, 245 MW	CONSTELL PTID Node - PJM/AEP	TBD	245	2015	106
4A	Big Rivers	Coal_5	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015	
4B	Big Rivers	Coal_10	Coal	1-15 yr PPA, Wilson Station, 417 MW	BREC.WILSON1 - MISO	TBD	417	2015	
5A	Quantum Choctaw Power	CCCT (2X1)_20	CCCT (2x1), Siemens	20-35 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	
5B	Quantum Choctaw Power	CCCT (2X1)_Own	CCCT (2x1), Siemens	Asset Sale, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2015	450
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)
5D	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2015	701	2013	
5E	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2016	701	2013	
5F	Quantum Choctaw Power	CCCT (2X1)_5	CCCT (2x1), Siemens	5 yr PPA, 701 MW	Ackerson, MS - TVA	1/1/2014	701	2013	
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	
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	
7A	Ameren	Coal_5	Coal	5 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015	
7B	Ameren	Coal_10	Coal	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015	
7C	Ameren	Coal_10	Coal-to-NG Conversion	10 yr PPA, 668 MW	EEI/LGE Interface	1/1/2015	668	2015	
7D	Ameren	Coal_10	Portfolio (Coal and NG)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015	
7E	Ameren	Coal_10	Portfolio (Coal to NG Conv.)	10 yr PPA, Up to 700 MW	EEI/LGE Interface	1/1/2015	700	2015	
7F	Ameren	SCCT_5	SCCT	5 yr PPA, 5 units, 222 MW	EEI/LGE Interface	1/1/2015	222	2015	
8	Paducah Power Systems	SCCT_5	SCCT	5 yr PPA, 26 MW	LGEE-PPS1	1/1/2015	26	2015	
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
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	
10	KMPA	RTC	Coal, Base Load	5 yr PPA, 25 MW (RTC)	AMIL, MISO	1/1/2015	25	2015	
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	
11B	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016	
11C	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Murdock, IL - MISO	1/1/2015	746	2016	
11D	Khanjee	RTC	CCCT (2X1), Base Load	22 yr PPA, Fixed Price w/ Min Take (85% CF)	Kentucky	1/1/2015	746	2016	
11E	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016	
11F	Khanjee	CCCT (2X1)_20	CCCT (2X1)	22 yr PPA	Kentucky	1/1/2015	746	2016	
12	Exelon Generation Company	RTC	Firm Physical Energy	10 yr PPA, 200 MW	Indiana Hub - MISO	1/1/2015	200	2015	
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	
14A	Duke	Coal_Own	OVEC	Asset Sale in 2015, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2015	203	2015	100
14B	Duke	Coal_Own	OVEC	Asset Sale in 2013, 203 MW of OVEC	OVEC Busbar - LGE	1/1/2013	203	2013	50
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
16A	Power4Georgians	RTC	Supercritical Coal	24 yr PPA, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	
16B	Power4Georgians	RTC	Supercritical Coal	24 yr Tolling Agreement, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	
16C	Power4Georgians	RTC	Supercritical Coal	Asset Sale, 850 MW	Georgia ITS - Southern/TVA	1/1/2019	850	2019	3,030
17	Solar Energy Solutions	Solar_Own	Solar (PV Array)	Asset Sale, 1-5 MW	LGE/KU System	1/1/2016	1	2015	2.9
18A	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 or 20 yr PPA, 99 MW	MISO/LGE Interface	1/1/2015	99	2015	
18B	EDP Renewables	Wind	Wind (Firm, RTC Blocks)	15 yr PPA, 151.2 MW	MISO/LGE Interface	1/1/2016	151	2016	
18C	EDP Renewables	Wind	Wind (As Available)	20 yr PPA, 100 MW	LGE/KU System	1/1/2016	100	2016	
19A	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013	
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
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
19D	LS Power	SCCT_20	SCCT	20 yr PPA 1/1/2014, 495 MW	LGE Buckner Station	1/1/2014	495	2013	
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
19F	LS Power	SCCT_5	SCCT	5 yr PPA 1/1/2015, 495 MW	LGE Buckner Station	1/1/2015	495	2013	
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	
21	Wellington	RTC	Waste Coal w/ CFBC	20 yr PPA, 112 MW	PJM West	9/1/2016	112	2012	
22A	Southern Company Services	SCCT_5	SCCT	5 yr PPA, 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015	
22B	Southern Company Services	SCCT_5	SCCT	5 yr PPA (Summer Only), 75-675 MW	Demopolis, AL - SOCO	1/1/2015	75	2015	
22C	Southern Company Services	Coal_10	Coal	15 yr PPA, 109-159 MW	Unit GSU - SOCO	1/1/2016	159	2016	
23	Santee Cooper	Coal_10	Coal	7.8 yr PPA, 250 MW	Georgetown, SC	4/1/2017	250	2012	
24A	Nextera	Coal_5	Coal	6 yr PPA, 30 MW	Into LG&E/KU	1/1/2015	30	2015	
24B	Nextera	Coal_10	Coal	10 yr PPA, 50 MW	Into LG&E/KU	1/1/2015	50	2015	
25	South Point Biomass	RTC	Biomass	20 yr PPA, 165 MW	AEP/Bellefonte/Proctorville PJM	5/1/2015	165	2015	
26	North American BioFuels	RTC	Landfill Gas	20 yr PPA, 19 MW	WI and PA - MISO and PJM	1/1/2014	19	2013	
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	
27B	Southern Power Company	CCCT (2X1)_20	CCCT (2X1), GE	20 yr PPA, 770 MW	Site TBD	6/1/2017	770	2012	
28	LGE/KU	CCCT (1X1)_Own	GE CCCT (1X1) - F Class	Self-Build, 298.5 MW	Site TBD	6/1/2017	299	2015	438
29	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - F Class	Self-Build, 332 MW	Site TBD	6/1/2017	332	2015	420
30	LGE/KU	CCCT (1X1)_Own	MHI CCCT (1X1)	Self-Build, 372.7 MW	Site TBD	6/1/2017	373	2015	463
31	LGE/KU	CCCT (1X1)_Own	Siemens CCCT (1X1) - H Class	Self-Build, 379.4 MW	Site TBD	6/1/2017	379	2015	458
32	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), GE	Self-Build, 598 MW	Site TBD	6/1/2017	598	2015	609
33	LGE/KU	CCCT (2X1)_Own	CCCT (2X1), Siemens	Self-Build, 670.4 MW	Site TBD	6/1/2017	670	2015	617
35	LGE/KU	Solar_Own	Solar (PV Array)	Self-Build, 10 MW	Site TBD	1/1/2016	10	2015	46
36	LGE/KU	Coal_Own	BR1-2 Retrofit	Retrofitted Coal, 270 MW	Brown Station	1/1/2015	269	2015	194
37	LGE/KU	SCCT_Own	SCCT	Trimble CT Retrofit	Trimble County Station	4/1/2015	54	2015	108
38	LGE/KU	CCCT (1X1)_Own	Steam Augmentation	Steam Augmentation for Trimble CTs	Trimble County Station	4/1/2015	1	2015	10
39	LGE/KU	Coal_Own	Coal-to-NG Conversion	BR1-2 Coal to NG Conversion	Brown Station	4/1/2016	1	2015	10
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

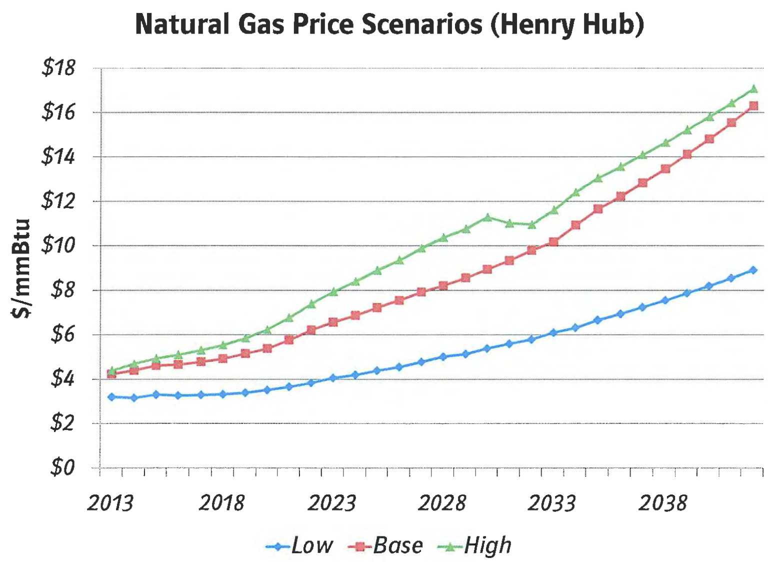
Response	Fixed Costs (FCs, Expressed as $/MW at TIP) – Per Bid: FC #1 ($/MW-yr)	FC #1 Escalation	FC #2 ($/MW-yr)	FC #2 Escalation	Additional Costs Incurred by LGE/KU ($2015): LGE/KU Fixed XM Cost ($/MW-yr)	LGE/KU Firm Gas Transport ($/MW-yr)	Other LGE/KU Fixed O&M	Fixed Cost Escalator
1A	64,800	2.00%	6,515	2.00%		23,074		2.00%
1B	64,800	2.00%	6,515	2.00%		23,074		2.00%
1C						23,074		2.00%
2	147,022	0.00%			20,894			2.00%
3					20,895	30,009	13,509	2.00%
4A	145,647	1.00%			36,056			2.00%
4B	145,647	1.00%			36,056			2.00%
5A	69,000 ($2015)	2.00%			24,998	15,431		2.00%
5B	12,114 in 2015; 7,513 in 2016 esc at 2%				24,998	15,431		2.00%
5C	67,200 in 2015; 12,356 in 2016; 7,663 in 2017 esc at 2%				24,998	15,431		2.00%
5D	48,000 ($2015)	Schedule			24,998	15,431		2.00%
5E	60,000 ($2016)	Schedule			24,998	15,431		2.00%
5F	36,000 ($2014)	Schedule			24,998	15,431		2.00%
6A	74,160	2.30%			24,998	27,418		2.00%
6B	74,160	2.30%			24,998	27,418		2.00%
7A	137,496	0.00%						
7B	137,688	Schedule						
7C	83,796	Schedule				17,662		
7D	131,484	Schedule						
7E	87,936	Schedule				17,662		
7F	85,896	0.00%				17,662		
8	1,825					27,200		
9A						23,268	29,800	2.00%
9B	157,000	0.00%	29,800	2.00%		23,268		
10	34,255	2.00%			36,056			
11A					36,056	33,279		
11B	111,000 in 2017	Schedule			36,056	33,279		
11C	111,000 in 2017	Schedule			36,056	33,279		
11D						23,898		
11E	100,800 in 2017	Schedule				23,898		
11F	100,800 in 2017	Schedule				23,898		
12					36,056			
13	132,000	0.00%	23,400		20,895	30,941		
14A								2.00%
14B								2.00%
15						23,898	29,800	
16A	359,983	0.00%	27,673	2.50%	56,349			
16B	359,983	0.00%	27,673	2.50%	56,349			
16C					56,349		27,673	2.50%
17							10,185	2.00%
18A								
18B								
18C								
19A	30,000	Schedule	7,800	2.50%		34,724		2.00%
19B	38,195	Schedule				34,724		2.00%
19C	38,195	Schedule				34,724		2.00%
19D	12,000	Schedule	7,800	2.50%		34,724		2.00%
19E	11,662	Schedule				34,724		2.00%
19F	30,000	Schedule	7,800	2.50%		34,724		2.00%
20	108,000	0.00%	27,000			49,005		2.00%
21	388,014	Schedule	41,050	2.00%				
22A	45,000				56,349	25,266		
22B	35,000				56,349	25,266		
22C	246,000	1.50%			56,349			
23	100,080	0.00%			84,038			2.00%
24A								
24B								
25					20,895			
26								
27A	110,520 ($2017)	1.50%				21,924		
27B	118,680 ($2017)	1.50%				21,924		
28						21,924		2.00%
29						21,924		2.00%
30						21,924		2.00%
31						21,924		2.00%
32						21,924		2.00%
33						21,924		2.00%
35							10,185	2.00%
36								
37								
38								
39								
40A								
40B								
40C								
40D								
40E								
40F								
40G								

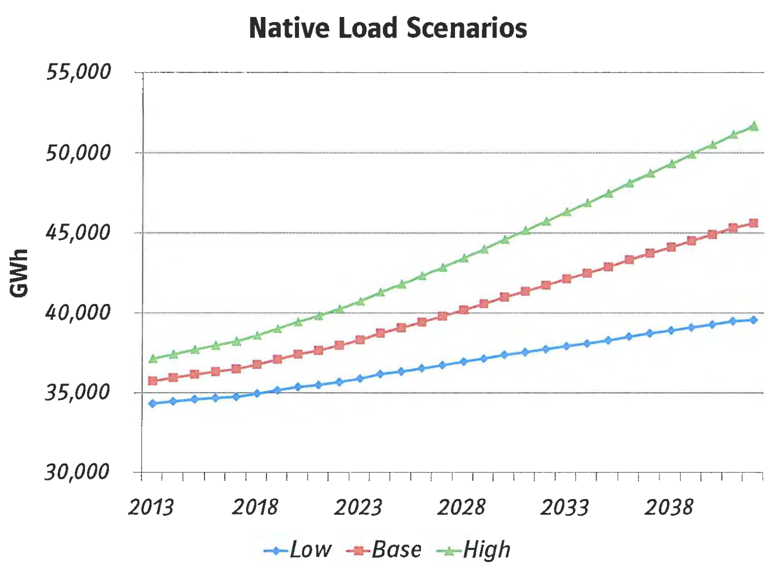
Response	Fuel/Energy Costs – Per Bid: Unfired Heat Rate @ TIP (Btu/kWh)	Energy Price @ TIP ($/MWh)	Energy Price Escalator	Variable Costs – Per Bid: Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu or gallons)	Variable O&M ($/MWh)	Start Cost and VOM Escalator	Additional Costs Incurred by LGE/KU ($2015): Start Cost ($/Start)	Cost per Hour ($/Hr)	Fuel per Start (mmBtu)	Variable O&M ($/MWh)	Start Cost and VOM Escalator
1A	6,705			20,000/strt or 680/hr			1.70	2.00%					
1B	6,705			20,000/strt or 680/hr			1.70	2.00%					
1C	6,705								0	264	3,019	0.36	2.00%
2		31.91	0.00%				0.55	2.00%					
3	10,650						0.55	2.00%			320	4.10	2.00%
4A	11,029			88,391			2.85	2.00%					
4B	11,029			88,391			2.85	2.00%					
5A	7,064			23,900/strt or 800/hr			1.00	2.50%					
5B	7,064								0	883	3,019	0.35	2.00%
5C	7,064						1.00 in 2015; 0.35 at 2%		0	883	3,019		2.00%
5D	7,064			23,900/strt or 800/hr			1.00	2.50%					
5E	7,064			23,900/strt or 800/hr			1.00	2.50%					
5F	7,064			23,900/strt or 800/hr			1.00	2.50%					
6A	7,400			25,700		1,000	2.00	2.00%					
6B	7,500			12,850		475	2.00	2.00%					
7A		31.41	Schedule	7,428			2.61	Schedule					
7B		25.68	Schedule										
7C		43.94	Schedule										
7D		25.80	Schedule										
7E		43.80	Schedule										
7F	13,366			16,900		290	1.40	Schedule					
8	13,090												
9A	8,793										288	4.2	2.00%
9B	8,793					288	4.20	2.00%					
10		33.61	Schedule										
11A		50.04 in 2017	Schedule										
11B		35.13 in 2017	Schedule	0									
11C	6,800			0			4.24 in 2017	Schedule					
11D		44.16 in 2017	Schedule										
11E		30.63 in 2017	Schedule	0									
11F	6,800			0			0.55 in 2017	Schedule					
12		47.78	0.00%										
13	7,009			18,690		3,808	3.13	2.00%					
14A		34.87	Schedule										
14B		34.87	Schedule										
15	10,000										3	4.20	
16A		32.40	1.85%				4.73	2.50%					
16B	9,000						4.73	2.50%					
16C	9,000								162,694			1.87	2.00%
17													
18A		50.00	3.00%										
18B		50.00	3.00%										
18C		69.50	0.00%										
19A	10,900			25,500			0.62	2.5%					
19B	10,900			25,500			0.62	2.5%					
19C	10,900			25,500			0.62	2.5%					
19D	10,900			25,500			0.62	2.5%					
19E	10,900			25,500			0.62	2.5%					
19F	10,900			25,500			0.62	2.5%					
20	7,000					500							
21		61.10	Schedule										
22A	12,850						4.65	0.0%					
22B	12,850						4.65	0.0%					
22C	10,400			14,136				3.5%					
23		40	2.00%				5.00	0.0%					
24A		55.00	0.96%										
24B		55.00	0.96%										
25		65.50	Schedule				0.55	2.00%					
26		52.00	3.00%				0.55	2.00%					
27A	7,250			42,000	1,275		0.80	2.00%					
27B	7,250			42,000	1,275		0.80	2.00%					
28	6,857								0	175	1,510	0.37	2.00%
29	6,880								0	441	1,510	0.35	2.00%
30	6,813								0	633	1,510	0.34	2.00%
31	6,613								0	687	1,510	0.33	2.00%
32	6,848								0	264	3,019	0.36	2.00%
33	6,866								0	883	3,019	0.35	2.00%
35												0.91	2.00%
36	10,500						3.10 in 2016	Schedule			2,443		2.00%
37	10,139												2.00%
38	9,969												
39	10,000												
40A													
40B													
40C													
40D													
40E													
40F													
40G													

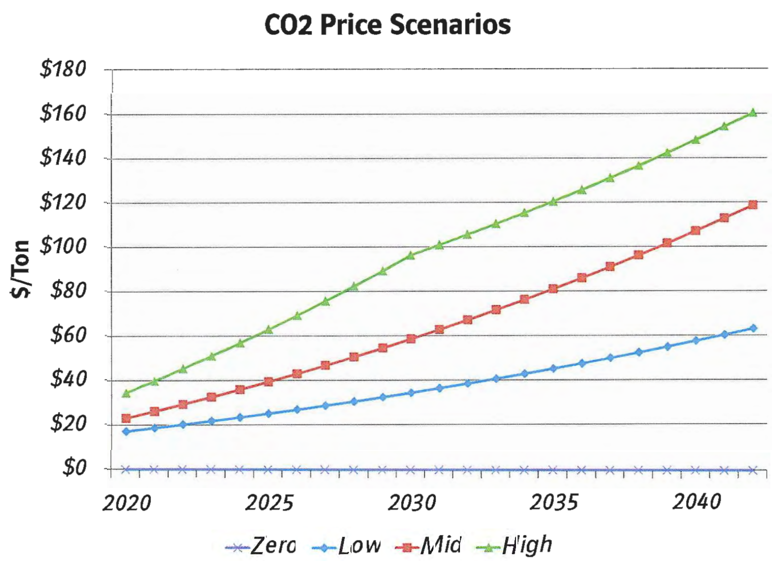
8.2 Appendix B – Phase 1 Screening Analysis Results

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.

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

Thompson, Paul

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

Paul,

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

Thanks,
David

CCN and ECR Filing Schedule 20...

Proposed Schedule for 2013 CCN/ECR Filing

Draft July 6, 2012

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

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