COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

COMMENTS OF WALLACE MCMULLEN AND SIERRA CLUB

INTRODUCTION

Intervenors Wallace McMullen and Sierra Club (collectively, "Sierra Club") hereby submit comments on Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Companies' ("KU") 2014 Joint Integrated Resource Plan ("IRP"). LG&E and KU are in the midst of important changes concerning both the customers they serve and how they meet customers' energy needs. On the demand side, the Companies received notices of termination last year from several municipal customers, representing more than 300 MW in load, who will no longer be receiving wholesale energy from the Companies after April 2019. LG&E and KU, 2014 Resource Assessment Addendum at 1 (Oct. 2014) ("Resource Assessment Addendum"). On the supply side, the Companies retired Tyrone 3 in 2013 and expect to retire five units at Cane Run and Green River by the end of 2015 or 2016. LG&E and KU, 2014 Resource Assessment at 2 (Mar. 2014); LG&E and KU Response to Sierra Club Data Request 1.21. The Companies are constructing a 640 MW natural gas combined cycle facility ("NGCC") at Cane Run. *Id.* And the Companies recently secured Commission approval for their first utility-scale solar project, to be located at the Brown facility. Case No. 2014-00002, Order, Dec. 19, 2014.

While the new resource acquisitions and coal unit retirements have helped diversify the Companies' supply portfolio, the Companies still generate the vast majority of their energy from only one resource: coal.[1] This IRP represents an important opportunity to gauge whether the Companies are planning to use a prudent mix of supply and demand resources to serve customers' needs in the least-cost, least-risk manner. Unfortunately, the IRP falls short when it comes to evaluating whether it is economic to continue investing in existing units, and whether the Companies are fully realizing the benefits that renewable resources and demand-side management ("DSM") can provide for their customers. In particular, the IRP contains the following significant flaws:

- The IRP uses neither economic modeling nor another mechanism to evaluate whether capital and fixed costs may render existing coal units uneconomic to operate;
- In particular, despite anticipating that they will spend hundreds of millions of dollars on environmental capital projects, the Companies do not evaluate whether environmental capital costs will render any units uneconomic to operate;
- The modeling results indicate Brown Unit 3 rarely is dispatched on an economic basis, and the Companies did little to evaluate whether Brown 3 would be dispatched in the absence of being designated a must-run resource;
- The Companies likely underestimated the scenarios in which Brown Units 1 and 2 operate at such low capacity factors that they should be retired;

[1] The Companies' modeling results forecast that in 2014, in the mid-gas, base load, zero carbon scenario, the Companies would generate 95% of their energy from coal. The modeling results for this scenario predict that the share of generation from coal drops to 71% in 2018, before rising to 86% in 2028. IRP Volume III, Appendix to Section 8.(4)(c) at 3.

- The IRP uses only one DSM forecast and fails to explore any alternative levels of DSM;
- The IRP assumes that no additional energy savings can be achieved from DSM for an entire decade, from 2019-2028, because of the remarkable assertion that achievable energy efficiency will be exhausted by 2018; and
- The Companies did not explore the system savings they could achieve by encouraging expanded deployment of rooftop and large-scale solar in their territories.

Most of these flaws bias the IRP analysis in favor of existing coal units. Yet despite this bias, the IRP concludes that in every scenario with a carbon price or a carbon cap, both Brown Units 1 and 2 would operate at such low capacity factors that they should be retired the first year the carbon price or carbon cap goes into effect. As explained below, even in certain scenarios with no carbon price—such as some of the low load, zero carbon scenarios—Brown Units 1 and 2 operate at very low capacity factors. Taken together, the IRP results counsel in favor of closely scrutinizing planned capital spending on Brown Units 1 and 2 to revisit whether retiring the units is the least-cost, least-risk option for ratepayers.

Additionally, the Companies should improve their analysis of demand-side management and renewable resources by using up-to-date information to evaluate what level of DSM and renewable resources would be most beneficial to ratepayers under a range of potential future scenarios. In place of the flawed assumption that energy efficiency gains grind to a halt in 2018, the Companies should be considering a range of levels of DSM programs in the years after 2018. Instead of assuming that distributed solar generation is too small to consider, the Companies should model distributed solar as a resource and consider how it can help meet customers' energy needs. Finally, given the significant advances in wind turbine technology and the continued decline in cost, the Companies should ensure that they use up-to-date data to analyze both building new wind capacity in Kentucky and pursuing power purchase agreements with out-of-state wind resources.

I. IRP STANDARDS

Every three years, the Companies must submit a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of the Companies' system. 807 KAR 5:058 Section 1(2). Core elements of the filing include the following:

- A base load forecast that is "most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system." 807 KAR 5:058 Section 7(3).

- A "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost," and that includes consideration of "key uncertainties" and an "assessment of potentially cost-effective resource options available to the utility." 807 KAR 5:058 Section 8(1).

- The revenue requirements and average system rates resulting from the plan set forth in the IRP. 807 KAR 5:058 Section 9.

As the Commission Staff stated in reviewing LG&E and KU's last IRP filing:

> The goal of the Commission in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.[2]
>
> The Staff has further explained that, in reviewing an IRP, its goals are to ensure that:
>
> 1. All resource options are adequately and fairly evaluated;
>
> 2. Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and

[2] Kentucky PSC, Staff Report on the 2011 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Case No. 2011-00140 (Mar. 2013) at 2.

3. The report also includes an incremental component, noting any significant changes from the utilities most recently filed IRP.[3]

Evaluation of an IRP should also be guided by the overall requirement that utility rates are "fair, just, and reasonable." KRS § 278.030(1); *see also* KRS § 278.040; *Ky. Pub. Serv. Comm'n v. Commonwealth of Ky. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010). As the Commission has explained, it has long been recognized that "'least cost' is one of the fundamental principles utilized when setting rates that are fair, just, and reasonable." Case No. 2009-00545, Order of June 28, 2010 at 5. A utility's rates will almost certainly not be fair, just, and reasonable if they do not result from planning processes that seek to determine the least-cost, least-risk resource plan.

II. THE IRP'S ANALYSIS OF EXISTING UNITS SUFFERS FROM SEVERAL FLAWS.

The heart of the IRP is the Resource Assessment, in which the Companies conducted economic modeling that purports to determine the optimal mix of supply resources that would meet customers' peak demand and energy needs at the "lowest reasonable cost." IRP Volume I at 5-1. LG&E and KU updated the Resource Assessment after municipal customers gave notices to terminate their wholesale power contracts with the Companies. The Companies used Strategist for the optimization modeling. *Id.* at 8-70.

The Companies evaluated 21 different scenarios. Resource Assessment Addendum at 6. Each scenario is a combination of three key forecasts: the CO_2 price, natural gas price, and load forecast. *Id.* at 6-8. The Companies analyzed 9 scenarios with a zero carbon price, 6 scenarios with a mid-carbon price, and 6 scenarios with a carbon cap. *Id.*

[3] *Id.* at 3.

In the Resource Assessment Addendum, the Companies concluded that in all of the zero carbon price scenarios, no existing units would retire during the analysis period. Under the Companies' modeling assumptions and constraints, many of the optimal plans add a natural gas combined cycle ("NGCC") or combustion turbine ("CT") as early as 2019. Resource Assessment Addendum at 6.

In all 12 of the mid carbon price and carbon cap scenarios, the optimal plan produced by the Strategist modeling has Brown Units 1 and 2 retire in 2020.[4] Resource Assessment Addendum at 7-8. In the mid carbon scenarios, the optimal plan entails building a new NGCC as early as 2020. *Id.* at 7. In the carbon cap scenarios, an NGCC is added as early as 2019, and new wind resources are also added in some of the carbon cap scenarios. *Id.* at 8.

While we commend the Companies for including scenarios with a carbon price and a carbon cap, the Companies set up the modeling in a way that does not capture all costs facing existing units or meaningfully compare existing units to all alternative resources. First, the Companies did not allow Strategist to make market purchases, instead confining the model to the Companies' existing units or new, self-build units. Second, the Companies never analyzed whether future capital and fixed costs could cause an existing unit to become uneconomic. Third, the Companies designated Brown Unit 3 as must-run up to a certain capacity, and dispatchable above that minimum capacity, yet Strategist rarely dispatched Brown 3 more than the model was forced to run the unit. This calls into question how much the unit would run in the absence of a must-run designation.

[4] As explained below, the Companies did not allow the Strategist model to select retirement for Brown Units 1 and 2 or any other generating unit. Instead, the Companies reviewed the modeling results and then decided that Brown Units 1 and 2 should retire in certain scenarios based on the low capacity factors the units would have otherwise achieved in certain years.

A. The Companies Unreasonably Prevented the Model from Making Market Purchases.

The IRP analysis "assumed the Companies had no access to energy from the market and made no off-system sales." LG&E and KU Response to Sierra Club Data Request 1.7. This assumption conflicts with reality; in practice, the Companies are able to purchase energy and capacity from other entities. Both the IRP and the Companies' data responses lack a compelling justification for this counter-factual assumption.

In a discovery response, the Companies stated that "the analysis assumed the Companies had no access to energy from the market and made no off-system sales." LG&E and KU Response to Sierra Club Data Request 1.7. The Companies further stated that they "do not plan generation to make off-system sales in a speculative power market." *Id.* We agree that the Companies should not plan new resources, or retain existing resources, based solely or primarily on off-system sales, given the risk that customers would pay for generation that would not be profitable in the market.

However, the Companies could purchase energy from the market in ways that do not expose customers to such risks. For example, the Companies could secure long-term, fixed-price power purchase agreements. There may also be scenarios in which short-term capacity or energy purchases from the market may serve to defer the need for new generation; market purchases can play an important role in deferring the need for new generation or in allowing the retirement of an existing unit that is no longer economic.

Indeed, the Companies plan on executing a short-term PPA in order to meet near-term requirements in the wake of cancelling plans for another natural gas facility. Resource Assessment Addendum at 4. At the very least, the Companies' modeling of resource options should reflect the resources that the Companies have in fact recently selected. The Companies' decision to set up Strategist so that market purchases were not an option is unreasonable.

B. The Companies Biased the Modeling Results in Favor of Retaining Existing Units by Failing to Consider the Economic Impact of Capital and Fixed O&M Costs.

1. The Companies Provide no Legitimate Reason for not Considering how Anticipated Capital and Fixed Costs will Affect the Economics of Existing Units.

In order to ensure that a utility will deliver a "reliable supply of electricity . . . at the lowest possible cost," 807 KAR 5:058 Section 8(1), the IRP rules require utilities to fully consider both the capital and operating and maintenance ("O&M") costs of generating assets over the 15-year planning period, 807 KAR 5:058 Section 8(3)(b)12. The Companies made clear that they did not use any capital and fixed O&M costs for existing units as inputs for the Strategist modeling. LG&E and KU Response to Sierra Club Data Requests 2.2 and 2.3. This omission fails to conform to the requirement to consider capital and O&M costs for generating assets. *See* 807 KAR 5:058 Section 8(3)(b)12. The failure to analyze whether future capital and fixed O&M costs may render existing units uneconomic is particularly troubling given the potentially large capital expenses that will be needed to operate the Companies' existing coal-fired units.

The Companies' two justifications for not considering the expected capital costs for existing units have no merit. First, the Companies asserted that "[s]ince the capital and fixed O&M costs for existing units are the same for each portfolio, they do not contribute to differences between the PVRRs of the various expansion plans as determined in the 2014 IRP." LG&E and KU Response to Sierra Club Data Request 3.1(b). But that is only true because the modeling "did not include an explicit retirement analysis where existing units were iteratively removed from the Companies' generation portfolio." *Id.* For at least the most economically marginal units, the Companies should have compared continued operation to the cost of replacement capacity. Had the Companies done so, capital and fixed O&M costs would vary across portfolios, because the Companies would not be assuming, as they have done here, that existing units will continue to operate. In short, the uniformity in capital and fixed O&M costs for existing units is an artifact of the Companies' decision to not model retirement of existing units—a decision that is deeply flawed.

Second, the Companies agree that capital and fixed O&M costs can cause an existing unit to become uneconomic to operate. LG&E and KU Response to Sierra Club Data Request 3.2(b). But the Companies contend that "there are no current or pending environmental regulations that would result in a choice between increased capital and/or fixed O&M costs and retiring units." *Id.* The Companies' assertion is undermined by the Companies' 2015 Business plan, which forecasts significant capital spending to ensure the Brown units comply with the Effluent Limitations Guidelines ("ELG")[5] and the Coal Combustion Residuals ("CCR") rules.[6] The 2015 Business plan forecasts that the Companies will spend $200 million to comply with the ELG rule and $33.2 million to comply with the CCR rule at Brown:

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Voyles

Capital Costs to Comply with Regulations ($ Millions)

2015 Business Plan

(b) Coal Combustion Residuals Rule

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Brown	0.0	0.4	7.3	4.5	4.6	7.9	8.5	0.0	0.0	0.0
Ghent	0.2	1.7	70.6	37.3	37.9	70.9	73.0	0.0	0.0	0.0
Green River	0.0	0.0	0.8	9.0	20.4	0.7	7.3	0.0	0.0	0.0
Pineville	0.0	0.0	0.2	2.9	0.2	1.3	0.0	0.0	0.0	0.0
Tyrone	0.0	0.0	0.2	3.0	0.2	1.6	0.0	0.0	0.0	0.0

[5] By the terms of an amended consent decree, EPA must finalize the ELG rule in September of this year.

[6] EPA has already released the pre-publication version of the final CCR rule, and should publish the final rule in the federal register soon.

Cane Run	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mill Creek	0.1	0.7	7.1	4.8	6.9	13.3	13.5	0.0	0.0	0.0
Trimble	0.1	0.8	18.7	15.5	15.9	25.3	27.4	0.0	0.0	0.0

(c) Effluent Limitations Guidelines

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

Moreover, at Brown, the Companies expect to incur significant capital and fixed O&M costs unrelated to environmental rules. For example, the 2013 Black & Veatch study of the remaining useful life of Brown Units 1 and 2 noted that LG&E and KU anticipate significant capital spending on the two units, including over $20 million in capital expenditures at Brown 2 in 2016-2017. LG&E and KU Attachment to Response to Staff Data Request 7(b) at 28. None of these costs were considered in the IRP.

Contrary to the Companies' claim, the Companies' forecast of $233.2 million in capital spending at Brown[7] *would* "result in a choice between increased capital and/or fixed O&M costs and retiring units." LG&E and KU Response to Sierra Club Data Request 3.2(b). That choice should have been evaluated in the IRP, rather than ignoring the upcoming capital and fixed costs that the Companies' own capital spending plan forecasts for Brown.

[7] The Companies anticipate having to make similarly large capital expenditures at Mill Creek and Trimble to comply with the ELG rule, and to spend over $200 million at Ghent to comply with the CCR rule. LG&E and KU Attachment to Response to Sierra Club Data Request 1.15(1).

2. The Companies' Reliance on Low Capacity Factors as a Proxy for Retirement is no Substitute for a Proper Economic Analysis of Retirement of Existing Units.

Although capital and fixed costs were not inputs in the Strategist modeling, it appears that fixed costs for existing units were added after the model had returned results in order to calculate the present value of revenue requirements ("PVRRs"). The Companies decided whether to retire units early based on average capacity factors, and capital and fixed costs played no role in determining capacity factors. For the purposes of the IRP modeling, the Companies did not assess whether it would be economically beneficial to retire Brown Units 1 and/or 2 based on high capital and fixed O&M costs.

The only way in which the Companies evaluated early retirement of existing units was to review the modeling results and assume that any unit with three consecutive years of an average capacity factor below 10% would retire in the first year in which its capacity factor dropped below 10%. IRP Volume I at 8-71. The Companies never explained how they selected three consecutive years of below 10% capacity factors as the threshold for retirement. While capacity factors consistently below 10% suggest that a coal unit likely should be retired, coal units will often be uneconomic even if operating at capacity factors higher than 10%, especially if they face significant capital costs. Coal units were typically designed to serve as base load facilities operating at high capacity factors, not cycling units operating at low capacity factors.

In addition, the Companies' methodology of analyzing potential unit retirements focuses on capacity factors based on variable operating costs rather than a full financial analysis accounting for capital and fixed costs. Yet it is critical to evaluate retirement by comparing the total revenue requirements—including capital and fixed costs—for retaining an existing unit to the revenue requirements for other options. And a key factor in determining whether a coal unit should be retired early is whether the capital and fixed costs needed to keep the unit operational exceed the net revenues the unit would earn from operating. Yet the Companies' IRP never evaluates that question and, instead, only factors in capital and fixed costs after deciding that its coal units should not retire.

To meaningfully assess existing units, the IRP needed some mechanism for evaluating whether future capital and fixed costs may lead existing units to become uneconomic to operate relative to alternative resources. The Companies did not conduct such an analysis in this IRP, thereby preventing this IRP from serving as a reliable guide to the least-cost way to meet customers' electricity needs. *See* 807 KAR 5:058 Section 8(1). In sum, the Companies' failure to analyze how expected capital and fixed O&M costs affect the economics of existing units biased the result toward retaining existing units and violated 807 KAR 5:058 Section 8(2)(b)12.

We are not suggesting that the Companies must separately model retiring each unit or combination of units in each year of the analysis. But at the very least, in the IRP, the Companies should evaluate scenarios in which generating units that face significant capital costs are instead retired. Brown Units 1 and 2 are small, old, and less efficient than many other coal units in LG&E and KU's fleet. Moreover, the Companies project that they will incur significant capital costs at Brown from 2016-2021. Thus, the Companies should have modeled retirement of Brown Units 1 and/or 2 in years, such as 2016 or 2017, that would avoid these significant capital expenses.

C. <u>The Companies Did Not Adequately Evaluate the Economics of Brown Unit 3.</u>

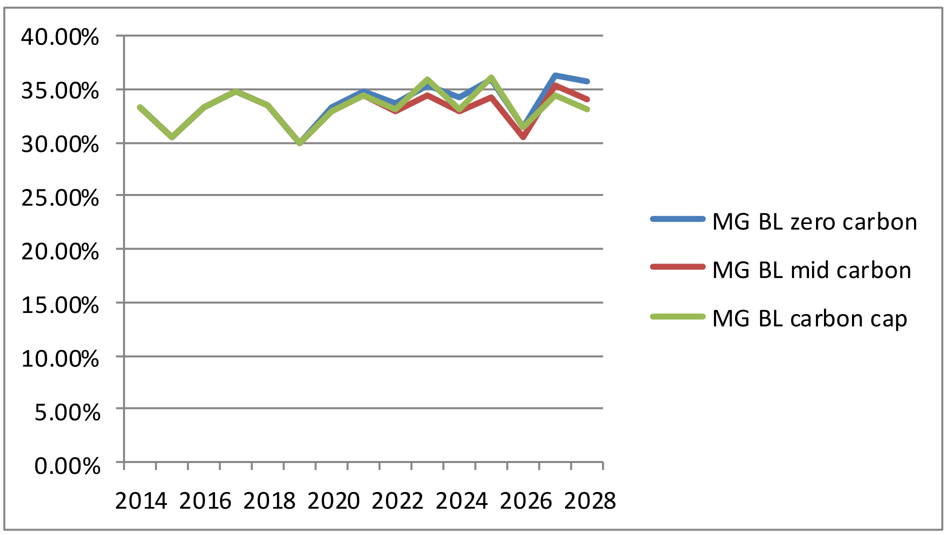
For the IRP modeling, the Companies designated Brown Unit 3 as a must-run resource for all hours in all years. LG&E and KU Response to Sierra Club Data Request 2.5. As a result, the model was forced to select Brown Unit 3 at a minimum load of 155 MW. LG&E and KU Response to Sierra Club Data Request 2.5(b). The minimum capacity segment of 155 MW is

38% of Brown Unit 3's maximum capacity of 411 MW. Above the minimum load of 155 MW, the model could select Brown Unit 3 for economic dispatch, subject to various constraints.

The Companies' IRP does not explain why Brown Unit 3 is designated as must-run in the modeling in all hours of all days. In both this and in future IRPs, the Companies should provide an explanation for must-run designations and only use such designations if justified by reliability concerns.

The following graph plots the capacity factor for Brown Unit 3 in the mid gas, base load scenarios.

Brown Unit 3 Capacity Factors in the Mid Gas and Base Load Scenarios, 2014-2028[8]



Brown Unit 3 is projected to rarely run above its must-run designation, which suggests that the model is running Brown Unit 3 because of the must-run designation, not because the unit is actually economic to run. The Companies acknowledged in discovery that "[w]ithout the must-run constraint, the Companies would expect the capacity factor for Brown Unit 3 to be lower." LG&E and KU Response to Sierra Club Data Request 3.3(a). Given that Brown Unit 3 is not

[8] Capacity factors come from LG&E and KU Attachment to Response to Sierra Club Data Request 1.6(e) at 15-17.

economic enough to be dispatched above its must-run designation, it is an open question to what extent Brown 3 would run in the absence of a must-run designation.

As noted above, the Companies have not offered any justification, much less a compelling one, as to why Brown Unit 3 is assumed to be a must-run unit. Even if such must-run designation were justified by reliability concerns, however, an analysis of the economics of Brown Unit 3 in the absence of a must-run designation would indicate whether it would be appropriate to examine alternatives to a must-run designation that could preserve reliability. For example, if modeling were to indicate that Brown Unit 3 would have very low capacity factors in the absence of a must-run designation, or that the unit is uneconomic to continue operating, then it would be important for LG&E and KU to compare the economics of designating Brown Unit 3 a must-run to alternatives that would preserve reliability.

III. THE MODEL RESULTS INDICATE THAT BROWN UNITS 1 AND 2 RETIRE IN MANY SCENARIOS, AND WOULD LIKELY RETIRE IN ADDITIONAL SCENARIOS.

A. Brown Units 1 and 2 Retire in All Scenarios in Which There Is a Carbon Price or Carbon Cap.

The Companies' modeling results indicate that the most economic option is to retire Brown Units 1 and 2 if there is either a carbon price or a carbon cap. In all of the mid-carbon scenarios, Brown Units 1 and 2 retire in 2020, the first year the carbon price goes into effect. Resource Assessment Addendum at 7. Likewise, in all of the carbon cap scenarios, Brown Units 1 and 2 retire in 2020, the first year the carbon cap goes into effect. *Id.* at 8. Simply put, a mid-carbon price or a carbon cap would result in Brown 1 and 2 running at such low capacity factors that the Companies assume they would be retired.

The Companies should be commended for using a carbon price and a carbon cap to evaluate the impact of future carbon regulations, as Commission Staff recommended in their comments on the Companies' 2011 IRP. Staff Report at 41. Evaluating scenarios with a carbon price or a carbon cap is a critical step toward evaluating how resources will fare under the Clean Power Plan and any other future carbon regulations. While the Clean Power Plan is not yet final, and Kentucky has therefore not proposed a plan for complying with the Clean Power Plan, it is prudent to use a carbon price and/or carbon cap as proxies for the economic effects of carbon regulation on generating resources.

In a recent order, the Commission recognized that it is appropriate for utilities to plan for a carbon-constrained world. Case No. 2014-00002, Order of Dec. 19, 2014 at 12 ("[I]t is appropriate for Joint Applicants to diversify their generation portfolio in light of a likely future carbon-constrained world."). The Commission's recent order is consistent with the Environmental Protection Agency's ("EPA") proposal to regulate carbon emissions from existing power plants, otherwise known as the Clean Power Plan.

On June 25, 2013, President Obama announced a comprehensive plan to cut the carbon pollution that causes climate change and endangers public health. Noting that nearly 40 percent of this pollution is produced by the power sector, the President directed EPA to revise its proposal for carbon pollution standards for new power plants by September 20, 2013, to issue proposed standards, regulations, or guidelines addressing carbon pollution from existing power plants by June 1, 2014, and to finalize those limits by June 1, 2015.[9] EPA issued the proposed Clean Power Plan, which would regulate carbon emissions from existing power plants, in June 2014. 79 Fed. Reg. 34,830 (June 18, 2014). Moreover, the guidelines for existing power plants

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[9] *See* Presidential Memorandum – Power Sector Carbon Pollution Standards (June 26, 2013), *available at* http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

must include a requirement that States submit their implementation plans to EPA no later than June 30, 2016.[10]

The President's announcement confirmed and publicized a regulatory process that has been underway for years. In 2007, the Supreme Court held that carbon dioxide and other greenhouse gases are covered by the Clean Air Act's broad definition of "air pollutant" and that EPA must decide whether greenhouse gases endanger public health. *Massachusetts v. EPA*, 549 U.S. 497, 532-34 (2007). After analyzing the available climate science, EPA issued a formal finding that current and projected emissions of six greenhouse gases, including CO_2, threaten the public health and welfare of current and future generations. The U.S. Court of Appeals for the District of Columbia Circuit upheld this finding, and the Supreme Court denied certiorari on this issue. *See Coal. for Responsible Regulation v. EPA*, 684 F.3d 102, 120–22 (D.C. Cir. 2012). The D.C. Circuit also confirmed that the Clean Air Act requires the EPA to address greenhouse gas emissions under its stationary source permitting programs. *Id*. at 134–36. As confirmed by these decisions, Section 111 of the Clean Air Act requires the EPA to issue performance standards for air pollutants from both new and existing electric generating units. *See* 42 U.S.C. §§ 7411(b), (d).

While the final details of the Clean Power Plan are still unknown, EPA has not wavered from its commitment to finalizing the Clean Power Plan this year. Once the rule is finalized, states will have to submit plans for reducing the carbon emission rate from their existing power plants. Based on the information available today, federal carbon regulations for both new and existing units are reasonably expected, and therefore it was appropriate and, in fact, necessary, for LG&E and KU to model scenarios involving a carbon price or carbon cap.

[10] *Id.*

B. Even in One of the Scenarios with No Carbon Regulation, Brown Unit 1 Has Consecutive Years Where the Unit Achieves Barely More than a 10% Capacity Factor.

The Companies evaluated early retirement of existing units using the following methodology:

> . . . in evaluating the Companies' 2014 IRP scenarios, capacity factors for existing coal units were averaged over the three gas price scenarios in each load-CO2 price scenario. If an existing coal unit's (average) capacity factor was consistently less than 10 percent in a given load-CO2 price scenario, the unit was assumed to be retired (in all three gas price scenarios) in the year when its capacity factor consistently dropped below 10 percent. For a given load-CO2 price scenario, if the average capacity factor was not consistently less than 10 percent, the unit was not assumed to be retired in any of the associated gas prices scenarios.

LG&E and KU Response to Sierra Club Data Request 2.14(b). Based on the Companies' statements, they assumed that a unit would be retired if the unit's three-year average capacity factor was below 10% in any load and carbon price combination, taking the average across the three gas prices (mid, high, and low prices).

As the table below indicates, between 2020 and 2022, Brown 1 barely avoids having three consecutive years where its average capacity factor falls below 10% – which would trigger retirement under the Companies' methodology.

Brown Unit 1, Capacity Factors in the Low-Load, Zero Carbon Scenarios, 2020-2022

		2020	**2021**	**2022**
HG	LL	18.00%	23.60%	20.90%
LG	LL	0.60%	0.60%	0.70%
MG	LL	7.30%	8.80%	8.20%
Unweighted Average		**8.63%**	**11.00%**	**9.93%**

Thus, the modeling results indicate that even without any form of carbon regulation, in the low load scenario, the economics of Brown Unit 1 are marginal at best.

C. <u>The Results for Brown Units 1 and 2 in the Zero Carbon Scenarios Likely Underestimate the Probability that the Units Should Retire Before 2028.</u>

In all of the scenarios without a carbon price or carbon cap, the Companies' modeling projects that Brown Units 1 and 2 do not retire, but instead operate through 2028. Resource Assessment Addendum at 6. However, as mentioned previously, these results underestimate the likelihood that Brown Units 1 and 2 would retire prior to 2028 because the Companies did not evaluate whether future capital and fixed O&M costs, including environmental capital costs, could cause Brown Units 1 and 2 to become more expensive than alternative supply- and/or demand-side options. There is an additional reason Brown Units 1 and 2 are more likely to retire in the zero carbon scenarios than the model results indicate: the Companies relied on an unweighted average of the capacity factor across the three gas prices, thereby effectively assuming that each gas price is equally likely to occur. Such an equal weighting is unexplained and likely underestimates the probability of the mid-gas price occurring.

In this IRP, "[t]he potential for retirement was evaluated after reviewing model results." LG&E and KU Response to Sierra Club Data Request 1.11. The Companies reviewed the capacity factor for each unit under each combination of load and carbon price/cap, averaged over the three gas prices. If the average capacity factor was less than 10% in three consecutive years, the unit was assumed to retire in the first year in which the capacity factor dropped below 10%. Resource Assessment at 39; LG&E and KU Response to Sierra Club Data Request 2.14.

The Companies weighted each gas price equally; that is, the Companies assumed that each gas price is equally likely to occur. LG&E and KU Response to Sierra Club Data Request 3.5(a). The base gas price forecast comes from the 2013 gas price reference case put forth by the Energy Information Agency's ("EIA"), which is a federal agency that is widely relied upon for energy sector forecasts. LG&E and KU Response to Sierra Club Data Request 1.19. We do not question the Companies' reliance on EIA's forecasts. However, the Companies' weighting of the three gas prices is questionable.

EIA did not assign a probability to the mid-gas price used in its reference case. However, forecasting agencies and utilities often treat a mid or base price forecast as the forecast most likely to occur, and consider the sensitivities that bound the mid or base price as less likely to occur. Here, EIA designed the reference case as a projection of current trends, based on information available at the time of the forecast. 2013 AEO at iii ("[t]he AEO2014 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends.").[11] EIA developed sensitivities to "explore[] the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress." *Id.*

In the absence of any countervailing information, we would have expected the Companies to treat its mid gas price forecast as more likely to occur than each of the high and low gas price forecasts. Instead, the Companies made the opposite assumption: that in the absence of any reason to do otherwise, they would treat the mid, low, and high gas prices as equally likely to occur.

If the mid gas price is weighted more heavily, and the sensitivities are weighted less, the average capacity factor across all three gas prices changes, along with the Companies' assumption about whether the units retire early. For example, for Brown 1, in the low load, zero carbon scenario, the average capacity factor across the three gas prices for 2020 to 2022 falls below 10% if the base case is approximately 80% likely to occur and the high and low gas prices are each 10% likely to occur. Using this weighting would indicate that Brown Unit 1 should be

[11] *Available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

retired in 2020 in the low load, zero carbon scenarios. The following tables show the unweighted average capacity factors:

Brown Unit 1, Unweighted Average Capacity Factor, 2020-2022

		2020	2021	2022
HG	LL	18.00%	23.60%	20.90%
LG	LL	0.60%	0.60%	0.70%
MG	LL	7.30%	8.80%	8.20%
Unweighted Average		**8.63%**	**11.00%**	**9.93%**

The next table weights the mid gas price as 80% likely to occur, and the high and low prices as each 10% likely to occur.

Brown Unit 1, Weighted Average Capacity Factor, 2020-2022

		2020	2021	2022
HG	LL	1.80%	2.36%	2.09%
LG	LL	0.06%	0.06%	0.07%
MG	LL	5.84%	7.04%	6.56%
Weighted Average		**7.70%**	**9.46%**	**8.72%**

Using this weighting, Brown Unit 1 has three consecutive years with an average capacity factor below 10%, which, according to the Companies' methodology, would trigger retirement of Brown 1 in 2020. We selected this weighting of the gas prices merely to show that the results can flip—from no retirement to retirement—depending upon how the three gas prices are weighted, not to advocate for this particular weighting.

At a minimum, the IRP should have included an explanation for the Companies' weighting of the three gas prices, and a brief discussion of how the retirement outcomes would change based on different weightings of the gas prices.

IV. THE COMPANIES CONTINUE TO DRAMATICALLY UNDERESTIMATE ENERGY EFFICIENCY POTENTIAL.

A. LG&E and KU Failed to Analyze a Reasonable Range of Alternative DSM Amounts in the Years After 2018.

Energy efficiency is the least-cost, least-risk system resource. With an average levelized cost of roughly 2-3 cents per KWh, no emissions, and the ability to defer or avoid the need for generation and related infrastructure, energy efficiency programs are a critical part of a cost-effective utility resource mix that can lower system costs and risk, thereby reducing customer bills. In LG&E and KU's most recent DSM case, the Companies found that every dollar invested in DSM resulted in approximately three dollars in energy savings. Case No. 2014-00003, Direct Testimony of Michael Hornung at 12; *see also* Exhibit MEH-1, Appendix C. Moreover, as this Commission has observed, energy efficiency and other demand-side programs are critical resources that will "become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation." Case No. 2010-00204, Order of Sept. 30, 2010 at 14; *see also* Case No. 2010-00222, Order of Feb. 17, 2011 at 15; Case No. 2008-00408, Order of Oct. 6, 2011 at 22.

The Commission's IRP rules require that utilities fully consider these critical resource options in developing their plans to meet their customers' power needs for the 15-year forecast period. Specifically, utilities must identify and describe existing DSM programs and estimate their load impact; account for existing and continuing DSM programs in their 15-year load forecast; describe DSM resources that are not already in place and are considered for inclusion in the plan; provide detailed information about each new DSM program, including the energy and peak savings and cost savings; and describe the criteria used to screen each resource alternative, including DSM. 807 KAR 5:058 Sections 7, 8.

Moreover, the Commission has adopted an IRP standard that requires each electric utility to "integrate energy efficiency resources into its plans and [] adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options" and, in each IRP, "fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5:058)." Case No. 2008-00408, Order of July 24, 2012 at 10. In so doing, the Commission has affirmed "its support for greater energy efficiency." *Id.*

The Companies evaluated DSM by modifying their load forecast to account for the reductions in demand and energy requirements achieved by their approved DSM programs. LG&E and KU Responses to Sierra Club Data Request 1.13(b) ("Therefore, in conducting the 2014 IRP analysis, the Companies used as the basis for future DSM-related savings their most recent DSM/EE Program Plan, which the Commission recently approved for calendar years 2015-2018.") and 2.2(d). Strategist could not select DSM as a resource. LG&E and KU Response to Sierra Club Data Request 2.2(d). Moreover, the Companies did not vary the level of DSM in any of their load forecasts. In short, the Companies did not evaluate any alternatives to the levels of DSM assumed in the 2015-2018 DSM plan approved in Case No. 2014-00003.

This is a critical flaw, because the Companies' approved DSM plan ends in 2018. The Companies have no approved DSM plan covering 2019-2028 and they conducted no analysis for this IRP of DSM plans for 2019-2028. This leaves a gap of ten years, from 2019-2028, in which the IRP assumes no new energy savings or demand reductions from DSM.

The Companies could have evaluated DSM for 2019-2028 in a number of ways. For example, the Companies could have evaluated DSM alternatives by allowing Strategist to select DSM in blocks, similar to a supply-side resource. Although it is an inferior method, the

Companies could at least have considered and applied different levels of DSM to the load forecast. The Companies chose neither of these options. Instead, the Companies used a single, pre-determined amount of DSM, which fails to evaluate the optimal amount of DSM, especially after the Companies' DSM plan ends in 2018. Accordingly, the Companies failed to consider a proper range of resource portfolios and evaluate how they perform under different conditions. *See* 807 KAR 5:058 Section 8(2).

B. LG&E and KU's Claim That They Will Exhaust Achievable Energy Efficiency Potential by 2018 Is Unfounded.

In this IRP, the Companies assume that energy efficiency and demand response grind to a halt after 2018: there is no additional energy savings or peak load reduction from energy efficiency and demand response after 2018. Across every one of the 21 scenarios, the Companies assume that it is not achievable to cost-effectively save a single, additional kilowatt hour of energy. The Companies make this remarkable assumption on the theory that "the Companies are currently on track to exhaust their *achievable* energy-efficiency potential by 2018." IRP Volume I at 8-29; *see also* IRP Volume I at 6-33, Table 6.(1)-23 (indicating DSM reductions remain flat at 406 MW from 2019-2028); Resource Assessment Addendum at 5, Table 1 (showing no growth in DSM after 2018).[12]

The notion that the Companies will exhaust their achievable energy efficiency potential by 2018 is baseless.[13] Instead, this view merely underscores the Companies' reluctance to aggressively pursue DSM. There are many reasons to question the Companies' assumption that achievable energy efficiency potential will be exhausted by 2018.

[12] The Companies' assertion that achievable energy efficiency potential will be exhausted by 2018 is based on a flawed energy efficiency potential study that the Companies received from a consultant.
[13] In its November 14, 2014 Order in 2014-00003, the Commission did not address the Companies' contention that it is on track to exhaust achievable energy efficiency by 2018.

First, the Companies have been achieving relatively low rates of energy efficiency compared to utilities in neighboring states that have similar electricity market characteristics, including similar prices and a similar mix of customers. Second, technologies that enable energy savings—from more energy efficient light bulbs to more energy efficient appliances—are constantly evolving, so there is no reason to believe that manufacturers will cease developing energy efficiency technology in 2018.

Third, the Companies do not offer any DSM programs to industrial customers, who make up roughly one-third of the Companies' energy sales. Case No. 2014-00003, Order of Nov. 14, 2014 at 27. The Commission recently ordered the Companies to investigate the potential for offering a DSM program to industrial customers. *Id.* at 30-32. Given that the Companies offer no DSM programs whatsoever to the customers who are a third of the Companies' load, it is difficult to fathom how the Companies could exhaust the potential for industrial programs that have not even been offered yet. Put differently, it is unclear how the Companies can exhaust potential that they have yet to even tap.

To examine a reasonable range of DSM plans for this IRP, the Companies had several options short of commissioning a new energy efficiency potential study. For example, there are commercially available models, such as Plexos Linear Program, that the Companies could have used to develop DSM plans for 2019-2028. These DSM programs could then either be available in Strategist as resources to select, or, at a minimum, the Companies could have applied the DSM amounts to reduce their load forecasts.[14] The Companies' decision to instead assume that no new energy savings or demand reductions can be achieved after 2018 results in an

[14] Of course, whether the Companies treat DSM as a supply-side resource or as a load modifier, the Companies must develop reasonable DSM programs. To appropriately analyze DSM, the Companies would have to use reasonable inputs and assumptions to develop a reasonable range of DSM programs to consider.

unreasonably narrow range of portfolios—since all 21 scenarios use the same assumption of no incremental growth in DSM after 2018. As a result, the Companies did not consider a meaningful variety of resource portfolios and did not evaluate them under meaningfully different conditions. *See* 807 KAR 5:058 Section 8(2).

V. THE COMPANIES SHOULD ENSURE THAT FUTURE ANALYSES OF WIND ENERGY ARE BASED ON THE MOST ADVANCED WIND TURBINES AVAILABLE.

In the IRP, the Companies take the position that "[t]he use of renewable and distributed energy resources are on the rise but generally are not currently economical in Kentucky." IRP Volume I at 6-38. However, significant advances in wind turbine technology are changing the economics of wind power in Kentucky. Data on the most recent generation of wind turbines, and the next generation of wind turbines, shows that there is technical potential for far more wind energy to be generated within Kentucky than was previously considered feasible.

The Department of Energy and the Southeastern Wind Energy Coalition recently released fact sheets showing wind potential in several states, including Kentucky.[15] Wind potential was calculated based on the prior generation of wind turbines with 80 m height, current turbines with a height of 100 m, and turbines in development that will have a height of 140 m.[16] The current and future generations of wind turbines enable dramatically more wind to be produced in Kentucky than was possible with the older, smaller generation of wind turbines.[17] Given the potential for these technology advances to make wind power more economical in Kentucky, the

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[15] Southeast Wind Energy Fact Sheet, December 2014, *available at* http://www.eenews.net/assets/2014/12/10/document_ew_01.pdf. Wind potential was calculated using data from the National Renewable Energy Laboratory, which is working with DOE to make the data publicly available via its website.

[16] The Wind Energy Fact Sheet does not undertake a detailed analysis of the economics of site-specific wind

[17] Since the Wind Energy Fact Sheet was issued after the Companies submitted their IRP, we acknowledge that the Companies could not have incorporated this data into the current IRP.

Companies should ensure that future analyses of wind energy are based on up-to-date assessments of wind turbine technology.

The Companies' IRP largely dismisses wind power, except in the out years of the high gas carbon cap scenario, on the grounds that wind costs have only "decreased slightly" since the 2011 IRP, which presumably used data from 2010 or earlier. IRP Vol. I at 8-38. In reality, however, technological advances and market developments have led to substantial drops in the price of wind power. For example, the U.S. Department of Energy's 2012 Wind Technologies Market Report (published in August 2013), found that the average levelized price for long-term wind energy power purchase agreements dropped to $40 per MWh in 2011-2012.[18] The 2013 Report (published in August 2014) found that the average levelized price for such PPAs entered in 2013 had reached an "all-time low" of $25/MWh.[19] Similarly, an August 2013 report from the financial advisory firm Lazard found that the levelized cost of energy from wind power had dropped 50% in the previous four years, and reported an unsubsidized cost range of $45 to $95 per MWh.[20] Lazard's most recent report, from September 2014, reports an even lower unsubsidized cost range for wind of $35 to $81 per MWh.[21] And in Michigan, a report by the Michigan Public Service Commission on utility pursuit of renewable energy found that:

> The actual cost of renewable energy contracts submitted to the Commission to date continues to show a downward pricing trend. The most recent contracts approved by the Commission for new wind capacity have levelized costs in the low $50s per MWh range, which is about 10 percent less than the least expensive

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[18] U.S. Dept. of Energy, 2012 Wind Technologies Market Report (Aug. 2013) at iv to ix *available at* http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf).

[19] U.S. Dept. of Energy, 2013 Wind Technologies Market Report (Aug. 2014) at ix *available at* http://emp.lbl.gov/sites/all/files/lbnl-6809e.pdf)

[20] http://www.windpowerengineering.com/construction/projects/lazard-finds-cost-wind-power-dropped-50-last-4-yr/

[21] Lazard's Levelized Cost of Energy Analysis – Version 8.0 (Sept. 2014), at 2, available at http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf.

> levelized contract prices from 2011 and half of the levelized cost of the first few renewable energy contracts approved in 2009 and 2010.[22]

While Michigan has a renewable portfolio standard that has driven the increase of the use of renewable energy in that state, that does not change the importance of the fact that wind costs have declined significantly in Michigan as throughout the nation.

The declining price of wind power is already leading utilities throughout the country to ramp up their acquisition of wind resources. Kentucky Power Company committed to issuing a Request for Proposal for 100 MW of wind power as part of its settlement agreement in Case No. 2012-00578. KPC received numerous responses to its RFP, demonstrating the availability and interest of wind generators to respond to make wind available to Kentucky utilities. In its latest IRP, Kentucky Power indicates that it intends to pursue 100 MW of wind power in 2015. Kentucky Power Company, 2013 Integrated Resource Plan, Volume A at ES-3, 3, 165.

In addition, the DOE wind technologies market report found that in 2012, 13.1 GW of new wind energy capacity was installed in the US, accounting for 43% of all new energy capacity installed, and that wind power produced more than 12% of energy generation in nine states.[23] Alabama Power executed a long-term wind PPA in 2011 that will deliver energy at a price that is "expected to be lower than the cost the Company would incur to produce that energy from its own resources (i.e., below the Company's avoided costs), with the resulting energy savings flowing directly to the Company's customers."[24] Similarly, Southwestern Electric Power Company entered into a contract for wind power at a price that is lower than their current

[22] Michigan Public Service Commission, Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-Effectiveness of the Energy Standards (Feb. 2015) at p. 30, available at http://www.michigan.gov/documents/mpsc/PA_295_Renewable_Energy_481423_7.pdf

[23] U.S. Dept. of Energy, 2012 Wind Technologies Market Report (Aug. 2013) at iv to ix *available at* http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf).

[24] Order, Alabama Public Service Commission, Docket No. 31653 (Sept. 9, 2011) at 3.

average cost of energy.[25] American Electric Power's Oklahoma affiliate – the Public Service Co. of Oklahoma – "originally planned to purchase up to 200 megawatts of wind energy but contracted for an additional 400 megawatts after seeing pricing opportunities that will lower utility costs by an estimated $53 million in the first year and even more thereafter."[26] There are many more examples of recent utility decisions to either build their own wind projects or sign PPAs with wind farms.

As the data cited above indicates, given the rapid developments in technology and costs of wind power, the Companies should ensure that their analyses of wind power are based on up-to-date information. The Companies should investigate low-cost wind power purchase agreements regardless of where the wind is generated. States to the west, such as Iowa, Kansas, and Nebraska, have wind farms that generate electricity at very low cost. The IRP contains no discussion of the feasibility, such as the availability of transmission, and the cost of power purchase agreements with such wind farms.

VI. THE IRP FAILS TO ACCOUNT FOR THE POTENTIAL FOR DISTRIBUTED SOLAR GENERATION.

Kentucky's solar potential, and the many benefits solar can provide to the state, are outlined in the report conducted by Karl Rabago on behalf of the Sierra Club as part of our comments on KPC's 2013 IRP. *See* Sierra Club's Comments on Kentucky Power Company's Integrated Resource Planning Report, Exhibit B, No. 2013-00475. As discussed in the Rabago report, Kentucky has better or equivalent solar resources than many neighboring or nearby states

[25] Direct Testimony of Sandra S. Bennett for Southwestern Electric Power Company, http://www.apscservices.info/pdf/13/13-033-u_4_1.pdf, at 7 ("[T]he combined impact of the new wind REPAs is expected to lower SWEPCO's projected overall energy supply cost to customers. SWEPCO estimates the decrease will average approximately $28.7 million over the 10 year period of 2013 to 2022.").

[26] *See* http://m.tulsaworld.com/business/aep-pso-agrees-to-buy-wind-energy-citing-substantialsavings/article_5b273a3a-9a91-59cc-a984-38af5b2e7923.html?mode=jqm.

that surpass Kentucky in development of solar energy, including North Carolina, Tennessee, Virginia, Ohio, and Pennsylvania. *Id.* at 3.

Solar resources can play a significant role in delivering low cost and reliable power to the Companies' customers. In addition to the fuel-free energy it provides, solar has a natural coincidence with peak summer demand. Smaller solar systems sited on the distribution grid closer to load can avoid transmission capacity costs and line losses. *Id.* As a carbon-free resource, solar can be an important component of complying with EPA's forthcoming Clean Power Plan. Despite these substantial benefits, however, the Commonwealth's potential for solar energy development has remained almost entirely untapped to date.

Sierra Club applauds the Companies for undertaking the state's first utility-scale solar project. But this project barely begins to scratch the surface of Kentucky's solar potential. The potential for economical solar power is not limited to utility-scale solar. Distributed solar generation should be considered as well.

The IRP contains only passing references to distributed solar generation, and the Companies did not include distributed solar generation as a supply-side resource in their modeling. IRP Volume III at 4. The Companies have 199 net metering customers with distributed solar systems. *Id.* The Companies correctly note that the capacity from the current distributed solar systems is very small relative to the Companies' peak demand. However, an IRP is not an exercise in focusing on the present; an IRP is a long-range plan that focuses on the future.

The Companies note the "downward trend" in projections of the price of residential solar systems, but fail to appreciate that this downward trend merits consideration of the economics of distributed solar in the future. IRP Volume I at 6-38. Depending on the size of the system, the reported prices of residential and commercial PV systems declined 6-7% each year, on average, from 1998-2013 and by 12-15% from 2012-2013. *See* David Feldmand et al., Photovoltaic System Pricing Trends, slide 4, DOE SunShot (2014), *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf. Analysts predict that residential and commercial solar PV systems will continue to decline in price. *Id.* at 28. Given that solar PV prices have declined dramatically, and are forecast to continue declining, the Companies should have examined the potential for increased distributed solar generation over the planning horizon.

Moreover, the Companies appear poised to take steps that would deter customers from investing in rooftop solar. As part of their current rate case, the Companies have proposed an increase in their fixed charge. An increase in the fixed charge will discourage the adoption of distributed solar generation, and so should not be supported by the Commission.

VII. THE COMPANIES SHOULD TAKE STEPS TO ADJUST THEIR LOAD FORECAST IN LIGHT OF THEIR PRACTICE OF REGULARLY OVERESTIMATING ENERGY SALES.

The Companies provided data on the annual deviation between forecasted sales and actual sales (weather normalized and not weather normalized). The following table reproduces the Companies' actual and forecasted energy sales data from 2005 through September 2014.

Comparison of Budgeted Electricity Sales to Actual Sales, 2005-2014[27]

Year	**Budget sales**	**Actual sales**	**Actual, weather normalized ("WN") sales**	**Deviation to Budget, %**	**Deviation to Budget, WN, %**
2005	32,522	33,282	32,828	2.3%	.9%
2006	33,667	32,639	Not provided	-3.1%	Not provided
2007	34,324	34,301	33,706	-.1%	-1.8%
2008	34,731	33,273	33,115	-4.2%	-4.7%
2009	34,145	31,665	31,993	-7.3%	-6.3%
2010	31,973	34,276	33,007	7.2%	3.2%
2011	33,675	32,803	32,570	-2.6%	-3.3%
2012	33,840	32,793	32,993	-3.1%	-2.5%
2013	33,710	32,968	32,994	-2.2%	-2.1%
2014, through September	25,683	25,475	25,071	-.8%	-2.4%

In eight of the last ten years, actual sales were lower than budgeted sales. The deviation is consistently in one direction: the Companies regularly overestimate energy sales. In discovery, the Companies asserted that this can largely be attributed to the fact that their load forecasting relies heavily on macroeconomic forecasts, and the macroeconomic forecasts have overestimated economic growth in recent years. LG&E and KU Response to Sierra Club Data Request 2.13. The Companies are certainly not expected to do their own macroeconomic forecasts. But when budgeted sales regularly exceed actual sales, some adjustment to the load forecast should be made, particularly since the load forecast is one of the primary inputs in an IRP.

There are several options for accounting for the Companies' pattern of overestimating energy sales, ranging from altering the forecasting methodology to applying a correction factor at

[27] LG&E and KU Attachment to Response to Sierra Club Data Request 1.25.

the end. Whatever path the Companies choose to take, they should account in some way for their tendency over the last decade to forecast energy sales that exceed actual sales.

CONCLUSION

For the foregoing reasons, the Commission Staff should recommend that LG&E and KU:

- Include market purchases as a resource option in the modeling;
- Include an economic analysis of whether anticipated capital and fixed costs may cause existing units to become uneconomic to operate relative to alternative resources during the planning period;
- In particular, the Companies should analyze the economics, relative to alternative resources, of retiring Brown Units 1 and/or 2 prior to anticipated, significant capital expenditures;
- Provide an explanation for designating any units as must-run resources, document whether the Companies have examined alternatives to the must-run designation, and perform an economic analysis of how resources designated as must-run would be dispatched in the absence of a must-run designation;
- Continue to model scenarios that use a carbon price or carbon cap to account for regulation of greenhouse gas emissions from new and existing units;
- Use alternative amounts of DSM, as either a supply-side resource or as a load modifier, for the planning period not covered an approved DSM plan;
- Ensure that evaluations of wind energy are based on the use of the latest data regarding wind turbine technologies and costs, and consider PPAs with wind projects in other states; and

- Include a forecast of customer adoption of distributed solar, and model distributed solar generation based on the latest data available on current and projected costs.

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Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of COMMENTS OF WALLACE MCMULLEN AND SIERRA CLUB is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on March 4, 2015; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that a copy of the filing in paper medium is being mailed to the Commission on March 4, 2015.

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