BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Staff's Review of Commission Rules 4 CSR 240-20.060 (Cogeneration), 4 CSR 240-3.155 (Filing Requirements for Electric Utility Cogeneration Tariff Filing), and 4 CSR 240-20.065 (Net Metering)	)))))	File No. EW-2018-0078
In the Matter of a Working Case to Explore Emerging Issues in Utility Regulation	))	Case No. EW-2017-0245

KANSAS CITY POWER & LIGHT COMPANY'S AND KCP&L GREATER MISSOURI OPERATIONS COMPANY'S RESPONSE TO ORDER DIRECTING UTILITIES TO EVALUATE IMPACTS OF STANDARD OFFER CONTRACTS

Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations Company ("GMO") (collectively, "KCP&L/GMO") hereby submit this response to the Order of the Missouri Public Service Commission ("Commission"), filed in these dockets on July 25, 2018. The Commission ordered that no later than August 24th, 2018, Union Electric Company d/b/a Ameren Missouri, Kansas City Power & Light Company, KCP&L Greater Missouri Operations Company, and The Empire District Electric Company shall each file an evaluation of the impacts, including distribution system impacts, of raising the Standard Offer Contract ("SOC") size to 1 MW, 2.5 MW, and 5 MW. For its response, in addition to joint comments of the utilities previously submitted on July 26, the Company states as follows:

1. In discussing SOCs, there are certain components relevant to this discussion in addition to evaluating impacts to the distribution system based on various system sizes. These components include such things as system size, standard rates, standard contract templates, interconnection costs, and term of contracts. As described further, there is limited value in looking at system size limits in isolation of other components when determining impacts of SOCs.

2. With regard to evaluating the impacts of various system sizes on the distribution system, Distributed Energy Resources ("DER"), currently represented mainly by Photovoltaic ("PV"), creates diverse distribution system planning and operational impacts which are very specific to location and the associated grid attributes. Thus, DER deployed without an engineering study guiding placement would certainly result in the utility making reactive investments in time, materials, or both to ensure the local system can accommodate the DER without disturbing grid integrity. Key factors in determining how much DER capacity a distribution feeder can accommodate include; type of DER, size of the DER, location of DER, feeder characteristics, proximity to other DER, and DER control. High DER concentrations in the past have resulted in power quality issues and have required corrective action in the form of additional system investments by the utility. These reactive measures can be impactful to the local grid and frustrate customers, often requiring significant coordination between the customer, the DER provider, and the utility to deploy power quality remedies.

3. From an operational perspective, some of the more significant impacts which can be expected, especially with larger DER systems or concentrations of DER, include reverse power flow conditions, voltage fluctuations, conflict with voltage regulating devices such as substation voltage regulators, line voltage regulators, capacitor banks, etc., reactive power fluctuations and voltage unbalance due to single-phase, typically residential, DER that may already exist on a given feeder. Even small amounts of DER can have a significant impact, particularly at lower system voltages. Therefore, any DER exceeding the customer load or above 100 kW must be subject to site specific analysis by utility planning engineers which would include recommendations for all associated system improvement and interconnection costs. Just because there may be a SOC in place does not mean the generating systems will automatically be connected when requested – the

utility still must do a study to determine any system upgrades and interconnection costs to handle the generation no matter if the customer system size is 1 MW, 2.5 MW, or 5 MW.

4. A typical argument offered by those promoting DER is that DER eliminates needed excess distribution capacity. In practice, distribution design does include additional capacity for the customer's benefit. For example, the additional capacity serves as a secondary customer source upon a primary source line failure as well as capacity for additional load growth. Instead of eliminating excess, ideally, DER eliminates the future capacity needed. However, there are currently several barriers preventing DER from providing these capacity requirements. Most significant is that most customer-owned DER cannot provide reliability at the same level as dispatchable generation. Customers who own dispatchable DER do not always perform proactive maintenance and monitoring. The first time some customers may know their systems are not generating is when the utility credit is not present on the customer's monthly bill. Next, DER is typically an intermittent resource. The most common form of customer owned DER is PV, which will vary according to sunlight variances. Battery DER is a step toward achieving back up capacity. However, battery technology currently does not provide the multiple hours of capacity needed and is prone to similar reliability concerns as customer owned/maintained PV systems.

5. It is important to point out that KCP&L/GMO will accommodate the needs for customer systems of different sizes, and any associated system improvement and interconnection costs identified in a site-specific analysis is paid by the customer prior to contract approval and completion of the customer owned installation.[1] These same provisions are also included in the proposed cogeneration rule 7(A): The customer shall be required to reimburse the utility for the

[1] According to established Extension Rules. For KCP&L these rules are found in Section 9 of the Company rules and Regulations, beginning on Sheet 1.30. For GMO the rules are found in Section 7 of the Company Rules and Regulations, beginning on Sheet R-46.

interconnection costs of any equipment or facilities which result from connecting the customer's generating system with the utility's system. This is consistent with the cost causation principle where costs are assigned to those customers who cause the additional cost on the system. As a result, there is a limited risk of any costs associated with a distribution system upgrade from a 1 MW, 2.5 MW, or 5 MW customer system being subsidized by other rate payers because that cost is separate from any Standard Rate associated with a SOC and is collected from the customer before the system is installed.

6. As described above, from an engineering perspective, KCP&L/GMO can accommodate varying sizes of a customer system, including 1 MW, 2.5 MW, and 5 MW systems, that is part of an SOC through a site-specific analysis and any resulting upgrades needed for the distribution system. In fact, under PURPA, utilities are required to connect such customer systems whether or not such a SOC exists. Standard rates are another common component of a SOC. Section 4(A) of the proposed cogeneration rule states that each electric utility shall put into effect commission-approved standard rates for purchases from qualifying facilities with a (specified) design capacity. SOC is as much about price and not engineering - the larger the SOC size, the more risk will be transferred to other customers when tied to a standard rate. Customer systems have unique profiles and also have demographic and geographical differences. A standard rate that does not take into account such differences runs the risk of overcompensating the customer system and transferring risk to the detriment of other customers. Today customers up to 100 kW are compensated through KCP&L/GMO's standard net metering rate or our parallel generation rate. For customer systems over 100 kW, the rate KCP&L/GMO uses to compensate customers is defined by the avoided cost, but it established through a separate, individual agreement. The

current avoided cost rate is defined and updated every two years in compliance with established cogeneration regulations.

7. Section (4) (C) of Staff's proposed cogeneration rules also state that "the commission shall approve standard contract templates for purchases from qualifying facilities with the design capacities described in (4)(A). The approved standard contract templates will be the basis of the standard contracts utilized by each utility through its respective tariffs." Standard contract template deals with structure and organization of SOCs, and may have placeholders to input specific information that may vary by contract, but a standard template does not necessarily include the same standard sizes, standard rates, and other information that may make up a SOC.

8. Another component of an SOC would also include the technical and performance standards and interconnection test specifications specific to each utility's distribution system. Such technical and performance standards will include provisions related to metering, protection equipment, and disconnect switches. This component of an SOC is captured in Section 4(D) of Staff's proposed cogeneration rule.

9. An additional component of an SOC will typically include a term, or length of contract. A key point for advocates favoring a longer term is the "fixed price" for the length of the contract. KCP&L/GMO previously submitted joint comments on July 26 stating concerns as to why long-term contracts with fixed pricing is not appropriate:

> Forcing utilities into long-term contracts at prices that are potentially substantially above market may provide a producer a favorable economic position, but it could have a negative impact on utility customers. Ultimately, utility customers pay for the energy a utility purchases to serve them. Currently, power producers are free to negotiate with Utilities at any time and receive terms that are based on the current market environment, which puts customers in a financial position comparable to that they would otherwise be in.

> Long-term contracting at an administratively determined set rate, which does not take into consideration the unique conditions of a unique producer, shifts the risk of the generation development from the developer to the customer. All parties should have a primary interest in ensuring that customers are not taking on excessive risks for securing capacity today that isn't needed for a point much further out into the future.

With the options available today in the wholesale markets that did not exist when PURPA came into existence, the risk of overcompensating customer systems to the detriment of other customers through long-term fixed pricing only increases with the increasing system sizes.

10. KCP&L/GMO appreciate the work of Staff in developing recommendations for next steps on these important issues and the opportunity to actively participate in this docket as well as any potential future rulemaking proceedings or other proceedings to address the various recommendations.

WHEREFORE, KCP&L/GMO request the Commission accept its initial response to Staff's Report.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been hand delivered, emailed or mailed, postage prepaid, this 24th day of August 2018, to all counsel of record.

|s| Roger W. Steiner

Counsel for Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company