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November 29, 2011

Jeff Derouen
Executive Director
Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615

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PUBLIC SERVICE COMMISSION

In re: Kentucky Public Service Commission Case #2011-00140

Dear Mr. Derouen,

On behalf of Environmental Intervenors, please accept, and file in the matters above, the enclosed originals and appropriate copies of:

1. Motion of Environmental Intervenors to File Corrected Comments; and
2. Environmental Intervenors' Corrected Comments, including a two-page Errata Sheet explaining the six corrections.

Should the Commission grant our motion, please discard the original comments as filed on November 23, 2011. Because there have been no changes to the voluminous supportive documents, they relate to our corrected comments as they did to our originals, so there is no need for any related action.

Thank you, kindly, for your assistance.

Best Regards,

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enclosures

cc: Parties

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2011 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	**CASE NO. 2011-00140**

MOTION OF INTERVENORS NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB TO FILE CORRECTED COMMENTS

****

COME NOW Natural Resources Defense Council and Sierra Club ("Environmental Groups") to respectfully request the Commission allow for corrected comments to be filed in the above-styled matter. In support of movants' request, the following is offered:

1. On Wednesday, November 23, 2011, movants timely filed their comments in this matter.
2. The undersigned counselor mistakenly filed the second-to-final edited version of said comments, thereby omitting the six changes as moved to correct herein (please see Errata Sheet for a detailed description of each edit).
3. The changes do not add any pages to movants' comments, nor add or remove any supportive documents as originally filed on November 23.

WHEREFORE, Environmental Groups ask that this Commission enter the corrected comments, including explanatory Errata Sheet, into the docket in this matter, and to remove the comments filed on November 23, 2011, from the same.

Dated: November 29, 2011

Respectfully submitted,

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CERTIFICATE OF SERVICE

I certify that I served a copy of Environmental Groups' Comments via first class mail on November 29, 2011, to the following:

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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 2011 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	**CASE NO. 2011-00140**

CORRECTED COMMENTS OF INTERVENORS NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB ON THE 2011 JOINT INTEGRATED RESOURCE PLAN OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC

Intervenors Natural Resources Defense Council and Sierra Club (collectively, "Environmental Groups") hereby comment on Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies") 2011 Joint Integrated Resource Plan ("IRP"). The Environmental Groups are gladdened that the IRP calls for the retirement of the Companies' aging and dirty Cane Run, Green River, and Tyrone coal-fired electric generating units, and for some increase in the demand side management ("DSM") and energy efficiency ("EE") efforts of the Companies. However, the IRP includes a number of flaws that result in the plan failing to set forth the lowest cost approach for the Companies to meet their future energy needs. Specific shortcomings in the IRP include:

- A failure to provide a meaningful analysis sensitivity analysis for the load growth projections;
- Selection of an excessive reserve margin;
- A need to enhance the demand side management programs so as to more fully capture all cost-effective means for reducing demand growth;
- Reliance on an unsupported assumption that there will be zero future costs related to carbon dioxide ("CO2"), rather than evaluating a range of potential CO2 costs;
- An inadequate assessment of the full set of capital, environmental, fuel, and operating and maintenance costs facing the Companies aging coal-fired electric generating units; and
- Failure to factor in and account for uncertainty in energy planning.

A thorough and well-reasoned IRP is especially important now as it is a critical time for the Companies. A number of the Companies' coal-fired electric generating units have reached or exceeded their expected service lives, raising the need for major capital investments if such units are to continue to operate. In addition, existing and expected environmental standards will finally require the Companies (and utilities throughout the country) to either install pollution controls on coal units or to retire such units. Technological advances and changes in market conditions have made a larger suite of both supply- and demand-side options available for the Companies to satisfy their customers' needs. And growing awareness of the economic, public health, and environmental impacts of energy production have increased the importance of the pursuit of energy efficiency and renewable energy resources from both a cost and environmental perspective. In short, the Companies face a new reality involving a growing set of costs to its existing generation fleet, an expanding set of options for how to service its customers, and an increasingly complex set of factors relevant to identifying the lowest cost mix of supply- and demand-side resources for meetings its customers' needs. The Environmental Groups present these comments on the IRP in the spirit of helping the Companies and the Commission pursue a clean energy future that benefits the ratepayers' pocketbooks and the health of all Kentuckians.

I. IRP Standards

The IRP process in Kentucky is governed by 807 K.A.R 5:058, which requires the Companies 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 the Companies' system. 807 K.A.R. 5:058 Section 1(2). Core elements of the filing include:

- A base load forecast the Companies consider "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).

- The Companies' "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost." 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 have stated:

> 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]

It is with that intent in mind that the Environmental Groups offer the following comments.

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

II. The Companies' Load Growth Projections Fail to Include A Meaningful Sensitivity Analysis.

The first fundamental step in any IRP process is to reasonably project the amount of energy demand that the Companies will need to satisfy over the planning period. The Companies carried out an analysis of total electricity sales and peak demand over the 15 year planning period and concluded that while demand has dropped significantly due to the 2008 recession it will recover and grow at a faster rate than was predicted by the Companies in their 2008 IRP. For total electricity sales, the Companies predict levels for 2011 to 2015 will be 5.8% lower than was predicted in the 2008 IRP. (IRP at 6-3). The Companies also, however, project a higher annual growth rate of 1.6% from 2011 to 2015 (compared to 1% in the 2008 IRP) and 1.5% for 2011 to 2025 (compared to 1.2% in the 2008 IRP). (*Id.*) As a result, total energy demand is projected to be 23.2% higher in 2025 than in 2011. Similarly, peak demand in 2011 to 2015 is projected to be 5% lower than was predicted in the 2008 IRP. (*Id.* at 6-5). The Companies then project that peak demand will grow at 1.7% through 2025, rather than the 1.3% level identified in the 2008 IRP. (*Id.*). As a result, peak energy demand is projected to be 28.4% higher in 2025 than in 2011.

While the Companies have apparently assumed a full recovery from the 2008 recession, they have not provided any explanation for why they expect total electricity sales and peak energy demand to grow at a higher annual rate than they projected in the 2008 IRP. This higher projected growth rate is especially surprising given that the energy efficiency provisions of the Energy Independence and Security Act of 2007 (EISA") and the American Recovery and Reinvestment Act of 2009 ("ARRA") were supposedly incorporated into the demand growth projections. The ARRA programs alone are projected to reduce residential demand by 0.2% per year every year through 2020.[2] The lighting efficiency standards in the EISA are expected to reduce residential energy use by 1.5 to 2.5% in 2012-2014.[3] And various provisions of EISA and ARRA were projected by Itron to reduce the projected increase in commercial sector electricity use from the 2.1% annual increase projected in 2008 for 2009 to 2019 to only a 1.6% annual increase.[4] In light of these reductions and the continued economic difficulties facing Kentucky, it would appear that the Companies' estimate of increased annual electricity demand growth as compared to the 2008 IRP is overstated.

The Companies do acknowledge that "within each forecast cycle, there is uncertainty in the forecast values of the independent variables." (IRP at 7-25). This uncertainty is especially acute for peak demand growth, with regards to which the Companies note "significant uncertainty about the rate of growth of peak demand and capacity additions." (*Id.* at 6-26). For example, Cambridge Energy Research Associates ("CERA") has projected a nationwide peak

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[2] Itron, 2009 Residential Statistically Adjusted End-Use (SAE) Spreadsheets – ARRA Stimulus Forecast, Attachment to Companies' Resp. to NRDC-SC Interrogatory No. 2.

[3] Itron, 2009 Residential SAE Update at 1, Attachment to Companies' Resp. to NRDC-SC Interrogatory No. 1.

[4] Itron, 2009 Commercial SAE Update, at 13, Attachment to Companies' Resp. to NRDC-SC Interrogatory No. 1.

demand growth increase of 1.9% per year from 2010 to 2015, while the U.S. Department of Energy's Energy Information Administration projects only 0.1% peak demand growth. (*Id.*).

Robust utility planning addresses such uncertainty through the use of sensitivity analyses that measure the impact of a range of different input scenarios combined with an assignment of probabilities to each scenario. So, for example, with regards to load growth, a sensitivity analysis would evaluate how different assumptions regarding economic growth, population growth, or weather would impact the projected change in electricity demand growth over the planning period. Utilities would then assign different probabilities to each set of assumptions in order to conclude which scenario is most likely.

The Companies purport to have undertaken a sensitivity analysis with regards to electricity demand growth, but it was not a meaningful analysis. Instead of testing a range of input assumptions in order to identify different projected demand growth trajectories, the Companies generated a "high case" by assuming that demand in 2011 would be 4% higher than projected, and a "low case" by assuming that demand in 2011 would be 4% lower than projected. (IRP at 7-26). The Companies then assumed that energy sales and peak demand will grow at the exact same annual rates as were used in identifying the "base case." (*Id.*). In other words, the only sensitivity that was added into the evaluation concerned whether the demand would be higher or lower than expected. No sensitivity analysis was presented regarding the rate of energy demand growth over the planning period, which is the critical factor in determining what level of energy demand the Companies will need to serve over the next fifteen years.

The Companies acknowledge that "alternative load growth scenarios may have a significant impact on the selection of an optimal technology, type, and size." (IRP at 5-13). For example, a lower rate of growth could delay, shrink, or eliminate the need for new generating capacity, thereby saving ratepayers money. Conversely, a higher growth rate could lead to an increased need for additional generating capacity. Carrying out sensitivity analyses that look at the range of potential demand growth trajectories is critical to ensuring that the optimal combination of energy resources is selected.

III. The Companies Have Selected an Excessive Reserve Margin

The Companies appear to have overstated the amount of capacity they need by selecting an excessive 16% reserve margin for the system. A reserve margin is the amount of excess capacity a utility carries in order to minimize the likelihood of reliability events. Relying on an analysis by Astrape Consulting titled LG&E and KU 2011 Reserve Margin Study ("RMS"),[5] the Companies contend that the current 14% reserve margin should be increased to 16% because that latter figure purportedly represents the level that optimally balances the cost of holding reserve energy resources with the risk and impact of a reliability event. In other words, the RMS

[5] Astrape Consulting, LG&E and KU 2011 Reserve Margin Study (April 8, 2011) (hereinafter "RMS"). The RMS was filed with the Commission by the Companies as Ex. CRS-3 to the Rebuttal Testimony of Charles R. Schram in PSC Case Nos. 2011-00161 and 00162.

focused on the "estimated total costs and risks to customers" of various reserve margins,[6] rather than the traditional approach of identifying the minimum level of generation planning reserve margin needed to maintain electric system reliability. Regardless of the validity of this non-traditional approach, the 16% figure is higher than is necessary or beneficial to ratepayers.

One way that the RMS overstates the appropriate reserve margin is by explicitly modeling two types of load forecast uncertainty rather than just one. In particular, the RMS incorporates weather uncertainty and economic uncertainty, both based on historical loads. This increases the amount of uncertainty being modeled and raises questions about the possibility of historical uncertainty being duplicated by the multiple methods used in the RMS. Load forecast uncertainty due to economic uncertainty results in a peak load, in the most extreme case, that has only a 2.25% probability of occurring. Given that most economic uncertainty is currently on the downside, with lower than expected loads, this seems extreme and acts to improperly increase the apparently optimal reserve margin.

More traditional loss-of-load-probability ("LOLP") planning uses a load forecast that has a certain overall confidence level, such as a "50/50" forecast that has a 50% chance of being exceeded in any one year. Some Regional Transmission Organizations use a 90/10 load forecast, in which the forecast load has a 10% chance of being exceeded in any one year, for some system planning purposes. But, the 50/50 forecast is still widely used for generation adequacy purposes.[7] In either event, a specific overall confidence level applies to the loads being studied. This compares to the RMS which reflects economic uncertainty such that the worst case load has less than 2.25% chance of being exceeded.[8] And this is before weather-driven load forecast uncertainty is taken into account. While load forecast uncertainty should be considered, the method used in the RMS departs from the planning basis on which our electric utility system has been developed and operated and acts to increase what the planning reserve margin should be relative to traditional LOLP study methods. As such, it should be strictly scrutinized.

A second problem with the RMS is that it overestimates the level of reserve margin needed to achieve a loss of load probability ("LOLP") of 0.1, which is the equivalent of 1 day of lost energy in ten years. The appendix to the reserve margin study contends that a 20% reserve margin is needed to reduce the LOLP to 0.1, and that the LOLP would be at 0.2 with a reserve margin of 16%.[9] But other utilities have found that a far lower margin than 20% is needed to get the LOLP down to 0.1. For example, NERC has reported that the Florida Reliability Coordinating Council found that a 15% reserve margin would achieve a LOLP of 0.1.[10] Similarly, PacificCorp recently determined that a 14.8% reserve margin was sufficient to achieve a 0.1 LOLP.[11] The LOLP at various reserve margin rates represents the probability that the

[6] RMS at 2.
[7] PJM uses a 50/50 load forecast in its generation adequacy determination.
[8] RMS at 14.
[9] RMS at Appendix A.
[10] NERC, 2011 Summer Reliability Assessment (May 2011), at 47, *available at* http://www.nerc.com/files/2011%20Summer%20Reliability%20Assessment_FINAL.pdf.
[11] PacifiCorp, Stochastic Loss of Load Study for the 2011 Integrated Resource Plan (Nov. 18, 2010), at 9-10, *available at*

system is likely to experience a shortage of generation over a given planning year. Therefore, overstating the LOLP at a particular reserve margin rate would suggest a higher margin than is cost effective.

The RMS is also flawed because it does not appear to give any credit to demand side resources ("DSR"). The NERC 2011 Summer Reliability Assessment[12] documents how NERC has enhanced its method of calculating reserve margin to account for controllable DSR, which acts similar to generation in its ability to "serve" load. Rather than being subtracted from capacity and load, as was previously the case, now controllable DSR MWs are now added to generating capacity, which will tend to increase the calculated reserve margin in 2011 and later years, all else held equal. DSR should be factored into the Companies' reserve margin analysis.

Finally, the Companies' reserve margin study appears to omit consideration of the Contingency Reserve Sharing Group ("CRSG") that the Companies have joined with the Tennessee Valley Authority and East Kentucky Power Company.[13] The members of the CRSG share 1,347MW of contingency reserves, which enables each individual utility to reduce the amount of contingency reserves it carries on its own.[14] Other utilities have assumed that participation in similar reserve sharing groups reduces the reserve margin that a single utility needs by as much as 1.5%.[15] The CRSG should similarly be factored into further analysis of the reserve margin for the Companies.

IV. The Companies Should Enhance Demand Side Management Programs and Adjust the Underlying Load Forecasts for the IRP Accordingly.

The best energy resource from both an economic and environmental perspective is demand side management ("DSM"), which uses energy efficiency and demand response programs to reduce the total amount of electricity that a utility needs to produce in order to satisfy its customers' needs. Experience throughout the country shows that well-designed and implemented DSM programs can reduce energy demand by 1% to 2% per year at a significantly lower cost than it takes to produce that same amount of energy. As such, any energy planning process that seeks to achieve the lowest cost energy portfolio should prioritize the implementation of all cost effective DSM.

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http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PAC_2011IRP_LossOfLoadStudy_11-18-10.pdf

[12] NERC Reliability Assessment at 3; NERC, Recommendations for the Treatment of Controllable Capacity Demand Response Programs in Reserve Margin Calculations (June 1, 2010), available at http://www.nerc.com/docs/pc/ris/RIS_Report_on_Reserve_Margin_Treatment_of_CCDR_%2006.01.10.pdf.

[13] Contingency Reserve Sharing Group, Certificate of Deliverability, available at http://www.oatioasis.com/EKPC/EKPCdocs/TEE_CRSG_Certification_of_Deliverability_04302010.pdf

[14] Companies' Resp. to Staff Interrogatory No. 10.

[15] PacifiCorp at 10; Ventyx, Analysis of "Loss of Load Probability" (LOLP) at Various Planning Reserve Margins (Dec. 1, 2008).

To their credit, the Companies have, in a separate filing (PSC Case No. 2011-00134) recently approved by the Commission, sought to expand their DSM programs.[16] The Companies' existing DSM programs have achieved 182 MW of peak demand reduction through 2010. The continuation of those programs and addition of new programs approved in Case No. 2011-00134 are expected to lead to additional peak demand reduction of 309 MW over the next seven years, for a total peak demand reduction of 491 MW by the end of 2017. (IRP at 6-24). The IRP then assumes another 58MW of peak demand savings from DSM programs each year through 2025, for a total of 838.7MW of peak demand reduction. (IRP at 8-75). This equates to a total peak energy demand savings of 9.36% by the end of 2025, which is an average reduction of approximate 0.52% of peak demand per year since the DSM programs started in 2008. With regards to total energy sales, the Companies estimate that their DSM programs will lead to a 1,950GWh reduction by the end of 2025. (IRP at 8-74). This equates to a 4.6% reduction in total energy sales by the end of 2025, which is an average energy savings of only 0.25% per year.

While these DSM programs are a good start, the Companies can cost- effectively achieve far more reduced demand. The Companies' own filings show that the proposed DSM programs' expected benefits far outweigh their costs, which provides strong evidence that there are significant opportunities for additional energy savings through cost-effective DSM programs. For example, the IRP estimates the existing and new DSM programs from 2011 through 2017 will cost $261 million, while the net present value of those programs is estimated at $864 million. (IRP at 8-76). That 3.3 to 1 benefit-cost ratio suggests that there is a lot of additional energy savings that the Companies could achiev through DSM programs with a positive benefit-cost ratio.

That the Companies can and should pursue far more DSM is also seen through the DSM Program Review that was carried out by ICF International.[17] Among other things, the DSM Review evaluated the Companies' DSM programs in terms of the four cost-effectiveness tests set forth in the California Standard Practice Manual. (IRP at 8-109 to 8-111). The Companies' DSM programs have significant positive net economic benefits under the Participant Test (8.24), Utility Cost Test (3.39), and Total Resource Cost Test (3.01). The high Utility Cost Test result indicates that there is significant opportunity to cost effectively increase the DSM incentives offered in order to increase participation in energy saving programs. And the high Total Resource Cost score indicates that the Companies could expand the DSM programs to go after much deeper energy savings, while still staying cost effective and delivering net benefits to the service territory.

ICF did find that the DSM programs had a marginally negative Ratepayer Impact score of 0.82. (IRP at 8-111). While the Companies should not use the Ratepayer Impact test alone to

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[16] *See* In re Joint Application of Louisville Gas & Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand Side Management and Energy Efficiency Programs, PSC Case No. 2011-00134.

[17] ICF International, Louisville Gas and Electric Company / Kentucky Utilities Company – DSM Program Review (Mar. 18, 2011). The ICF Report was filed with the Commission as Exhibit 10 to the Companies' Demand Side Management and Energy Efficiency Program Plan filing in PSC Case No. 2011-00134.

evaluate the cost effectiveness of DSM because, as the ICF analysis noted, that test has "serious disadvantages" stemming from the fact that it likely provides the least certain results of any of the cost effectiveness tests.[18] While the Ratepayer Impact score should play a role in determining which specific DSM programs to pursue and how to design those programs to properly balance the costs and benefits for participants, utilities, and non-participants, the appropriate overall level of DSM is most appropriately evaluated by considering the results of all of the cost-effectiveness tests.[19] Doing so here reveals a substantial benefit from the Companies' existing and recently-approved DSM programs, and the opportunity to cost effectively reduce significantly more demand through further DSM efforts.

The 0.52% per year demand reduction from the Companies' DSM programs also falls far short of the energy saving goals targeted for Kentucky. In particular, Kentucky Governor Steven L. Beshear has called for the establishment of an Energy Efficiency Resource Standard that would seek to reduce energy consumption by at least 16 percent below projected 2025 levels, for a savings rate of 1.13% per year.[20] While the Governor's goal is not a binding requirement yet, it provides additional evidence that the Companies could achieve far more cost effective demand reduction through enhanced DSM efforts.

The projected energy savings from the Companies' DSM programs also falls far below the energy saving requirements established in many other states. For example, at least eleven states now have policies requiring more than 10% cumulative annual energy savings by 2020 through DSM policies.[21] Most states are meeting their energy saving goals, and nine states achieved energy savings of more than 1.2% in 2009 or 2010.[22] Ohio recently passed legislation requiring 22% energy savings by 2025, starting at 0.3% annual savings in 2009, ramping up to 1% annual savings by 2014, and 2% in 2019.[23]

Based on all of the above, the Companies should evaluate and implement a much more robust DSM program that would achieve significantly higher annual reductions of peak energy demand and total energy sales. The best way to evaluate the level of DSM that should be pursued is to allow DSM programs to compete against supply side resources on equal footing in any energy planning modeling undertaken by the Companies. In addition, the Commission should follow ICF's recommendation and call on the Companies to conduct an energy efficiency potential study, which would help the Companies determine how much energy efficiency is available in their service territory and at what cost it is available. American Electric Power

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[18] ICF Plan at 20.
[19] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers.* Energy and Environmental Economics, Inc. and Regulatory Assistance Project, at p. 3-1, *available at* http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf
[20] Governor Steven L. Beshear, 2008, *Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence*, available at http://energy.ky.gov/resources/Pages/EnergyPlan.aspx
[21] American Council for an Energy-Efficient Economy, Energy Efficient Resource Standards: A Progress Report on State Experience (June 2011), at 8-9.
[22] *Id.* at 9.
[23] Ohio Revised Code 4928.66.

recently completed such a study in Ohio and concluded that utilities could realistically reduce load by more than 20% by 2028 with cost effective energy efficiency.

For purposes of the present IRP, the Companies should, at a minimum, assess the impact of achieving higher levels of energy savings and peak demand reduction through the use of DSM. The Environmental Groups recommend that the Companies double their DSM related energy savings to 1% of sales for each of the next three years, and to increase the level to 2% per year thereafter. Such energy savings would save ratepayers money not only by reducing the amount of electricity they need to purchase, but also by enabling the Companies to reduce the amount of new or retrofitted power generation capacity that it pursues.

V. The Companies Should Factor In the Likelihood of a Cost on CO2 Emissions

A serious shortcoming in the Companies' IRP is a failure to assume any cost related to the emission of carbon dioxide ("CO_2"). The Companies currently generate 97% of their electricity from coal, which is the most carbon-intensive energy source there is. Even after the coal unit retirements and natural gas proposals included in this IRP, the Companies would still generate approximately 90% of their electricity from coal. As such, the Companies and their ratepayers have significant exposure in the event that a price is placed on CO_2 emissions or that environmental standards require reductions in those emissions. Given the significant environmental impacts that result from CO_2 emissions, it remains highly probable at some time during the planning horizon under consideration in this IRP the Companies will need to either reduce their CO_2 emissions or pay a fee for such emissions. As such, it is in the best interest of the ratepayers for the Companies to factor that likelihood into their planning and to begin taking cost effective steps now to reduce such emissions.

A regulatory cost related to CO_2 emissions is likely to come in one of two forms. First, there could be a federal price on CO_2 as part of a cap-and-trade type system in which overall CO_2 emissions are capped and then major sources of CO_2 emissions are able to purchase and trade CO_2 pollution allowances. Second, U.S. EPA is in the process of promulgating greenhouse gas New Source Performance Standards ("NSPS") under the federal Clean Air Act. The NSPS is likely to require new sources, and existing sources that carry out modifications, such as the installation of pollution controls that increase greenhouse gas emissions over a certain threshold, to take particular steps to limit their CO_2 emissions. In conjunction with this NSPS rule, EPA is slated to issue binding emission guidelines that will regulate greenhouse gas emissions from electric generating units regardless of whether the source undergoes a major modification.[24] Either regulatory approach is likely to establish some cost for emitting CO_2 or to achieve required reductions in such emissions.

While the Companies pretend to ignore CO_2 costs on the grounds that those costs are purely speculative and unknowable, they in reality treat the CO_2 issue as if there were complete

[24] See, e.g., Settlement Agreement between EPA and various states and Environmental Groups (*New York v. EPA*, D.C. Cir. No. 06-1322, and *American Petroleum Institute v. EPA*, D.C. Cir. No. 08-1277); see Fact Sheet describing settlement at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf

certainty around it. In particular, the Companies assign a price of $0 to CO_2 emissions, which means that the Companies are asserting certainty that neither EPA nor Congress will not regulate or establish a price for CO_2 over the 15 year IRP planning period. In fact, in testimony recently filed with the Commission, the Companies claimed that "it would be imprudent" to assume otherwise.[25]

Numerous other utilities disagree with the Companies' certainty. For example, here is a list of just some of the utilities that have included a price related to CO2 emissions in recent energy planning:

- In September 2011, Duke Energy Carolinas submitted an IRP in South Carolina that assumed a CO2 price starting at $12 per ton in 2016 and increasing to $42 per ton by 2031.[26] The filing also used higher CO2 price assumptions from 2009 and 2010 IRPs as the basis for sensitivity analyses.[27]

- In an August 2011 filing, Georgia Power (a subsidiary of Southern Company) modeled four different CO2 price scenarios - $0, $10, $20, and $30 per ton – starting in 2015 in order to "span the plausible short term and long term range of CO2 requirements"[28]

- In July 2011, Duke Energy Ohio submitted an IRP that included a "CO2 price curve beginning in 2016 to represent the potential for future federal climate legislation."[29]

- In March 2011, the Tennessee Valley Authority submitted an IRP that tested eight scenarios involving CO2 prices that ranged from $0 throughout the planning period to a price starting at $17 per ton in 2012 and increasing to $94 per ton by 2030.[30]

- In March 2011, PacifiCorp submitted an IRP in Utah in which the utility modeled four different CO2 price scenarios, ranging from an assumption of no CO2 price, to prices starting in 2015 at $12, $19, or $25 per ton and escalating at different rates after that through 2030. The utility also modeled two scenarios involving hard caps on overall CO2 emissions.[31]

- In February 2011, Ameren Missouri submitted an IRP that included an evaluation of CO2 cap-and-trade scenarios involving a CO2 cost that started at $7.50 per ton in 2015 and increases to $47.22 in 2040.[32]

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[25] PSC Case No. 2011-00161, Rebuttal Testimony of David S. Sinclair at p. 31 lines 11-12.

[26] Duke Energy Carolinas, LLC's 2011 Integrated Resource Plan (Sept. 1, 2011), at 100-101.

[27] *Id.*

[28] Georgia Power's Application for Decertification and Updated Integrated Resource Plan, Georgia PSC Docket No. 34218 (Aug. 4, 2011), at 37.

[29] Duke Energy Ohio, Inc., 2011 Electric Long Term Forecast Report and Resource Plan, Ohio PUC Case No. 11-1439-EL-FOR (July 15, 2011), at 186.

[30] Tennessee Valley Authority, Integrated Resource Plan: TVA's Environmental and Energy Future (Mar. 2011), at 96.

[31] PacifiCorp, 2011 Integrated Resource Plan (Mar. 31, 2011), at 159-160.

[32] Ameren Missouri, 2011 Integrated Resource Plan (Feb. 2011), at 31.

- In December 2010, Delmarva Delaware filed an IRP in which it assumes a federal CO2 price of $20 per ton in 2018, increasing to $25 per ton by 2020.[33]

The Companies are correct that there is uncertainty about what the future cost of CO2 emissions will be. But the proper way to address such uncertainty is not to simply declare that there will be no cost. Instead, prudent utility planning calls for carrying out sensitivity analyses that assume a range of different CO2 prices and assigning reasonable probabilities to each scenario so that the lowest cost plan for approaching likely future scenarios can be developed.

Moreover, under the already promulgated tailoring rule existing facilities that perform a major modification that would increase GHG emissions by at least 75,000 tpy CO2e, and that also exceed 100/250 tons per year of GHGs on a mass basis, will be required to obtain construction permits that address GHG emissions (regardless of whether they emit enough non-GHG pollutants to require a permit for those emissions.).[34] The Companies anticipate in the "no retirements" Strategist run, performed for the CPCN to retrofit four power plants docket no: 2011-00161, 2011-00162, that some of their coal units—units that are receiving major environmental modifications—would increase GHG emissions beyond this threshold in the next few years. Therefore, it was completely unreasonable for the Companies to not address this regulation. That would mean that these units need to establish emission limits based on the Best Available Control Technology ("BACT") for these units.[35]

The Environmental Groups recommend that the Companies carry out such analyses using the mid-range, low, and high CO2 price projections set forth in the CO2 price forecast from Synapse Energy Economics that is further discussed in the attached report from Dr. Jeremy Fisher.

VI. The Companies' Evaluation of Supply Side Resources Understates the Substantial Costs Facing the Companies' Aging Coal Units.

The IRP is also flawed because it presents an inadequate assessment of the significant costs that would need to be incurred to keep the Companies' aging coal-fired electric generating units operating throughout the planning period. In their IRP, the Companies rely on an analysis they did in the context of a separate Commission proceeding in which the Companies are seeking Certificates of Public Necessity and Convenience ("CPCN") for the installation of pollution controls on a number of their coal units. In the CPCN proceedings, the Companies carried out Strategist modeling to determine the net present value revenue requirement ("NPVRR") of retrofitting versus retiring each of its coal units. Through that analysis, the Companies concluded that it would be most cost effective to retire the Cane Run, Green River, and Tyrone

[33] Delmarva Delaware, IRP Filing Resource Modeling – Supporting Documentation (Dec. 1, 2010), at 16-17.
[34] 40 C.F.R. 52.21(b)(49)(v)(b).

[35] See, e.g., EPA Guidance Document on GHG Permitting, available at: http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

coal units and decided that the rest of their coal units should be retrofitted to comply with existing and pending U.S. EPA environmental regulations.

As explained in the attached report by Dr. Jeremy Fisher from Synapse Energy Economics, the Strategist modeling carried out by the Companies was flawed in a number of ways that understate the substantial costs facing the Companies' coal units. Specific flaws in the modeling identified by Dr. Fisher include:

- **Natural gas price correction:** The Companies' base-case natural gas price forecast appears to inappropriately represent the highest end of gas price assumptions;

- **SCR cost:** The Companies have inappropriately dismissed the risk that some of its units may require selective catalytic reduction (SCR) to meet emissions limits for oxides of nitrogen (NO_x) under both promulgated and proposed ozone standards;[36]

- **CO_2 price risk:** The Companies have assumed that there is no chance that the federal government will regulate carbon dioxide (CO_2) emissions anytime in the future, thereby exposing ratepayers to a very real financial risk;

- **Oversized replacement capacity:** The Companies assume that replacement generation is only available from three types of natural gas plants, a single-cycle turbine of 194 MW, and two combined cycle sized at 605 and 907 MW (summer capacity), respectively. These large-size combined cycle units are larger than many of the coal units under consideration, forcing the model to only evaluate unduly expensive alternatives that present potentially non-optimal solutions.

- **Utility modeled in isolation:** The model used by the Companies assumes that they have no interactions with the Eastern Interconnection, which forces the model into unrealistic solutions.

- **Emergency generation purchases:** The model uses a very high cost for emergency generation with an unreasonably high frequency, resulting in very high costs with no apparent basis.

- **NO_x and SO_2 Prices:** The Companies have assumed that the trading price of NO_x and sulfur dioxide (SO_2) will diminish to zero in two years, in contradiction to

[36] Not identified in Dr. Fisher's Testimony but acknowledged by the Companies in their response to comments, the second phase of CSAPR is likely to require units without SCRs to install that technology. KU's Response to Commission Staff's First Information Request, Question 20, in Docket No. 2011-00161. When CSAPR was issued, it was acknowledged that a second phase was coming because the rule was not based on the latest ozone NAAQS. 76 Fed. Reg. 48,259. In addition, subsequent phases of the rule would issue each time the ozone NAAQS was changed. Id.

EPA estimates; thereby denying the Companies the opportunity cost of avoiding these emissions through retirement or emissions controls.

- **Order of Retirement:** The Companies have chosen a semi-arbitrary order in which to test the retire/retrofit decision without regard to the impact that this order imposes on the modeled economic merit of each unit. Simply changing this order could result in a more optimal solution and retire/retrofit decisions.

Synapse reran the modeling carried out by the Companies using more reasonable assumptions regarding natural gas prices, CO2 prices, and the need for SCRs, and found that the NPVRR of retrofitting each of the Companies' coal units declined significantly. That modeling showed that the economics generally favors retirement, rather than retrofitting, of Brown Units 1 and 2 and, depending on the scenarios, a number of the other Companies' other coal units were also more economic to retire rather than retrofit.[37]

The new modeling analyses performed by Synapse also understates the costs facing the Companies' coal units, as limited time and resources restricted the number of factors that could be fully evaluated and modeled. Additional costs or not reflected in either the Companies or the Synapse modeling that are relevant to the question of whether Brown Units 1 and 2 and other coal units should be retired or retrofitted include:

- **Age of the Coal Units:** As the Companies note, the typical design life for coal unit is 50 years. (IRP at 5-49). Put into service, Brown Unit 1 has already exceeded that design life, and Brown Unit 2 will turn 50 years old in 2013. The Companies have noted that, based on a "life assessment study" the probable retirement year for those two units is 2026, at which time they would be 70 and 63 years old, respectively.[38] A retirement date of 2026 was also identified for Ghent Unit 1 and Mill Creek Units 1 and 2.[39] Yet for purposes of modeling retirement versus retrofit of those units, the Companies assumed that the units would continue operating (and generating revenue) through 2040, at which time Brown Unit 1 would be 84 years old, and Brown Unit 2 would be 77 years old. Such unrealistic and inconsistent assumptions about the lifespan of those units biased the analysis in favor of retrofitting coal units rather than retiring them.

- **Non-Environmental Capital Costs for Coal Units:** It is quite likely that any coal units – such as Brown Units 1 and 2 - that operate beyond their design life will require substantial additional capital investments simply to continue operating. The Companies acknowledge as much, stating that coal units that operate beyond their design life "run a greater risk of catastrophic failure," (IRP at 8-106) and that older units will require additional investment. (IRP at 5-50). Yet in modeling the costs facing its coal units, the Companies assumed relatively steady non-environmental capital investments increasing at a rate of 2.5% per year. That assumption does not reflect the full range of capital costs

[37] Dr. Fisher Report at Ex. JIF-E2.
[38] PSC Case No. 2011-00161, KU Response to KIUC's Data Request No. 2-8
[39] PSC Case No. 2011-00161, LG&E Response to KIUC's Data Request No. 2-8

that would likely be needed to keep the Companies aging coal units operating through their probable retirement dates, much less through 2040.

- **Emission Allowance Prices:** As Dr. Fisher explains in his report, the Companies assumed in their retirement vs. retrofit modeling that the value of SO2 and NOx emission allowances would decline to zero by 2014. This assumption is incorrect, as the Companies themselves realized in including SO2 and NOx emission allowance prices for every year through 2035 in their evaluation of DSM.[40] Failure to include these prices in their retirement vs. retrofit modeling biases the analysis in favor of retrofit, especially given that the Cross State Air Pollution Rule allows coal units to continue to receive allowance for four years after they retire.[41]

- **Emergency Generation Purchases:** As Dr. Fisher explains in his report, the Companies factored in a cost of $16,600 per MWh to reflect the costs incurred by its customers when there is an interruption in electric service. This approach is unreasonable because that cost figure vastly exceeds the cost of emergency power that would be able to avoid such interruptions of service in the great majority of situations. In rebuttal testimony in the CPCN proceedings, the Companies acknowledged that assuming a more reasonable emergency generation cost of $1,000 per MWh would reduce the NPVRR of retrofitting Brown Units 1 and 2 by $23 million, and of Mill Creek Units 1 and 2 by $80 million.[42]

- **Other Regulations:** The IRP assumes no costs for complying with pending regulations on disposal of coal combustion waste, water intake structures, or effluent limitation guidelines, despite the risk that these costs could be large and that these regulations could require capital investments within the time period of this IRP. Rather than quantitatively considering scenarios that include cost of compliance with coal combustion waste regulation, the IRP notes that "The companies will continue to review this issue." (IRP at 8-137). The IRP contains the same statement regarding regulation of cooling water intake structures, and again regarding Clean Water Act effluent guidelines. (IRP at 8-106, 8-134).

Determining the most economically efficient resource option requires a comprehensive and detailed assessment of the costs associated with a variety of options. This assessment must include a full understanding of all of the costs that are associated with specific options, such as retrofitting potentially inefficient and aging coal plants to make them compliant with environmental regulations, as well as an understanding and evaluation of costs and the risk of costs that can reasonably be anticipated for specific options. The IRP submitted by the Companies does not satisfy these basic standards.

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[40] Companies' Resp. to PSC Staff's Second Information Request No. 8.
[41] PSC Case No. 2011-00375, Companies Resp. to PSC Staff Information Request No. 26.
[42] PSC Case Nos. 2011-00161 and 00162, Rebuttal Testimony of Charles R. Schram, Ex. CRS-2.

VII. The Need to Factor In Uncertainty

A final, overarching concern about the IRP is that it does not assess the uncertainties and risks attendant on a resource plan. A resource plan that is projected to have the lowest life cycle cost under one set of assumptions about the future, may or may not also be the best under another set of assumptions. Assumptions that can make a material difference to the performance of resource plans include, but are not limited to, (1) load growth and other factors affecting the size and timing of resource needs over time, such as trends in customer types, end use make up and load shape, (2) cost, availability and deliverability of fuels, equipment, construction materials and expertise, labor, land, transmission service and other goods and services that determine the cost of the various resources in the portfolio, (3) financial factors, such as inflation rates, utility bond ratings and changes in the rating criteria, cost and availability of various types of insurance, cost and availability of various types of capital, (4) factors relating to implementation schedules and "lumpiness" of various resource options, such as construction or installation times or delays in those times, risk of project failure or cost increase, (5) environmental and regulatory risks, such changes in emission standards (including the likelihood of CO_2 regulations), new emission standards or fees, permitting risk, and (6) planning risk, for example, the risk that a resource will become obsolete or unnecessary while under construction.

While the technicalities can be somewhat abstract, the essence of risk and uncertainty assessment in this context is to measure the variability of a resource portfolio's results due to uncertainties in factors or assumptions. The IRP should, but does not, contain (1) a thorough inventory and description of the relevant risks, together with an assessment of their probabilities, (2) an objective analysis of how those risks impact the performance of various resource plans individually and in combination, (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life-cycle cost over the fullest possible range of plausible future scenarios.

VIII. Conclusion

In order to ensure that the Companies go down the path of the lowest cost approach for meeting their customers' energy needs, the Companies should address and correct the above errors in their IRP.

Dated: November 29, 2011

Respectfully submitted,

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CERTIFICATE OF SERVICE

I certify that I served a copy of Environmental Groups' Comments via first class mail on November 29, 2011, to the following:

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Errata Sheet re: Environmental Groups' Corrected Comments

<u>On page 9:</u>

- Change the parenthetical abbreviation CO_2 (and similar textual abbreviations thereafter), to CO2.

- Change the fifth sentence under heading number V from

  Given the significant environmental impacts that result from CO2 emissions, it remains very likely that the Companies will be required at some time during the planning horizon under consideration in this IRP to either reduce their CO2 emissions or pay a fee for such emissions.

to

  Given the significant environmental impacts that result from CO2 emissions, it remains highly probable at some time during the planning horizon under consideration in this IRP the Companies will need to either reduce their CO2 emissions or pay a fee for such emissions.

- Insert the following paragraph (thus, adjusting the footnote numbering, accordingly) after the second full paragraph under heading number V:

  A regulatory cost related to CO2 emissions is likely to come in one of two forms. First, there could be a federal price on CO2 as part of a cap-and-trade type system in which overall CO2 emissions are capped and then major sources of CO2 emissions are able to purchase and trade CO2 pollution allowances. Second, U.S. EPA is in the process of promulgating greenhouse gas New Source Performance Standards ("NSPS") under the federal Clean Air Act. The NSPS is likely to require new sources, and existing sources that carry out modifications, such as the installation of pollution controls that increase greenhouse gas emissions over a certain threshold, to take particular steps to limit their CO2 emissions. In conjunction with this NSPS rule, EPA is slated to issue binding emission guidelines that will regulate greenhouse gas emissions from electric generating units regardless of whether the source undergoes a major modification.[24] Either regulatory approach is likely to establish some cost for emitting CO2 or to achieve required reductions in such emissions.

- Change the second-last complete sentence of the page from

  In particular, the Companies assign a price of $0 to CO2 emissions, which means that the Companies are asserting certainty that there will not be any regulations or price for CO2 over the 15 year IRP planning period.

  to

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[24] See, e.g., Settlement Agreement between EPA and various states and Environmental Groups (*New York v. EPA*, D.C. Cir. No. 06-1322, and *American Petroleum Institute v. EPA*, D.C. Cir. No. 08-1277); see Fact Sheet describing settlement at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf.

In particular, the Companies assign a price of $0 to CO2 emissions, which means that the Companies are asserting certainty that neither EPA nor Congress will not regulate or establish a price for CO2 over the 15 year IRP planning period.

On page 11:

- Insert the following paragraph (thus, adjusting the footnote numbering, accordingly) before the final full paragraph of heading number **V**:

  Moreover, under the already promulgated tailoring rule existing facilities that perform a major modification that would increase GHG emissions by at least 75,000 tpy CO2e, and that also exceed 100/250 tons per year of GHGs on a mass basis, will be required to obtain construction permits that address GHG emissions (regardless of whether they emit enough non-GHG pollutants to require a permit for those emissions.).[34] The Companies anticipate in the "no retirements" Strategist run, performed for the CPCN to retrofit four power plants docket no: 2011-00161, 2011-00162, that some of their coal units—units that are receiving major environmental modifications—would increase GHG emissions beyond this threshold in the next few years. Therefore, it was completely unreasonable for the Companies to not address this regulation. That would mean that these units need to establish emission limits based on the Best Available Control Technology ("BACT") for these units.[35]

- Insert the following footnote (thus, adjusting the footnote numbering, accordingly) at the end of the bullet point, **SCR cost**:

  [36] Not identified in Dr. Fisher's Testimony but acknowledged by the Companies in their response to comments, the second phase of CSAPR is likely to require units without SCRs to install that technology. KU's Response to Commission Staff's First Information Request, Question 20, in Docket No. 2011-00161. When CSAPR was issued, it was acknowledged that a second phase was coming because the rule was not based on the latest ozone NAAQS. 76 Fed. Reg. 48,259. In addition, subsequent phases of the rule would issue each time the ozone NAAQS was changed. Id.

[34] 40 C.F.R. 52.21(b)(49)(v)(b).
[35] See, e.g., EPA Guidance Document on GHG Permitting, available at: http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.