COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC., FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF NEW TARIFFS; 3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 4) ALL OTHER REQUIRED APPROVALS AND RELIEF.	**))))))))**	**CASE NO. 2019-000271**

DIRECT TESTIMONY OF BRIAN C. COLLINS
ON BEHALF OF
NORTHERN KENTUCKY UNIVERSITY

Filed: December 13, 2019

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Q. Please state your name and business address.

A. Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. What is your occupation?

A. I am a consultant in the field of public utility regulation and a Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please describe your educational background and experience.

A. This information is included in Attachment BCC-1.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of Northern Kentucky University ("NKU"). NKU purchases a substantial amount of electricity from Duke Energy Kentucky, Inc. ("DEK" or "Company").

Q. What is the subject matter of your testimony?

A. I will comment on the Company's proposed class cost of service studies ("CCOSS") as well as its proposed class revenue allocation. I will also comment on DEK's Battery Storage Project, EV Pilots, and Major Storm Deferral Mechanism proposals. My silence on any issue addressed by the Company in its testimony should not be taken as tacit approval or agreement with that issue.

Q. What are your findings and recommendations?

A. My findings and recommendations are as follows:

1. I do not object to the Company's recommended CCOSS that allocates production-related costs using the Average of the Twelve Coincident Peaks ("12 CP") and allocates certain distribution costs partially on a customer basis to the Company's rate classes in this proceeding.

2. I do not object to the Company's proposed class revenue allocation in this proceeding because it recognizes the principle of gradualism.

3. I am opposed to the Company's proposed Major Storm Deferral Mechanism. DEK has not demonstrated that the current regulatory tools available to it are inadequate to recover major storm costs.

4. If the Commission approves DEK's proposed EV Pilots, I recommend additional consumer protections that are necessary to ensure value to DEK customers.

5. If the Commission approves DEK's proposed Battery Storage Project, I recommend additional consumer protections that are necessary to ensure value to DEK customers.

<u>Company's Proposed CCOSS</u>

Q. Did the Company prepare a CCOSS in order to allocate its proposed revenue requirement to its rate classes?

A. Yes. According to the testimony presented by Company witness James E. Ziolkowski, the Company prepared three CCOSS for its test year consisting of the 12 months ending March 31, 2021. The three studies prepared by the Company differ by the methodology used to develop the allocation factor for the demand component of production-related costs. The three methods used by the Company for allocating production-related costs to classes include: (1) the 12 CP method; (2) the Average and Excess ("A&E") method; and (3) the Production Stacking method.

For this proceeding, the Company recommends the use of the 12 CP cost of service methodology for allocating costs to its rate classes. This is the methodology used by the Company in its last rate case and is an accepted methodology in the electric utility industry.

Q. Have you reviewed the Company's proposed CCOSS in the context of developing your findings and recommendations?

A. Yes, I have.

Q. How does the Company's 12 CP cost allocation methodology allocate demand-related costs to customer classes?

A. Each respective customer class's cost responsibility for production-related costs is equal to the ratio of its respective demand in relation to the total demand placed on the Company's system. The 12 CP cost allocation methodology used by the Company allocates production and transmission demand-related costs to classes based upon the 12 monthly coincident peaks.

Q. Could an argument be made for the use of a 4 CP cost allocation methodology to allocate demand-related costs to customer classes?

A. Yes. Based on my review of the Company's 12 monthly system peaks, an argument could be made to allocate costs on the four highest peaks of the Company which occur in the summer months. However, this would not capture any demands of the electric heating class because this class has approximately zero demand in the summer. The Company's use of a 12 CP methodology captures the non-summer demands of the electric heating class when allocating demand-related costs to the Company's rate classes.

Q. Did the Company allocate a portion of certain distribution-related costs on a customer basis to classes in its recommended CCOSS?

A. Yes. The costs of distribution poles, conductors, and transformers were allocated between customer and demand using the minimum size method. It is appropriate to allocate these costs partially on a demand basis because this equipment is sized to meet the maximum demand on the Company's system. It is also appropriate to allocate these costs partially on a customer basis because the utility also incurs the costs of this equipment to connect customers to its distribution system that are geographically dispersed throughout its service area. Allocating these costs on both a demand and customer basis appropriately reflects class cost of service and the principles of cost causation.

Q. How did the Company determine the customer component of distribution poles, conductors, and transformer costs?

A. The Company used the minimum size method to allocate these costs between customer and demand-related cost components. The minimum size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the Company's customers.

Q. Is the Company's proposal for the allocation of poles, conductors and transformer costs to its rate classes partially on a customer basis reasonable?

A. Yes. Classifying and allocating these costs on both a demand and customer basis is consistent with cost causation and is a generally accepted costing methodology in the utility industry. The primary purpose of the distribution system is to deliver power from the transmission grid to the Company's customers in various geographical locations with service at different voltage levels. Certain distribution investments must be made just to connect a customer to the system. Also, many equipment manufacturers have only minimum sized equipment available. Safety concerns and construction practices often require minimum sized equipment which is not determined by demand. These investments are properly considered to be customer-related.

Q. Why do you believe that the minimum size system is an acceptable industry practice?

A. The concept of a minimum size distribution system has been accepted for decades as a valid consideration by numerous state public utility commissions. It has also been presented in the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") published by NARUC.

The central idea behind the minimum size system concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution systems and connects an additional customer to them. By definition, the minimum size system comprises every distribution component necessary to provide utility service, i.e., meters, service drops, secondary and primary wires, poles, transformers, etc. The cost of the minimum size system, however, is only that portion of the total distribution cost the utility must incur to provide service to customers. It does not include costs specifically incurred to meet the peak demand of the customers.

Q. Please elaborate further on the minimum size system concept and the distinction between customer-related and demand-related costs in the context of a CCOSS.

A. A certain portion of the cost of the distribution system–poles, conductors and transformers–is required just to attach customers to the system in different geographical locations, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered as customer-related cost since it depends primarily on the number of customers, rather than on demand or energy usage.

Q. Do you object to the use of the Company's recommended CCOSS based on the 12 CP method and on the classification of certain distribution costs as customer-related for allocating costs to rate classes in this proceeding?

A. No, I do not.

<u>Company's Proposed Class Revenue Allocation</u>

Q. What is the overall rate of return calculated by the Company in its CCOSS?

A. The overall rate of return calculated by the Company in its CCOSS at present rates is 3.03%.[1]

Q. What are the class rates of return results for the Company's recommended CCOSS based on the 12 CP cost of service methodology?

A. The results of the Company's 12 CP CCOSS indicate that six rate classes, specifically Rates DS, GS-FL, SP, DT-Secondary, DT-Primary, and TT are providing rates of return above the system average rate of return of 3.03% at present rates. The CCOSS indicates that five rate classes, specifically Rates RS, EH, DP, Lighting, and Water Pumping are providing rates of return below the system average rate of return.

A CCOSS compares the cost that each customer class imposes on the system to the revenues each class contributes. This relationship is generally presented by comparing the rate of return that a class is providing with the utility's overall jurisdictional rate of return. A rate class that produces a rate of return above the system average rate of return is providing revenue in excess of its allocated class cost of service. It is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce below system average rates of return.

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[1] Company's response to NKU-DR-02-008, Attachment, Page 1 of 1.

A rate class that produces a rate of return below the system average rate of return provides revenue that does not recover its allocated class cost of service. The revenue provided by the class is insufficient to cover all relevant costs to serve that class.

Q. Does the Company base its proposed class revenue allocation on its recommended CCOSS?

A. The Company uses the results of its recommended CCOSS as a guide in allocating its revenue requirement to its rate classes but does not propose to bring all classes to full cost of service. Because the Company's CCOSS indicated that there were considerable differences among the rate classes with respect to the rate of return provided to the Company at present rates, some classes would experience much greater increases on a percentage basis as compared to other classes in order to bring all classes to cost of service. At cost of service based rates, each class would provide the proposed system average return of 6.71%.

As a result, the Company determined that it was appropriate to mitigate rate shock for certain customer rate classes by not bringing all classes to their calculated class cost of service under proposed rates. To accomplish this, the Company is proposing a two-step process to allocate its proposed revenue increase to rate classes. The first step eliminates 5 percent of the subsidy/excess revenue between customer classes based on present revenues. The second step allocates the rate increase to customer classes based on rate base.

Q. Do you object to the Company's proposed class revenue allocation in this proceeding?

A. No, I do not. The Company's proposal recognizes that some classes would experience large cost of service based increases without some form of rate mitigation. The Company's proposed class revenue allocation results in some movement toward cost of service and appropriately recognizes the principle of gradualism.

<u>**Major Storm Deferral Mechanism**</u>

Q. Have you reviewed DEK's testimony regarding a major storm deferral mechanism?

A. Yes. I have reviewed the testimony of DEK witnesses Danielle L. Weatherston and William Don Wathen Jr.

Q. Do you agree with DEK's proposal for implementing a major storm deferral mechanism?

A. No, I am opposed to implementing the major storm deferral mechanism. I would also note that DEK's proposal could also be classified as a major storm expense tracker.

Q. How do storm expense trackers and the major storm deferral mechanism work as proposed by DEK?

A. DEK would "track" actual expenses for major storms and compare the actual expense level to that level of costs built into customer base rates. The difference would be classified either as a regulatory asset in those instances where actual storm costs exceeded the level built into customer base rates or a regulatory liability where the actual storm costs were less than the amount built into customer base rates.

Q. Why are you opposed to DEK's proposed storm tracker?

A. DEK has failed to demonstrate a need for a major storm tracker. DEK did not demonstrate in testimony any instances wherein DEK showed significant under recovery or over recovery of major storm costs. DEK merely makes statements about the fairness of its proposed tracker.

Q. What is your general view regarding trackers?

A. Trackers should only be used in rare instances.

Q. Why should trackers only be used in rare instances?

A. There are several reasons why I believe trackers should only be used in rare instances. First, the use of a tracker engages in single-issue ratemaking. The tracked expense is singled out for assessment during a period of time when all other operations of the utility are not considered. For example, assume storms are being tracked during 2019 and those storm costs are greater than the level built into customer rates by $1,000. Now also assume that during 2019, the cost of office supplies decreased by $1,500 from the level built into customer rates, with all other costs equal to the amounts included in customer rates. The utility is still collecting enough revenues (actually more revenues) to cover all of its expenses. Yet because of the tracker, future customers will have to pay for the $1,000 greater expense in storms although the utility total cost of service decreased by $500 in this example. The use of trackers clearly engages in single-issue ratemaking. Single-issue ratemaking is also referred to as violating the all relevant factors test. This test requires that all relevant factors of a utility cost of service be determined during the same time period. By using a tracker, a utility is violating the all relevant factors test.

Second, the use of trackers eliminates the utility's incentive to control costs. When actual incurred expenses are simply included in customer rates, a utility has no incentive to control costs. Any increased spending will simply be captured in the tracker, thus there is no incentive to control costs. This disincentive to control costs can lead to gold-plating utility infrastructure. This disincentive could be accomplished by doing more expensive types of repairs than would not ordinarily be performed, but for the tracker.

Third, the tracker as proposed by DEK traces dollar for dollar recovery of storm costs. DEK proposes to simply remove all uncertainty with respect to storm cost recovery without regard to the actual level of deviation in the expense. As discussed above, total utility costs will actually vary from year to year, and if they exceed a certain amount such that the utility feels it cannot earn a reasonable return, then it can file a rate case.

Finally, and most importantly, DEK already has the financial protection in place for recovery of major storm costs. If a major storm would strike DEK's service territory and cause significant damage to the DEK infrastructure, DEK has the special regulatory tools at its disposal to capture those extraordinary costs. DEK would simply file an Accounting Authority Order request with the Commission to defer those storm costs for possible recovery in a future period. In fact, DEK has exercised this option in Case No. 2018-00416.

Q. How do you respond to the argument that a tracker is simply easier and does not cause undue regulation from the Commission?

A. Easing any supposed regulatory burden may not result in just and reasonable rates. Many of the points I previously discussed regarding my opposition to trackers would support just and reasonable rates for DEK customers. Commissions in general are tasked with the authority to set just and reasonable rates. Given that task, the special regulatory tools available to DEK may require additional work by this Commission, but at the conclusion, rates will be set to cover actual costs and nothing more.

Q. Please summarize your position on DEK's proposed major storm deferral mechanism.

A. I am opposed to implementing this accounting deferral mechanism. DEK has not demonstrated that the current regulatory framework has resulted in significant financial harm to DEK. Deferrals are a form of single-issue ratemaking. Deferrals can create incentives to not control spending, thus increasing customer rates. DEK's proposed deferral will trace dollar for dollar changes in one category of expense which may not constitute a significant deviation in the overall cost of service of DEK. Certain costs may go up, while other costs may go down from the level of costs included in customer rates, obviating the need for an increase in cost recovery. Once the utility cannot earn a fair return, it is free to file a rate case. For all these reasons, I am opposed to the storm accounting deferral mechanism proposed by DEK.

Q. If the Commission is not persuaded by your arguments, do you have an alternative method to propose?

A. Yes, I do. I would propose that the level of annual major storm expenses currently included in base rates be recorded in a major storm reserve account. When DEK experiences a major storm in its service territory, the costs to repair the system would be deducted from the reserve. By analyzing the reserve one can determine if the current funding for major storms is sufficient to cover actual major storm costs. For example, if the major storm reserve grows, this would indicate that the annual level of expense included in base rates is greater than the costs to date for major storms. If the opposite occurred where the major storm reserve is negative, this would indicate that the annual level of expense was not sufficient to cover the costs of major storms. Also, by analyzing the storm reserve, one can determine if the current expense built into base rates is causing a material difference from actual storm costs. The storm reserve can be reviewed at any time to measure the adequacy of the storm expense built into base rates.

Q. How is this different than the DEK proposal?

A. By establishing a major storm reserve account, DEK would have the necessary tool to determine if the annual level of expense was sufficient to address costs associated with major storms. The storm reserve account will also allow parties to determine if the difference between what expense is included in rates and the costs of major storms is significant enough to justify a storm tracker. As I mentioned earlier, a tracker traces dollar for dollar fluctuations of cost in specific expense, which is something that regulation was not intended to address. There may be a situation wherein the difference between the costs of major storms and the amount included in rates results in a minor difference in costs. In that situation, the Commission should not desire the use of a storm tracker.

Q. Do you have any summary comments on the major storm reserve account proposal?

A. Yes, the major storm reserve account proposal is an alternative the Commission could accept to use to determine whether special cost recovery is actually needed for major storm expenses. By evaluating the major storm reserve account level, the Commission can determine if no action or additional special cost recovery (storm tracker) is necessary for DEK to recover its cost of service. However, until it can be shown that the current special regulatory tools available to DEK – Accounting Authority Orders – do not result in sufficient cost recovery, the Commission should deny DEK's request for a major storm deferral mechanism or tracker.

<u>Electric Vehicle/Transportation Pilot Programs</u>

Q. Have you reviewed the pilot programs proposed by DEK regarding electric vehicle/transportation programs ("EV Pilots")?

A. Yes. I have reviewed the testimony of DEK witnesses Lang Reynolds, Sarah Lawler, and Danielle Weatherston as it relates to the EV Pilots.

Q. Please explain DEK's proposal as it relates to the EV Pilots.

A. DEK has proposed several pilot programs regarding EV transportation. Specifically, DEK is proposing five EV Pilot Programs that I list below:

1. EV Fast Charging,
2. Electric Transit Bus Charging,
3. Non-Road Electrification,
4. Residential EV Charging, and
5. Commercial EV Charging.

In addition, DEK is requesting $395,000 in education, outreach, marketing, and project management costs. My prior reference to EV Pilots includes all of the above programs and costs.

Q. What specific conditions has DEK proposed for the EV Pilots?

A. DEK has proposed the following conditions for the EV Pilots:

1. DEK will install, own and operate up to 5 EV Fast Charging locations totaling 10 charging stations.
2. DEK will credit customers through the Profit Sharing Mechanism ("PSM") rider for any net revenues generated by the EV Fast Charging Stations. Note, this will require a modification to the current Rider PSM.

3. DEK will continue to operate the EV Fast Charging Stations beyond the Pilot Program period of three years until the end of the assets' useful life (10 years).

4. DEK will deploy EV Bus Charging Stations to prospective customers.

5. DEK will continue to operate the EV Bus Charging Stations beyond the Pilot Program (three years) until the end of the assets' useful life (10 years).

6. DEK will provide incentive funding to grow Non-road Electrification Usage.

7. DEK will provide incentives for, and monitor up to, 300 Residential Charging Stations.

8. DEK will provide incentives for, and monitor up to, 160 Commercial Charging Stations.

9. DEK will invest approximately $85,970 toward Marketing, Education, & Outreach for the EV Pilots. In addition, DEK will spend $308,780 in Project Management.

10. The EV Pilots will last three years.

11. DEK will defer in a regulatory asset all Operation and Maintenance ("O&M") costs associated with the EV Pilots.

12. DEK will file a Report on the EV Pilots six months after the expiration of the EV Pilot Program.

13. DEK proposes $1.375 million of capital investment and $1.459 million of O&M for the EV Pilots. The amount included in rate base reflects the 13-month average rate base as calculated by DEK for the forecasted test year ended March 31, 2021.

Q. If the Commission approves the EV Pilots, do you have additional conditions you recommend the Commission require of DEK?

A. Yes. I believe that additional consumer protections are necessary to ensure value to DEK customers. Furthermore, the EV Pilots should not be construed to support additional EV investments until a full review, including a cost/benefit analysis, of the EV pilots is subsequently performed and filed with the Commission.

Q. If the EV Pilots are approved by the Commission, what are the additional consumer protections that should be included in the EV Pilots?

A. If the Commission approves the EV Pilots, I recommend several additional consumer protections associated with the EV Pilots listed below:

1. The investment and O&M costs in the EV Pilots should be limited to those total dollar values listed on Table 1 of DEK witness Reynolds' direct testimony at page 9. (Application, Volume 16, part 2 of 2, page 11 of 219.) DEK should be restricted to those investment totals until a further evaluation of the program is conducted as stated below.

2. All revenues generated from all EV Pilot programs should be recorded as an offset to the deferred O&M costs (regulatory asset) proposed by DEK. To the extent the revenues exceed the O&M costs, then a regulatory liability would be created to capture those revenues to be returned to customers in the next rate case. Note that this approach would negate the need to expand the provisions of the current Rider PSM to include EV programs.

3. No extension of the Pilot Programs recovery of investment in EV Bus Charging Stations and Fast Charging Stations should occur beyond three years without prior Commission approval. If stranded investment occurs because of changes in site ownership, any party is free to argue whatever position they desire regarding recovery of those stranded investments.

4. DEK will maintain all documentation to perform a cost/benefit study either at the conclusion of the EV Pilots or included with the direct testimony of DEK during its next rate case if that rate case occurs before the expiration of the EV Pilots. If DEK is required to file a cost/benefit study prior to the expiration of the EV Pilots, DEK will still be required to file a cost/benefit study at the expiration of the EV Pilots. If possible, the cost/benefit analysis should be filed in the public record in order to afford the ratepayers the opportunity to independently assess project benefits.

5. DEK should be prohibited from expanding the EV Pilots before the expiration of the current program. If the Commission does allow DEK to seek expansion of the program before the currently proposed expiration by way of a subsequent filing, all Parties to the current rate case should be notified by DEK and be afforded the opportunity to participate in the filing or proceeding.

6. Once the Pilot program has expired, the Commission should consider whether a separate EV class should be created. This approach would ensure that EV customers pay actual, non-subsidized cost of service rates for this service and help prevent other DEK customers from subsidizing EV investment. This proposal is reasonable because it would help to promote private industry competition in the EV charging station market. Indeed, DEK should not be allowed to exert its monopoly power to restrict, impair or otherwise interfere with competitive entry into the EV charging station market.

7. Any funds received from the Volkswagen Environmental Mitigation Trust Program should be recorded as a regulatory liability to reduce the EV investment in a future DEK rate case.

Q. If the Commission approves the EV Pilot programs, will the consumer protections you recommend provide more benefits to DEK customers?

A. Yes.

Proposed Battery Storage Project

Q. Have you reviewed DEK's proposal for its Battery Storage Project?

A. Yes. I have reviewed the direct testimonies of DEK witnesses Zachary Kuznar and Sarah E. Lawler as it relates to the Company's proposed Battery Storage Project. The Company originally proposed a 5 MW installation near a hospital, but now has revised its proposal to include a 3.4 MW battery storage installation at a different location on the DEK system, the Crittenden Solar Farm.

Q. Please summarize DEK's proposal regarding its Battery Storage Project.

A. DEK proposes the following as it relates to the Battery Storage Project:

1. Include $2.4 million of investment in rate base, which corresponds to an in-service date of December 31, 2020 for the Battery Storage Project. The amount included in rate base reflects the 13-month average rate base as calculated by DEK for the forecasted test year ended March 31, 2021. Because of the revised proposal, the investment amount has been revised.[2]

2. Include in rates a total test year revenue requirement associated with the Battery Storage Project of approximately $350,000.[3]

3. No recognition of any O&M expenses in rates resulting from this rate case for operating the Battery Storage Project.

4. Locate the Battery Storage Project at the Company's Crittenden Solar Farm.

5. Return to customers any revenues associated with the operation of the Battery Storage Project through either Rider FAC or Rider PSM.

6. Battery Storage Project Pilot Program to last for three years.

Q. If the Commission approves the battery storage pilot project, do you have some additional project conditions you recommend be included with Commission approval?

A. Yes. I have identified some consumer protections that I believe should be included with the Battery Storage Project if the Commission approves this pilot project.

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[2] For the latest investment estimate, refer to the Confidential Response to Staff-DR-02-082. Also refer to the response to Staff-DR-03-046.

[3] For the latest revenue requirement estimate, refer to the Confidential Response to Staff-DR-02-079. Also refer to the response to Staff-DR-03-046.

Q. Please describe the customer protections you recommend.

A. First, I propose that DEK be required to document all revenues generated by the Battery Storage Project and provide sufficient information to allow the tracking of those revenues back to customers either through the Rider FAC or Rider PSM.

Second, DEK should maintain the necessary information to evaluate the benefits of the Battery Storage Project to DEK customers. To the extent that DEK files another rate case prior to the expiration of the Battery Storage Project pilot program, DEK should be required to file a cost/benefit study for the Battery Storage Program at the time of the rate case. Ideally, this cost/benefit study should be filed in the public record to enable the ratepayers the opportunity to see the financial "rewards" of the program. If the Pilot Program expires at the end of the proposed three-year period but before the next rate case, the Company should be required to file a cost/benefit study regarding the Battery Storage Project six months after expiration of the pilot. Again, the study should be filed in the public record if possible.

Finally, I recommend that DEK be limited to only that level of investment necessary to install the Battery Storage Project at the solar farm. DEK should be prohibited from further investments in battery storage until a full analysis of the current pilot program is performed and filed with the Commission.

Q. Do you have any additional comments as they relate to DEK's proposal?

A. Yes. If the Commission approves the battery project, I agree that any revenues generated from the Battery Storage Project should be returned to customers.

Because the Company is not recognizing any O&M costs in rates, sharing revenues from the project through Rider PSM between the Company and customers is reasonable; i.e., 90 percent to ratepayers and 10 percent to DEK's shareholders.

If the Commission approves the battery project, DEK should be prohibited from expanding the Battery Storage Project before the expiration of the current program. If the Commission does allow DEK to seek expansion of the program before the currently proposed expiration by way of a subsequent filing, all parties to the current rate case should be notified by DEK and be afforded the opportunity to participate in the filing or proceeding.

Based on Commission approval of the battery project, the Commission should review the results of the pilot program before approving any future battery storage investments on the DEK system.

Finally, Commission approval of this pilot should not be construed as a carte blanche endorsement of future battery storage investments, even with the suggested ratepayer protections previously articulated.

Q. If the Commission approves the battery project, do you believe that the consumer protections discussed above make the proposed Battery Storage project more beneficial to DEK customers?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

Qualifications of Brian C. Collins

Q. Please state your name and business address.

A. Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. What is your occupation and by whom are you employed?

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. Please state your educational background and experience.

A. I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm has participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.