COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF	)	
KENTUCKY POWER COMPANY'S INTEGRATED	)	**CASE NO. 2013-00475**
RESOURCE PLANNING REPORT	)	

SIERRA CLUB'S COMMENTS ON KENTUCKY POWER COMPANY'S INTEGRATED RESOURCE PLANNING REPORT

Intervenor Sierra Club hereby comments on Kentucky Power Company's ("KPC" or "Company") 2013 Integrated Resource Planning Report ("IRP"). After decades of being almost entirely reliant on coal-fired power generation, KPC's IRP reflects important and laudatory progress that the Company is planning to make over the next few years towards having a more diverse energy portfolio. For example:

- KPC is scheduled to retire Unit 2 of the Big Sandy coal plant in 2015, which will avoid the more than 30% rate increase that would have been needed to keep that uneconomic coal unit operating.

- As a result of the retirement of Big Sandy Unit 2 and the conversion of Big Sandy Unit 1 to natural gas, KPC will no longer obtain nearly 99% of its capacity and energy from coal-fired generation.

- Following the settlement of the Mitchell Transfer Proceeding, KPC is committed to double its investment in demand side management ("DSM") from $3 million in 2013 to $6 million per year in each of 2016 through 2018.

- KPC has signaled its intent to pursue 100 megawatts ("MW") of low-cost wind resources in 2015.

Each of these steps should reduce costs and risks for KPC ratepayers, help KPC adjust to fundamental changes in today's energy markets, and enable the Company to start seizing the opportunities presented by the growing availability of low cost DSM and renewable energy resources.

Unfortunately, KPC's IRP suggests that the Company's progress is limited to the short term. In particular, under the Company's preferred resource plan:

- Fifteen years from now, 85% of KPC's energy would still be produced from fossil fuels, and 71% of KPC's capacity would still be coal-fired generation.

- While 100MW of wind capacity is assumed to be added in 2015, no additional wind resources are added through 2028.

- Energy savings from existing and future energy efficiency programs amount to only 3.2% savings by 2028.

In short, after some positive developments over the next few years, KPC's IRP suggests a disappointing return to business as usual, with the Company planning long-term overreliance on coal-fired generation and a failure to accurately assess, much less pursue, low cost and low risk DSM and renewable resource opportunities.

Such disappointing results stem from a fundamental shortcoming in KPC IRP – namely, that the Company failed to meaningfully evaluate a range of potential resource plans. As a result, the IRP does not incorporate the type of thorough and reasonable planning needed for KPC to achieve a least cost and least risk energy future.

As discussed in detail below, the IRP is a flawed document that fails to satisfy the standards of Kentucky law because, among other things:

- The portfolios modeled by KPC all involved virtually identical generation resources, rather than evaluating meaningfully different levels of DSM, solar, wind, and coal generation;

- The IRP ignores or understates the significant environmental compliance costs that the Company faces;

- The IRP failed to evaluate scenarios in which KPC declines to renew its contract with the Rockport Generation Station in Indiana, or terminates that contract in advance of its current 2022 expiration date;

- The IRP failed to evaluate a reasonable range of likely future carbon prices;

- The IRP evaluated only a single level of DSM energy savings, and improperly discounted potential demand response savings;

- KPC failed to consider bidding its energy efficiency and demand response savings into the PJM Base Residual Auction ("BRA");

- The IRP's analysis of solar generation ignores ways in which solar resources provide significant value, and relies on an unreasonable 10MW cap on the level of solar generation that can be added each year;

- KPC's preferred resource plan unreasonably fails to add any wind capacity after 2015; and

- The IRP overstates future load by unreasonably assuming that coal mining energy demand will remain steady over the planning period.

Until these serious shortcomings in KPC's IRP are remedied, the reasonableness of the Company's future actions relying on this resource planning is suspect. As such, the Commission Staff should find the IRP to be inadequate and require KPC to address each of these shortcomings in all future resource planning and decision making.

I. IRP STANDARDS

The IRP process in Kentucky is governed by 807 K.A.R 5:058, which requires KPC to submit every three years a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of KPC's system. 807 K.A.R. 5:058 Section 1(2). Core elements of the filing include:

- 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 K.A.R. 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 K.A.R. 5:058 Section 8(1).

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

As the Commission Staff stated in reviewing KPC'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[1]

The Staff has further explained that, in reviewing an IRP, its goals are to ensure that:

---

[1] Kentucky PSC, Staff Report on the 2009 Integrated Resource Plan of Kentucky Power Company, Case No. 2009-00339 (Mar. 2011), at 1 (hereinafter "2009 IRP Staff Report").

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

3. The report also includes an incremental component, noting any significant changes from Kentucky Power's most recently filed IRP.[2]

Evaluation of an IRP should also be guided by the overall requirement that utility rates are "fair, just, and reasonable." KRS § 278.030(1); KRS § 278.040; *Kentucky Public Service Com'n v. Com. 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." *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010). 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.

It is with these standards in mind that the Sierra Club offers the following comments.

II. THE IRP FAILS TO CONSIDER A REASONABLE RANGE OF RESOURCE PORTFOLIO OPTIONS.

One of the central requirements of the IRP process is that a utility develop a plan that provides "an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost." 807 KAR 5:058 Section 8; *see also id.* Section 8(4). To achieve this goal, a utility must "describe and discuss all options considered for inclusion in the plan," including an assessment of existing generation sources, potential new generation sources, and nonutility generation options. *Id.* Section 8(2). The resource plan must also "consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility." *Id.* Section 8(1). Implicit within that requirement is the notion that a utility will not limit itself to a single resource portfolio, but will instead consider alternative portfolios so "that all reasonable options for the future supply of electricity were being examined and pursued."[3]

KPC's 2013 IRP filing fails to meet these requirements in several respects. *First*, the IRP fails to consider an array of resource options but, instead, evaluates resource portfolios that each assume virtually the same mix of generating assets. *Second*, KPC compounds this error by failing to adequately assess the capital costs associated with its generating facilities. In particular, the IRP does not consider the significant capital costs associated with the installation of pollution control equipment needed to ensure that the Rockport and Mitchell coal-fired units

---

[2] *Id*. at 2-3.
[3] 2009 IRP Staff Report at 1.

meet environmental compliance requirements. The failure to consider these environmental compliance costs is not only an independent breach of the IRP rules, it also skews the IRP's financial analysis. *Third*, with respect to the Rockport Power Plant specifically, from which KPC currently purchases 393 MW (15% of the plant's capacity), the IRP improperly assumes that KPC will continue to purchase that stake throughout the entire planning period, rather than evaluating scenarios in which the Rockport contract is not renewed in 2022 or is cancelled before then.

For all of these reasons, the IRP's analysis of the costs and risks of its preferred resource portfolio and its comparison of that portfolio with alternatives fails to live up to the requirements of the IRP rules. Sierra Club therefore respectfully requests that the Commission Staff note these deficiencies in its report on the Company's IRP and call on KPC to engage in resource planning that looks at a wide range of resource options.

A. The Five Resource Portfolios Evaluated In The IRP All Consist Of Virtually The Same Mix Of Generating Assets.

As noted above, one of the central purposes of the IRP process is to consider a variety of resource portfolios and evaluate how they perform under different future conditions. 807 KAR 5:058 Section 8(2). A robust analysis of different resource alternatives helps ensure that a utility will meet the overarching goal of providing a reliable supply of electricity at the lowest possible cost. KPC's IRP fails this requirement because all of the resource portfolios considered in the IRP involve virtually the same set of generating resources.

In the IRP, the Company developed its preferred portfolio by examining five commodity pricing scenarios:

- a base case based on the vacatur of the Cross-State Air Pollution Rule ("CSAPR"), by the D.C. Circuit Court of Appeals, implementation of the Mercury and Air Toxics ("MATS") rule in 2015, an initial drop in natural gas prices, and the imposition of a price on CO_2 starting in 2022;
- a case assuming lower than expected gas prices;
- a case assuming higher than expected gas prices;
- a scenario assuming higher than expected CO_2 prices; and
- a scenario assuming no price on CO_2.

IRP at 154-56. Any potential differences in the impacts of these commodity pricing scenarios, however, were obscured by the fact that each of the resource portfolios modeled under the scenarios were virtually identical. In particular, all of the portfolios considered in the IRP assume that KPC will rely on the same existing generation assets – namely 50% of the Mitchell coal-fired power plant and 15% of the Rockport plant – throughout the planning period. *See* Resp. to SC 2-13(a)(ii); Resp. to Staff 1-33; IRP at 123. And, as discussed more fully below, every modeled portfolio assumed the same level of DSM, and capped utility solar resources at no more than 10MW per year starting in 2020. No portfolios were modeled in which Rockport and/or Mitchell were retired before 2028, in which higher levels of DSM were pursued, or in which higher levels of solar resources could be pursued.

In short, the IRP failed to consider a broad mix of "potentially cost-effective resource options," thereby limiting the Company's ability to evaluate different resource portfolios and identify the least-cost, least-risk plan for the future. 807 KAR 5:058 Section 8. Instead, the IRP created a fait accompli in which the preferred resource plan identified by KPC was essentially pre-determined. Indeed, the IRP implicitly acknowledges as such, noting that "[b]ecause much of Kentucky Power's resource portfolio is already in place, the differentiation that such different economic scenarios provided was somewhat muted." IRP at 161. But the point of an IRP process is to evaluate alternative portfolios and scenarios in order to assess whether or in what circumstances a utility should be taking a different resource approach in the future than it is today. By assuming that the resource portfolio currently in place would remain so for the entire fifteen year planning period, the Company short-circuited such assessment and undercut the primary reason for carrying out an IRP to begin with.

KPC's approach here was especially problematic because the available evidence suggests a more robust evaluation of resource options may have led to a different preferred resource portfolio. In particular, when KPC compared its preferred portfolio, which included a small amount of DSM and the 10MW maximum solar per year, to a portfolio based on the fossil-only sources and the EcoPower biomass facility, it found that "the addition of EE and solar generation, both distributed and utility-scale, worked to reduce the risk or revenue requirement volatility," IRP at 169, and that "the addition of wind, solar, and customer and grid energy efficiency resources serve to reduce overall costs." *Id.* at 170. Such results suggest that an evaluation of portfolios with increased levels of DSM, solar, and wind, and/or reduced levels of coal-fired generation would have been even lower cost and lower risk. But the IRP never investigates such a portfolio.

Because the IRP did not consider any resource portfolios without all of the existing generating assets, KPC failed to fully "consider the potential impacts of selected, key uncertainties and [] include assessment of potentially cost-effective resource options available to the utility." 807 KAR 5:058 Section 8; *see also id.* KAR 5:058 Section 8(e) ("The utility shall describe and discuss all options considered for inclusion in the plan including . . . ."). This means that the Commission, and KPC's customers, cannot be ensured that KPC is pursuing a least-cost, least-risk resource plan. The Staff should address this shortcoming by calling on KPC to evaluate and model resource portfolios that assume a range of options regarding coal plants, renewable resources, and DSM, rather than simply assuming the continued operation of existing resources for the entire planning period.

B. The IRP's Modeling Failed To Properly Account For Pollution Control Costs.

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, 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(2)(b)12, and to report, among other things, the average system rates per year. 807 KAR 5:058 Section 9(4). And because environmental compliance costs represent a significant share of a coal-fired plant's total costs, it is critical that those compliance costs be incorporated into an assessment of the resource portfolios being evaluated.

The IRP, however, failed to do so. Although the IRP purports to show the "Financial Effects" of KPC's preferred portfolio through a year-by-year breakdown of the average "rate per kWh expected to be paid by Kentucky Power customers . . . that results directly from the costs and energy consumption impacts associated with this plan," IRP at 17, these rates do not reflect the capital costs of installing the pollution control equipment that will be needed at Mitchell and Rockport during the 15-year planning period. *See* Resp. to Staff 1-33; Resp. to SC 2-13(a)(ii); Resp. to SC 2-25(d), (e) (noting that Table 7 does not include the costs of installing pollution control equipment at Rockport required by AEP's consent decree). In other words, these capital costs were omitted from the economic modeling that resulted in KPC's preferred portfolio. IRP at 17 (noting that "[t]he Financial Effects represented do not consider the prospect of . . . increases in base generation-related costs not uniquely incorporated into the planning/modeling process").

The failure to consider these environmental compliance costs is an independent breach of the IRP rules, which specifically require that such costs be considered. 807 KAR 5:058 Section 8(2)(b)12. Equally important, the omission of these capital costs from KPC's modeling likely means that the modeling results are skewed, thereby calling into question KPC's conclusion that its preferred portfolio represents the least-cost option for customers. *Cf.* 807 KAR 5:058 Section 8.

It is important to note that these omitted costs are significant: in the first three years of the planning period alone, KPC has estimated that Rockport and Mitchell will incur $79.3 million in capital environmental compliance costs, with the Rockport plant expected to incur another $42.3 million in costs for the installation of pollution control equipment during the 2017-19 timeframe. SC 2-12 Attachment 1; Resp. to SC 2-13. Moreover, the two Rockport units face the need to install flue gas desulfurization ("FGDs" or "scrubbers") in 2025 and 2028, respectively, if they are to continue operating. *See* IRP at 118, 121, 154. And, as discussed in Section II.C below, the Rockport units especially face the likelihood of larger or earlier costs due to the likely reinstatement of the federal Cross-State Air Pollution Rule ("CSAPR") and the implementation of the one-hour National Ambient Air Quality Standards ("NAAQS") for sulfur dioxide ("SO2").[4]

Nevertheless, KPC concluded that there was no need to include incremental fixed costs -- such as those resulting from the installation of pollution controls -- in its economic modeling, "[b]ecause all of the portfolios evaluated in Kentucky Power's 2013 IRP included the same existing generation assets." Resp. to SC 2-13(a)(ii). But this merely compounds the error discussed above in Part II.A above: by limiting its resource planning to scenarios that rely on the same generation assets, and by omitting the capital costs of pollution controls needed for those assets, the IRP's analysis is skewed in favor of existing (and potentially more costly) assets such as Rockport and Mitchell. The Commission Staff should reject this circular analysis.

Curiously, although the IRP modeling omits the *capital* costs of new pollution control equipment, the modeling includes the *O&M* costs of those controls once installed. *See* Resp. to SC 2-25(b); Resp. to Staff 1-33 (stating that the modeling "takes into account all variable costs and the incremental fixed costs that vary among the resource portfolios").[5] While such O&M costs should be included in the modeling, the inclusion of these costs merely underscores the inappropriateness of omitting the capital costs of pollution control equipment in identifying the revenue requirements and rate impacts of KPC's preferred resource portfolio.

The Commission Staff should remedy this shortcoming by requiring KPC to incorporate all reasonably foreseeable future capital costs (including both environmental and non-environmental capital investments) into its assessment of the revenue requirements and rate impacts of the resource portfolios being evaluated in the IRP.

---

[4] In this respect, the IRP has failed to adequately address one of the recommendations of the Commission Staff from KPC's last IRP. The Staff noted that "the possibility of either federal emissions-limiting legislation or targeted EPA actions limiting various emissions may have significant impacts on Kentucky Power's service territory," and directed KPC to "explicitly account for potential federal legislation imposing stricter emissions limits on its generation in its forecasts and risk analysis." IRP at 53. The Staff further stated that "[p]otential EPA actions limiting emissions should also be explicitly accounted for in the forecasts and risk analysis." *Id.* Despite these admonitions, the IRP fails to fully address environmental compliance costs, omitting them from the modeling performed to develop its preferred portfolios. *See* Resp. to SC 2-13(a)(ii); *see also* IRP at 53 (asserting that the "Company's risk analysis for its resource portfolio considers the impacts of various Federal mandates, but conceding that "[t]he timing and impact of specific rules and regulations have not been evaluated").

[5] At the Informal Conference held on April 16, 2014, Sierra Club queried KPC about this issue, and KPC stated that the O&M costs associated with pollution control equipment were included in the modeling.

C. The IRP Should Have Evaluated Scenarios In Which KPC Ends Its Interest In The Rockport Power Plant In 2022 Or Earlier.

KPC's failure to evaluate portfolios with different mixes of generation resources skews, among other things, the IRP's treatment of the Rockport Power Plant in Indiana. All of the resource scenarios considered in the IRP, including the preferred portfolio, assume that KPC will continue to purchase 15% of the Rockport plant's power – representing 393 MW of capacity – throughout the entire 15-year planning period. IRP at 5-6; *see also id.* at 123 ("For planning purposes, it has been assumed that the Rockport agreements extend indefinitely beyond [the 2022] expiration date."). Thus, in addition to maintaining its current agreement to purchase 15% of Rockport's output, the IRP assumed that KPC would renew this purchase agreement, such that KPC would continue to rely on Rockport beyond the planning period. *Id.* at 6. Although KPC's continued reliance on Rockport is an assumption that undergirds the IRP planning process, KPC's resource portfolio fails to account for the future environmental compliance costs facing this plant. Nor does the IRP adequately address the potential uncertainties of higher compliance costs than those already anticipated by the Company.

Rather than assume continued purchases of Rockport for the next 15 years, the Company should be evaluating, and planning for, the possibility of terminating the Rockport contract prior to December 2022. And even if KPC decides not to terminate that contract early, the Company should still be evaluating resource scenarios that do not include energy from Rockport for the last six years of the IRP planning period. These steps are necessary to ensure that KPC has identified the least-cost least-risk resource plan, because Rockport faces significant known environmental compliance costs and potentially even higher costs as discussed below.

1. Costs Associated with the MATS Rule and NSR Consent Decree.

As the IRP acknowledged, Rockport will face substantial environmental compliance costs in the coming years due to (a) EPA's implementation of the Mercury and Air Toxics ("MATS") rule and (b) the terms of AEP's New Source Review ("NSR") consent decree. To comply with these mandates, the Rockport plant must be retrofitted with an array of pollution equipment, including:

- By April 16, 2015, the Rockport units must be retrofitted with dry sorbent injection ("DSI") technology and an associated landfill to control mercury emissions. IRP at 117-18; Resp. to SC 2-12(c);

- By December 31, 2017 and December 31, 2019, the Rockport units must be retrofitted with selective catalytic reduction ("SCR") systems to control NOx emissions, IRP at 118; and

- By December 31, 2025, and December 31, 2028, the Rockport units must be retrofitted with flue gas desulfurization ("FGD") systems to control SO2 emissions, IRP at 118.

Under the consent decree, the Rockport units are also subject to an annual SO2 cap, in which SO2 emissions from the plant must be steadily decreased over the IRP planning period. Thus, for example, whereas Rockport will be subject to an annual cap of 28,000 tons of SO2 starting in 2016, that limit will drop to 22,000 tons starting in 2020, and 18,000 tons starting in 2026. IRP at 119.

Collectively, the costs of these pollution control requirements will be significant. The MATS rule, NSR consent decree, and other regulatory requirements at Rockport are expected to cost KPC nearly $38.5 million during the 2014-16 timeframe. SC 2-12 Attachment 1. And KPC estimates that it will be responsible for $42.3 million in compliance costs over 2017-19 due to the installation of SCRs. Resp. to SC 2-13. In addition, these compliance costs will likely pale in comparison to the cost of installing FGD systems at the Rockport in 2025 and 2028. As KPC's December 2011 proposal in PSC Case No. 2011-00401 to install a scrubber on Big Sandy Unit 2 demonstrated, an FGD can cost nearly a billion dollars, and Rockport needs two of them. Even though KPC's share of the Rockport plants is only 15%, that does not excuse KPC's obligation to factor its portion of those costs into an evaluation of whether continuing to purchase 393MW of capacity from Rockport for the entire planning process is reasonably part of a least-cost, least-risk portfolio.

2. Costs Associated With the Cross-State Air Pollution Rule ("CSAPR").

In addition to compliance costs from the existing MATS rule and NSR consent decree, the Rockport plant faces the strong possibility of additional costs from other likely environmental standards that are erroneously ignored in the IRP. Perhaps most significantly, the IRP fails to address the impact on the Company's preferred resource plan from the likely reinstatement of CSAPR.[6]

On April 29, 2014, the U.S. Supreme Court reversed the lower court decision vacating CSAPR. *See U.S. EPA v. EME Homer City Generation, LP*, Nos. Nos. 12–1182, 12–1183, 2014 WL 1672044 (U.S. Apr. 29, 2014). The Court's decision will likely result in the reinstatement of this EPA regulation. Although KPC was aware that the Supreme Court would be ruling on this issue in 2014, IRP at 116, the IRP did not attempt to analyze the impact that a reinstated CSAPR might have on the Rockport plant's future costs. Thus, for example, the IRP lacks any analysis of whether a reinstated CSAPR would force an acceleration of the projected timeline for installing air pollution controls at Rockport (DSI in 2015; SCR in 2018/2020; FGD in

---

[6] *See* SCOTUSblog, *Environmental Protection Agency v. EME Homer City Generation*, Docket No. 12-1182, *at* http://www.scotusblog.com/case-files/cases/environmental-protection-agency-v-eme-homer-city-generation/.

2025/2028).[7] The IRP similarly does not address whether the DSI systems that will be installed at Rockport in 2015 to comply with MATS and the NSR Consent Decree will enable the plant to comply with CSAPR's SO2 requirements if CSAPR is reinstated, or if (as KPC's affiliate I&M found in 2011) compliance with CSAPR at Rockport would require installing an SCR system on at least one Rockport unit in the near future. Instead, all of KPC's resource scenarios assumed that CSAPR would remain vacated. *See* IRP at 154 (noting that the base "case recognizes the vacatur of CSAPR by decision of the U.S. Court of Appeals"). And KPC prepared no cost estimates or other assessments evaluating the costs that Rockport could face if CSAPR were reinstated or replaced by EPA. When Sierra Club sought further clarification of the SO2 and NOx emissions reductions that might be necessary should CSAPR be reinstated, KPC failed to quantify them, simply asserting that "[t]he level of reductions necessary would have been determined by the availability and price of CSAPR allowances in the market at the time they were needed." Resp. to SC 2-11(a).

Even if CSAPR's likely reinstatement does not impact the timing of environmental retrofits at Rockport, at a minimum the imposition of a more stringent rule governing interstate transport of air pollution would likely increase the cost to KPC of any purchases of SO2 or NOx emission allowances need to comply with CSAPR. Yet the Company does not evaluate these possible future costs and risks at all in the IRP.

3. Costs Associated With the 1-Hour SO2 NAAQS.

Another potential compliance cost facing the Rockport plant stems from EPA's recent revision of the one-hour NAAQS for SO2, and the strong likelihood that additional SO2 emission reductions from Rockport will be needed to avoid exceedances of that NAAQS. Although the IRP includes a cursory mention of these new SO2 NAAQS, *see* IRP at 121, KPC failed to address the possible future costs and risks to its preferred portfolio that could result from implementation of the new standard. Instead, the IRP simply noted that "[t]he scope and timing of potential requirements is uncertain." *Id.* But the way to address such uncertainty is to evaluate a range of reasonable options regarding the types and timing of controls that the NAAQS could lead to, rather than pretending as if the Rockport plant will not face any additional compliance costs related to the NAAQS.

In 2010, EPA promulgated stringent NAAQS requiring ambient SO2 concentrations of less than 75 ppb over one-hour averaging periods; EPA found this limit necessary to protect public health because exposure to even small amounts of SO2 over short periods of time can

---

[7] By contrast, in 2011, before CSAPR was stayed by a federal appeals court, KPC's affiliate I&M found that CSAPR could have very significant impacts on the Rockport plant. I&M requested that Indiana's Utility Regulatory Commission ("IURC") issue a Certificate of Public Convenience and Necessity to install both FGD and SCR on one of the Rockport units to comply with CSAPR and MATS. *See* IURC, Cause No. 44033, Direct Testimony of Paul Chodak III & Scott C. Weaver (Aug. 1, 2011), available at: https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b63180170fd7.

cause adverse health effects.[8] While NAAQS are not emission limitations on individual sources, they impact emission limitations because states are required to develop plans to implement the NAAQS in areas that exceed the required concentrations ("nonattainment areas").[9] EPA's most recent SO2 NAAQS implementation strategy would require states to complete all SO2 NAAQS implementation plans by 2019 or 2022, with corresponding deadlines for bringing any non-attainment areas back into attainment (through measures such as more stringent emissions limits on individual sources) by 2022 or 2025, respectively. The earlier schedule applies to areas designated nonattainment through modeling, while the later schedule applies to areas designated through monitoring.[10] Even before non-attainment designations are completed and state implementation plans approved, major sources of SO2 emissions such as the Rockport plant may also be subject to emission limits ensuring compliance with the one-hour SO2 NAAQS if they are found to contribute significantly to violations of NAAQS in other states,[11] or in connection with seeking approval for any physical modifications at the facility that would cause a significant emissions increase.[12] In short, there are multiple legal mechanisms, and potential timeframes, under which the Rockport plant may be subject to emission limits designed to ensure that the SO2 NAAQS is not violated.

The current emission control plans for Rockport would not ensure compliance with the one-hour SO2 NAAQS until at least 2025, if not 2028. Those are the years in which KPC's affiliate, Indiana and Michigan Power ("I&M"), plans to install the FGD systems per the requirements of the NSR consent decree. *See* IRP at 118. In 2015, I&M plans to add cheaper, less effective dry sorbent injection ("DSI") SO2 controls to both Rockport units as a stopgap attempt to comply with the MATS rule and the NSR consent decree. *See* IRP at __. Even assuming that DSI enables Rockport to comply with the MATS rule and the NSR consent decree, this equipment does not ensure that Rockport will not cause violations of the one-hour SO2 NAAQS. And nothing in the NSR consent decree addresses what types of controls or levels of emission reductions would be needed to achieve to ensure that Rockport complies with the 1-hour SO2 NAAQS. *See United States of America v. Am. Elec. Power Serv. Corp.*, Civil Action No. C2-99-1182 (S.D. Ohio May 14, 2013).

In fact, modeling has shown that Rockport will likely cause violations of the one-hour SO2 NAAQS in surrounding parts of Indiana and Kentucky until Rockport installs FGD, a period of more than 10 years. In a report dated December 10, 2012, expert air quality modeler Camille Sears concluded, using EPA's AERMOD air dispersion model, that Rockport's SO2 emissions will violate the one-hour NAAQS and may result in EPA's designation of the surrounding area as nonattainment even if Rockport is retrofitted with DSI controls with 50%

---

[8] *See* Primary National Ambient Air Quality Standard for Sulfur Dioxide, 75 Fed. Reg. 35,520 (June 22, 2010) (to be codified at 40 C.F.R. pt. 50).
[9] *See* 42 U.S.C. § 7410(a).
[10] *See* U.S. EPA, Next Steps for Area Designations and Implementation of the Sulfur Dioxide National Ambient Air Quality Standard at 5 (Feb. 6, 2013), *available at* http://www.epa.gov/airquality/sulfurdioxide/pdfs/20130207SO2StrategyPaper.pdf.
[11] 42 U.S.C. §§ 7410(a)(2)(D)(ii), 7426(b)-(c).
[12] 40 C.F.R. § 52.21(k).

SO2 control efficiency.[13] Even after DSI controls are added, Sears's report projects peak ambient SO2 concentrations of up to 145% of the one-hour NAAQS.[14] Furthermore, Sears's modeling showed that Rockport would need to install SO2 controls with an efficiency rate of at least 82% to ensure compliance with the NAAQS.[15] Consistent with this finding, modeling showed no violations of the one-hour SO2 NAAQS at Rockport with 95% efficient FGD on both units.[16]

KPC does not refute the modeling results in its IRP materials, asserting instead that "the scope and timing of potential [NAAQS-related] requirements is uncertain." IRP at 121. Put differently, the Company is gambling that the one-hour SO2 NAAQS will not be enforced at the Rockport plant until at least 2025, if not 2028. This approach imprudently dismisses both the economic and health risks associated with the Company's preferred portfolio, and puts the portfolio at an unrealistic advantage as compared with alternative portfolios that KPC should have considered, such as one in which KPC terminated the Rockport contract early or elected not to renew that contract after 2022. Either of these alternatives could have reduced the risks to KPC's ratepayers of unexpected increases in environmental compliance costs and, therefore, should have been evaluated as part of this IRP process.

4. Costs Associated With the ELG and CCR rules.

Although it provides some aggregate figures for the first three years of the planning period, the IRP does not fully disclose KPC's assumed capital expenditures at the Rockport plant that will likely be necessitated by EPA's proposed effluent limitation guidelines for wastewater discharges from steam electric sources (ELG rule) and EPA's proposed rule for handling coal combustion residuals (CCR rule).[17] *See* Resp. to SC 2-12 Attachment 1 (estimating $769,000 in compliance costs in 2016). The amount of and basis for KPC's assumed capital expenditures to satisfy these regulatory should have been fully considered in the IRP. Under the IRP rules, a utility must not only provide actual data and projections of capital costs at the start of the planning period, it must also provide estimates of capital and variable costs for the entire 15-year period. 807 KAR 5:058 Section 8(3)(b)(12).

KPC acknowledges that the ELG and CCR rules will require capital expenditures for projects at its coal-fired units. For example, KPC anticipates that the CCR rule "would require plant modifications and capital expenditures (which are factored into this IRP) to address these requirements by, approximately, the 2018 timeframe." IRP at 120. And as a result of the upcoming ELG rule, KPC "anticipates that wastewater treatment projects will be necessary at the

---

[13] *See* Camille Sears, Air Dispersion Modeling Analysis for Verifying Compliance with the One-Hour SO2 NAAQS: AEP – Rockport Power Plant at 12, attached as Exhibit A.
[14] *Id.* at 12.
[15] *Id.* at 11.
[16] *Id.*
[17] *See* Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Source Category, 78 Fed. Reg. 34,432 (June 7, 2013); Disposal of Coal Combustion Residuals from Electric Utilities, 75 Fed. Reg. 35,128 (June 21, 2010).

Rockport and Mitchell units and these have been considered as part of the respective long-term unit evaluations." *Id.* But KPC does not identify, let alone quantify, its assumptions concerning these expenditures in the IRP, some of which may be significant. As a result, the Commission and interested parties have no way to determine whether the Company's estimates are reasonable, or whether they have been appropriately factored into the resource portfolios.

For example, EPA's proposed ELG includes some regulatory options that would require the Company to retrofit its bottom ash handling at Rockport to a dry handling or closed loop system that would result in zero discharge of bottom ash sluice water.[18] EPA estimates that, on average, each plant undertaking such a retrofit would incur $17 million in capital costs and $2 million in annual O&M costs.[19] Moreover, these costs may be larger for a 2,600 MW power plant such as Rockport than the average plant costs estimated by EPA. KPC's IRP filing, however, contains no discussion of whether the Company factored into its IRP modeling the risk that it will have to meet these significant additional compliance costs at Rockport or took any steps to evaluate what the costs of a bottom ash retrofit would be for the plant. And when the Commission Staff sought further clarification of these future costs, KPC provided no information beyond 2016, simply noting that "any estimates of future compliance costs, and the timing of those investments, is highly uncertain." Resp. to Staff 1-33.

5. Costs Associated With Carbon Regulations.

KPC's fossil-fuel generating resources, including Rockport, will likely incur significant costs due to the implementation of GHG regulations. Even accepting KPC's assumptions about the timing and magnitude of a carbon price, the shortcomings of which are discussed in Section III below, Rockport would face substantial compliance costs. Under the IRP's base case for CO_2 pricing, KPC's customers will face $525 million in costs between 2014-2040. IRP at 169-70. As the second largest source of CO_2 emissions in KPC's portfolio, Rockport will represent a meaningful proportion of those costs.

6. Recommendation Regarding Rockport.

The Commission Staff should ensure that future options regarding KPC's share of the Rockport plant are fully evaluated by calling on KPC to provide a full accounting of potential environmental costs facing the plant, and to evaluate resource portfolios in which KPC does not renew its Rockport contract in 2022 and/or ends that contract early.

[18] 78 Fed. Reg. at 34,458.
[19] EPA, Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 9-40 (Apr. 2013), Docket No. EPA-HQ-LW-2008-0819-2257, *available at* http://water.epa.gov/scitech/wastetech/guide/steam-electric/upload/Steam-Electric_TDD_Proposed-rule_2013.pdf.

III. THE IRP FAILS TO ROBUSTLY ANALYZE LIKELY FUTURE CARBON PRICES.

With a preferred resource plan that continues to have 85% of its energy coming from fossil fuels, and 71% of its capacity being coal plants for the next fifteen years, KPC has significant exposure to likely future carbon regulation. To its credit, KPC factored a carbon price into its analysis in this IRP. Given the ongoing efforts of the U.S. Environmental Protection Agency ("EPA") to regulate greenhouse gas ("GHG") pollution, building this assumption into the IRP is necessary to ensure that the resource portfolios accurately estimate the costs of carbon-intensive generating facilities such as coal-fired power plants. Assuming a future price on carbon is also consistent with the terms of KPC's recently-approved settlement in Case No. 2012-00578. Under that settlement agreement, KPC is required to file, as part of its IRPs, "an economic analysis of all generating unit costs, including the costs of complying with greenhouse gas emission regulation." Order, Case No. 2012-00578, at 34 (Oct. 7, 2013); *see also id.*, Appx. A ¶ 21(c) (Stipulation and Settlement Agreement).

But although KPC's assumption of a carbon price is an important first step, its analysis still falls short of IRP requirements. Specifically, by evaluating only a narrow range of fairly low carbon prices that do not begin until 2022 and decline over time, the IRP underestimates the potential cost of carbon regulation to a system that continues to be over-reliant on fossil fuels, and the benefits of pursuing low carbon resources such as DSM, wind, and solar. In particular, the IRP's carbon pricing assumptions fall short in two fundamental respects. First, all of the commodity pricing scenarios examined in the IRP, which were used to develop KPC's preferred portfolio, assume an unreasonably low and small range of potential carbon prices. Second, the IRP fails to consider the potential that a carbon price would take effect prior to the 2022 date assumed by KPC. IRP at 16, 121-22, 154-56.

A. The IRP Failed To Consider A Reasonable Range Of Likely Carbon Prices.

The IRP contains no serious evaluation of the sensitivity of alternative resource portfolios to potential carbon prices. Despite recent developments in federal greenhouse gas policies, KPC assumes that the cost of CO2 will "stay within the $15-20/metric ton range over the long-term analysis period."[20] IRP at ES-2. KPC's three main commodity pricing scenarios for evaluating alternative resource portfolios in its 2013 IRP assume a nominal carbon price of $15/metric ton. Resp. to SC 1-32(c); IRP at 157. In terms of real dollars, KPC assumes that a carbon price, once established in 2022, will decrease over the remaining six years in the planning period. *See id.* at 157 (showing that the assumed price of carbon, in 2011 dollars, will fall slightly between 2022 and 2028). Although the IRP does include one scenario assuming a zero carbon cost and one assuming a $25/metric ton cost, *id.* at 156, usch a narrow and low range of carbon prices fails to reflect the potential impacts that carbon regulations could have on KPC.

---

[20] KPC does not specify, but this price appears to be given in nominal dollars; the commodity price graph in Figure 19 of the IRP show the prices KPC assumed for CO_2 in 2011 dollars. *See* IRP at 157. Under the base case, the CO2 price in 2011 dollars starts at approximately $11/metric ton in the year 2022 and gradually *drops* in the following years. *Id.*

A more reasonable and supported estimate of future carbon prices has been published and regularly updated by Synapse Energy Economics ("Synapse"). Synapse projects three levels of carbon prices based on its evaluation of regulatory developments, the carbon price used to assess the climate benefit of federal rulemakings, carbon forecasts in IRPs from 28 utilities, and the results of a multi-year Energy Modeling Forum ("EMF") research effort on the costs of U.S. emissions abatement.[21] In its November 2013 update, Synapse published low, mid, and high cases for the years 2020-2040.[22]

Synapse's low case is based on the type of scenario KPC believes is most likely: one in which federal policies to limit greenhouse gases exist, but are not stringent.[23] Yet, Synapse's low case forecasts a price of $10/ton beginning in 2020, increasing to $13/ton in 2022 and $22/ton in 2028 (2012 dollars), expressed in American tons.[24] By contrast, KPC's assumed $15/metric ton (nominal dollars) carbon price, expressed in the same units, would yield a price of approximately $11/ton that would take effect in 2022, with a slight decrease in the carbon price over the following six years. IRP at 157. Thus, Synapse's low price forecast begins two years earlier than KPC's, is approximately $2 higher in 2022, rises during the planning period, and finishes at approximately $10/ton more than what KPC considers likely.

Synapse's mid case represents a future in which federal policies implement more ambitious but "reasonably achievable" goals.[25] In this forecast, CO2 costs $15/ton in 2020 and increases steadily to reach $19.50/ton by 2022 and $33/ton in 2028.[26] Again, these prices begin two years earlier. Synapse's high case assumes that "somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions" will influence the CO2 price.[27] Synapse's high case forecast begins at $25/ton in 2020, reaches $31.50 by 2022, and reaches $51 by 2028.[28] Thus, Synapse's high case forecast results in a carbon price approximately three times greater than the High CO_2 case modeled in the IRP. *Cf.* IRP at 156, 157.

KPC's carbon price assumptions ignore more than Synapse's forecast. Other utilities have recognized that carbon prices pose serious risks that their IRP processes should take into

---

[21] Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast* (Nov. 1, 2013) [hereinafter Synapse 2013 Carbon Price Forecast], *available at* http://www.synapse-energy.com/Downloads/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf.
[22] *See id.* at 20, Table 1.
[23] *Id*.
[24] *See* Synapse 2013 Carbon Price Forecast, at 20, Table 1.
[25] *Id.* at 3.
[26] *Id.* at 20, Table 1.
[27] *Id.* at 3.
[28] *Id.* at 20, Tbl. 1.

account. Of the 29 high case forecasts from utility planning processes in 2012-2013 that Synapse reviewed, all but three modeled prices higher than $20/ton (American tons, 2012 dollars) after 2022.[29] The list includes Duke Energy Indiana, which has a carbon price in its reference case that begins at $17/ton in 2020 and rises to $50/ton by 2033.[30] In addition, the vast majority of the IRPs cited in the Synapse report assume that carbon prices will rise over time, in contrast to KPC's assumption that they will gradually decline.

B. The IRP Should Evaluate The Potential For A Carbon Price To Go Into Effect Earlier Than 2022.

KPC assumes that any price on carbon will not go into effect until 2022. IRP at 154-56. The IRP itself does not clearly identify the basis for this assumption, and KPC's data request responses offer varying rationales for this assumption. *Compare* Resp. to SC 1-32(a) (justifying 2022 start date based on the unlikelihood of near-term congressional action) *with* Resp. to SC 2-16(c) (justifying start date based on assumption that EPA regulations will not be implemented until 2022).

Regardless of its rationale, KPC's assumption that CO_2 will not be regulated until 2022 does not appear reasonable in light of recent developments that confirm the Obama Administration's intention to finalize and implement new GHG regulations for existing sources within the next two years. On June 25, 2013 (approximately six months before KPC submitted its IRP), 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.[31] Moreover, the guidelines for existing power plants must include a requirement that States submit their implementation plans to EPA no later than June 30, 2016.[32]

The President's announcement only 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 the EPA must decide whether greenhouse gases endanger public health.[33] After analyzing the available climate science, the EPA issued a formal finding that current and projected emissions of six greenhouse gases, including CO2, threaten the public health and welfare of current and

---

[29] *Id.* at 25, Fig. 8.

[30] *Id.* at 17, Fig. 2; *see also id.* at 16.

[31] *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.

[32] *Id.*

[33] *Massachusetts v. Envtl. Prot. Agency*, 127 S. Ct. 1438, 1462–63 (2007).

future generations. This finding has since been upheld by the U.S. Court of Appeals for the District of Columbia Circuit.[34] That court also confirmed that the Clean Air Act requires the EPA to address greenhouse gas emissions under its stationary source permitting programs.[35] 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.[36]

While the precise details of these rules are still uncertain, it is clear that utilities will need to meet new regulatory requirements (and their associated costs) in the near future. Therefore, at a minimum, KPC should have considered scenarios in which there is an effective price on carbon emissions earlier than 2022.

C. Recommendation Regarding Carbon Prices.

In order to help ensure that the risks of KPC's proposed fossil fuel heavy future and the benefits of pursuing low-carbon renewable and DSM options are fully accounted for, the Commission Staff should recommend that KPC evaluate in its resource planning a range of carbon prices similar to those set forth by Synapse.

IV. KPC FAILS TO ADEQUATELY EVALUATE ENERGY EFFICIENCY IN THE LONG-TERM AND UNDERESTIMATES THE POTENTIAL FOR INCREASED SAVINGS.

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. As KPC observed in its IRP, energy efficiency is a readily deployable, relatively low cost, and clean energy resource that provides many benefits and reduces portfolio risk. (IRP at 88, 169). 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, PSC Order September 30,2010, p. 14; *see also* Case No. 2010-00222, PSC Order, February 17, 2011, p. 15; Case No. 2008-00408, PSC Order October 6, 2011, p. 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

---

[34] *See Coal. for Responsible Regulation v. Envtl. Prot. Agency*, 684 F.3d 102, 120–22 (D.C. Cir. 2012).
[35] *Id*. at 134–36.
[36] *See* 42 U.S.C. § 7411(b) & (d).

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 5:05 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 5058)." (Case No. 2008-00408, PSC Order, July 24, 2012, p. 10). In so doing, the Commission has affirmed "its support for greater energy efficiency." (*Id.)*

Although KPC's IRP reflects increased DSM investment in the near term pursuant to the Mitchell Transfer Stipulation, the plan fails to adequately evaluate and pursue the energy efficiency resource during the planning period and, as such, fails to meet the requirements set out in the IRP standard. The Company projects that incremental savings from existing demand-side programs end roughly midway through the planning period, and annual growth of new efficiency programs remains flat from 2016-2022 and then declines. Overall, this leads to a declining rate of efficiency growth during the IRP period. Critically, and as mentioned above, the IRP fails to model any variation in the level of DSM savings in the five scenarios it evaluated, thereby foreclosing consideration of a higher level of DSM resources. Moreover, the Company does not sufficiently explain or justify the restriction it imposed to arrive at the selected amount in its Preferred Portfolio. This is especially troubling because the Company's projected savings remain low, in large part due to its assumptions that federal lighting standards eliminate much of the future cost-effective savings opportunities and its failure to account for the substantial savings opportunity in the energy-intensive industrial sector.

A. KPC's IRP Reflects a Commitment to Increase its Energy Efficiency Investment in the Near Term.

KPC projects the largest period of growth in terms of energy savings in the first three years of the planning period. This increase in DSM investment is the result of the Company's obligation to ramp up its annual spending on cost-effective DSM to $6 million by 2016. In the Mitchell transfer proceeding, Case No. 2012-00578, KPC, Sierra Club and Kentucky Industrial Utility Customers, Inc. entered into a Stipulation and Settlement Agreement ("Stipulation"), which provides, among other things, that:

> KPC agrees to increase its aggregate annual spending on cost-effective DSM and energy efficiency measures through Commission-approved DSM programs to $4 million in 2014; $5 million in 2015; and $6 million in 2016, 2017, and 2018. The Company also will seek to maintain a minimum spending level of $6 million for Commission-approved cost-effective DSM and energy efficiency measures in years after 2018.

October 7, 2013 Order, Appendix A, ¶12, Case No. 2012-00578. The Commission approved the Stipulation subject to several modifications, including the requirement that the Company seek prior Commission approval should it want to spend less than $6 million on DSM or energy efficiency programs after 2018, *id.* at Appendix B, ¶4, and the Company accepted the modifications on October 14, 2013.

In its pending application to amend its 2014 DSM Plan, which is before the Commission in Case No. 2013-000487, KPC seeks to comply with the first required increase in DSM investments. Specifically, the Company has proposed an expanded 2014 DSM portfolio with an estimated annual cost of $4,115,956 in direct program expenses, which represents a roughly 58% increase over 2013 direct program expenses. As Sierra Club noted in comments filed in that case, although KPC's 2014 projected energy savings remains low and further DSM program improvements and additions should be implemented, the Company's increased DSM investment is expected to enhance program participation in several existing programs in the near term, and is a step in the right direction. (Sierra Club Comments at 2, Case No. 2013-00487).

Recognizing the benefit of energy efficiency, the Commission has "strongly encourage[d] Kentucky Power to promote its DSM programs, educate applicable customers who would qualify for DSM program participation, and work to increase participation levels in its DSM programs."[37] The increase in DSM investments required by the Stipulation, and resultant expansion of certain existing programs and projected increase in new efficiency resources, provides KPC with an opportunity to accomplish all of these tasks and increase energy savings through DSM.

B. KPC Did Not Consider Higher Levels of Energy Efficiency and its Modeling Assumptions Constrain the Growth of this Resource in the Long Term.

Although KPC plans to ramp up its efficiency investment in the near term, the IRP fails to adequately integrate efficiency throughout the planning period. KPC evaluated two categories of DSM impacts in its IRP, "existing programs" and "future impacts." IRP at 85. The impacts of existing programs are embedded in the Company's load forecast whereas impacts from future programs are reflected as incremental savings estimated through modeling. (*Id.).* While KPC projects the continued growth of the efficiency resource, the savings achieved from approved programs ends in 2022 and the growth of future programs flattens and then declines for most of the planning period. (*See* IRP at 61, 101 and Resp. to Staff 2-18, Attachment 2).[38]

KPC incorporates existing programs into its IRP by adjusting its load forecast to account for the program impacts. While forecasts must include the utility's estimates of existing and continuing demand-side programs, 807 KAR 5:058 Section7(3), existing resources should be allowed to increase based on need. Here, the Company did not specifically evaluate an expansion of current programs. (KPC Resp. to SC 1-11). This is surprising given the Company's position that the required increased investment in cost-effective DSM will come from existing

---

[37] *In re Application of Kentucky Power Co.*, KPSC Case No. 2011-00300 (Jan. 23, 2012).
[38] Although Figure 10 (IRP at 101) depicts steady incremental savings of 10 GWh in 2016-2028, Attachment 2 to KPC's response to Staff's Request No. 2-18 shows a steady decrease in incremental savings from 10 GWh in 2022 to 3 GWh in 2028.

programs, at least initially. (IRP at 18) ("In the near term, an expansion of current programs is the most practical way to adhere to the stipulated settlement agreement."). As the Company recognized, the impacts of the approved efficiency program are "relatively minor and do not significantly affect the long-term load growth rates." (IRP at 9). Thus, the Company should continue to look for ways to expand and improve current program offerings (beyond the pending proposal in the 2014 DSM docket) in addition to developing new programs.

The Company models future efficiency impacts from new programs using generic cost and impact data. Specifically, KPC utilizes an optimization model, Plexos® Linear Program, to develop a least cost resource plan that includes "the appropriate level" of additional demand-side resources. (IRP at ES-3). While modeling additional demand-side resources as "demand-side power plants," IRP at 138, can facilitate comparable treatment to supply-side alternatives, the Company appears to have assumed a single level of DSM resources in each of the five economic scenarios studies. (IRP at 100, 165). Higher levels of DSM were not evaluated. KPC asserts that "[o]ptimization under the five economic scenarios yielded five unique resource portfolios." (IRP at 161). However, this is not accurate with respect to DSM. Rather, KPC did not model *any* variation in DSM and, as a result did not conduct a comprehensive analysis of DSM options consistent with least cost planning recognized in the Commission's integrated resource planning standards. As discussed above, an IRP should consider a variety of resource portfolios and evaluate how they perform under different future conditions. *See* 807 K.A.R. 5:058 Section 8(2). In evaluating only one potential efficiency future, KPC's IRP falls short.

1. KPC's Assertion of "Realistically Achievable Levels" of Savings is not Adequately Supported.

KPC limited the addition of new efficiency resources – incremental to those included in the Company's load forecast – to what it called "realistically achievable levels" in each year. (IRP at 153). KPC asserts that efficiency resources "optimized in equal amounts under all five economic scenarios." (*Id.* at 100). The IRP includes a brief discussion of the "assessment of achievable potential," *id.* at 87, however, it is unclear from that discussion how the Company arrived at the ceiling it placed on new efficiency. As the Company admits in discovery, "[n]o assessment of EE potential was performed by or for the Company." (KPC Resp. to SC 1-14). Indeed, the Company has not performed a market potential study in the last five years. (Sierra Club Comments at 10, Case No. 2013-00487).

The Company's limited discussion of achievable potential underscores the need for a comprehensive assessment of the potential for efficiency savings in the KPC service territory. Fortunately, in its 2014 DSM Plan, the Company has proposed to conduct a market potential study to support its DSM strategy and resource deployment over a ten-year planning period. A potential study is a quantitative analysis of the amount of energy savings that exists, is cost-effective, and/or could be realized by implementing energy efficiency programs and policies.[39] Such studies have long been used as an effective tool to assess the efficiency resource and help develop program plans.[40] As noted in comments in the DSM docket, Sierra Club strongly supports the Company's proposal to conduct a market potential study.

2. KPC's Incremental Energy Efficiency Cost Assumptions Appear Unreasonably High.

KPC modeled additional energy efficiency resources based on measure and cost assumptions that it derived from Efficiency Vermont data. (IRP at 95). KPC "adapted" the Efficiency Vermont data to "fit the climate of Kentucky." (*Id.).* However, the result is incremental cost assumptions that appear to be out of step with the cost of efficiency across the country.

In Table 12 of the IRP (p. 108), KPC presents its assumptions of the costs of the additional efficiency resource options it considered. At the outset, it is important to note that the "$/first year savings" cost metric that KPC presents, also called "energy efficiency acquisition costs," represents the annual cost to administer an efficiency measure/program (or install a resource) divided by the first year of savings that the installed measures produce.[41] However, the savings for a given installed measure will continue to accrue throughout the life of the measure. By capturing only first-year savings, this metric of incremental efficiency costs does not reflect the full value of investments in energy efficiency and "thus misrepresent[s] the full benefits of efficiency."[42] As such, the cost per first-year savings is not comparable to the cost of generating electricity ($/MWh) and should not be used to compare demand- and supply-side resources.

Instead, for a comparison to supply-side resources, it is widely accepted that the levelized cost of energy efficiency (or electricity saved) over the measure life of savings should be used. This apples-to-apples comparison shows the clear benefit of efficiency. For example, two recent national studies found that energy efficiency has an average levelized cost of 2-3 cents per kWh,

---

[39] National Action Plan for Energy Efficiency, *Guide for Conducting Energy Efficiency Potential Studies*, prepared by Optimal Energy, Inc., p. 2-1, (Nov. 2007), available at http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.
[40] *Id.* at ES-1.
[41] *See* Maggie Molina, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs ("National Review of the Cost of Utility Energy Efficiency Programs"), p. 8, ACEEE (Mar. 2014), available at http://www.aceee.org/research-report/u1402.
[42] *Id.*

as compared to 6.5-14.5 cents per kWh for coal and 6-9 cents per kWh for natural gas.[43] This national trend is reflected in KPC's service territory. KPC's average cost of energy savings from 2009-2011 was 2.7 cents/kWh and its annual cost of savings decreased in 2012 and 2013 to 2.6 cents/kwh and 1.9 cents/kWh, respectively. (KPC Resp. to Staff 3-1, Docket No. 2013-00487).

KPC's "$/first year savings" cost assumptions for efficiency additions range from $158 - $1,654/MWh for commercial and $453-$1,156/MWh for residential measures, with total first-year cost of $873/MWh and $545/MWh, respectively. IRP at 108. KPC appears to have adjusted the Efficiency Vermont data to account for different heating and cooling days and for its assumptions regarding the limits of lighting measures going forward. (KPC Resp. to SC 1-19; Informal Conference). However, the resultant assumptions of incremental efficiency resource costs appear high in comparison to estimates from other states. For example, the four-year average (2009-2012) of electric efficiency program first-year acquisition costs from 20 states across the country is $230 per first-year MWh.[44] Efficiency Vermont (the source of the data KPC uses) delivered energy efficiency at an average cost of $330/first year MWh from 2009-2012.[45] This discrepancy in cost calls into question the reasonableness of KPC's assumptions[46] and the results of "optimization" of incremental efficiency resources.

C. KPC's Energy Savings Projections Are Far Below the Levels Being Achieved by Other Utilities.

KPC's failure to model different levels of DSM is compounded by the fact that the level of DSM KPC selected in its Preferred Portfolio, presumably as a result of its questionable incremental cost assumptions, is far below what has been or is expected to be cost effectively achievable by states and utilities throughout the country.

KPC's Preferred Portfolio is projected to include efficiency programs (excluding VVO and Distributed Solar) that save roughly 213 GWh, or 3.2% of retail sales, by 2028. (KPC Resp. to Staff 2-18). Averaged over the 15-year planning period, the annual incremental energy

---

[43] For efficiency estimates, see *id.* at p. 18-19, tbl 3 (based on 2009-2012 data); Megan A. Billingsley *et al.*, The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs, p. xi tbl.ES-1, Ernest Orlando Lawrence Berkeley National Laboratory (March 2014), available at http://emp.lbl.gov/publications/program-administrator-cost-saved-energy-utility-customer-funded-energy-efficiency-progr (based on 2009-2011 program administrator costs in 2012 $ and levelized gross savings). For supply-side estimates, *see* Lazard's Levelized Cost of Energy Analysis – Version 7.0 (2013), available at http://gallery.mailchimp.com/ce17780900c3d223633ecfa59/files/Lazard_Levelized_Cost_of_Energy_v7.0.1.pdf.

[44] National Review of the Cost of Utility Energy Efficiency Programs at 21-22. (2011$ per first-year net kWh at meter).

[45] *Id.*

[46] To the extent KPC's cost estimates include participant costs, such an estimate is not comparable to KPC's cost of supply-side resources because it captures costs that KPC does not incur.

savings amounts to roughly 0.21% of sales per year.[47] This level of energy savings is inadequate. As Sierra Club discussed in comments filed in the DSM docket, the experience of other regional utilities underscores not only the low levels of savings that KPC has achieved, but also the opportunity that the Company has for substantial increases in cost effective efficiency. For example, from 2009-2011, KPC saved roughly 0.13% total, or 0.02%, 0.03%, and 0.07% on an annual incremental basis at an average cost of 2.7 cents per kWh. During this same period, KPC's sister utility in the neighboring state of Ohio, AEP Ohio, achieved 2.4% savings, or 0.5%, 0.8%, and 1.1% incrementally, at a cost of approximately 1 cent per kWh.[48] AEP Ohio and the other investor owned utilities in Ohio are not alone in achieving 1% savings in 2011. In fact, Ohio is among 14 states that have achieved annual energy savings of 1% of retail sales or more in 2011.[49] In Michigan, electric utilities have, on average, exceeded the state's energy efficiency standard, which escalated from 0.3% in 2009 to 1% in 2012, in each of those years.[50] In 2012, the Michigan utilities achieved savings that were 125% of the 1% standard, at a cost of $20 per MWh of energy saved.[51] By contrast, KPC projects that in the 15-year planning period at issue here, the Company's energy efficiency programs will achieve, on average, only 1/5 of the 1% savings that is regularly being achieved or exceeded by utilities and states throughout the country.

The level of savings achieved in KPC's territory does not reflect the critical role energy efficiency is expected to play in Kentucky's energy future. Although Kentucky is not among the 26 states that have long-term binding energy efficiency savings targets,[52] DSM is a priority resource in the Commonwealth and, as such, Kentucky law provides for the three components of cost recovery to facilitate the successful implementation of utility-administered energy efficiency.[53] Specifically, pursuant to KRS 278.285(2) a proposed demand-side management mechanism can include (i) full program cost recovery; (ii) lost revenue recovery; and (iii) financial incentives. Sierra Club is supportive of properly designed cost-recovery for

---

[47] The annual incremental energy savings from existing and future efficiency programs can be derived from the information provided in KPC Resp. to Staff 2-18.

[48] Max Neubauer *et al.*, Ohio's Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State, p.14, ACEEE (Apr. 2013), available at http://www.aceee.org/sites/default/files/publications/researchreports/e138.pdf.

[49] Annie Downs *et al.*, The 2013 State Energy Efficiency Scorecard, p. 31, ACEEE (Nov. 2013), available at
http://www.aceee.org/research-report/e13k.

[50] Michigan Public Service Commission, 2013 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs (Nov. 26, 2013), at 4, available at https://www.michigan.gov/documents/mpsc/eo_report_441092_7.pdf.

[51] *Id*. at 4, 6.

[52] ACEEE, State Energy Efficiency Resource Standards (EERS) (Feb. 2014), available at http://www.aceee.org/files/pdf/policy-brief/eers-02-2014.pdf.

[53] *See, e.g.*, National Action Plan for Energy Efficiency, Aligning Utility Incentives with Investment in Energy Efficiency (Nov. 2007) at ES-5, available at http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

EE and DR investments as well as incentive mechanisms with proper consumer protections tied to strong performance. Ensuring these mechanisms are beneficial to both KPC and its customers will likely result in lower bills for KPCs customers by capturing higher levels of available energy and demand savings.

The Governor's 2008 Energy Strategy[54] identified energy efficiency as the first strategy to ensure Kentucky's energy security, create jobs and maintain low-cost, reliable energy into the future, setting a goal of reducing 18% of Kentucky's projected 2025 energy demand through energy efficiency.[55] Further, in 2010, the Kentucky Department for Energy Development and Independence ("DEDI"), along with Midwest Energy Efficiency Alliance, utilities (including KPC), Sierra Club, and other stakeholders, participated in the Stimulating Energy Efficiency in Kentucky ("SEE KY") process to expand Kentucky's energy efficiency efforts, which has the "*ultimate goal of ... achieve[ing] one percent annual electric savings in Kentucky through energy efficiency*" by 2015.[56] The SEE KY Action Plan for Energy Efficiency, which was developed through two years of stakeholder engagement and is the primary means of achieving the efficiency goals in the Governor's Energy Strategy and the SEE KY process, outlines annual electric savings goals ramping up from 0.2% in 2012 to 1% in 2015 and each year thereafter through 2025.[57] KPC remains far from achieving the levels outlined in the Action Plan.

D. KPC Must Continue to Pursue Cost-Effective Savings Opportunities.

Although KPC has made progress in terms of achieving efficiency savings, the Company unreasonably limits the growth of the efficiency resource going forward. KPC projects a limited role for efficiency going forward in large part due to the phasing in of federal lighting standards under the Energy Independence and Security Act of 2007 (EISA), which began in 2012. (IRP at 81-82). As KPC notes, a substantial amount of utility efficiency savings comes from lighting-focused programs (e.g. residential and commercial lighting programs). (*Id.*). A significant

---

[54] The Governor's Energy Strategy, *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence*, is available at http://energy.ky.gov/resources/Pages/EnergyPlan.aspx.

[55] *See* Governor's Energy Strategy, *Strategy 1: Impove the Energy Efficiency of Kentucky's Homes, Buildings, Industries and Transportation Fleet*, available at http://energy.ky.gov/Energy%20Plan/Strategy%201-%20Improve%20the%20energy%20efficiency%20of%20Kentucky%27s%20homes,%20buildings,%20industries%20and%20transportation%20fleet.pdf.

[56] DEDI, Stimulating Energy Efficiency in Kentucky: Kentucky's Action Plan for Energy Efficiency ("SEE KY Action Plan"), p.3 (May 15, 2013), http://energy.ky.gov/Programs/Documents/Action%20Plan%205-15-2013.pdf (emphasis in original).

[57] SEE KY Action Plan at 55.

amount of cost effective savings potential remains for lighting technologies, including CFLs, even after accounting for federal efficiency standards.[58]

KPC does not have an estimate of the socket saturation rate for CFLs in its service territory. (KPC Resp. to SC 1-12). However, inefficient light bulbs still occupy more than 70% of the lighting sockets in the U.S. and federal standards alone will not eliminate inefficient lighting.[59] Moreover, the price for light-emitting diode (LED) bulbs continues to decline.[60] Thus, a substantial amount of energy savings from lighting has not yet been realized.

As baselines increase in lighting and other technologies, KPC should continue to explore emerging technologies and different marketing approaches for existing measures. For example, in response to increasing baselines and other challenges in the CFL market, Efficiency Vermont developed new approaches to increase consumer participation in the residential CFL market.[61] Efficiency Vermont launched a specialty CFL campaign and new collaboration with food banks targeting low-income customers, which resulted in a combined 15% increase in socket saturation of CFLs. As discussed in the IRP, KPC should also evaluate ways to expand its program offerings in the commercial sector. (IRP at 102).

Other regions of the country with a long history of substantial efficiency savings continue to save energy at high levels through efficiency programs – and plan to do so long into the future – despite the phase out of the least efficient light bulbs. The most recent power plan from the Northwest Power and Conservation Council, for example, projects that cost-effective, available energy efficiency will meet 85% of the region's growing power needs through 2030.[62] Although KPC and other utilities will need to adapt to changing baselines, significant cost-

---

[58] *See, e.g.*, Dan York *et al.*, Frontiers of Energy Efficiency: Next Generation Programs Reach for High Energy Savings, ACEEE (2013) p.5, http://www.aceee.org/sites/default/files/publications/researchreports/u131.pdf ("Frontiers of Energy Efficiency"); Seth Craigo-Snell, Is it Still Cost Effective to Promote Light Bulbs? Should We?, Applied Proactive Technologies, Inc., Presented at the International Energy Program Evaluation Conference (2013); Bonn, The Once and Future CFL Efficiency Vermont, (2013), http://efficiencyvermont.com/docs/about_efficiency_vermont/whitepapers/White_Paper_Bonn.pdf.

[59] Frontiers of Energy Efficiency at 30; U.S. EPA, Next Generation Lighting Programs: Opportunities to Advance Efficient Lighting for a Cleaner Environment (2011), pp. 1,11 http://www.energystar.gov/ia/partners/manuf_res/downloads/lighting/EPA_Report_on_NGL_Programs_for_508.pdf

[60] *See, e.g.*, U.S. Energy Information Administration, LED Bulb Efficiency Expected to Continue Improving as Cost Declines (March 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=15471#.

[61] Lara Bonn, A Tale of Two CFL Markets: An Untapped Channel and the Revitalization of an Existing One, Efficiency Vermont, (2012), available at http://www.aceee.org/files/proceedings/2012/data/papers/0193-000197.pdf.

[62] Sixth Northwest Conservation and Electric Power Plan, http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf.

effective savings opportunities remain. KPC should continue to evaluate additional programs, measures and delivery options in an effort to increase cost-effective efficiency saving. This is particularly important in light of the Company's "even more-pressing *energy* position prospectively." (IRP at ES-8) (emphasis in original).

E. KPC Should Explore Opportunities to Pursue Industrial Efficiency Programs.

KPC projects energy savings from existing and future programs targeting the residential and commercial sectors. KPC does not, however, account for the most energy intensive customer-sector, industrial customers. The industrial sector represents roughly 44 % of all energy consumption in Kentucky and 43% in the KPC service territory. Yet, KPC does not currently offer any programs to its industrial customers and does not plan to offer any during the IRP planning period. The Company should begin now to explore efficiency opportunities in the industrial sector and work to develop a program to offer this critical customer sector.

Industrial energy efficiency generally has the most cost-effective potential of all of the sectors. Specifically, industrial efficiency resources can be half the cost of resources in other sectors, in terms of dollars per kWh saved, and offer higher benefit-to-cost ratios than measures in the residential and commercial sectors.[63] For this reason, investing in industrial energy efficiency should be a priority for resource planning and acquisition purposes, and for providing ratepayer benefits across customer sectors.[64]

The Company has not discussed efficiency programs with its industrial customers since it discontinued industrial programs in 1998. (KPC Resp. to Staff 2-8). However, stakeholder feedback during the SEE KY process indicated that the industrial community is underserved with respect to energy efficiency programs and services.[65] In light of the critical role the industrial sector plays in Kentucky's economy and KPC's electric resource planning, efficiency opportunities must be evaluated. KPC's obligation to provide adequate, efficient and reasonable service to customers in its service territory, *see* KRS 278.030(2), can be accomplished through the provision of low-cost, reliable resources, like energy efficiency. As a resource that lowers system cost and customer bills, efficiency should be offered to all customer sectors, including industrials.

Moreover, while KRS 278.285 permits "individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs," this opt out provision does not preclude a utility from offering an industrial DSM program. In fact, K.R.S. 278.285 is premised upon the notion that utilities will offer industrial customers DSM programs (i.e. "*in lieu*

[63] Anna Chittum, Follow the Leaders: Improving Large Customer Self-Direct Programs, ACEEE, p. 5 (2011), available at http://www.aceee.org/research-report/ie112.
[64] *Id.*
[65] SEE KY Action Plan at 38.

of measures approved as part of the utility's demand-side management programs") and some Kentucky utilities, such as EKPC and Big Rivers, offer industrial programs to their customers.[66]

As discussed in the DSM case, KPC's planned market potential study "will review *all customer sectors* within the Company service territory to access the market potential for implementing cost-effective DSM programs." (Sierra Club Comments at 10, Case No. 2013-00487, quoting KPC's Response to Sierra Club's Initial Request No. 11) (emphasis added). Sierra Club supports the Company's proposal to study all customer sectors, a critical component of a comprehensive study, and the Company should work with stakeholders to develop programs to capture the potential available in the industrial sector.

V. KPC'S IRP FAILS TO ADEQUATELY CONSIDER DEMAND RESPONSE AS A RESOURCE.

The IRP also contravenes Kentucky's regulatory requirements by failing to sufficiently assess the potential to deploy cost-effective demand response within KPC's territory. 807 KAR 5:058, Section 8(2), mandates that "[t]he utility shall describe and discuss all options considered for inclusion in the plan including… (b) conservation and load management or other demand-side programs not already in place." KPC's failure to incorporate cost-effective demand response program options into its planning process is unjustified in light of significant potential benefits to ratepayers. As a result, KPC has not demonstrated that the IRP "adequately and fairly evaluated" all resource options. *See* Staff Report, Case No. 2012-00149 (outlining standards applied by staff in assessing the reasonableness of EKPC's IRP).

A. Demand Response Can Supply Quantifiable and Substantial Benefits Within KPC's Territory.

Demand response can provide many important benefits to both the utility and its customers. As KPC itself acknowledges, a robust demand response program can forestall the need to construct additional capacity. IRP at 90. Moreover, demand response can serve the same function as other non-traditional supply resources that benefit a utility because they are "not subject to the same price volatility as conventionally fueled units [and so] have a stabilizing impact on overall system costs, acting as a hedge against volatility."[67] Demand response can also provide price mitigation and improve system stability, increase grid reliability, and significantly reduce operating system costs, particularly by reducing use of the highest-cost generating units.[68]

---

[66] *Id.*

[67] See KPC Resp. to Staff 2-3. While the request referenced biomass and utility-scale solar, the same principle applies to energy efficiency and demand response.

[68] DOE Oak Ridge National lab, "Assessment of Industrial Load for Demand Response across US Regions of the Western Interconnect," Sept 2013; NREL, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," Dec. 2013.

For example, in one study of a Colorado system, the National Renewable Energy Laboratory found that implementing demand response led to $7.9M in operational savings, higher than the revenue that the demand response could earn in a market setting.[69] In addition, because demand response can be deployed more flexibly than traditional supply-side resources, it can better complement renewable energy development.[70] These benefits and others highlight the importance of evaluating demand response on a level playing field with supply-side resources in the IRP process.

B. The IRP Fails to Quantify the Cost Effective Demand Response Potential from its Major Sectors.

Despite KPC's general acknowledgement of the benefits of demand response, the IRP makes little effort to assess the availability of cost effective demand response within its territory, abrogating KPC's responsibility to adequately explore all resource options. Of the utility's total 2012 internal energy requirements of 7,155 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31.3%, 18.9%, and 42.8%, respectively. IRP at 5. A properly conducted IRP should thus evaluate the cost-effective demand response potential from all three major sectors. Instead, KPC conducted only a limited, back-of-the-envelope calculation of industrial demand response potential, and no analysis of its residential and commercial sectors. IRP at 91-92. In its industrial "demand response potential survey," KPC tallied participants in AEP affiliate companies' territories to determine the percentage of their load they committed as demand response to PJM. IRP at 91-92. From this brief survey, KPC concludes that its own territory may contain approximately 97 MW of demand response potential, including 24 MW from the mining industry[71] and 67 MW from other large industrials. IRP at 92. Contrary to KPC's assertion, however, this back-of-the-envelope calculation does not qualify as an analysis of demand response "potential" for KPC as no information is presented regarding whether the AEP affiliates are achieving their potential for demand response or whether the levels of demand response being achieved constitute all of the cost-effective demand response that is reasonably achievable.

While KPC's assessment of industrial demand response is incomplete at best, an assessment of its residential and commercial demand response potential is missing altogether. KPC provides no justification for failing to evaluate the demand response potential of its

---

[69] NREL, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," at viii, Dec. 2013.
[70] NREL, "Grid Integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model," Dec. 2013.

[71] Mining accounts for 10.2% of KPC's retail sales and 7.7% of its peak internal demand, and so represents a large potential source of savings. KPC Resp. to Staff 2-5. A study by the U.S. Department of Energy demonstrates that there are significant cost-effective energy efficiency savings available from mining operations, including coal, minerals and metals mining. US Department of Energy, "Mining Industry Energy Bandwidth Study, Industrial Technologies Program," June 2007, pp. 21-24.

residential sector, but instead only summarily claims that demand response resources in its territory are limited to commercial or industrial demand response. IRP at 91. While KPC does not have an advanced metering network, KPC did conduct a pilot load management program for its residential sector; but the IRP does not explain why the pilot was dismantled or summarize the pilot's findings. *See* KPC's Response to Staff's Initial Request Nos. 16 and 21. Elsewhere in the IRP, KPC states only that residential demand response "may be considered in the future." IRP at 97. Similarly, with respect to small commercial and industrial loads, KPC admits that the "introduction of a tariff that allows for the aggregation of smaller commercial and industrial loads would likely result in meaningful resources becoming available," but nonetheless decided not to evaluate these resources "due to Kentucky Power's current reserve margin." IRP at 97.

These brief and conclusory remarks fall far short of a fair evaluation of demand response potential, and do not provide the information needed to weigh it against other resource options. This failure makes it impossible to evaluate whether KPC has in fact selected the least-cost, least-risk approach, undermining the usefulness of the IRP process. As such, KPC should be required to give fair and adequate consideration to this potentially valuable resource, through a comprehensive study of the cost-effective demand response potential of all three of its customer sectors.

C. The IRP Fails to Incorporate Any Demand Response Programs into KPC's Resource Portfolio.

Given KPC's failure to adequately evaluate the cost-effective demand response potential for any of its major customer sectors, it is unsurprising that KPC does not include a single demand response program in its resource plan. KPC validates its planning decision by claiming that, "[g]iven Kentucky Power's current and expected capacity position within PJM, it is not necessary to aggressively pursue all available demand response at this time." IRP at 92; *see also* IRP at 99 (alleging "little incentive to offer such enrollment program in the near-term" given current capacity length). Even if KPC is in fact long on capacity at present, however, this does not mean KPC cannot derive substantial economic benefit from investing in demand response now. Not only would investment in demand response assist KPC in diversifying its resource portfolio, but it could also serve to displace higher-cost supply-side resources and provide significant operational benefits, among others.

D. Recommendation Regarding Demand Response.

Because KPC failed to adequately and fairly assess cost-effective demand response potential in its territory, the Company should be required to complete a comprehensive demand response potential study that examines a variety of demand response program structures for all customer classes, and that analyzes market and policy barriers to increased investment in this potentially cost-saving resource.

VI. KPC SHOULD BID ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES INTO THE PJM BASE RESIDUAL AUCTIONS.

Despite the shortfalls in KPC's evaluation of all EE and DR potential within its resource plan, KPC is currently investing additional dollars in its portfolio of efficiency programs. Both its current programs and future programs, which should become more aggressive and effective, have the potential to help reduce energy bills and avoid risk. In order to maximize this potential, KPC must utilize the peak savings from its energy efficiency ("EE") and demand response ("DR") programs in its capacity plans by bidding such savings into PJM's Base Residual Auction ("BRA"). Utilizing these coincidental peak savings will provide the greatest protection for all KPC customers from unnecessary cost increases, while at the same time achieving several other desirable outcomes, notably the creation of more Kentucky jobs and reducing the potential environmental impacts caused by the provision of electricity service to KPC customers at the lowest possible cost. By bidding EE and/or DR peak savings into the PJM auction, KPC could also generate revenue that can be used to finance additional cost-effective EE and DR programs.

To date, KPC has declined to evaluate the benefit to its customers of utilizing the peak demand savings from EE or DR programs into the PJM auction.[72] The Companies' decision, if unchanged, will have at least three adverse financial consequences for its customers:

1. KPC customers will forgo a substantial revenue stream from an investment for which they are committed to pay;

2. KPC's customers will pay much more than they would otherwise need to pay because they will have to acquire capacity that will be redundant with the capacity savings produced by KPC's efficiency programs; and

3. KPC will undervalue the benefit to its customers of pursuing additional EE and DR savings, and will leave on the table revenue that could be used to help fund such programs.

1. Peak Demand Benefits from Efficiency Programs.

In addition to the direct energy benefits resulting from efficiency programs, there are also capacity price reductions that stem from reductions in peak demand. However, at least in the short term, the full value of the peak demand reduction benefit will only be realized if the savings are accounted for in KPC's capacity planning and bid into the PJM auction.

It is important to emphasize that the value of these peak demand savings is significant. PJM allows efficiency savings to receive capacity payments for four years.[73] The revenue earned from these capacity auctions can then be used to offset the cost of implementing energy efficiency programs and can have a profound price lowering impact on the total cost of energy

[72] KPC Resp. to Staff 1-22(b).
[73] See PJM Manual 18b

efficiency programs. When considering a bid into PJM, it should be emphasized that most efficiency measures last much longer than a year and PJM allows efficiency measures to receive capacity payments for up to four years. After this time, PJM assumes that the efficiency savings have been reflected in load forecasting, and are therefore automatically built into capacity expectations. Bidding these planned resources into the BRAs at PJM results in significant revenue for customers to use to offset efficiency program costs and/or to finance additional cost-effective EE and DR programs.

2. The Commission Staff and Commissions in Other States Have Recognized the Value of Utilities Bidding Efficiency Resources Into the PJM Auction.

The Commission Staff have already recognized the value of utilities bidding efficiency resources into the PJM auctions. In particular, with regards to the 2012 IRP filed by East Kentucky Power Cooperative ("EKPC"), the Staff explained that EKPC should "continue to study and pursue all cost-effective energy-efficiency and peak-demand reductions achievable so that all benefits of PJM integration can be realized" and included "EKPC bidding its peak savings from DSM into the PJM capacity markets" in such benefits.[74]

The Staff's finding regarding EKPC is supported by a recent decision of the Public Utilities Commission of Ohio ("PUCO) to adopt its Staff's recommendation and require the First Energy Electric Distribution Utilities ("FirstEnergy") to bid 75% "of the planned energy efficiency resources for the 2016/2017 delivery year under their program portfolio."[75] PUCO found that such bidding would "substantially benefit ratepayers by lowering capacity auction prices and reducing Rider DSE costs." PUCO ordered such bidding after careful consideration of any "uncertainty of future PJM BRAs, including resources planned, but not yet installed, unknown clearing prices for capacity in incremental auctions, risk of PJM penalties for obligations cleared, but not delivered, and other uncertainties."[76] PUCO stated that by adopting the Staff's recommendation[77] and requiring the Companies to bid 75% of the planned energy efficiency resources it was striking an appropriate balance between benefiting ratepayers and mitigating the Companies' risk.[78] Although this bid requirement was required for only the 2016/2017 planning year, PUCO stated that**,** "Thereafter, the Commission may issue an order addressing the Companies' bids for the remaining two planning years."[79]

---

[74] EKPC 2012 IRP Staff Report at p. 30 and n. 49.
[75] *In the Matter of the Application of the Cleveland Electric Illuminating Company*, Pub. Util. Comm. No. 12-2190-EL-POR, Opinion and Order at 20 (March 2, 2013). In addition, several parties recommended a more substantial PJM auction bid.
[76] Id.
[77] Staff noted that bidding in 75% of planned resources would mitigate any potential "performance or quantity risks." Staff Initial Brief at 10-11 (November 20, 2012).
[78] Id. at 20-21.
[79] Id. at 20-21.

In a July 17, 2013 Entry on Rehearing, PUCO reiterated its Order that the Companies bid in 75% of all eligible, planned resources into the auction.[80] PUCO denied[81] FirstEnergy's Application for Rehearing that the requirement to bid in planned resources was unjust and unreasonable because, *inter alia*, of the perceived risk such a bid posed to customers.[82]

3. KPC's Status as an FRR Should Not Hinder Its Ability to Bid EE and DR Resources Into the PJM BRA

Fixed Resource Requirement ("FRR") status should not hinder KPC's ability to bid such savings into the PJM auction, as the company has acknowledged.[83] To the extent that KPC demonstrates that its status as an FRR restricts the amount of EE and/or DR that it can bid into the PJM auction, such restriction should be factored into the company's annual decision as to whether to continue as an FRR, or whether to elect to be an RPM company.

4. The Commission Should Implement a Process to Ensure that KPC Bids 75% of its Efficiency Savings Into the PJM Auction.

While KPC should be required to incorporate the bidding of EE and DR savings into PJM as part of its next IRP, the company should not wait the three years until that filing to pursue the significant benefits that can result from such bidding. Instead, the Commission should implement a process now to ensure that KPC is effectively bidding at least 75% of all planned efficiency resources into the annual BRAs.

An important component of doing so is for Kentucky Power to provide a general description of its anticipated bid structure to the Commission and the DSM Collaborative. This anticipated bid structure should be reviewed annually by the Commission and interested parties prior to submission to PJM in order to ensure that the Company's customers accrue the additional, potential benefits from their investments in energy efficiency programs through the PJM auction process. Any anticipated bid structure must seek to obtain the potential energy efficiency and peak demand reduction resources that are installed, planned or otherwise expected to be generated for the time period covered by the auction.

As part of the bidding process, KPC should be provided with full recovery of PJM monitoring and evaluation costs and any applicable penalties associated with PJM auctions, including the costs of purchasing replacement capacity from PJM incremental auctions, to the extent that such costs or penalties are prudently incurred. Accordingly, any of the Companies' perceived risks would be greatly diminished, if not eliminated, and the potential benefits to customers would be appropriately sought through participation in the PJM auctions.

---

[80] *In the Matter of the Application of the Cleveland Electric Illuminating Company*, Pub. Util. Comm. No. 12-2190-EL-POR, Entry on Rehearing, at 4 (July 17, 2013).
[81] Id.
[82] Id. at 2. The Commission also rejected the assertion that the bid should be diminished or eliminated due to legislative activities (Entry at ¶8).
[83] KPC Resp. to SC 1-43, Case No. 2012-00578.

A second important component for ensuring effective bidding of efficiency resources into the PJM auction is for the Commission to develop a process for KPC to receive a share of any revenue returned from bidding efficiency resources into the auction as a mechanism to incentivize bids above 75% of all planned resources, while also mitigating any potential risk of bidding.[84] For example, In its Entry on Rehearing in the FirstEnergy proceeding discussed above, PUCO chose to "better align the interests of the electric distribution utility and the interests of its customers in support of the implementation of energy efficiency and peak demand reduction programs" by adopting a Staff recommendation to split the proceeds between the FirstEnergy EDUs and their customers.[85] The Commission proposed and adopted a pilot program to split auction proceeds 80/20 between the Companies' customers and FirstEnergy.[86] A similar structure for KPC would entitle the Company to 20% of any revenue obtained from successfully bidding greater than 75% of all planned energy efficiency and demand response resources into the PJM auctions while 80% of the revenue would be used to offset the costs to customers of implementing the energy efficiency and demand response programs.

5. Conclusion Regarding Bidding Efficiency Into the PJM BRA.

In order to save customer money, minimize risk, and maximize investment in cost effective energy efficiency and demand response, KPC should be required to factor bidding of efficiency savings into the PJM BRA into its resource planning, and the Commission should implement a process to ensure that KPC bids at least 75% of its efficiency savings into the auction.

VII. THE COMPANY FAILED TO ADEQUATELY CONSIDER THE VALUE OF SOLAR RESOURCES.

Solar resources can play a significant role in delivering low cost and reliable power to KPC customers. In addition to the fuel-free energy it provides, solar has a natural coincidence with peak summer demand; can avoid transmission capacity costs and line losses through smaller systems sited on the distribution grid closer to load, is scalable and modular, among other attributes. KPC appears to generally recognize the range of benefits and costs of utility- and distributed-scale solar generation in the IRP. Despite these substantial benefits, however, the Commonwealth's potential for solar energy development has remained almost entirely untapped to date.

---

[84] See, e.g., *In the Matter of the Application of the Cleveland Electric Illuminating Company*, Pub. Util. Comm. No. 12-2190-EL-POR, Opinion and Order at 30 (March 2, 2013) (concurring opinion of PUCO Commission Slaby explaining that incentives for the utility will help overcome any risks of bidding efficiency savings into the PJM auction).
[85] Id. at 5.
[86] Id. at 4-5.

The failure to realize the potential of solar in Kentucky and in KPC's service territory more specifically stems from the absence of a robust analysis of solar resource value. In order to properly compare solar and other alternative resources in an IRP, each resource must be valued correctly. As summarized below and discussed in detail in the attached technical comments from Karl R. Rábago of Rábago Energy LLC (Exhibit B), which is incorporated herein by reference, KPC does not adequately assess the value of solar energy resources, particularly distributed solar generation. Instead, KPC offers an incomplete analysis that artificially constrains the amount of utility scale solar that can be modeled and ignores the full suite of benefits distributed solar generation provides. The result is an inaccurate assessment of the value of the solar resource and underrepresentation of solar generation in the Company's Preferred Portfolio.

Although KPC recognizes that the costs of solar are falling rapidly and concludes that solar costs are expected to become "nominally flat" on or about 2020, the Company does not model any utility-scale solar until 2020, at which point it limits the amount of solar that can be added to 10 MW per year. This 10 MW ceiling amounts to a flat annual growth rate of about 0.33 percent. The Company cites no basis for these and other solar-related assumptions, nor does it propose any alternative growth scenarios in any of its analysis. As discussed in the Rábago report, Exhibit B at p. 7, the modeling results suggest that the constraints and assumptions imposed on utility-solar in the model limited the amount of solar selected.

KPC concludes that distributed solar generation (which represented all distributed generation resources via net metering in the Company's analysis) is uneconomic from the utility's perspective. (IRP at 98, 102). However, a careful review of the IRP and the responses provided by the Company to information requests shows that the only benefits KPC quantified were assumptions of wholesale energy and generation capacity value in PJM, ignoring several significant benefits, as discussed in the Rábago report, Exhibit B at pp. 5-7. Moreover, KPC assumes, without explanation, that the rate of distributed solar adoption decreases as solar prices fall.

KPC's analysis of utility and distributed solar generation contains several questionable and largely untested assumptions and ignores several benefits that these resources provide and the vast amounts of solar data available from similar locations across the United States. In short, the analysis is incomplete and insufficient, and falls short of the requirements contained in the IRP rules, as the analysis cannot be considered a real "assessment of [a] potentially cost-effective resource option," nor can KPC show that it has fully considered potentially lower cost, lower risk resources when it has ignored significant benefits of such resources. 807 KAR 5:058 Section 8(1).

Consistent with the recommendations discussed in the Rábago report, Exhibit B at pp. 11-13, KPC should develop a comprehensive value of solar methodology and assessment that identifies and characterizes the value attributes of solar energy generation through a third-party administered process that engages solar energy. The results of this process should be reported to the Commission on or before December 31, 2014. Additionally, KPC should work with Staff and interveners in this proceeding to develop a more robust set of portfolio alternatives or scenarios, sensitivity analyses, and risk assessment analyses to be used in the next IRP. Finally, KPC should develop a program aimed at supporting the development and use of cost-effective distributed solar generation, which can leverage the benefits of net energy metering, encourage the creation of new jobs, put downward pressure on rates, strengthen the grid, and overcome commercialization barriers that exist today.

VIII. THE IRP FAILS TO FAILS TO PROVIDE FOR CONTINUING INVESTMENTS IN WIND POWER.

One of the strong points of the IRP is its assumption that KPC will add 100MW of wind capacity in 2015. IRP at ES-3, 171. This assumption arose out of the settlement agreement in Case No. 2012-00578, in which KPC committed to issuing a non-binding Request for Proposals ("RFP") for 100MW of wind power, with the results to be incorporated into this IRP. Order, Case No. 2012-00578, Appx. A ¶19 (Oct. 7, 2013). KPC received numerous responses to its RFP, *id.* at 153-54, so the Company should little difficult meeting this assumption.

Pursuing wind projects like this one is a crucial component in developing a resource portfolio that provides a "reliable supply of electricity . . . at the lowest possible cost." 807 KAR 8:058 Section 8. As the IRP acknowledged, "the addition of *wind*, solar, and customer and grid energy efficiency resources serve to reduce overall costs." IRP at 170 (emphasis added). Unfortunately, KPC's preferred portfolio fails to fully realize these potential cost savings because – other than the wind project KPC is already pursuing – the IRP assumes that no additional wind capacity will be added. *See id.* at ES-7, 3 (assuming that 100MW of wind capacity will be added in 2015, but no further wind capacity will be added during 2016-2028). KPC offers no explanation for why it failed to pursue additional wind projects for the last 13 years of the planning period. KPC's failure to consider additional wind capacity is all the more puzzling because, despite assuming the expiration of the federal production tax credit, KPC's cost assumptions show a continuing decline in the cost of wind power throughout the 15-year period. *See* IRP at 135.

The declining price of wind power is already leading utilities throughout the country to ramp up their acquisition of wind resources. For example, a recent U.S. Department of Energy ("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.[87] The DOE report also found that the average levelized prices for long-term wind energy power purchase agreements dropped to $40 per MWh in 2011-2012. 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."[88] Similarly, Southwestern Electric Power Company entered into a contract for wind

---

[87] 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).

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

power at a price that is lower than their current average cost of energy.[89] 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."[90]

The Commission Staff should note KPC's failure to explain its decision to not pursue additional wind resources after 2015, and should recommend that KPC fully evaluate and pursue cost-effective wind opportunities in its resource planning.

IX. KPC'S LOAD FORECAST LIKELY OVERESTIMATES FUTURE DEMAND FROM THE COAL MINING SECTOR.

One of the central requirements of an IRP is that it provide an accurate forecast of the load expected over the 15-year planning period. *See* 807 KAR 8:058 Section 7(3) (for each year of the planning period, utility must "provide a base load forecast it considers 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"); *see also id.* Section(7)(d) (forecast must discuss "[t]he utility's treatment and assessment of load forecast uncertainty"); Section(7)(e)2 (forecast must discuss the extent to which the utility considered "[c]hanges in population and economic conditions in the utility's service territory and general region"). Accurate load forecasts are not only an express requirement of the IRP rules, but they are also necessary to ensure that the utility's resource portfolio addresses customers' needs in a cost effective manner. Overestimating a utility's load could skew the IRP modeling, prompting a utility to overinvest in generating capacity and exposing ratepayers to unnecessary costs.

The IRP appears to overestimate future energy demand from the coal mining sector, which has likely resulted in an overestimate of KPC's total demand over the planning period. It is well-documented that the coal mining sector within KPC's service territory has decreased significantly in recent years. The IRP acknowledges these steep declines, noting that over the last four years "mining sector sales have been sharply reduced." IRP at 15. KPC's sales to the mining sector certainly bear this out, with energy sales to the mining sector having fallen continuously since 2009. Staff 1-5 Attachment 1. Demand from this sector declined at an annual rate of between 1.8% and 5.7% prior to 2012, and has seen declines of greater than 10% since then. *Id.*

---

[89] 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.").

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

Despite these ongoing (and accelerating) declines, the load forecast assumes that energy use from the coal mining sector will remain steady throughout the IRP planning period and beyond, with only minor changes to the sector expected all the way through 2042. *Id.* This assumption is at odds with recent historical experience, which suggests that the sector's energy use will continue to decrease throughout the planning period, and also runs counter to current forecasts of the Eastern Kentucky coal mining sector.

At the Informal Conference, KPC clarified that its forecast of the sector's future energy demand was based on regional Energy Information Administration ("EIA") data, rather than data specific to Eastern Kentucky. *See also* IRP at 40 (noting that mining forecast was produced through "a model relating mine power energy sale to regional coal production").[91]

The IRP's use of that regional data is likely why the load forecast is skewed, thereby predicting a higher demand from the coal mining sector than KPC should reasonably expect. Both historical data and future projections indicate that Eastern Kentucky's coal mining sector is decreasing much more quickly than other parts of the eastern U.S., including the Illinois Basin, western Kentucky, and other parts of Appalachia. To take just a few examples:

- A 2013 report issued by Kentucky's Energy and Environment Cabinet ("EEC") found that in 2012 coal production in Eastern Kentucky decreased 26.7% from 2011, while Western Kentucky coal production increased by 2.5%.[92] These trends are mirrored by EIA data, whose figures are slightly different, but which also estimated a significant decrease in Eastern Kentucky coal production in 2012 while Western Kentucky production increased.[93]

- A January 2014 report issued by EEC noted that in 2013, Eastern Kentucky coal production decreased by 19.2%, while Western Kentucky production dropped only 2.7%.[94]

- Citing EIA data, a 2012 report by Mountain Association for Community Economic Development ("MACED") noted "that Central Appalachian coal production is expected to decline from 175 million tons in 2012 to 77 million tons in 2020," and that "future coal production in eastern Kentucky could decrease even more

---

[91] At the Informal Conference, KPC further clarified that the forecasts had been generated using information up through the first quarter of 2013.
[92] EEC, *Kentucky Coal Facts* at 4 (13 ed. June 20, 2013), *available at*: http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Coal%20Facts%20-%2013th%20Edition%20(2013).pdf.
[93] *See* EIA, *Annual Coal Report 2012* at 2 (Dec. 2013), *available at*: http://www.eia.gov/coal/annual/pdf/acr.pdf.
[94] EEC, *Kentucky Quarterly Coal Report: October to December 2013* at 2-3 (Jan. 2014), *available at*: http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q4-2013%20year%20end).pdf.

> dramatically than Central Appalachia's already steep decline." Using EIA data, the MACED report estimated that coal production in eastern Kentucky would decline 70% between 2012 and 2020, and with production below 20 million tons by 2028, the end of the IRP planning period.[95] This is approximately half of the eastern Kentucky coal production in 2013, and yet the IRP assumes that this mining sector's energy use will be fairly stable throughout the planning period. *Cf.* Staff 1-5 Attachment 1.

These differences indicate that the Eastern Kentucky mining sector has decreased much more quickly than other parts of the eastern coal market, such that KPC's reliance on that regional data overestimates the likely future energy demand from this sector.[96] The Commission Staff should note these deficiencies in its report on the IRP filing, and recommend that KPC's next IRP provide a more accurate forecast of the coal mining sector's future demand.

X. CONCLUSION

In order to help ensure that KPC continues its recent laudatory steps towards increasing DSM and renewable resources, and reducing high cost high risk coal generation, rather than reverting to business as usual, KPC should address and correct the above errors in their IRP so that a full evaluation of a reasonable range of resource portfolios can occur.

Respectfully submitted,

Joe Childers, Esq.
Joe F. Childers & Associates
300 Lexington Building
201 West Short Street
Lexington, Kentucky 40507
859-253-9824
859-258-9288 (facsimile)

---

[95] MACED & Kentucky Center for Economic Policy, *Promoting Long-Term Investment in Appalachian Kentucky: A Permanent Coal Severance Tax Fund*, at 1-2 (Mar. 2012), *available at*: http://www.maced.org/files/MACED_Coal_Severance_Tax_Brief.pdf.

[96] Indeed, KPC has acknowledged that its load forecast does not account for these steep declines. The IRP states that the forecast do not reflect "do not reflect the experience for the summer season of 2013 and later, or other relevant changes." IRP at 7. In response to a data request seeking clarification on the "other relevant changes" that were not incorporated into the load forecast, KPC stated that "[t]here were no significant 'other relevant changes' other than the further deterioration of the coal mining sector." Resp. to SC 1-8(b).

Of counsel:

Shannon Fisk
Earthjustice
1617 John F. Kennedy Blvd.
Suite 1675
Philadelphia, PA 19103
(215) 717-4522
sfisk@earthjustice.org

Jill Tauber
Michael Soules
Earthjustice
1625 Massachusetts Ave., NW
Suite 702
Washington DC 20036
jtauber@earthjustice.org
msoules@earthjustice.org

Laurie Williams
Sierra Club
50 F St. NW, 8th Floor
Washington DC 20001
(202) 548-4597
laurie.williams@sierraclub.org

Dated: April 30, 2014

CERTIFICATE OF SERVICE

I certify that I had filed with the Commission and served via U.S. Mail the foregoing Comments of the Sierra Club on April 30, 2014 to the following:

Mark R. Overstreet
Attorney at Law
Stites & Harbison
421 West Main Street
P. O. Box 634
Frankfort, KY 40602-0634

Lila P. Munsey
Managing, Regulatory Services
Kentucky Power Company
101 A Enterprise Drive
Frankfort, KY 40601

Michael L. Kurtz
Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Grant Tolley