BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DIRECT TESTIMONY OF

BRADLEY D. LUTZ

ON BEHALF OF
KANSAS CITY POWER & LIGHT COMPANY

IN THE MATTER OF THE APPLICATION OF
KANSAS CITY POWER & LIGHT COMPANY
TO MAKE CERTAIN CHANGES IN
ITS CHARGES FOR ELECTRIC SERVICE

DOCKET NO. 18-KCPE-____-RTS

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Q: Please state your name and business address.

A: My name is Bradley D. Lutz. My business address is 1200 Main, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L" or "Company") as Senior Manager – Regulatory Affairs.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L.

Q: What are your responsibilities?

A: My current responsibilities are focused on regulatory policy, providing support for the Company's regulatory activities in the Missouri and Kansas jurisdictions. Specifically, my duties require me to be current with industry issues with the potential to impact the Company and to provide guidance to optimize KCP&L's response to those issues. Previously, I was responsible for the rate design function, including class cost of service

("CCOS") support, rate design, tariff management, and filing preparation. Furthermore, I have represented the Company through participation in regulatory rulemakings and compliance reporting. I have also managed certain analytical activities for the department including docket management system administration, rate change implementation, billing determinant calculation, and retail revenue calculation.

Q: Please describe your education, experience and employment history.

A: I hold a Master of Business Administration from Northwest Missouri State University and a Bachelor of Science degree in Engineering Technology from Missouri Western State University.

I joined KCP&L in August 2002 as an Auditor in the Audit Services Department. I moved to the Company's Regulatory Affairs group in September 2005 as a Regulatory Analyst where my primary responsibilities included support of our rate design and class cost of service efforts. I was promoted to Manager in November 2010 and was promoted to my current position in October 2017.

Prior to joining KCP&L, I was employed by the St. Joseph Frontier Casino for two years as Information Technology Manager. Prior to St. Joseph Frontier Casino, I was employed by St. Joseph Light and Power Company for nearly 14 years. I held various technical positions at St. Joseph Light and Power Company, including Engineering Technician-Distribution, Automated Mapping/Facilities Management Coordinator, and my final position as Senior Client Support Specialist-Information Technology.

Q: Have you previously testified in a proceeding before the Kansas Corporation Commission ("Commission" or "KCC") or before any other utility regulatory agency?

A: Yes, I have provided written testimony in Docket Nos. 07-KCPE-905-RTS, 09-KCPE-246-RTS, 12-KCPE-764-RTS, 14-KCPE-272-RTS, and 15-KCPE-116-RTS supporting the Company's CCOS studies or rate design proposals. Recently, I have testified before the Commission as part of the General Investigation to Examine Issues Surrounding Rate Design For Distributed Generation Customers, Docket No. 16-GIME-403-GIE. Additionally, I have testified multiple times before the Missouri Public Service Commission concerning class cost of service and rate design issues as part of recent rate proceedings.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

I. Discuss how the Company approached production allocation within the Class Cost of Service Study ("CCOS") filed in this case;

II. Explain the Company's proposed Solar Subscription Pilot Rider tariff;

III. Explain the Company's proposed Renewable Energy Rider tariff;

IV. Explain the Company's proposed Standby Service Rider tariff;

V. Explain the Company's proposed LED Municipal Street Lighting and LED Private Lighting tariffs.

VI. Discuss the Company efforts to quantify and value Distributed Generation ("DG") in support of proposing a new rate for its residential DG customers.

I. PRODUCTION ALLOCATION WITHIN CCOS

Q: What is the purpose of this part of your testimony?

A: The Company is proposing to use the Average & Excess ("A&E") method to allocate its electric generating assets, its production plant, as part of the CCOS study offered in this case. Use of this method represents a transition from past allocation methods proposed by the Company and my testimony is offered to help explain the conditions behind this change.

Q: Why did the Company reconsider its production allocation method?

A: The Company believes that it is important to continually monitor the environment in which it operates, and as I noted in the Company's last general rate proceeding, Docket No. 15-KCPE-116-RTS ("15-116 Docket"), much has changed with regard to the current environment being experienced by the Company due to the Southwest Power Pool's ("SPP") move to an Integrated Marketplace in 2014. Because of the changes resulting from the Integrated Marketplace at the time of the 15-116 Docket, the Company sponsored two CCOS studies - a BIP and an A&P 4CP methodology – and recommended the Commission approve a blended result from the two studies. At that time, we were cognizant of the fact that the Integrated Marketplace would likely drive the need to transition away from the BIP methodology and toward a methodology more aligned with how plant is used under the Integrated Marketplace regime. As we conducted our review of the most appropriate CCOS for this rate case, it became apparent that our initial thoughts on the potential impacts due to the Integrated Marketplace were correct, and that fact coupled with other changes facing the Company, as I'll discuss below in more detail, resulted in our decision to use the A&E approach in this case. However, the core consideration in our analysis has always been Production plant utilization. Because Production plant is the single, largest component cost to allocate to the classes within the CCOS study, a shift to an allocation methodology that best represents the way production costs are incurred, such as the A&E, is proper. Allocation methodologies are not necessarily fixed and are subject to change. The ways production plant is used and the conditions that plant operates can evolve as that plant ages and is utilized differently than when first placed in-service.

Q: Would you please describe the production allocation changes that the Company has proposed in the past?

A: The Company began regular rate cases in 2005 with the initiation of the Comprehensive Energy Plan ("CEP"). The CEP initiative resulted in the building of the Spearville Wind Generation Facility, the Iatan 2 Generating Station, environmental retrofits at LaCygne and Iatan 1, as well as distribution system enhancements and the deployment of demand side programs. The CEP contemplated a series of rate cases to bring these investments into rate base and adjust rates accordingly. With the first case, Docket 06-KCPE-828-RTS, the Company prepared a CCOS study to support rate design utilizing an Average & Peak ("A&P") methodology for allocation of production plant.

Use of the A&P method continued until 2010 when in case Docket 10-KCPE-415-RTS the Company prepared its CCOS study using the Base-Intermediate-Peak (BIP) methodology. The BIP methodology, which was introduced but not offered in in Docket No. 09-KCPE-246-RTS, represented a more detailed means to assign the Company's generating assets and allocate them depending on their use in meeting customer loads. Individual generating plants were assigned to the base, intermediate, or peak segments and then allocated using varying methods that aligned with that individual segment's purpose. As the BIP method continued to rely on a combination of energy and demand allocation, the transition remained true to the intent of the blended allocation method started with the A&P approach.

Subsequently, the BIP method was offered and adopted by the Commission in Docket No. 10-KCPE-415-RTS.

Use of the BIP method continued until 2015 when, in case Docket No. 15-KCPE-116-RTS, the Company prepared its CCOS study using an equal blending of the A&P methodology with the BIP methodology. Expressing concern that the transition SPP to an Integrated Marketplace with centralized dispatch would make it difficult to accurately assign the generating units into base, intermediate, and peak groups based on their use, the Company proposed the blended approach. The Company did not consider this lightly, acknowledging the past value of the BIP approach. However, the Company could not ignore the impact of the SPP Integrated Marketplace and changes observed in the utilization of generating resources. With that in mind, the Company further indicated it would consider returning to the A&P methodology exclusively.

Q: How did the Company evaluate its production allocation methodology in this case?

A: As with each transition in the past, the Company began by examining the way the production assets were being utilized and considered the environment surrounding those assets. This allows cost causation to be the primary focus. Next, the Company considered influences such as testimony and orders from recent rate cases as well as other information available within the public domain. This allowed the Company to examine for trends and applications that could be relevant to our situation. Finally, the Company turned to the National Association of Regulatory Utility Commissioners' ("NARUC") "Electric Utility Cost Allocation Manual" to reexamine the common allocation methods defined by that organization. Published in January 1992, the NARUC Manual has served as a reference of common allocation approaches.

Q: You indicated earlier that certain changes facing the Company influenced the Company's decision to adopt an A&E approach for this case. To what changes were you referring?

A: Most significant is the proposed merger with Westar. Details of the merger are discussed in more detail by Mr. Darrin Ives in his testimony. This proposed merger led the Company to take a closer look at the CCOS processes and allocation methods used by Westar since 2012. Additionally, the Company examined the competitiveness of its rates, with some emphasis on commercial and industrial rates. Exemplified by the public efforts of Amazon to identify a location for their second headquarters and the recent decision by Nucor to locate within our KCP&L Greater Missouri Operations Company ("GMO") service area, highlighted the economic benefit of providing competitive commercial and industrial rates.

Q: Please describe how these elements were utilized to perform the reconsideration.

A: The various elements were reviewed and discussed by Regulatory Affairs personnel. The group reviewed our production plant and evaluated for any changes in how it is being utilized. The group then critically evaluated the perceived strengths and weaknesses of various allocation methods. Some comparisons were assembled from previous rate cases to understand the methodologies. The Company also looked at other CCOS efforts, particularly those proposed by Westar and considered the efforts made in KCP&L's

Missouri jurisdiction. In the end, two methods seemed appropriate for more detailed consideration, the A&P and A&E methodologies.

Q: Was the Base, Intermediate, Peak method considered?

A: Yes. In considering BIP, the Company evaluated the additional experience gained in operating our generation resources within the Integrated Market place since 2015, and did not observe anything that would alleviate our concerns about assigning our plants to the BIP categories. The Company continues to see a level of uncharacteristic use of our intermediate and peaking units, whether to run them more frequently to serve load when network congestion dictates, or to provide ancillary services demanded by the SPP operators to support other generation on the grid. As such, concerns that were leading us to deploy the A&P methods in 2015 continue to occur and limit the suitability of the BIP method for the current study.

Q: How did the Company proceed with the more detailed consideration of these alternatives?

A: The Company felt it was very familiar with the A&P method as it had been proposed and supported by the Company many times in the past. To address the A&E method we explored the details of the method internally, reviewed publicly available testimony supporting the method, and spoke with consultants to learn their thoughts and opinions concerning the method. Ultimately, the combination of these inputs led the Company to decide the A&E method was likely the most appropriate production allocation method to apply in this case.

Q: Did the Company then prepare the Average & Excess Production allocator?

A: Yes. The Company retained the services of Mr. Thomas J. Sullivan, Jr., P.E. with Navillus Utility Consulting LLC to support the Company in this effort. Mr. Sullivan has more detailed and comprehensive knowledge of the allocation methodology and is better suited to prepare, support, and validate the allocator on the Company's behalf. Mr. Sullivan describes the A&E production allocation method and calculates the allocator for use in the CCOS study as part of his testimony offered in this case.

Q: Have you reviewed the testimony prepared by Mr. Sullivan?

A: Yes.

Q: Do you agree with using this allocation method in this case?

A: In light of the various changes facing the Company today that were not present previously, yes, I do. I recognize that this represents a deviation from the methods used by the Company in the past and is contrary to past Company testimony concerning A&E allocation. However, each past transition was purposeful, and this is no different.

Q: Please explain what you mean.

A: The transition from A&P to BIP was driven by the need for detailed cost data to support rate design. The transition from BIP back to a BIP/A&P blended method was driven by changes to the use of our production assets resulting from changes within SPP. This current transition is reflective of the movement of the Company to a longer view, more focused on the way our customers utilize the production plant than simply the operational characteristics. Past methods supported by the Company considered energy production as a significant factor in the cost causation for production plant. Operationally, this is still true. However, a broad consideration of the CCOS study process and the role that the CCOS study plays in the rate design process suggests other views are warranted.

Q: What is the impact of the transition?

A: Mr. Sullivan performs a comparison of the A&E method to other allocation alternatives as part of his testimony. In short, the A&E method emphasizes load factor in allocating cost. Lower load factor customer classes will receive higher allocations relative to methods used in the past.

Q: Do you believe this is reasonable?

A: Again, given the changed circumstances, yes I do.

Q: How were these allocations used by the Company?

A: The A&E allocations were combined with numerous other allocations and used to apportion the jurisdictional cost to the Company's customer classes. This process is described and supported by KCP&L witness Marisol Miller in her direct testimony. The results of the study were then considered in completing the rate design offered in this case.

Q: How does the Company suggest the Commission use the CCOS study and should there be any emphasis placed on the Company's decision to transition to a new method?

A: The Company believes that all CCOS studies, regardless of the methods used hold value and that generally, a collective view provides the best information. As has been done in the past, the CCOS results should be used as a guide and other considerations such as bill impacts, revenue stability, rate stability and public acceptance should be considered.

I would not specifically recommend any emphasis be applied to this transition other than that it is reflective of the continuing change experienced within the business and facing the Company. As detailed in this testimony, the operations and investments of the Company do not occur in a vacuum and often external factors shape the approaches we take. I offer that this decision is no different.

II. SOLAR SUBSCRIPTION PILOT RIDER TARIFF

Q: The Company is proposing a new Solar Subscription Pilot Rider tariff. Are you sponsoring that proposal?

A: Yes. A copy of the proposed tariff is included as Exhibit BDL-1.

Q: Are any other witnesses providing testimony concerning this program?

A: Yes. Company witness Kimberly H. Winslow is providing testimony supporting the customer aspects of the Rider. Specifically, she describes the drivers for this proposal, such as customer needs and preferences, industry direction, corporate goals, and program development.

Q: Please provide an overview of the Solar Subscription Pilot Rider.

A: The Solar Subscription Pilot Rider ("Solar Rider") is a form of shared solar where one or more solar generating units will be installed on the Company system and Customers will be offered the opportunity to receive the output through a subscription, in some ways similar to community solar projects used in other jurisdictions. The Solar Rider will be offered to both residential and commercial Customers. Initially, it will be composed of 10,000 five-hundred-watt capacity subscription blocks for an expected solar generating unit of 5 MW-AC[1]. Each customer will be allowed to subscribe to the number of capacity

[1] Stated fully, 5 MW-AC means, 5 Megawatt-Alternating Current.

blocks required to produce up to 50 percent of their annual energy usage, which will be based on their previous 12 months of usage history. A Customer will also need a minimum historical or estimated annual energy usage to ensure that one subscription block could be fully consumed. In addition, a Customer may not subscribe to more than 25 percent of the total number of blocks offered within the Solar Rider. This will allow sufficient allocation of the solar generating unit across Customers and Customer classes.

All customer classes are eligible to participate in the Solar Subscription Pilot Rider. Customers receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Solar Rider while participating in those service agreements. Further, the Company has identified some subscription limitations by Customer and Customer class to provide for class equity. The Company will reserve 50 percent of the generating solar capacity to residential Customers and the remainder to non-residential Customers. However, if after the first three months of open enrollment, the Company has experienced more or less interest from a specific Customer class, the Company may revise or eliminate these reservations so that the minimum subscription percentage may be achieved and construction of the solar generating unit may proceed. It is anticipated that a similar process would be repeated for any future expansion of the Solar Subscription Pilot Rider.

Q: What is the cost associated with subscribing?

A: A Solar Block Subscription Charge ("Charge") is defined in the tariff and charged to participants based on their level of subscription to the solar resource. Based on preliminary information and project projections the initial rate is being set at $0.144 per kWh.

Q: How was that cost determined?

A: The Charge will be reflective of two elements, the Solar Block cost and an interconnection charge. The Solar Block cost is defined by the total cost of the solar resources built to serve the Solar Rider. Once the required level of interest is obtained, the Company will go through a procurement process to construct the solar resource. All costs associated with that construction, operations, and maintenance, as well as general and administrative cost will be compiled or estimated and a “per kWh” charge calculated. If multiple solar resources are deployed, the Solar Block cost will be the levelized costs for those resources, blending the costs to provide a uniform rate for Subscribers. To ensure the cost of the Solar Rider is borne by participants, the Solar Block cost will include all construction, operations, maintenance, and assignable administrative costs related to the solar resource. Under the current projections, this component is $0.115 per kWh. The interconnection charge is the embedded cost of Transmission and Distribution for the Residential class based on the Company’s class cost of service study from this rate case. Based on those calculations, this component is $0.029 per kWh.

Q: Can this cost change in the future?

A: Yes. The Company will file a revised tariff to update the Solar Block charge if these proposed rates do not appropriately reflect the costs of the initial system and again if additional solar resources are added to serve Subscribers. Filing would occur after the required subscriber interest is received and the Company has a firm estimate of the cost. The interconnection charge will change if the costs attributed to Transmission and Distribution functions change in a subsequent rate case. The Charge may increase or decrease due to these provisions.

Q: What will be done with the renewable energy certificates associated with this energy production?

A: The renewable energy certificates ("REC") associated with the generation output of the solar facility received by Subscribers will be retired by the Company on behalf of those Subscribers.

Q: Please provide an example of how a participating Customer's bill will be determined.

A: The assumptions are contained in the Table 1 below. The Company elects to install 5,000 kW AC (5 MW) of capacity (Row A). Based on National Renewable Energy Laboratory ("NREL") solar production estimations for 1 kW of installed capacity in Kansas City (Row B)[2], the monthly energy output of the total solar generating facility is 598,500 kWh (Row C).

Table 1 - Solar Production Calculation

	Calculation/Assumption	Reference Row
System Capacity	5,000 kW AC	A
Estimated per kW AC Monthly Production	119.7 kWh per kW	B
System Energy Production for the month	598,500 kWh	C

Next, we look to evaluate how to calculate a subscriber's capacity using the assumptions in Table 2 following. The subscriber has a 12-month usage of 10,000 kWh (Row E) and the subscriber wants to offset 50% (Row F) of their traditional energy consumption with energy from the Solar Subscription Pilot Rider program. By multiplying the subscriber's

[2] Based on PVWatts estimate for 1 kw standard module, fixed array, default losses, tilt, and azimuth. http://pvwatts.nrel.gov/pvwatts.php

annual load with their requested offset percentage and then dividing by the result of the NREL per kW production estimate (Row B) by 12 months, we are left with the customer's needed capacity to offset their percentage request (Row G). The capacity is then converted to blocks (Row H) where one block is equal to half a kW of capacity. The Solar Subscription Pilot Rider Program will be made of approximately 10,000 blocks.

Table 2 - Customer Subscription Calculation

	Calculation/Assumption	**Reference Row**
Annual Customer Usage	10,000 kWh per Year	E
Customer Subscription Level	50%	F
Calculated Capacity Subscription	(E x F) / (B x 12 Months/Yr) = G (10,000 kWh/Yr x .50) / (119.7 kWh/kW-Mo. x 12 Mo/Yr)= 3.48 kW	G
Customer Subscribed Blocks	G / 500 w = H 3.48 kW / 500 w = 6 blocks (Rounded down to the nearest whole number	H

The subscriber's monthly energy allocation is calculated using the assumptions in Table 3 below. First, we convert the subscriber's subscription to a percentage of the total Solar Rider by dividing their subscription of 6 blocks (Row H) by the total solar blocks available resulting in 0.0006 (Row I). We then multiply this percentage by the System Energy Production (Row C) to find the Subscriber's monthly energy allocation (Row J). The System Energy Production will vary for each month and represents the metered output of the system.

Table 3 - Monthly Energy Allocation

	Calculation/Assumption	Reference Row
Customer's Percentage Allocation	H / Total Solar Blocks = I 6 Blocks / 10,000 blocks = 0.0006	I
Subscriber's Monthly Energy Allocation	I x C = J 0.0006 x 598,500 kWh = 359.10 kWh	J

Finally, the subscriber's monthly energy allocation is utilized in monthly billing under the assumptions contained in the following Table 4. First we assume a Residential Energy Price of $0.10 per kWh (Row K) and a Solar Energy Price of $0.15 per kWh (Row L). Next, we obtain the customer's actual monthly energy use through the normal meter reading processes (Row N). From this monthly customer usage, we subtract the Subscriber's Monthly Energy Allocation (Row J) leaving us with the Non-Solar Energy Usage (Row O). The Non-Solar Energy Usage is multiplied by the Residential Energy Price of $0.10 per kWh (Row K) resulting in the Monthly Non-Solar Energy Cost of $47.42 (Row P). The Subscriber's Monthly Energy Allocation (Row J) is multiplied by the Solar Energy Price of $0.15 per kWh (Row L) resulting in the Monthly Solar Energy Cost of $53.87 (Row Q). The final customer bill is the combination of the Non-Solar Energy Cost (Row P) plus the Solar Energy cost (Row Q) plus the Remaining Bill Charges (Row M).

Table 4 - Monthly Billing

	Calculation/Assumption	Reference Row
Residential Energy Price	$0.10 per kWh	K
Solar Energy Price	$0.15 per kWh	L
Remaining Bill Charges	$20.00 (represents charges from the standard rate tariff that include customer charges, riders, taxes, fees, etc.)	M
Customer Energy Usage for the Month	833.33 kWh	N
Non-Solar Energy Usage	N – J = O 833.33 kWh/Mo. – 359. 10 kWh/Mo = 474.23 kWh/Mo.	O
Monthly Non-Solar Energy Cost	O x K = P 474.23 kWh/Mo. X $0.10/kWh = $47.42/Mo.	P
Monthly Solar Energy Cost	J x L = Q 359.10 kWh/Mo. X $0.15/kWh = $53.87/Mo.	Q
Final Bill	P + Q + M = R $47.42 + $53.87 + $20.00 = $121.29	R

It is important to note that rate blocks and riders will be accounted for in this Solar Rider. Specific to rate blocks, customers will pay the corresponding block prices for the remaining energy after the subscriber’s monthly energy allocation is separated from the monthly customer usage. Riders will be applied based on the subscriber’s metered usage. Taxes will apply to the subscriber’s total bill once all adjustments are made.

Q: Will this bill calculation occur during the normal billing cycles?

A: Although the billing will occur as part of our normal billing processes, we anticipate that there will be lag between the actual solar energy production and the presentation on the customer bill. We have allowed a delay of one billing month to allow for the data to be received from the solar facility, calculated, and then applied to bills.

Q: May a customer elect to unsubscribe from the Solar Subscription Pilot Rider if they deem it is not advantageous to them?

A: Yes. Customers who have subscribed to less than 25 percent of the available solar blocks will be required to stay enrolled in the Solar Subscription Pilot Rider for a minimum of 12 months. Those who have subscribed to greater than 25 percent of the available solar blocks (typically a non-residential Customer) have a minimum 60-month commitment. We want Customers demanding large portions of the solar resource to stay committed to the Solar Rider to provide an "anchor" effect. Following the minimum enrollment period, customers may elect to reduce or eliminate their participation in the Solar Subscription Pilot Rider effective on their next billing cycle. Any block returned to the Company will be placed back into the Solar Subscription Pilot Rider block pool and will be distributed to Customers on the wait list on a first-come, first-served basis.

Q: May a customer elect to transfer their subscription?

A: Yes. Participants who move to another location within the Company's Kansas service territory may transfer their subscription, provided the total kWhs of the subscribed amount is not more than the new locations allowed subscription level (actual or estimated). If the subscription level exceeds the allowed amount at the new location, the subscription will be adjusted down accordingly. Upon cancelation of a Participant's service, Participants may transfer their entire subscription to another eligible Participant's service agreement, including non-profits, for a $25 fee.

Q: How will the Company expand the Solar Rider beyond its initial offering?

A: The Company plans to closely evaluate the subscription interest of the Solar Subscription Pilot Rider on an ongoing basis. When the initial 5 MW system becomes fully subscribed, the Company will form a 'wait list' that will aggregate Customer information and desired subscription size. The Company will monitor the wait list and will determine the appropriate time to add solar capacity to the Solar Rider. The Company is proposing to add additional solar resources up to 50 MW of solar capacity. To compensate for changes in the cost of solar generation as new units are added, the Company anticipates that the price for the Solar Block charge should decrease to reflect the levelized cost of the Solar Rider and lower costs over time.

Q: Do you anticipate a change will be needed to the Company's Energy Cost Adjustment to account for this Solar Rider?

A: No.

Q: Will the Solar Rider be designed to reflect all costs and recover those from participants?

A: Yes. Those receiving benefit from the solar energy will be responsible for the program costs.

Q: Does the Company have any obligation under the Solar Rider?

A: Yes. Although the Company will strive to appropriately size the Solar Rider to meet the needs of the customers that are participating it is expected that, from time to time, subscription levels will be below the total renewable resource capacity. When that occurs, the Company assumes the unsubscribed amounts on behalf of all Customers and accounts for that cost through the Energy Cost Adjustment ("ECA"). For example, at the end of each billing period, and after all subscriptions have been applied we expect that there might be times when there remains some level of unsubscribed capacity. This unsubscribed amount would be “purchased” at the Solar Block Subscription Charge. This purchase would flow through the ECA as a purchased power cost. As this is a remainder, we expect the amount will vary from month to month. All efforts will be made to identify subscribers to first claim the energy production.

Q: Is the Company seeking uniformity of the Solar Subscription Pilot Rider program across its three jurisdictions?

A: Yes. The Company has proposed the same tariff design in its KCP&L-Missouri, KCP&L-Kansas, and KCP&L-Greater Missouri Operations jurisdictions. If approved, a single renewable resource would be utilized to satisfy the needs of the subscribers. The Company believes combining the subscriptions would allow for a larger and likely more economical solar resource to be deployed. This uniformity will also aid in the facilitation and growth of the Solar Rider by alleviating any customer confusion that could be generated by differences between jurisdictions. To help ensure fairness, all costs for the Solar Rider would be apportioned between the three companies based on the respective subscription levels for each.

III. RENEWABLE ENERGY RIDER PROGRAM TARIFF

Q: The Company is proposing a new tariff that offers Customers the opportunity to purchase renewable energy. Are you sponsoring that proposal?

A: Yes. A copy of the proposed tariff is included as Exhibit BDL-2.

Q: Are any other witnesses providing testimony concerning this program?

A: Yes. Company witness Kimberly H. Winslow is providing testimony supporting the customer aspects of the Tariff. Specifically, she describes the drivers for this proposal, such as Customer needs and preferences, industry direction, corporate goals, and program development.

Q: Please provide an overview of the Renewable Energy Rider program.

A: The Renewable Energy Rider program ("Renewable Rider") is a renewable subscription program where the Company executes one or more Power Purchase Agreements ("PPA") to supply renewable energy to participating Customers. The Renewable Energy Rider program will be offered to non-residential Customers except for those receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service, who are ineligible for this Renewable Rider while participating in those service agreements. The first procured renewable resource will be limited to a minimum capacity of 100 MW and will not exceed 200 MW. The Company plans to consolidate all subscriptions from its three companies (KCP&L-Missouri, KCP&L-Kansas, and KCP&L-Greater Missouri Operations Company) and serve them through this renewable PPA.

Q: How would this consolidation work?

A: Similar to the approach proposed for the Solar Subscription Pilot Rider, the Company has proposed the same tariff design in its KCP&L-Missouri, KCP&L-Kansas, and KCP&L-Greater Missouri Operations jurisdictions. If approved, a single PPA would be utilized to satisfy the needs of the subscribers. The Company believes combining the subscriptions would allow for a larger and likely more economical PPA to be procured. This uniformity will also aid in the facilitation and growth of the Renewable Rider by alleviating any customer confusion that could be generated by differences between jurisdictions. To help ensure fairness, all costs for the Renewable Rider would be apportioned between the three companies based on the respective subscription levels for each.

Q: Please describe the basis for participating in this Renewable Energy Rider program.

A: A Customer may subscribe up to 100 percent of their annual energy usage, which will be based on the previous 12 months' usage history. A Customer must have an average annual peak demand of 200 kW in order to participate. However, Customers with multiple accounts may aggregate their load by jurisdiction.

Q: What do you mean by aggregation?

A: We recognize that many customers have multiple accounts but would have the same renewable goals for each. Allowing the combination of accounts under this Renewable Energy Rider program would allow the Customer to address these needs more completely. For administrative clarity, limits have been established for this aggregation. These aggregated accounts must have a combined average annual peak demand of 2.5 MW and an average of 200 kW per account. Governmental and municipal accounts would be able to aggregate without limit to size, subject to the others terms of the Renewable Energy Rider program. Aggregation is only for the purpose of Renewable Energy Rider program participation and does not imply that account usage and/or demands would be consolidated for billing under the blocks, and minimums of the standard rates. Additionally, processing of aggregated participation may occur outside of normal cycle billing. To allow for the accumulation of data and calculation of the

Renewable Rider cost, adjustments associated with this Rider may be applied up to 60 days later than the market transactions associate with the renewable energy production.

Q: Are there terms set for the subscriptions?

A: Yes. Customers may opt for subscription terms of 5, 10, or 20 years. Should the renewable resource PPA contract term be other than 20 years, then the maximum term made available to the customer will be adjusted to match the PPA's term. Customers subscribing to more than 20% of the renewable resource will be required to commit to a minimum term of ten years.

Q: What will be done if there is excess interest in the Renewable Energy Rider program?

A: Interested customers, who are not allotted capacity in the initial resource offering, will be placed on a wait list that will be evaluated semi-annually. If a Customer subscribes after the resource has been available for some period, the Customer's term is limited to no more than the remaining term of the PPA.

Q: How will the Renewable Energy Rider program be initiated?

A: Similar to the Solar Subscription Pilot Rider detailed earlier in this testimony, the Company will compile a list of Customers who desire to participate before the procurement process is underway. Once the Company has gathered sufficient interest, it will solicit a PPA for a renewable resource. To ensure the renewable resource meets the desire of Customers to have "additionality", the Company would enter into a contract for renewable resources placed into service after January 1, 2019. The Company will begin this procurement process when it has a minimum of 100 MW of capacity subscription interest.

Q: Please describe how a Participant's bill will change when joining the Renewable Energy Rider program.

A: Also similar to the Solar Subscription Pilot Rider, Renewable Energy Rider program participants will subscribe to a renewable resource capacity amount to offset the amount of monthly energy as requested by the participant. This subscribed amount, or percentage, will be converted to a kW demand value that will be used to source the renewable resource. The Customer's monthly bill will be the sum of its standard bill, which is based on the Customer's monthly usage under their current retail rate, plus a renewable adjustment. The renewable adjustment is comprised of the following items:

- Renewable Output
- Subscribed Share
- Subscription Charge (with Administration charge)
- Final Market Price

The Renewable Output is the metered output from the renewable resource at the market node. The Subscribed Share is the capacity amount associated with a Customer's subscription. The Subscription Charge is the sum of the Delivered Price per MWh of energy delivered to the Company and the Administration Charge for the facilitation of the Renewable Energy Rider program. The Administration Charge will vary based on the term length of the customer subscription. The Final Market Price is sum of all applicable market revenues and charges arising from, or related to, the delivery of the energy output of the renewable resource into the wholesale energy market during that calendar month divided by the actual metered hourly energy production.

Q: The Subscription Charge and Final Market Price are key parts of the Renewable Adjustment. Would you please provide more detail concerning how these factors are determined?

A: The Subscription Charge reflects the cost of the PPA plus an administrative charge. To ensure the cost of the Renewable Energy Rider program is borne by participants, the Subscription charge will include all costs related to procuring the PPA. Administration charges are designed to cover the ongoing costs associated with the Renewable Energy Rider program such as processing the data, accounting, and customer billing. Internal labor will be needed to manage applications and administer the Renewable Energy Rider program each month. This cost is estimated to be approximately $0.10 per MWh. The administrative cost is increased to $0.30 per MWh for Participants desiring shorter agreement terms. The premium is expected to cover the increased turn-over resulting from the shorter terms.

The Final Market Price ("FMP") is the mechanism where the value of sale of the renewable energy is returned to the Subscriber. The tariff contemplates one of two approaches to complete this sale. One approach is to inject the energy directly in to the nearest market node and receive the market price at that location. Alternatively, the Company could choose to obtain transmission service and deliver the energy to an alternate load point. The Company believes it is important to provide a level of flexibility at this point in the Renewable Energy Rider program. Decisions made concerning the interaction with the market could impact the value stream delivered for the term of the subscription. The Company would plan to use these alternatives to attempt and capture the best value possible for participants and reduce the risk of depressed nodal prices. As with the rest of the tariff approach, all costs associated with either alternative will be identified and borne by Subscribers.

Q: Please provide an example of how a participating customer's bill will be determined.

In this example, we demonstrate how the Renewable Adjustment associated with this Renewable Rider can impact a Customer's monthly bill. First, we assume that the Company has received enough Customer interest in the Renewable Energy program to source a 100 MW generation resource, noted as the Renewable Resource Capacity (Row A). With an assumed Renewable Resource Capacity Factor of 35% (Row B), we can estimate the System Energy Production for the month (Row C). This results in a total of 26,040 MWh of energy for the month.

Table 5 - Renewable Resource Production Calculation

	Calculation/Assumption	**Reference Row**
Renewable Resource Capacity	100 MW	A
Renewable Resource Capacity Factor	35%	B
System Energy Production for the month	26,040 MWh	C

Next, to show how a Customer's subscription is calculated we assume that the Customer has an Annual Customer Energy Usage of 100,000 MWh from the prior year (Row D) and that they desire to set their Subscription Increment at 100% (Row E). Using this information, the Customer's Subscription Level (Row F) is the result of 100,000 MWh multiplied 100%, then divided by the product of 8,760 Hours/year and the Renewable Resource Capacity Factor of 35%. The result is a Subscription Level of 32.62 MW.

Table 6 - Subscription Level Calculation

	Calculation/Assumption	Reference Row
Annual Customer Energy Usage	100,000 MWh/Yr.	D
Chosen Subscription Increment	100%	E
Subscription Level	(D x E) / (8,760 Hrs./Yr. x B) (100,000 MWh/Yr. x 100%) / (8,760 Hrs./Yr. x 35%) = 32.62 MW	F

The Subscription Level is then converted in a Subscription Share (Row G) by dividing the Subscription Level (Row F) by the Renewable Resource Capacity (Row A), resulting in a Subscription Share of 32.62%. The Monthly Renewable Energy Allocation (Row H) would then be the Subscription Share multiplied by the System Energy Production for the month (Row C) resulting in an allocation of 8,493.15 MWh in our example month.

Table 7 - Subscription Share Calculation

	Calculation/Assumption	Reference Row
Subscription Share	F / A 32.62 MW / 100 MW = 32.62%	G
Monthly Renewable Energy Allocation	G x C 32.62% x 26,040 MWh = 8,493.15 MWh	H

The final part of the example outlines how the Monthly Renewable Adjustment is calculated. Assuming that the Customer had agreed to a Subscription Charge of $20 per MWh (Row I) and that for this month the Final Market Price was $30 per MWh (Row J). The Adjustment would be the Subscription Charge minus the Final Market Price multiplied by the Monthly Renewable Energy Allocation (Row H). The result is an adjustment of negative $84,931.51 (Row K), which would be a credit to the customer.

This adjustment would be applied to Customer's Standard Bill prior to taxes being applied. It is important to note that should the Final Market Price be $10, less than the Subscription Charge, then the Customer would be required to pay the Company an additional $84,931.51 on their monthly bill.

Table 8 - Renewable Adjustment Calculation

	Calculation/Assumption	**Reference Row**
Subscription Charge	$20 per MWh	I
Final Market Price	$30 per MWh	J
Monthly Renewable Adjustment	(I – J) x H ($20/MWh - $30/MWh) x 8,493.15 MWh = ($84,493.15)	K

Q: Will this bill calculation occur during the normal billing cycles?

A: Although the billing will occur as part of our normal billing processes, we anticipate that there will be lag between the renewable energy production and the presentation on the customer bill. Since meter data supporting the monthly production is needed to support the billing must be obtained from third parties and in anticipation of additional bill processing to manage aggregation, we have allowed a delay of two billing months to allow for the transactions to be applied to bills.

Q: May a Customer participate in both the Solar Subscription Pilot Rider and the Renewable Energy Rider?

A: No. Customers with an account that meets the requirements necessary for participation in both programs may only select one program.

Q: May a Customer transfer their subscription?

A: Yes. Participants who move to another location within the Company's Kansas service territory may request transfer of their subscription, provided the total kWh of the subscribed amount is less than the new location's average annual historical usage (actual or Company estimated). If the existing subscription level exceeds the allowed usage amount at the new location, the subscription will be adjusted down accordingly.

Q: May a Customer terminate their subscription?

A: Yes. Participants may request termination of the Participation Agreement before the expiration of the term of the Participation Agreement. However, to avoid any impact to other participants or non-participants, the terminating Customer must pay any associated costs and administration associated with termination of the subscribed renewable resource. The Company will make an effort to transfer the subscription to another interested Customer. If another Customer fully assumes the obligation for the purchase of the renewable energy prior to the effective date of the termination, costs for the termination could be minimized or eliminated.

Q: How will the Company expand the Renewable Energy Rider program beyond its initial offering?

A: If the Company receives interest that would require capacity greater than the initial offering, then it will form a 'wait list' that will aggregate customer information and desired subscription size until it deems it has a great enough need to start a new renewable facility procurement process. This will be at the Company's discretion so that it may balance Customer interests with each tranche of renewable facilities.

Q: Does the Company intend to own and operate the renewable resources required for the Renewable Energy Rider program?

A: No, the Company intends to utilize PPAs to fulfill the subscriptions within this Renewable Rider.

Q: Do you anticipate a change will be needed to the Company's ECA to account for the Renewable Energy Rider program?

A: Yes. Revisions will be needed to exclude amounts associated with the PPAs made to satisfy the Renewable Energy Rider program. Specifically, changes to the Purchased Power and Off-System Sales provisions. Those changes are addressed in the testimony of Tim Rush.

Q: What will be done with the Renewable Energy Credits associated with this energy production?

A: Renewable Energy Credits associated with energy obtained through this Renewable Rider will be transferred to the Customer annually or at any time upon Customer request. Alternatively, and if requested, the Company will retire the credits on behalf of the Customer with all costs associated with the registration and retirement borne by the requesting Customer.

Q: Will the Renewable Energy Rider program be designed to reflect all costs and recover those from participants?

A: Yes. Those receiving benefit from the renewable energy will be responsible for the program costs.

Q: Does the Company have any obligation under the Renewable Rider?

A: Yes. Although the Company will strive to appropriately size the Renewable Rider to meet the needs of the Customers that are participating, it is expected that from time to time subscription levels will be below the total renewable resource capacity. When that occurs, the Company assumes the unsubscribed amounts on behalf of all Customers and accounts for that cost through the ECA.

Q: Are there any other features of the Renewable Energy Rider program you wish to address?

A: Yes. The proposed Renewable Energy Rider program includes a provision for renewable contracts supporting economic development. The Company anticipates that there will be customers who wish to enter into individual agreements for renewable energy. In these situations, the Company may, at its discretion, enter into the individual agreement if it will support customer retention or incremental load resulting from the construction or expansion of facilities within the Company's service territory. The individual terms concerning pricing will be established with the requesting Customer. All agreements are subject to availability and deliverability of renewable energy resources and will be structured in such a way as to ensure recovery of all related costs from the requesting Customer.

IV. STANDBY SERVICE RIDER TARIFF

Q: The Company is proposing a new tariff for Standby Service. Are you sponsoring that proposal?

A: Yes. A copy of the proposed tariff is included as Exhibit BDL-3.

Q: Please describe the proposal.

A: The Company is proposing to introduce a Standby Service Rider tariff for its customers. GMO does not currently offer standby service.

Q: What caused the Company to make this proposal?

A: In a recent Missouri rate case (ER-2014-0370) the Missouri Public Service Commission ordered the Company to conduct a review of its Standby Tariff ("SGC Tariff") with the results of that review to be provided within two years of the effective date of the order in that case. The Company established an internal cross-functional team to review the SGC Tariff. It was determined that the SGC Tariff is largely similar, based on the features evaluated, to the standby tariffs utilized by other utilities in Missouri and Kansas. It was also noted that the SGC Tariff was based on a Real-Time Pricing ("RTP") structure that was unique among those reviewed. At the time of that study the Company committed to continue monitoring utilization of the SGC Tariff and the role of the RTP pricing mechanism to determine if any revision or enhancement might be beneficial. As part of the review it was determined that revision could be made to the tariff to improve administration and make it clearer to potential customers.

Q: Please describe the new design.

A: The Standby Service Rider ("SSR"), is a rider, building from the Company's generally available rate schedules. Further, the SSR provides for different approaches for different sizes of customer generation. Small systems, those less than 2 MW, rely mainly on the generally available rate with the addition of two fixed charges to cover capacity reservation and interconnection costs. Larger systems, those between 2 MW and 10 MW would be subject to various charges for backup, maintenance, and supplemental service.

The largest systems, those greater than 10 MW would be treated individually due to Southwest Power Pool and North American Electric Reliability Corporation requirements but rates would be largely based on the charges defined in the SSR. For the systems between 2 MW and 10 MW, the focus of the tariff design, simplified methods are used to differentiate the types of service being received by the standby customer.

Q: Please provide some detail concerning the service.

A: Provisions are made for three types of service: backup, maintenance, and supplemental. Traditional standby tariff designs rely on predefined operational schedules to help determine which service is received by the customer. Backup service is received when the customer generator is unexpectedly offline and the utility must provide service. Maintenance service is received when the customer generator is offline when expected and the utility must provide service. Finally, supplemental service is the additional service needed by the customer beyond what they generate themselves. To remove the need for the predefined schedule, the Company proposal relies on predefined periods and thresholds. The following figure is useful to explain the design:

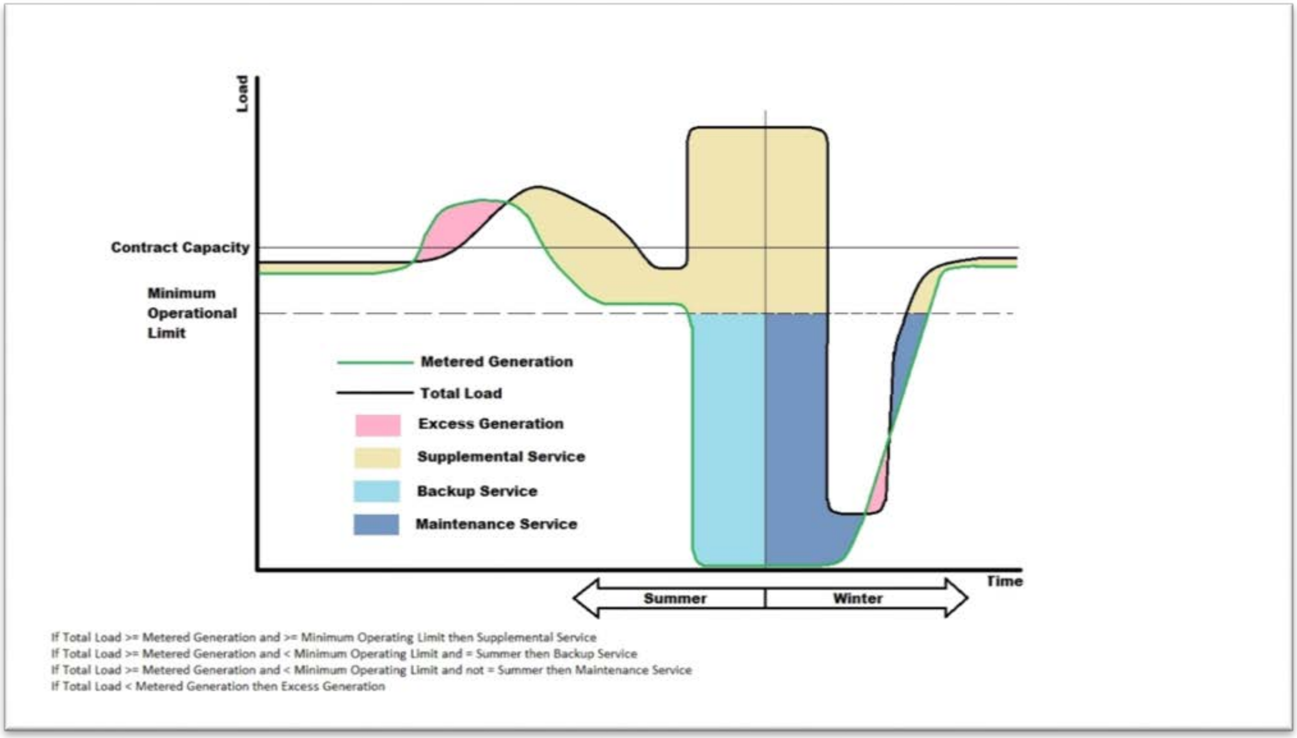


Figure 1 - Standby Period Example

Q: How do these periods and thresholds work to define the service?

A: At the time the customer applies for service under this rider a Standby Contract Capacity is defined. The Company presumes that the customer will normally operate at 90% or greater than this capacity. Supplemental Service is based on this minimum operational limit. Next, the design relies on the seasons defined in the Company's generally available rates. The Company wants customers to avoid outages of their generating systems in the summer period so it defines the summer as the Backup period. Conversely in the winter period, when capacity is generally more available, the Company defines the winter as the Maintenance period. Using these periods, combined with metering that measures the customer generator output and total load, the following service definitions result:

- Supplemental Service - Supplemental Service will occur if the Customer's Total Load is greater than the Metered Generation Output and greater than the Minimum Operating Limit.

- Backup Service - Backup Service will occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Summer period.

- Maintenance Service - Maintenance Service will occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Winter period.

The purpose of this design is to eliminate the need for scheduling and status communication. Many designs require communication within minutes of a customer generator outage. The Company believes this expectation can be onerous for both the customer and the Company. This design, by being predefined and subject to the actual metering, removes this complexity and produces a more manageable rate.

Q: What other charges are associated with service to customers with generation sized between 2 MW and 10 MW?

A: A Standby Service Metering & Administrative Charge is used to recover the cost of additional metering and bill processing. A Capacity Reservation Charge is applied to recover the cost of providing and maintaining the generation and transmission facilities required to support the capacity requirements of the customer within the Company system. Finally, there is an Excess Generation Credit to compensate the customer generator for energy delivered to the Company system.

V. LED LIGHTING

Q: The Company is proposing a revised tariff for LED Municipal Street Lighting. Are you sponsoring that proposal?

A: Yes. A copy of the proposed tariff is included as Exhibit BDL-4.

Q: Please describe the proposal.

A: The company is proposing to deploy Light Emitting Diode ("LED") technology for service to its Municipal Lighting Service customers, currently served under Schedule ML. The proposal includes the following elements:

- Add new rates for LED lighting – The company proposes to offer five LED types, providing equivalent replacements for the High-Pressure Sodium ("HPS") lights currently offered. These types will be offered under a new rate code. The Company also proposes to offer two LED alternates for Ornamental Lighting under Schedule MOL.

- Freeze the availability of existing MV and HPS rates to new customers – a number of existing light rates will be made obsolete by the LED conversion. This step will make it so that new customers cannot utilize these fixture types for new installations.

- Make LED the standard luminaire for replacement – Revise the current replacement terms to make LED the standard replacement for fixtures that are to be repaired or replaced.

- Present rates on a per month basis – In the current tariffs, lighting and equipment rates are expressed in per year amounts. However, the customer is billed on a monthly basis. This change will allow the tariff presentation to match the billing interval, providing a clear synchronization of the rate on the tariff and the rate on the bill.

- Convert MARC LED rates to the proposed rates – A number of LED luminaire were installed in 2013 under the KCP&L LED Pilot Program (Schedule ML-LED). At the time these luminaires were installed, the LED rate was set to be equal to the equivalent HPS fixture rate. As part of this proposal, the Company will move these luminaires to the new, proposed LED rates, based on the lumen size closest to the installed luminaire.

- Systematic conversion of existing lighting – In conjunction with this tariff change, the Company proposes to proactively change-out the non-ornamental, pole mounted street lights already deployed with new LED units.

Q: What is Municipal Street Lighting?

A: Municipal Street Lighting is street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality. In its Kansas jurisdiction, KCP&L owns and operates approximately 5,100 street lights.

Q: Why is LED technology desired?

A: LED lighting has been found to provide greater energy efficiency, reduced maintenance cost, longer life and improved visibility as compared to current lighting alternatives. The Company has been working for a number of years to understand and confirm these findings, ultimately identifying LED technologies suitable for deployment in our jurisdiction.

Q: Would you briefly describe this effort?

A: Yes. Beginning about 10 years ago, the Company began to experiment and participate in efforts targeted at understanding LED technologies for street lighting. Four initiatives best represent those efforts:

- Electric Power Research Institute LED SAL Project - KCP&L collaborated with the Electric Power Research Institute (EPRI), as a host utility, to test and evaluate the potential of then available LED lighting. KCP&L was one of over 20 test sites nationwide where the study took place. Serving as a test site in the project, KCP&L replaced twelve (12) of its High Intensity Discharge lighting systems with LED lighting systems.

- LED Information Sharing with City of Kansas City - The City of Kansas City, Missouri installed 120 LED luminaires within their customer-owned lighting circuits for testing and field measurement of lighting effectiveness. KCP&L and the City agreed to share the data and results of their respective LED pilot programs.

- KCP&L LED Pilot - KCP&L conducted a LED pilot program with five area communities (Blue Springs, Gladstone, Liberty, and St. Joseph in

Missouri and Prairie Village in Kansas) where 44 LED luminaires were installed representing products of six selected vendors.

- Mid-American Regional Council (MARC) Smart Lights for Smart Cities Pilot - MARC received $4.0 million from the US Department of Energy to retrofit existing street lights with new high efficiency street light luminaires through a three-year grant period, ending in July 2013. The objective of the Smart Lights for Smart Cities project was to deploy approximately 5,300 lights, utilizing different technologies from multiple vendors in 25 different cities, defining specifications, testing performance and measuring public opinion of the lights. Cities in the KCP&L-Kansas area include Merriam, Mission, Prairie Village, Roeland Park, Spring Hill, Gardner, and Westwood. This MARC project assisted KCP&L and Westar Energy in understanding the future technical changes needed to improve LED streetlights for utility use. The MARC pilot also provided the needed understanding to move forward with the proposed LED implementation.

Q: How did these efforts contribute to the Company's ability to propose LED for Lighting?

A: There were two results from these efforts that collectively allowed the Company to move forward with an LED proposal. First, and most direct, was to understand the nature of this new technology. While being a lighting source, the way the LED luminaires worked to provide this lighting was different. The Company explored various design approaches, including retrofits kits. Second, but less obvious, was the pilot work allowed time for the LED market to stabilize. In the early stages of the LED market, there were numerous vendors and designs. No standardization was present. Over time, vendors ceased to exist and design approaches began to formalize. This standardization was critical to allow the Company to define the requirements for our procurement, inventory processes, and construction standards, as well as being able to define costs to support ratemaking. The pilot efforts, particularly the MARC effort, provided needed confirmation of the benefits and proof of concept of the LED technology. In the end, the Company was able to reach a point where the LED product alternatives stabilized and the Company had the technology understanding needed to proceed and propose deployment.

Q: Please describe how the Company plans to convert its Municipal Street Lights to LED.

A: KCP&L proposes to systematically convert all existing Company-owned, pole mounted roadway lighting in the KCP&L-Kansas jurisdiction with LED luminaires. KCP&L intends to convert areas at a time to more efficiently utilize its crews and minimize travel time. This conversion would occur over approximately six months. KCP&L has completed a similar conversion in its KCP&L-Missouri jurisdiction, converting approximately 7,400 lighting in 54 communities and is nearing completion of conversion in its KCP&L-Greater Missouri Operation Company jurisdiction, converting approximately 39,000 lights in 172 communities.

Q: Why is it preferred to systematically convert the existing lighting to LED?

A: As already mentioned, part of the benefit is to more efficiently utilize Company crews and minimize travel time. This reduces the conversion cost. Once, converted, having consistent lighting deployed in the field should streamline maintenance activity for the company. Further, systematic conversion will provide more consistency in the street lighting. HPS lighting has a yellow light and LED is a white light. If street lights were converted at time of failure or other maintenance, you would have alternating light colors, with systematic conversion Customers and drivers will have consistent light quality projected on a given roadway segment. The final factor is ongoing cost. The Company proposed the LED fixtures at a rate less than the current HPS alternative.

Systematic conversion will put the more economic lights in service more quickly, allowing recognition of the benefit.

Q: The Company is also proposing a new tariff for LED Private Lighting. Are you sponsoring that proposal?

A: Yes. A copy of the proposed tariff is included as Exhibit BDL-5.

Q: What is Private Lighting?

A: Private Lighting is unmetered lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing Customer's premises. Private Lighting is provided in two ways, an area light that provides light in a circular pattern or a directional flood light that uses reflectors to project the light in a specific direction. Private Lighting is not available for Municipal Street Lighting. By contrast, Municipal Street Lighting tends to be larger in size and provide different lighting patterns designed for roadway use.

Q: Please describe the proposal.

A: The Company is proposing to offer a new tariff, Schedule PL to provide LED options for Private Lighting. Existing Private Lighting, offered under Schedule AL will be frozen and made unavailable to new customers.

Q: What Private Lighting options are to be offered?

A: The Company has identified three area light options and three flood light options. The sizes, based in lumens, range from 4,500 to 45,000 and effectively replace the current High-Pressure Sodium (“HPS”) and mercury vapor alternatives deployed under Schedule AL service.

Q: How do the new Private Lighting rates compare to those being replaced?

A: The rates for LED Private Lighting are lower than the current HPS standard available under Schedule AL. This rate reduction is reflective of the lower cost of maintenance and operation associated with the LED technology.

Q: How will the new LED Private Lighting options be deployed?

A: Subject to terms preexisting from Schedule AL, customers would be able to request the new lights once the new Schedule is approved as part of this case. The Company does not plan to systematically convert the Private Lights as it does with the Municipal Street Lights.

Q: Are the any other proposed changes you wish to address?

A: Yes. Currently, a copy of the Application for Private Area Lighting Service is represented within the AGREEMENTS section of the Company's Rules & Regulations. The Company is proposing to remove that form. The Company proposes to replace the form example with language allowing for various forms of agreement, acknowledging that business is often conducted using methods other than paper forms.

The Company proposes to change the availability under its Off-Peak Lighting rate. The proposed change would clarify the purpose for Off-Peak lighting and would update the terms around metered and unmetered approaches to providing this service. The update is offered to make the Off-Peak Lighting option more consistent across the KCP&L jurisdictions and to better manage customer-owned lighting systems.

Additionally, the Company proposed to eliminate the Commercial Street Lighting tariff, Schedule CL. There are no customers served by this rate and it is not needed at this time.

VI. DISTRIBUTED GENERATION BENEFIT & PROPOSED RATE FOR RESIDENTIAL DISTRIBUTED GENERATION CUSTOMERS

Q: What is the purpose of this part of your testimony?

A: I will describe the processes used and the results produced in evaluating the avoided cost associated with residential distributed generation ("DG"). Avoided cost has been identified by the Commission as the proper means to quantify the benefit of DG systems.[3] This testimony will identify the specific categories of avoided cost observed by the Company and will describe how that avoided cost information was incorporated into the class cost of service and ratemaking processes used in this case to ultimately support a proposed demand rate for new, residential DG customers.

Q: As you understand it, what is the responsibility of the Company concerning DG ratemaking?

A: The process undertaken in Docket No. 16-GIME-403-GIE ("16-403 Docket") provided clear definition of the steps the utility should make concerning ratemaking for residential DG customers. In that docket, a stipulation and agreement was approved by the Commission that captured nine key points. I will summarize each and describe its influence on this testimony:

[3] In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers. Docket 16-GIME-403-GIE, *Final Order*, ¶26, issued September 21, 2017.

16-403 Docket S&A Term	Testimony Impact
DG customers should be uniquely identified within the ratemaking process because of their potentially significant different usage characteristics.	<u>Direct Impact.</u> The company proposes sub-class identification with the Class Cost of Service Study.
Current two-part residential rate design is problematic for utilities and residential private DG customers.	<u>Direct Impact</u>. A three-part design, inclusive of a demand charge, is proposed in this filing.
Three-part rates, grid charges, and tiered customer charge are appropriate rate designs for residential private DG customers.	<u>Direct Impact.</u> A three-part design, inclusive of a demand charge, is proposed in this filing.
Customer education program must be implemented whenever new residential private DG rate structures are ordered.	<u>Direct Impact.</u> Education plans are being created in anticipation of Commission approval of the rate.
Rates for private residential DG customers should be cost-based and any unquantifiable value of resource approach should not be considered when setting rates.	<u>Direct Impact.</u> The Company has performed an avoided cost analysis and will rely of data from the CCOS studies to establish the proposed three-part rate for new, DG customers.
A value of resource study (i.e. cost-benefit analysis) is not required by the Commission at this time.	<u>Direct Impact.</u> The avoided cost analysis is the only DG-specific study offered by the company in this filing.
DG rate design policy is best determined in this docket.	<u>Direct Impact.</u> Policy decisions made in the 16-403 Docket were considered and applied throughout this filing.
New rate designs would apply to those customers adding DG systems on or after the effective date of new tariffs.	<u>Direct Impact.</u> The company proposed to apply the new, three-part rate to customers installing DG after the effective date of rates in this docket.
These terms provide non-binding guidance to the cooperatives.	<u>No impact.</u>

Q: Did the Company examine the costs associated with DG?

A: Yes. Costs associated with serving DG customers were examined in the CCOS in conjunction with the full residential class.

Q: Did the Company examine the benefits associated with DG?

A: Yes. The Company performed an evaluation of the avoided costs associated with residential DG in Kansas. A copy of the full analysis is in Exhibit BDL-6 in this testimony. A summary of the results is:

Avoided Cost Category	Quantification	Value	Avoided Cost
Energy	2,073,474 kWh	$0.02720 per kWh	$56,391
Capacity	471.14 kW	$2.00 per kW-month	$11,307
T&D Line Losses	160,331 kWh	$0.02720 per kWh	$4,361
Distribution Costs	0	see narrative	$0
Transmission Costs	0	see narrative	$0
Total			**$72,059**

Q: Would you describe the process used?

A: To complete this analysis, a team of subject matter experts representing Energy Resource Management, Distribution Engineering, Distribution Planning, Transmission Planning, Energy Solutions, Energy Accounting, and Regulatory Affairs was assembled. This team evaluated industry materials on DG valuation, considered studies completed by other companies, and examined the DG systems installed in the KCP&L-Kansas jurisdiction. In addition to identifying the avoided cost, the analysis established a framework for future analysis. This framework provides the initial view of the Company as to how to best quantify the benefit provided by DG. It is expected that this framework will mature and develop with increases in DG penetrations and utility understanding of DG impacts. The full analysis found in Exhibit BDL-6, is made up of five sections where each avoided cost category is detailed. For each, subject matter experts describe the methods used to quantify and value the impact of residential DG. Further, these experts provide observations and comments concerning how the avoided costs are determined now and might be under higher penetrations, highlighting grid conditions that influence the impact of DG, and consideration of technologies or practices that are developing around DG.

Q: In addition to the avoided cost previous identified, were there other notable finding in the analysis?

A: The most consistent finding is with respect to the limited impact of intermittent DG resources. Many of the avoided costs analyzed could be more significant if the DG resource could provide consistent generation. Because Customers require uninterrupted service, capable of powering all their load, utility systems from generation to the meter, must be designed to serve full, customer load. DG systems, however, remain unable to provide continuous, uninterrupted service. As long as this fact holds true, the quantity and value of avoided cost from DG will be limited. Other notable findings include:

- There is currently no specific tracking of energy produced by the DG system and consumed on-site by the DG owner. Therefore, to determine the total generation achieved by customer net metering systems, an engineering calculation must be used. To accurately determine avoided costs, particularly under high DG penetrations, behind the meter energy measurement would need to be obtained.
- Smart Inverters and storage are potentially the next transformational technologies for DG, particularly intermittent DG resources. Smart Inverters would allow solar photovoltaic systems to provide valuable, energy-related services such as voltage support, power factor compensation, or event ride-through capabilities. Storage would allow alignment of the DG production with the system loads.

- Solar production, particularly from south-facing systems, aligns poorly with residential load. At the time of peak, solar generation provides an average of 33% of its generation with a worst-case level of 17%. Westward alignment provides some improvement but at a cost to overall, annual production.
- The value of capacity can vary depending on the application. Different values are currently used within resource planning and in evaluation of demand side measures such as energy efficiency or demand response. While these different values for capacity are related, one should not expect to see identical values between applications as the considerations for term, size, and other factors are unique to each.
- Reverse current flow on the utility system as a result of excess generation will generate additional losses. These losses would offset avoided line losses.
- DG systems can impact distribution system protection schemes and can cause significant, additional wear on voltage support devices. Protection schemes must be revised to account for reverse power flow and voltage support devices may require more frequent maintenance or replacement.
- Transmission projects are currently aimed at improving reliability with no transmission expansion projects designed to respond to load growth expected. Unless DG can be relied on to address reliability needs, benefits to the transmission system will be limited.

Q: How are these results being incorporated into the Company's proposed rates?

A: The Company is using two, related means to incorporate avoided cost into the ratemaking process, first through preparation of a sub-class CCOS schedule that delineates the costs associated with residential DG service and second, through consideration in the rate design process. I specifically reference "consideration" because it would not be appropriate to directly apply the avoided costs to the rates.

Q: Why can't these avoided costs be directly applied to the rates?

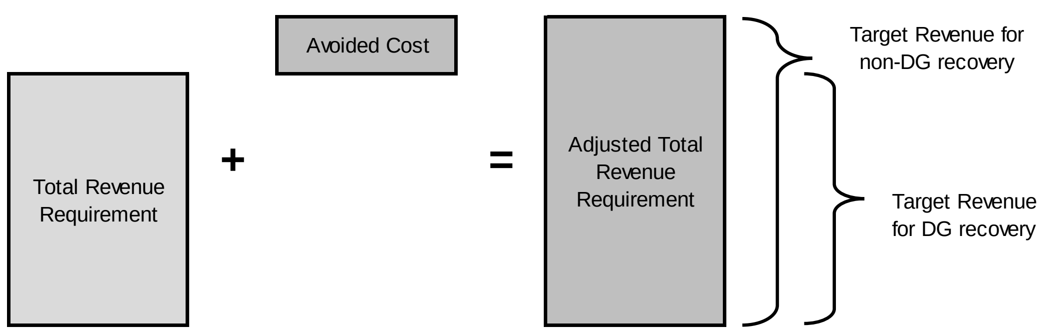
A: First, the avoided costs are not representative of actual costs but instead represent the potential for savings. The proper representation of these savings must take into account the nature of the cost and the related revenue recovery. We are attempting to show the impact on costs but for the existence of DG. In the case of the five avoided cost categories, some of the costs being avoided have different ratemaking treatment that would lead to different recognition approaches. For example, variable costs such as energy are mainly a pass-through of cost. With fixed costs, such as capacity or infrastructure costs would be reflected as a component of the base rate.

Q: How would savings related to variable costs such as energy be recognized?

A: Since variable costs, mainly represented by fuel costs are isolated to the ECA, savings related to avoided energy would appear immediately through a reduction in kWh consumed and a reduction in the cost paid through the ECA charge. This pass-through would ensure the savings are recognized immediately and by those customers creating the savings. No additional ratemaking treatment would be needed.

Q: How would savings related to fixed costs such as capacity be recognized?

A: Avoided costs that are associated with fixed costs are generally represented in the base rates and would need to be recognized within the class cost of service study. Said another way, in order for the benefits of the avoided costs to be passed to the DG customer, they first must be identified in the costs to be recovered. Current ratemaking processes require costs to be identified and evaluated to determine revenue requirement. Traditionally, only costs incurred are represented in the revenue requirement treatment. If avoided costs are to be considered, these avoided costs must be recognized, or added to the revenue requirement. During the ratemaking treatment, recovery of the adjusted revenue requirement would be built into rate designs for non-DG customers. DG customers would have rates reflective of the adjusted revenue requirement less the avoided cost, thereby passing that benefit to the DG customers. Expressed graphically, the process is as follows:



Stated plainly, the value of the avoided cost of DG will be recovered from the non-DG customer. Application of these costs will be reflected in the CCOS, particularly in as an adjustment to the Unbundled protestations of costs. Similar applications will be made in the rate design process to ensure the avoided costs are properly recognized.

Q: Please describe the application of DG to the CCOS.

A: Details of the CCOS, including its mechanics and processes are described in the testimony of Marisol Miller. In considering the integration of DG, there are two areas of particular focus within the CCOS that I would like to highlight. First, are the class costs. By definition, the purpose of the study is to apportion costs to the classes in line with the contribution those classes make to the causing the cost to occur. To accomplish this task an identification of the billing determinants (counts, usage, and revenue) is needed. To this point, the Company has not uniquely identified DG customers within the billing determinant processes. Information concerning DG customers is comingled with information for the broad class. Second is the relationship of these costs to the revenue produced to determine under or over recovery for the class. The revenues associated with DG customers is available, but absent the costs, recovery cannot be accurately determined.

Q: Given these conditions, how did the Company proceed with application of DG to the study.

A: Acknowledging that the Company needed to adjust its processes to properly incorporate DG into the study, the Company sought an interim method. The Company began by examining the starting point of the CCOS study, the costs reflected in the books and records of the Company, expressed on a Kansas basis. Using this approach, and based on the detail available, it was determined that at this time the costs to serve DG customers were the same as the costs to serve non-DG customers. The examination considered material cost accounts such as metering, meter reading, billing, distribution plant, and generation plant. For the purpose of this analysis, the Company did not presume any difference from the Residential rate of return for DG customers. The Company chose to focus its application on the Unbundled presentation of costs.

Q: What is the Unbundled presentation of costs and how it is used in the rate design process.

A: Within our CCOS model we have a presentation of the data that shows costs sorted by function and expressed in various component views. This presentation is useful to guide ratemaking decisions. An example of the structure is shown in Figure 2:

DESCRIPTION
RATE OF RETURN
$ / KWH
DEMAND COMPONENT EXCL LOCAL FACILITIES
DEMAND COMPONENT
DEMAND PRODUCTION COMPONENT
DEMAND TRANSMISSION COMPONENT
DEMAND DISTRIBUTION COMPONENT
DEMAND DISTRIBUTION PRIMARY COMPONENT
LOCAL FACILITIES
DEMAND DISTRIBUTION SECONDARY COMPONENT
DEMAND DISTRIBUTION TRANSFORMATION
ENERGY COMPONENT
CUSTOMER COMPONENT
CUSTOMER LIGHTING COMPONENT
CUSTOMER SERVICES COMPONENT
CUSTOMER METERS COMPONENT
CUSTOMER METER READING COMPONENT
CUSTOMER OTHER RECORDS & COLLECTIONS
CUSTOMER OTHER CUST ACCTS, SERV, INFO
CUSTOMER SALES COMPONENT
CUSTOMER MISC OTHER COMPONENT
TOTAL COMPANY
$/MO/CUST
TOTAL MONTHLY CUSTOMER CHARGE
LOCAL FACILITIES
DEMAND DISTRIBUTION SECONDARY COMPONENT
DEMAND DISTRIBUTION TRANSFORMATION
CUSTOMER COMPONENT
CUSTOMER LIGHTING COMPONENT
CUSTOMER SERVICES COMPONENT
CUSTOMER METERS COMPONENT
CUSTOMER METER READING COMPONENT
CUSTOMER OTHER RECORDS & COLLECTIONS
CUSTOMER OTHER CUST ACCTS, SERV, INFO
CUSTOMER SALES COMPONENT
CUSTOMER MISC OTHER COMPONENT

Figure 2

The Company chose to apply the avoided cost results as adjustments to these values.

Q: How would you expect to represent DG customers within the CCOS in the future?

A: Going forward, and consistent with guidance offered by the Commission in the 16-403 Docket, the Company requests authority to uniquely identify DG customers within the CCOS and ratemaking process. Given the small number of customers currently receiving DG service and similar to the treatment offered in this filing, the Company proposes to continue to utilize a separate sub-class within a future class cost of service study instead of a separate class. It has been our experience, learned after all but three customers abandoned the Large Power class following the 09-KCPE-246-RTS docket, that classes with small numbers of customers may not produce reliable cost allocation results. As Customers are placed on the proposed demand rate, the Company will begin compiling data concerning the Customer usage under the rate. This is expected to include load research and billing data, similar to the data compiled to support rate making for the existing retail rates. In the future, as the number of DG customers grows and becomes more significant, it would warrant unique identification through a separate class. It is uncertain what this precise threshold would be, but based on the estimated size of DG customers, the Company estimates this number should exceed approximately 250 customers. Until then, the Company believes it would be more practical to approach DG treatment as a sub-class.

Q: Are there any offsetting costs associated with DG that should be considered?

A: Yes. The Company believes that as the amount of DG deployed grows, it would be appropriate to include a recognition of the energy sales displaced by DG energy production. When a DG system is deployed and Customers begin generation of their own energy, recovery of utility costs is directly impacted. During the ratemaking process, there is an expectation of energy sales built into the rates. If these expectations are not met, the utility can under recovery its approved revenue requirement. In the case of DG and similar to the avoided cost process, the amount of these lost sales can be identified. The amount can, in turn, be valued at the rate of the non-fuel, retail revenue rate. The Company regularly calculates the marginal rate to support its recovery of energy efficiency costs in Missouri. As an example, the annual average marginal rate effective June 2017 for the residential class was $0.09494 per kWh. In evaluating the DG impact, the Company would propose identifying the lost revenue by multiplying this rate times the number of kWh produced and consumed by the DG customer. Based on data from the avoided cost determination, the Company estimates that 1,328,358 kWh were produced and consumed by residential DG customers[4]. Multiplying this total by the Missouri rate yields a value of $126,114.

Q: Were the lost margins included in the current application of avoided cost?

A: No. As this issue was not discussed as part of the 16-403 Docket, the Company did not wish to incorporate it here but instead proposes that future determinations of avoided cost be modified to include this provision.

Q: How do you propose to apply the avoided cost value to the rates?

A: As noted previously, the application began with adjustment to the Unbundled presentation of costs, an input to the rate design process. The next step is to design a rate that considers that input and other rate design principals. In this case, the Company has drawn from the work completed in the 16-403 Docket and the determination that the two-

[4] Total energy produced (2,073,477 kWh) less excess energy (745,119 kWh)

part rate is problematic for DG customers due to the lack of alignment between cost and rates, and that a three-part rate consisting of a customer charge, demand charge, and energy charge is appropriate. Consistent with that guidance, the Company is proposing a three-part rate to be applied to future DG customers.

Q: Please describe the proposed demand rate for residential DG customers?

A: The Company is proposing a simple, three-part rate to be applied to new, DG customers following the effective date of rates in this docket. An example of the tariff is included as Exhibit BDL-7 to this testimony. The rate will consist of a Customer Charge set equal to the Residential General Use Customer Charge, a seasonally differentiated Demand Charge, and a seasonally differentiated, flat Energy Charge. The demand rate is designed to be a transitional rate, priced to collect the distribution portion of the residential demand, leaving the generation and transmission portions with the energy charge. The proposed demand charge rate would be applied to Customers based on the demand measured within the peak period for the billing month measured in 15-minute intervals. The peak period is the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Q: Does the Company plan to offer education support for customers placed on the proposed demand rate?

A: Yes. As discussed in the 16-403 Docket, education of Customers is important to ensure the rate is properly used and the signals associated with the demand rate design are properly understood. The Company is continuing to work of the exact design and elements of the educational materials, but expects the educational support will initially consist of a direct exchange of materials as part of the interconnection process. If the DG demand rate is approved by the Commission, each customer applying for interconnection through net metering or parallel generation will be provided an explanation of the rate and the mechanics of the demand component. The Company is aware of pamphlets prepared by Arizona Public Service to support their demand rate.[5] These provide easy to understand explanations of demand and ways to save under the demand rate. If found acceptable, similar approaches are plausible for the Company. Later, if approved and after the residential pilot rates are effective, additional demand-related training will be offered. This education is expected to be more broadly directed to Customers, consisting of web-based content, billing inserts, bill messages, and other print alternatives. The Company is aware of web-based educational materials offered by the Salt River Project in conjunction with their mandatory demand rate for DG customers.[6] This example includes tips, calculators, graphics, and videos, all possible through the Company website. Further, there are opportunities to offer customer-specific usage information through "portal" functionality of the new billing system being implemented by the Company. Based on the current configuration, Customers who register to use the portal service can receive usage-based reporting and peer comparisons. The usage reports can provide five-minute, hourly, daily, and monthly details. Examples are offered in Exhibit BDL-8. The five-minute view would be particularly useful in understanding and managing usage. If supported, the Company would also consider television, newspaper, or other media forms to expand potential contact.

[5] http://www.azenergyfuture.com/getmedia/4a60158e-47db-418b-b630-4b998bc9b541/APS-Peak-Usage-Brochure.pdf/?ext=.pdf
[6] https://www.srpnet.com/prices/home/customergenerated.aspx

Q: Does the proposed three-part demand rate resolve all rate design needs concerning residential DG?

A: No. The three-part rate represents a meaningful initial design that resolves problems with the current two-part rate. However, a number of issues, both known and expected, could produce a need for revision of the DG rate design. As mentioned earlier, the proposed demand rate is designed to recover distribution related costs in the demand charge. It could be advisable to include all or part of the generation costs in the demand charge as well. This change would reinforce and better align the rate designs with cost causation. Also mentioned previously is the deployment of Smart Inverters. If accomplished, the value of the grid services provided should be recognized in the ratemaking and related compensation. Looking ahead, industry developments such as economic battery storage may introduce new considerations that must be reflected in the application of the demand charge. Continued refinement and Company experience with Time of Use rates, may inspire revisions to the DG rates to include these provisions. Finally, the Company can foresee value in four-part rate designs, similar to those used for our commercial and industrial customers. As described in comments to the 16-403 Docket, the Company believes these rates best parallel cost causation and could be used to provide expanded price transparency to Customers.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in Its Charge for Electric Service	)	**Docket No. 18-KCPE-____-RTS**

AFFIDAVIT OF BRADLEY D. LUTZ

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Bradley D. Lutz, being first duly sworn on his oath, states:

1. My name is Bradley D. Lutz. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Senior Manager – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of fifty-five (55) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Bradley D. Lutz

Bradley D. Lutz

Subscribed and sworn before me this 1st day of May 2018.

Anthony R Westenkirchner

Notary Public

My commission expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP

PURPOSE:

The purpose of the Solar Subscription Pilot Rider (Program) is to provide a limited number of Customers the opportunity to voluntarily subscribe to the generation output of a solar resource and receive electricity from solar resources. This Program will allow the Company to deploy and evaluate a structure for integrating solar energy directly into service provided to its Customers.

Program Participants will subscribe and pay for Solar Blocks of five hundred (500) watts (W AC) each. Energy produced by the subscribed Solar Blocks will offset an equivalent kWh amount of energy they receive and are billed for under their standard class of service. Approximately 10,000 Solar Blocks will be available for subscription with the initial offering. This program may be expanded to include up to 50 MW of installed solar capacity. Depending on Customer interest, additional solar resources may be built and Solar Blocks made available. Customers will be required to enroll for the Program in advance and each solar resource will be built when 75 percent of the proposed solar resource is committed. If the Company does not receive a sufficient number of subscriptions for the Program, the Company may terminate this Schedule SSP.

AVAILABILITY:

This Rider is available to any Customer currently receiving permanent electric service under the Company's retail rate schedules. Customers must complete the required Participant Agreement and have an account that is not delinquent or in default.

Participants will be enrolled on a first-come, first-served basis. Customers applying but not allowed into the Program due to Solar Block unavailability will be placed on a waiting list and incorporated into the Program in the order they are received. Should Solar Blocks become available due to construction of additional solar resources or subscription cancellations, Customers on the waiting list will be offered the opportunity to subscribe. Subscription hereunder is provided through one meter to one end-use Customer and may not be aggregated, redistributed, or resold.

Total participation of non-residential Customers will be limited to no more than 50 percent of the total solar resource capacity during the first three months of the Program. After three months, and at the Company's sole discretion, all available solar resource capacity may be made available to all eligible Customers.

This Rider may not be combined with any other renewable energy program offered by the Company for the same Customer account.

Customers receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Program while participating in those service agreements. This schedule is not available for resale, standby, breakdown, auxiliary, parallel generation, or supplemental service.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

PRICING:

The Solar Block Subscription Charge for energy sold through this Program is $0.14370 per kWh, made up of two costs:

1. The Solar Block cost of $0.11500 per kWh; and
2. The charge of $0.02870 per kWh for interconnection service costs.

The Solar Block cost is defined by the total cost of the solar resources built to serve the program. The interconnection charge is the embedded cost of Transmission and Distribution based on the Company's class cost of service study from the Company's most recent rate case. When an additional solar resource is added to the Program, the levelized cost of the new solar resource will be averaged with the remaining levelized cost of existing solar resource(s) to determine the new price for the cost of the Solar Block. This price may be greater than or less than the previous price. The cost of facilities for distribution interconnection is subject to change in future general rate proceedings, independent from the Solar Block cost.

SUBSCRIPTION LEVEL:

Participants may subscribe to Solar Blocks that, when combined, are expected to generate up to 50 percent of their annual energy. During initial sign-up, the Customer will designate their desired subscription percentage in increments of 10 percent. The Company will provide to the Customer the number of Solar Blocks necessary to supply their subscription percentage based on the Customer's annual energy usage. The Customer's annual energy usage will be determined in one of two ways. If during initial signup the Customer has 12 consecutive months of usage history at the address where the subscription is being requested, then the annual energy will be the energy consumed during that 12-month usage history. If the Customer does not have 12 consecutive months of usage history at the address where the subscription is being requested, then the annual energy will be estimated by the Company. The calculation for the number of Solar Blocks is equal to the annual energy (in kWh) divided by the expected annual energy production of one block rounded down to the lowest whole number. A Customer must have sufficient annual usage to support subscription of at least one Solar Block.

Until the Company expands its solar energy production beyond the initial 5 MW, the maximum amount any one Customer may subscribe to is 2,500 kW AC of capacity. After the expansion of solar energy production, subscription for any one Customer beyond 2,500 kW AC will be at the Company's discretion. A Participant may change their subscription level only once in any 12-month period after the initial 12-month subscription. In the event there is a significant and regular reduction in Participant metered energy consumption, the Company, at its sole discretion, may adjust the Participant's subscription level.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

BILLED PURCHASE QUANTITY:

The quantity of energy that will be purchased by a Participant for each monthly billing cycle will be computed as follows:

$$PQ = \frac{SL}{TSC} \cdot AME$$

Where,

PQ = Monthly Purchase Quantity in kWh

SL = Subscription Level in kW AC

TSC = Total Solar System Capacity in kW AC

AME = Actual Monthly Energy Produced by the Solar Resource in kWh.

The Total System Capacity will be re-determined whenever a new solar facility is brought online or an existing solar facility is taken offline.

MONTHLY BILLING:

1. The monthly energy production of the solar resource will be measured and apportioned to each Participant based on their respective subscription share. To facilitate billing, energy production will be applied to the monthly billing one month after it occurs.
2. The Participants share of the solar resource energy production will be subtracted from the metered energy consumed by the Participant for the billing month. Should the solar resource energy production amount for a given month be larger than the Participant's metered energy consumption, the net energy will be zero for that month.
3. Any remaining metered energy consumption will be billed under the rates associated with the Participant's standard rate schedule, including all applicable riders and charges
4. Other, non-energy charges defined by the standard rate schedule are not impacted by the Solar Block subscription and will be billed to the Participant.
5. The entire bill amount, inclusive of all standard rate charges and Program charges, must be paid according to the payment terms set forth in the Company Rules and Regulations.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

WAITING LIST:

If at the time of subscription request a Customer's desired subscription level is greater than the available energy of the solar resource, then the Customer may elect to be placed on a waiting list.

Customers will be offered an opportunity to subscribe in the order that they are placed on the waiting list, only if available capacity is greater than the customer's desired subscription level. If the available capacity is less than the Customer's desired subscription level, the Customer will be offered the opportunity to subscribe to the remaining available capacity. If the Customer does not wish to participate at this lower than desired subscription level, then the next Customer on the waiting list will be checked for subscription availability.

SUBSCRIPTION TERM:

Participants must remain in the Program for one year, as measured from the first bill received under this Rider.

Non-residential Participants who subscribe to 25 percent of the available Solar Blocks for a given solar resource, are required to commit to a minimum term of five years.

PROGRAM PROVISIONS AND SPECIAL TERMS:

1. All rights to the renewable energy certificates (REC) associated with the generation output of the solar facility will be retired by the Company on behalf of Participants.

2. Any Participant being served or having been served on this Program waives all rights to any billing adjustments arising from a claim that the Participant's service would be or would have been at a lower cost had it not participated in the Program for any period of time.

3. Participants who move to another location within the Company's Missouri service territory may transfer their subscription, provided the total kWhs of the subscribed amount is not more than the new location's allowed subscription level (actual or estimated). If the subscription level exceeds the allowed amount at the new location, the subscription will be adjusted down accordingly.

4. Participants must notify the Company in writing of their intent to transfer any subscription(s). Transfers will only be effective if the Transferee satisfies the terms and conditions applicable to the subscription and signs the Participant Agreement and assumes all responsibilities associated therewith.

SOLAR SUBSCRIPTION PILOT RIDER
Schedule SSP (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS: (Continued)

5. Customers that subscribe will continue as Participants until they cancel their subscription or the Program is terminated. New subscriptions and cancelations require notice 20 days prior to the end of the Participant's billing cycle and will take effect at the beginning of the next applicable billing cycle.

6. Upon cancelation of a Participant's service, Participants may transfer their entire subscription to another eligible Participant's service agreement, including non-profits, for a $25 fee. Participants with more than one Solar Block may transfer their Solar Block subscriptions in whole subscription increments to one or more Eligible Customers for a $25 fee per transfer.

7. Any Participant who cancels Program participation must wait 12 months after the first billing cycle without a subscription to re-enroll in the Program.

8. Ownership of unsubscribed Solar Blocks and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers.

ADJUSTMENTS AND SURCHARGES:

The Rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

RENEWABLE ENERGY RIDER
Schedule RER

PURPOSE:

This Program is designed to provide non-Residential Customers a voluntary opportunity to purchase Renewable Energy, in addition to service provided through a generally available rate, from Renewable Energy sources that the Company contracts.

Following Commission approval of this Rider, the Company will endeavor to procure the Renewable Energy sources necessary to fulfill Customer requests for service under this Program. Pricing and related terms will be updated to reflect these sources.

AVAILABILITY:

Customer accounts receiving Unmetered, Lighting, Net Metering, or Time-of-Use Service are ineligible for this Program while participating in those service agreements. This Program is not available for resale, standby, breakdown, auxiliary, parallel generation, or supplemental service.

Service under this Program is available on a limited and voluntary basis, at the Company's option, to non-Residential Customers currently receiving permanent electric service from the Company through Schedule SGS, MGS, LGS, SGA, MGA, or LGA, with an annual average monthly peak demand greater than 200 kW. At the Company's sole approval, Customers that have an aggregate electric load of at least 2.5 MW based upon peak annual demand and an average of 200 kW per account, or are recognized by the Company as Governmental or Municipal Customers, may combine separate accounts to participate in this Program.

Customers will be enrolled and subscribed on a first-come, first-served basis. Customers applying but not allowed to subscribe due to Renewable Energy resource unavailability will be placed on a waiting list and may be offered the opportunity to subscribe if subscription cancellations or forfeitures occur. Customers approved for aggregation of accounts may choose to participate in part or remain on the list as a consolidated group, depending on resource availability. Participants may cancel their subscription at any time subject to any net cost of the remaining Renewable Energy for the term. Service hereunder is provided to one end-use Customer and may not be redistributed or resold.

Within any limits prescribed by the individual tariffs, the Company will combine the subscription requirements for all Company jurisdictions in executing the power purchase agreement(s) for the Renewable Energy resource. The combined Program will be initially limited to a minimum total load of 100 megawatts (MW) and a maximum total load of 200 MW, split equally between the Company jurisdictions. The Company reserves the right to reapportion the allocation between Companies in response to Customer subscription. The production from the combined power purchase agreement(s) for the Renewable Energy resource will be allocated among the various Company jurisdictions based on the respective subscriptions within that jurisdiction. The limit will be re-evaluated if or when the 200 MW limit is reached. Additional subscriptions will be made available at the sole discretion of the Company.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

DEFINITION:

For purposes of this Program the following definitions apply:

1. PARTICIPANT — The Customer, specified as the Participant in the Participant Agreement, is the eligible Customer that has received notification of acceptance into the Program.

2. PARTICIPANT AGREEMENT — The agreement between the Company and Customer, utilized for enrollment and establishing the full terms and conditions of the Program. Eligible Customers will be required to sign the Participant Agreement prior to participating in the Program. This agreement may be provided and executed electronically.

3. POWER PURCHASE AGREEMENT (PPA) — an agreement or contract between a resource owner and the Company for renewable energy produced from a specific renewable resource.

4. RENEWABLE ENERGY CREDITS — also known as Renewable Energy Certificates or RECs, represent the environmental attributes associated with one (1) megawatt-hour of renewable electricity generated and delivered to the power grid.

5. RENEWABLE ENERGY — energy produced from a renewable resource as defined in K.S.A. 66-1257, K.A.R. 82-16-1 (l), and associated with this Program. Renewable resources procured will be utilized for this program or similar voluntary, green programs.

6. RESOURCE PROCUREMENT PERIOD — the period of time in which the Company will, if the subscriptions on the waiting list warrant such effort, attempt to obtain a renewable resource to serve the Participation Agreements queued on the waiting list. At a minimum, two Resource Procurement Periods will occur each calendar year

7. SUBSCRIPTION INCREMENT (SI) — An eligible Customer may subscribe and receive energy from a renewable resource in single percentage increments, up to 100% of the Customer's Annual Usage.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

DEFINITIONS: (Continued)

8. SUBSCRIPTION SHARE (SS) — The proportion of the renewable resource, adjusted for the Renewable Resource Capacity Factor, allocated to the Customer to achieve the desired Subscription Increment amount. The Subscription Share is determined at enrollment and is calculated using the following formula:

$$\mathrm{SS} = \frac{\mathrm{SL_{MW}}}{\mathrm{RRC_{MW}}}$$

Where,

$$\mathrm{SL_{MW}} = \frac{\mathrm{AU_{MWh}} \cdot \mathrm{SI}}{8{,}760_{\text{hours per year}} \cdot RRC_{factor}}$$

$\mathrm{AU_{MWh}}$ = Annual Usage; the Customer's actual metered energy usage over the previous 12 monthly billing periods, if available, or Customer's expected metered energy usage over 12 monthly billing period as determined by Company.

$\mathrm{RRC_{MW}}$ = Renewable Resource Capacity Factor; the average annual capacity of the renewable resource(s) as established by the Company.

$\mathrm{RRC_{factor}}$ = Renewable Resource Capacity Factor; the average annual capacity factor of the renewable resource(s) as established by Company.

ENROLLMENT:

1. The Customer must submit a completed Participant Agreement to the Company for service under this Program. In the Participant Agreement, the Customer must specify the Subscription Increment to be subscribed.

2. Customers applying for service under this Program must have an account that is not delinquent or in default at the beginning of the Resource Procurement Period and must have completed the required Participant Agreement.

3. Enrollment requests may be submitted to the Company at any time.

4. The Company will review the Participant Agreement and determine if the Customer will be enrolled into the Program.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

ENROLLMENT: (Continued)

5. In each Resource Procurement Period the Company will match as accurately as possible the combined Renewable Subscription Level of all Participants with a renewable resource, subject to availability. The minimum renewable resource to be acquired will have a capacity of 100 MW and the maximum will depend upon the level of Participation Agreements received. The renewable resource obtained for each Subscriber group may be made up of capacity from multiple renewable resources.

CHARGES AND BILLING:

All charges provided for under, and other terms and conditions of, the Customer's applicable standard service classification(s) tariff shall continue to apply and will continue to be based on actual metered energy use during the Customer's normal billing cycle.

Under this Schedule RER, Customers will receive a Renewable Adjustment (RA), in the form of an additional charge or credit to their standard bill based upon the sale of the metered output of the renewable resource(s) into the wholesale market. The Renewable Adjustment will be calculated as follows:

$$\mathrm{RA} = [\mathrm{RMO}_{\mathrm{MWh}} \cdot \mathrm{SS}] \cdot [\mathrm{SC}_{\$\ \mathrm{per\ MWh}} - \mathrm{FMP}_{\$\ \mathrm{per\ MWh}}]$$

Where,

$\mathrm{RMO}_{\mathrm{MWh}}$ = Metered output from the renewable resource at the market node.

$\mathrm{SC}_{\$\ \mathrm{per\ MWh}}$= Subscription Charge; the delivered price per MWh of the renewable resource plus the Company Administration Charge of $0.10 per MWh (RMO) for twenty-year term Participant Agreements. For all other Participant Agreements, the Company Administration Charge will be $0.30 per MWh (RMO).

$\mathrm{FMP}_{\$\ \mathrm{per\ MWh}}$ = Final Market Price; the accumulation of all applicable market revenues and charges arising from or related to injection of the energy output of the renewable resource into the wholesale energy market in that calendar month at the nearest market node, divided by the actual metered hourly energy production, using the best available data from the regional transmission operator, who facilitates the wholesale marketplace, for the calendar month as of the date the Customer's Renewable Adjustment is being prepared. Alternatively, and at the Company's discretion if determined to be economic, the Company may seek to obtain the necessary transmission to deliver the energy output of the renewable resource to a local, Company market node. If this occurs, the Final Market Price will be calculated based on the accumulation of all applicable market revenues and charges inclusive of this delivery. The energy produced under this alternative will be subject to curtailment by the regional transmission operator. The Final Market Price will be rounded to the nearest cent.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

CHARGES AND BILLING: (Continued)

The Renewable Adjustment may be applied up to 60 days later than the market transactions to allow for settlement and data processing.

Market revenues and charges may be adjusted to reflect net costs or revenues associated with service under the Program in prior months, for which more recent wholesale market settlement data supersedes the data that was used to calculate initial charges or credits that were assessed to participating Customers.

The Renewable Subscription Charge and the Subscription Share are to be determined at the time the Company obtains the renewable resource to satisfy the Participation Agreement.

Billing and settlement of charges under this Schedule may occur separately from the billing associated with service provided to a Customer's under the Standard Rate Schedules. The Company reserves the right to consolidate account data and process charges collectively to facilitate Customers electing to aggregate subscriptions under this Schedule.

TERM:

Agreements under this Program are available for enrollment for five-year, ten-year, and twenty-year terms. Customers will select the term at time of enrollment and will not be allow to change the term once the renewable resource serving the Customer has been obtained. Customers subscribing to more than 20% of the renewable resource will be required to commit to a minimum term of ten years.

RENEWABLE RESOURCE ENERGY CREDITS:

Renewable Energy Credits associated with energy obtained through this Program will be transferred to the Customer annually or at any time upon Customer request. Alternatively, and if requested, the Company will retire the credits on behalf of the Customer with all costs associated with the registration and retirement borne by the requesting Customer.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

TRANSFER OR TERMINATION:

Participants who move to another location within the Company's Kansas service territory may request transfer of their subscription, provided the total kWh of the subscribed amount is less than the new location's average annual historical usage (actual or Company estimated). If the existing subscription level exceeds the allowed usage amount at the new location, the subscription will be adjusted down accordingly.

Participants who request termination of the Participation Agreement, or default on the Participation Agreement before the expiration of the term of the Participation Agreement, shall pay to the Company any associated costs and administration associated with termination of the subscribed renewable resource. Such termination charge may be adjusted if and to the extent another Customer requests service under this Schedule and fully assumes the obligation for the purchase of the renewable energy prior to the effective date of the contract amendment or termination; provided, however, Company will not change utilization of its assets and positions to minimize Customer’s costs due to such early termination. The Participant must notify the Company in writing of their request to terminate.

RENEWABLE CONTRACTS SUPPORTING ECONOMIC DEVELOPMENT:

The Company may, at its discretion, enter into an individual agreement with a Customer requesting Renewable Energy to support customer retention or incremental load resulting from the construction or expansion of facilities within the Company's service territory. Depending on the details of the Customer need, the load may be served by the same Renewable Energy resource used for this Program or may result in agreements for additional Renewable Energy resources. The individual terms concerning pricing will be established with the requesting Customer. All agreements are subject to availability and deliverability of Renewable Energy resources and will be structured in such a way as to ensure recovery of all related costs from the requesting Customer.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS:

1. In procuring the Renewable Energy, the Company will ensure that Renewable Energy resources utilized under this Program are or have been placed in service after January 1, 2019.

2. At enrollment, the Company will calculate the Customer's demand for the prior twelve-month period to determine eligibility. If twelve months of demand data is not available, the Company may estimate the annual demand to the nearest kW, using a method that includes, but is not limited to, usage by similarly sized properties or engineering estimates.

3. Customers that the Company, at its sole discretion, determines are ineligible will be notified promptly, after such Participant Agreement is denied.

4. Customer participation in this Program may be limited by the Company to balance Customer demand with available qualified Renewable Energy resources, adequate transmission facilities, and capacity.

5. Customers who need to adjust in their commitments due to increases or decreases in electric demand may request such adjustment in writing from the Company. Efforts will be made to accommodate the requested adjustment. The Customer will be responsible for any additional cost incurred to facilitate the adjustment.

6. Any Customer being served or having been served on this Program waives all rights to any billing adjustments arising from a claim that the Customer's service would be or would have been at a lower cost had it not participated in the Program for any period of time.

7. The Company may file a request to discontinue this Program with the Commission at any time in the future. Prior to the termination, the Company will work with the participating Customer to transition them fully from the subscriptions in effect to a Standard Rate Schedule or to an alternate green power option that the Company may be providing at that time. Any Participant who cancels Program participation must wait twelve (12) months after the first billing cycle without a subscription to re-enroll in the Program.

8. Ownership of unsubscribed energy and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers. Unsubscribed amounts will be allocated between the jurisdictions based on the Customer Subscriptions in place at the time of processing.

RENEWABLE ENERGY RIDER
Schedule RER (Continued)

PROGRAM PROVISIONS AND SPECIAL TERMS: (Continued)

9. Ownership of unsubscribed energy and the associated RECs will be assumed by the Company and incorporated into the energy provided to retail Customers. Unsubscribed amounts will be allocated between the jurisdictions based on the Customer Subscriptions in place at the time of processing.

10. The Company shall not be liable to the Customer in the event that the Renewable Energy supplier fails to deliver Renewable Energy to the market and will make reasonable efforts to encourage the Renewable Energy supplier to provide delivery as soon as possible. However, in the event that the Renewable Energy supplier terminates the Renewable Energy contract with the Company, for any reason during the term of contract with the Customers, the Company, at the election of the Customer, shall make reasonable efforts to enter into a new PPA with another Renewable Energy supplier as soon as practicable with the cost of the Renewable Energy to the Customer revised accordingly.

11. Operational and market decisions concerning the renewable resource, including production curtailment due to economic conditions, will be made solely by the regional transmission operator. These decisions could impact the market price received for the renewable resource energy output.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

STANDBY SERVICE RIDER
Schedule SSR

APPLICABILITY:

Applicable to each Customer at a single premise(s) with behind-the-meter, on-site parallel Distributed Generation system(s) with a capacity greater than or equal to 100 kilowatts (kW), as a modification to standard electric service supplied under either the tariffed rate schedules of Small General Service (Schedule SGS or SGA), Medium General Service (Schedule MGS or MGA), or Large General Service (Schedule LGS or LGA). Customers must receive service under a standard rate schedule that includes a Facilities Charge and a Demand Charge. Provision of this Rider will be based on the nameplate rating of the Distributed Generation.

Customers with emergency backup, intermittent renewable generation, or energy storage systems are excluded from this Schedule SSR.

DEFINITIONS:

1. Distributed Generation – Customer's private, on-site generation that:

   A. is located behind the meter on the Customer's premise(s);

   B. has a nameplate capacity of greater than or equal to 100 KW;

   C. operates in parallel with the Company's system; and

   D. adheres to an applicable interconnection agreement entered into with the Company.

2. Standby Contract Capacity – Shall be the LESSER of:

   A. The sum of nameplate rating(s) of all Customer Distributed Generation systems;

   B. The sum of nameplate rating(s) less any generation on the same premises used exclusively for generation redundancy purposes; and

   C. The number of kilowatts mutually agreed upon by Company as representing the Customer's Standby Capacity requirements based on a Company approved Customer load curtailment plan. Any evidence that the load curtailment plan is not used as intended will result in the Standby Contract Capacity being reset to one of the other alternatives.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES:

1. For Customers with Standby Contract Capacity greater than or equal to 100kW and less than or equal to 2MW

A. Capacity Reservation Charge — An additional charge, based on the size of the Distributed Generation, applied to recover the cost of providing and maintaining the generation and transmission facilities required to support the capacity requirements of the Customer within the Company system.

B. Interconnection Charge — A charge applied in place of the Facility Charge associated with the standard rate, to recover the cost of providing and maintaining the distribution facilities required to interconnect the Customer to the Company system that are normally embedded in the volumetric energy charge of the standard rate.

C. Supplemental Service Charge — A charge for electric service (demand and energy) provided by the Company to the Customer to supplement normal operation of the Customer's Distributed Generation system to meet the Customer's full service requirements. Supplemental Service will be deemed to occur if the Customer's Metered Grid Interconnection Load is positive. Supplemental Service will be supplied at the applicable rates under the standard rate schedule.

D. Excess Generation Credit — If the Customer's Metered Grid Interconnection Load is negative, the excess energy received by the Company system will be credited at the then current Parallel Generation rate, as defined in Schedule PG.

	Small General Service	**Medium General Service**	**Large General Service**
Capacity Reservation Charge (per kW of Standby Contract Capacity)	$1.117	$1.117	$1.787
Interconnection Charge (per kW of Standby Contract Capacity)	$6.686	$6.384	$6.626

Supplemental Service Charge — All service will be supplied at the applicable rates under the standard rate schedule.

Excess Generation Credit — Excess energy will be credited at the current Parallel Generation rate as defined in Schedule PG.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

2. For Customers with Standby Contract Capacity between greater than 2MW and less than or equal to 10MW

A. Minimum Operating Limit — 90% of the Standby Contract Capacity.

B. Metered Grid Interconnection Load — all metered Customer usage from the Company system. Metering will measure both energy consumed and excess energy, if any, delivered back to the Company system.

C. Metered Generation Output — all metered output from the Customer's Distributed Generation system.

D. Total Customer Load — is the Metered Grid Interconnection Load plus the Metered Generation Output.

E. Standby Service Metering & Administrative Charge — A charge to cover additional meter costs, meter data processing, billing, and administrative costs beyond those covered in the standard tariff.

F. Supplemental Service Charge — A charge for electric service (demand and energy) provided by the Company to the Customer to supplement normal operation of the Customer's Distributed Generation system to meet the Customer's full service requirements. Supplemental Service will be deemed to occur if the Customer's Total Load is greater than the Metered Generation Output and greater than the Minimum Operating Limit.

G. Backup Service — Electric service (demand and energy) provided by the Company to Customer premises to replace capacity and energy normally produced by the Customer's Distributed Generation (formerly referred to as Breakdown service). Backup Service will be deemed to occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Summer period. Seasonal periods are defined in the applicable standard rate schedule.

H. Maintenance Service — Electric service (demand and energy) provided by the Company to customer premises to replace capacity and energy normally produced by the Customer's Distributed Generation. Maintenance Service will be deemed to occur if the Metered Generation Output is less than the Minimum Operating Limit and less than the Total Customer Load during any time in the Winter period. Seasonal periods are defined in the applicable standard rate schedule.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

I. Excess Generation Credit — If the Customer's Metered Grid Interconnection Load is negative, the excess energy received by the Company system will be credited at the then current Parallel Generation rate, as defined in Schedule PG.

	Small General Service	Medium General Service	Large General Service
Standby Service Metering & Administrative Charge (per month)	$140.00	$140.00	$160.00
Capacity Reservation Charge (per kW of Standby Contract Capacity)	$1.117	$1.117	$1.787
Demand Rate (per kW of Monthly Backup or Maintenance Demand):			
Backup Service	$0.186	$0.186	$0.298
Maintenance Service	$0.149	$0.149	$0.238
Energy Charge (per kWh of Monthly Backup or Maintenance Energy):			
Backup Service	$0.14429	$0.09178	$0.06879
Maintenance Service	$0.06337	$0.05754	$0.04916

Supplemental Service Charge: All service will be supplied at the applicable rates under the standard rate schedule.

Excess Generation Credit: Excess energy will be credited at the current Parallel Generation rate, as defined in Schedule PG.

Where:

a) Daily Backup Demand shall equal the Maximum Backup Demand metered during a calendar day;

b) Monthly Backup Demand shall equal the sum of the Daily Backup Demands for the billing period;

STANDBY SERVICE RIDER
Schedule SSR (Continued)

RATES: (Continued)

c) Daily Maintenance Demand shall equal the Maximum Maintenance Demand metered during a calendar day; and

d) Monthly Maintenance Demand shall equal the sum of the Daily Maintenance Demands for billing period.

3. For Customers with Standby Contract Capacity greater than 10MW

Terms for service to Distributed Generation systems of this size will be established by special rate and interconnection agreements. Provisions of the special agreements will address all requirements of systems of this size, including the requirements of the Southwest Power Pool and North American Electric Reliability Corporation. The Company may examine the locational benefit of the Customer Distributed Generation system and consider those benefits in defining the rates charged under this Schedule SSR. As practical, the terms of the special agreements will utilize rates and terms defined within the Company's Commission approved tariffs.

GENERAL PROVISIONS:

The contract term shall be one (1) year, automatically renewable, unless modifications to the Distributed Generation requires a change to the Standby Contract Capacity.

For Distributed Generation larger than 2MW, the Company will install and maintain the necessary suitable meters for measurement of service rendered hereunder, including the Metered Grid Interconnection Load and the Metered Generation Output. The Company may inspect generation logs or other evidence that the Customer's Distributed Generation is being used in accordance with the provisions this Schedule SSR. Upon installation of the metering, the Customer shall initially reimburse the Company for any metering investment costs that are in addition to the cost of metering of standard full requirements retail service.

Distributed Generation systems shall not commence parallel operation until after inspection by the Company and a written interconnection agreement is executed.

All metering occurring for service received and billed under this Schedule SSR will be measured in 15-minute intervals.

STANDBY SERVICE RIDER
Schedule SSR (Continued)

GENERAL PROVISIONS: (Continued)

It is expected that the Customer will perform routine and scheduled maintenance of the Distributed Generation systems during the Winter Season.

The Customer is responsible for timely notification of the Company, in writing, if the Distributed Generation system or load curtailment plan is changed in any what that would impact the Standby Contract Capacity. The Company reserves the right to confirm the Standby Contract Capacity at any time.

If at any time Customer desires to increase demand above the capacity of Company's facilities used in supplying said service due to plant modifications, Customer will sign a new agreement for the full capacity of service required and in accordance with applicable rules governing extension of its distribution system.

In the event a Customer adds Distributed Generation systems after investments are made by the Company in accordance with the Company’s Line Extension policy, the Company may require reimbursement by the Customer. Such reimbursement shall be limited to that investment which was incurred within the previous five years and shall be based upon the change in load requirements on the Company’s electric system.

In establishing interconnection agreements, parallel operating guidelines, purchase agreements and standby service arrangements with customers in accordance with 18 C.F.R. Sections 292.101 et seq., it is not the Company's intent to simultaneously sell electricity at system-wide average costs and to re-purchase the same electricity at avoided costs. Any condition which allows for this to occur, potentially or actually,shall not be permitted.

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML

AVAILABILITY:

Available for street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof.

RATE (Incandescent): 2MLIL (FROZEN)

1.0 Street lamps equipped with a hood and reflector, supported on a wood pole or existing trolley pole and supplied from overhead circuits by an extension not in excess of 500 feet per unit: (Code X)

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
1.1	2500 Lumen (187-watt)*	64	$128.88

2.0 Street lamps equipped with a hood, reflector, and refractor, on wood poles served overhead by an extension not in excess of 500 feet per unit: (Code IWT)

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
2.1	4000 Lumen (269-watt)*	92	$218.04
2.2	6000 Lumen (337-watt)*	115	$243.60

*Limited to the units in service on December 28, 1972, until removed.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Incandescent): 2MLIL (FROZEN) (Continued)

3.0 Street lamps equipped with hood, reflector, and refractor, on ornamental steel poles served underground by an extension not in excess of 300 feet per unit:

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
3.1	4000 Lumen (269-watt) Under Sod* [1]	92	$342.12

[1] Code ISE

* Limited to the units in service on December 28, 1972, until removed.

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Month Day Year

Effective:
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By: /s/ Darrin R. Ives Vice President
Title

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Customer Owned): 2MLCL (FROZEN)

4.0 Street lamps equipped with a hood, reflector, and refractor, owned and installed by customer, maintained and controlled by the Company, served overhead or underground:

	Size of Lamp	Monthly kWh	Rate per Lamp per Year
4.1	16000 Lumen Limited Maintenance (150-watt)[1]	67	$210.60
4.2	27500 Lumen Limited Maintenance (250-watt)[1]	109	$276.00

[1] Code LMX

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Mercury Vapor and High Pressure Sodium Vapor): 2MLML, 2MLSK, 2MLSL (FROZEN)

5.0 Basic Installation:
Street lamps equipped with hood, reflector, and refractor, on wood poles served from overhead circuits by an extension not in excess of 200 feet per unit: (Code OW)

	Size of Lamp	Monthly kWh	Lumen Charge per Lamp per Year[1]	Total Charge per Lamp per Year[1]
5.1	8600 Lumen Mercury Vapor (175-watt)*	71	$47.16	$214.08
5.2	12100 Lumen Mercury Vapor (250-watt)*	101	$66.00	$233.04
5.3	22500 Lumen Mercury Vapor (400-watt)*	157	$125.52	$292.56
5.4	5800 Lumen High Pressure Sodium (70-watt)***	34	$33.00	$199.92
5.5	9500 Lumen High Pressure Sodium (100-watt)***	49	$47.52	$214.56
5.6	16000 Lumen High Pressure Sodium (150-watt)***	67	$66.60	$233.64
5.7	27500 Lumen High Pressure Sodium (250-watt)***	109	$125.88	$292.92
5.8	50000 Lumen High Pressure Sodium (400-watt)***	162	$293.88	$460.80

[1]Rates above are based on a Base Unit Charge of $167.04 plus a Lumen Charge as stated above. Twin units will be billed at one and one-half (1 1/2) times the Base Unit Charge plus (2) times the appropriate Lumen Charge. KWh usage for twin lamps is two times the single monthly kWh.

6.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 8.0 above for Mercury Vapor and High Pressure Sodium Vapor installations only.

6.1 Ornamental steel pole instead of wood pole, additional charge per unit per year $46.68. (New installations are available with underground service only).

6.2 Laminated wood pole instead of wood pole.** (Available with underground service only). Additional charge per unit per year $97.92.

6.3 Aluminum pole instead of a wood pole, additional charge per unit per year $95.76. (Available with underground service only).

NOTE: Wattage specifications do not include wattage required for ballast

* Limited to the units in service on April 18, 1992, until removed.
** Limited to the units in service on December 1, 2010, until removed.
*** Limited to units in service on XXXXXXXX XX, XXXX until removed.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (Mercury Vapor and High Pressure Sodium Vapor): 2MLML, 2MLSK, 2MLSL (FROZEN) (Continued)

6.4 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per year $81.96.

6.5 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per year $444.00.

6.6 Breakaway base. Additional charge per unit per year $42.96. (Available with underground service only).

6.7 Special black square luminaire,* instead of basic installation luminaire. (Available with underground service only). Additional charge per unit per year $94.32.

RATE (LED): 2MLLL

7.0 Basic Installation:
Street luminaires on new wood poles serviced from overhead circuits by a new extension not in excess of 200 feet per unit: (Code OW)

	Size and Type of Luminaire–	Monthly kWh	Rate per Luminaire per Month(2),(3)
7.1	5000 Lumen LED (Class A)(Type V pattern)(1)	16	$16.20
7.2	5000 Lumen LED (Class B)(Type II pattern)(1)	16	$16.20
7.3	7500 Lumen LED (Class C)(Type III pattern)(1)	23	$18.93
7.4	12500 Lumen LED (Class D)(Type III pattern)(1)	36	$23.73
7.5	24500 Lumen LED (Class E)(Type III pattern)(1)	74	$25.36

(1) Lumens for LED luminaires may vary ±12% due to differences between lamp suppliers.
(2) Twin luminaires shall be two times the rate per single luminaire per month.
(3) Existing LED luminaires installed under the MARC Pilot (Schedule ML-LED) will be converted to these rates based on their installed lumen size.

* Limited to the units in service on December 1, 2010, until removed.

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

RATE (LED): 2MLLL (Continued)

8.0 Street luminaires on short bracket arm and existing wood poles served from existing overhead circuits: (Code EW)

	Size and Type of Luminaire–	Monthly kWh	Rate per Luminaire per Month
8.1	5000 Lumen LED (Class A)(Type V pattern)(1)	16	$16.20
8.2	5000 Lumen LED (Class B)(Type II pattern)(1)	16	$16.20
8.3	7500 Lumen LED (Class C)(Type III pattern)(1)	23	$18.93
8.4	12500 Lumen LED (Class D)(Type III pattern)(1)	36	$23.73
8.5	24500 Lumen LED (Class E)(Type III pattern)(1)	74	$25.36

(1)Lumens for LED luminaires may vary ±12% due to differences between lamp suppliers.

9.0 Optional Equipment: The following rates for Optional Equipment shall be added to the rate for Basic Installation listed in 10.0 above.

9.1 Metal pole instead of wood pole, additional charge per unit per month $3.78. (New installations are available with underground service only).

9.2 Underground service extension, under sod, not in excess of 200 feet. Additional charge per unit per month $6.64.

9.3 Underground service extension under concrete, not in excess of 200 feet. Additional charge per unit per month $35.95.

9.4 Rock Removal or other specialized trenching/boring for installation of underground service. Additional charge per service per month $20.00.

9.5 Breakaway base. Additional charge per unit per month $3.48. (Available with underground service on metal poles only).

10.0 Special Mounting Heights: The standard mounting height is 31 ft. or less. The following rates for Special Mounting Heights may be added to the rate for new, basic installations listed in section 7.0.

		Wood Pole	Metal Pole
10.1	Between 31 and 41 ft.	$2.13	$3.38
10.2	Greater than 41 ft.	$4.49	$7.89

MUNICIPAL STREET LIGHTING SERVICE
Schedule ML (Continued)

REPLACEMENT OF UNITS:

Existing street lamps shall be replaced at the same pole location with a different type of standard unit installation only by mutual agreement of the Company and the Municipality. The Company has the right to replace existing incandescent, mercury vapor, and high pressure sodium vapor street lamps in need of repair or replacement (or on poles in need of repair or replacement) with equivalent LED high pressure sodium vapor street lamps.

STANDARD UNITS:

Standard street lamps are those LED units for which a rate is stated except those with an X designation in the type code.

BURNING HOURS:

Unless otherwise stated, lamps are to burn each and every day of the year from one-half hour after sunset to one-half hour before sunrise, approximately 4100 hours per year.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

MUNICIPAL ORNAMENTAL STREET LIGHTING SERVICE
Schedule MOL

AVAILABILITY:

Available for ornamental street lighting service through a Company-owned Street Lighting System within corporate limits of a municipality.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than ten years from the effective date thereof. Termination prior to end of 10-year period results in a one-time charge equal to the Company's actual investment less depreciation.

RATE: (High Pressure Sodium Vapor) 2MOSL
(Light Emitting Diode (LED)) 2MOLL

1.0 Basic Installation:
Street lamps equipped with ornamental luminaire on ornamental poles served from underground extensions not in excess of 200 feet per unit:

	Size of Lamp	Monthly kWh	Total Charge, per Lamp, per Month, Under Sod	Total Charge, per Lamp, per Month, Under Concrete
1.1	9500 Lumen High Pressure Sodium (100-watt)	49	$64.66	$94.50
1.2	16000 Lumen High Pressure Sodium (150-watt)	67	$65.72	$95.89
1.3	4300 Lumen LED (Class K) (Acorn Style)	26	$61.83	$90.84
1.4	10000 Lumen LED (Class L) (Acorn Style)	41	$62.32	$91.65

Company inventory availability as follows (1,2):

1. Luminaire: Standard Ornamental
2. Post: 12-foot cast aluminum with 4 inch diameter shaft
3. Base: Standard Screw-in Base

(1) If any equipment becomes obsolete, then new installations will be accomplished with the most appropriate available equipment by mutual agreement of the Company and the Municipality.
(2) Any changes to above listed standard equipment will incur additional monthly facilities charges.

Lumens for LED luminaires may vary ±12% due to differences between luminaire suppliers.

NOTE: Hight Pressure Sodium wattage specifications do not include wattage required for ballast.

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Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

OFF-PEAK LIGHTING SERVICE
Schedule LS

AVAILABILITY:

For metered, secondary voltage, electric outdoor lighting service solely to a municipality or governmental entities for purposes of enhancing security and/or illuminating streets, parks, athletic fields, parking lots, or other outdoor facilities. At the Company's discretion, the metering requirement may be eliminated where it is impractical or difficult to install and read meters. Usage for unmetered lights will be estimated using wattage ratings and hours usage. The lamps served under this schedule must be controlled with a photo-electric cell or other positive controlled device which restricts service to non-daylight hours. Governmental entities qualifying for service under this schedule include departments, agencies, and subdivisions of the United States, the State of Kansas, counties, municipalities, and school districts.

Service to privately-owned lights or Company-owned street lights shall not be supplied under this schedule. Standby, breakdown, supplementary, temporary or seasonal service will not be supplied under this schedule.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

RATE: 2LS1E

$0.05963 per kWh for all kWh per month.

OFF-PEAK LIGHTING SERVICE
Schedule LS (Continued)

RATE: KSOLL, 2LSIE (Unmetered)

1. The Customer will pay a monthly charge for all lighting service as follows:

A.	Customer Charge	$21.70
B.	Energy Charge (All usage)	$0.05963

2. The monthly kWh usage for unmetered service will be calculated as follows:

$$\text{kWh Usage} = \frac{\text{Total Watts} \cdot \text{MBH} \cdot \text{BLF}}{1{,}000}$$

MBH = Monthly Burning Hours ($\frac{4{,}100\ hours}{12}$)
BLF = Ballast Loss Factor; one (1) plus the manufacturer's published ballast loss percentage (expressed as a decimal fraction) for the installed unit if applicable.

3. For unmetered service, the Company shall have the right to verify or audit the type, wattage, and number of lights installed.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL

AVAILABILITY:

For unmetered protective lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing customer's premises. Not available for municipal street, park or other public lighting, or for temporary service.

RATE: 2ALDA, 2ALDE

1. Base Charge:

The monthly rate for each private lighting unit installed on an existing wood pole and using existing secondary circuits is as follows:

	Monthly kWh	Area Lighting	Flood Lighting
5800 Lumen High Pressure Sodium Unit (70-watt)	34	$14.94	
8600 Lumen Mercury Vapor Unit* (175-watt)	71	$15.61	
16000 Lumen High Pressure Sodium Unit (150-watt)	67		$24.76
22500 Lumen Mercury Vapor Unit* (400-watt)	157	$25.17	
22500 Lumen Mercury Vapor Unit* (400-watt)	157		$26.78
50000 Lumen High Pressure Sodium Unit (400-watt)	162		$42.18
63000 Lumen Mercury Vapor Unit* (1000-watt)	372		$45.80

* Limited to the units in service September 30, 1985, until removed.

NOTE: Wattage specifications do not include wattage required for ballast.

2. Additional Charges:

If an extension of the Company's secondary circuit or a new circuit is required either on or off the customer's premises to supply service hereunder at the location or locations desired on the customer's premises, the above monthly rate shall be increased as follows:

Each 30-foot ornamental steel pole installed	$ 11.25
Each 35-foot ornamental steel pole installed	$ 12.35

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

RATE: 2ALDA, 2ALDE (Continued)

2. Additional Charges: (Continued)

Each 30-foot wood pole installed	$6.96
Each 35-foot wood pole installed	$8.06
Each overhead span of circuit installed	$2.17

If the installation of additional transformer facilities is required to supply service hereunder, the above monthly rate shall be increased by a charge equal to one and three-fourths percent of the Company's total investment in such additional transformer facilities.

If the customer requires underground service, the customer will be responsible for installing all underground ductwork in conformance with Company specifications and the Company will be responsible for installing cable and making the connection to Company facilities. There will be an additional $3.05 per month charge for each underground lighting unit served. If the underground conduit exceeds 300 feet in length, there will be an additional charge of $3.05 per month per 300 foot length, or fraction thereof.

BILLING:

The charges for service under this schedule shall appear as a separate item on the customer's regular electric service bill.

TERM:

The minimum initial term under this rate schedule shall be one year. However, if the private lighting installation requires extension of the Company's service facilities of more than one pole and one span of circuit or the installation by the Company of additional transformer facilities, the customer shall be required to execute a service agreement with an initial term of three years.

UNEXPIRED CONTRACT CHARGES:

If the contracting customer terminates service during the initial term of the agreement, and a succeeding customer does not assume the same agreement for private lighting service at the same service address, the contracting customer shall pay to the Company unexpired contract charges equal to the monthly rate times the number of remaining months in the contract period.

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

SPECIAL PROVISIONS:

1. The customer shall provide, without cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities.

2. The Company reserves the right to restrict installations served under this schedule to areas easily accessible by service truck.

3. All facilities required for service under this schedule will be furnished, owned, installed and maintained by the Company in accordance with the presently effective Construction Standards of the Company.

4. Extension of the Company's secondary circuit under this schedule to more than one pole and one span of wire for service hereunder to any customer is subject to prior study and approval by the Company.

5. The Company will not be obligated to patrol to determine outages or required maintenance of the facilities used for service under this schedule. Upon notification of any outage or required maintenance of facilities used hereunder, the Company will restore normal service as soon as practicable but only during regularly scheduled working hours. No reduction in billing shall be allowed for any outage of less than ten working days after notification of Company.

6. Upon receipt of written request from the customer, the Company will, insofar as it may be practicable and permissible, relocate, replace or change its facilities used or to be used in rendering service to the customer under this schedule, provided the customer agrees in writing to reimburse the Company upon being billed for the Company's cost so incurred.

Issued: May 1, 2018
Month Day Year

Effective:
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

PRIVATE UNMETERED PROTECTIVE LIGHTING SERVICE (FROZEN)
Schedule AL (Continued)

SPECIAL PROVISIONS: (Continued)

7. If a customer who has agreed to a specific lighting unit requests to change to a different lighting unit, the customer shall pay the labor cost for the removal of the existing unit and the Base Charge for the new unit shall be applicable thereafter.

8. All existing mercury vapor lights shall be changed to high pressure sodium lights when maintenance or change out is required. When these change outs occur, the customer charge will be changed to the high pressure sodium rate.

9. When the Company changes mercury vapor lights, all lights at the same location will be changed to high pressure sodium. The 22500 lumen mercury vapor area light will be retained. However, the customer may change to any other light under Section A.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL

AVAILABILITY:

For unmetered lighting service for private entrances, exits, yards, driveways, streets, alleys, walkways and other all-night outdoor private areas on existing Customer's premises. Not available for municipal street lighting or for temporary service. Customers will be required to sign an Application for Private Lighting Service before service will be provided.

RATE: 2ALLA, 2ALLE

1. Base Charge:

The monthly rate for each private lighting unit installed using existing secondary circuits is as follows:

	Monthly kWh	Monthly Rate
4,500 Lumen LED (Type A-PAL)	11	$11.01
8,000 Lumen LED (Type C-PAL)	21	$14.40
14,000 Lumen LED (Type D-PAL)	39	$19.06
10,000 Lumen LED (Type C–FL)	27	$14.40
23,000 Lumen LED (Type E–FL)	68	$26.37
45,000 Lumen LED (Type F–FL)	134	$51.53

Lumens for LED luminaires may vary ±12% due to differences between luminaire suppliers.

2. Additional Charges:

Optional Equipment: The following rates for Optional Equipment may be added to the rate for basic installation.

If an extension of the Company's secondary circuit or a new circuit is required either on or off the Customer's premises to supply service hereunder at the location or locations desired on the Customer's premises, the above monthly rate shall be increased as follows:

Each 30-foot metal pole installed (SP30)	$10.94
Each 35-foot metal pole installed (SP35)	$12.01
Each 30-foot wood pole installed (WP30)	$6.77
Each 35-foot wood pole installed (WP35)	$7.84
Each overhead span of circuit installed (SPAN)	$2.11
Optional Breakaway Base (for metal pole only) (BKWY)	$3.48

If the installation of additional transformer facilities is required to supply service hereunder, the above monthly rate shall be increased by a charge equal to one and three-fourths percent (1¾%) of the Company's total investment in such additional transformer facilities.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

RATE: 2ALLA, 2ALLE (Continued)

2. Additional Charges: (Continued)

If the Customer requires underground service, the Customer will be responsible for installing all underground duct work in conformance with Company specifications and the Company will be responsible for installing cable and making the connection to Company facilities. There will be an additional $2.97 per month charge for each underground lighting unit served up to a maximum of 300 feet of underground conduit per lighting unit (U300).

BILLING:

The charges for service under this schedule shall appear as a separate item on the Customer's regular electric service bill.

TERM:

The minimum initial term under this rate schedule shall be one year for the LED Luminaire. However, if the private lighting installation requires a wood pole or the installation by the Company of additional transformer facilities, the Customer shall be required to execute a service agreement with an initial term of three years. If the Customer wants a metal pole installed, the Customer shall be required to execute a service agreement with an initial term of five years.

UNEXPIRED CONTRACT CHARGES:

If the contracting Customer terminates service during the initial term of the agreement, and a succeeding Customer does not assume the same agreement for private lighting service at the same service address, the contracting Customer shall pay to the Company unexpired contract charges equal to the monthly rate times the number of remaining months in the contract period.

REPLACEMENT OF UNITS:

The Company has the right to replace existing fixtures in need of repair or replacement (or on poles in need of repair or replacement) with equivalent Light Emitting Diode (LED) luminaires. Customers will be given the opportunity to decline the replacement and remove the fixture entirely.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

SPECIAL PROVISIONS:

1. The Customer shall provide, without cost to the Company, all permits, consents, or easements necessary for the erection, maintenance, and operation of the Company's facilities.

2. The Company reserves the right to restrict installations served under this schedule to areas easily accessible by service truck.

3. All facilities required for service under this schedule will be furnished, owned, installed and maintained by the Company in accordance with the presently effective Construction Standards of the Company.

4. Extension of the Company's secondary circuit under this schedule more than one pole and one span of wire for service hereunder to any Customer is subject to prior study and approval by the Company.

5. The Company will not be obligated to patrol to determine outages or required maintenance of the facilities used for service under this schedule. Upon notification of any outage or required maintenance of facilities used hereunder, the Company will restore normal service as soon as practicable but only during regularly scheduled working hours. No reduction in billing shall be allowed for any outage of less than ten working days after notification of Company.

6. Upon receipt of written request from the Customer, the Company will, insofar as it may be practicable and permissible, relocate, replace or change its non-lighting facilities used or to be used in rendering service to the Customer under this schedule, provided the Customer agrees in writing to reimburse the Company upon being billed for the Company's cost so incurred.

7. If a Customer who has agreed to a specific lighting unit, requests a change to a different lighting unit during the initial term of the contract, the Customer shall pay the labor cost for the removal of the existing unit and the Base Charge for the new unit shall be applicable thereafter.

8. Company shall select style and make of lighting facilities provided within each type system for which rates are listed. Lighting will not be installed on poles or structures not owned or leased by Company.

PRIVATE UNMETERED LED LIGHTING SERVICE
Schedule PL (Continued)

OPERATING HOURS:

Unless otherwise stated, luminaires operate each and every day of the year from about one-half hour after sunset to about one-half hour before sunrise, approximately 4100 hours per year.

ADJUSTMENTS AND SURCHARGES:

The Rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

DISTRIBUTED GENERATION AVOIDED COST ANALYSIS

ANALYSIS SUMMARY: This analysis seeks to quantify and value the benefit of distributed generation ("DG") to KCP&L in Kansas for consideration in cost allocation and ratemaking. Following guidance established by the Kansas Corporation Commission order in the 16-GIME-403-GIV docket[1], KCP&L has examined clearly quantifiable, market-based benefits associated with DG[2]. These benefits are represented by the following avoided cost categories:

- Avoided Energy
- Avoided Generation Capacity
- Avoided Transmission & Distribution Line Losses
- Avoided Distribution Infrastructure Costs
- Avoided Transmission Infrastructure Costs

To complete this analysis, a team of subject matter experts representing Energy Resource Management, Distribution Engineering, Distribution Planning, Transmission Planning, Energy Solutions, Energy Accounting, and Regulatory Affairs was assembled. This team evaluated industry materials on DG valuation, considered studies completed by other companies, and examined the DG systems installed in the KCP&L-Kansas jurisdiction. The following analysis summaries detail these considerations and establish a framework for future analysis. This framework provides the initial view of the Company as to how to best quantify the benefit provided by DG. It is expected that this framework will mature and develop with increases in DG penetrations and utility understanding of DG impacts.

Below is a summary of the quantifications, valuations, and total avoided cost resulting from this analysis:

Avoided Cost Category	Quantification	Value	Avoided Cost
Energy	2,073,474 kWh	$0.02720 per kWh	$56,391
Capacity	471.14 kW	$2.00 per kW-month	$11,307
T&D Line Losses	160,331 kWh	$0.02720 per kWh	$4,361
Distribution Costs	0	see narrative	$0
Transmission Costs	0	see narrative	$0
Total			**$72,059**

KCP&L believes DG proliferation is inevitable based on the increasing economic value to the customer as the cost to entry decreases. This analysis acknowledges the current quantifiable benefits based on current penetration levels and the current technology. The Company's challenge going forward will be to balance the interests of DG customers, non-DG customers, and distribution system impacts as DG installations become more numerous. The Company accepts it will need to develop more robust distribution planning tools to handle higher levels of DG penetration, but also acknowledges these developments will come at increased costs to the Company and thereby its customers.

[1] Final Order, In the Matter of the General Investigation to Examine Issues Surrounding Rate Design for Distributed Generation Customers. Dated September 21, 2017

[2] DG in the KCP&L-Kansas jurisdiction is represented by 218 net metered systems (28 Commercial and 190 Residential) with an installed capacity of 2,219.94 kW (806.37 kW Commercial and 1,413.57 kW Residential). Of those systems, 7 are wind and 211 are solar. These values are from reporting filed under Docket 12-KCPE-665-CPL.

As DG penetration levels increase, KCP&L will make prudent judgements concerning investments in systems, personnel, and other resources in order to serve our customers interests and maintain a safe and reliable system.

DISTRIBUTED GENERATION AVOIDED COST ANALYSIS

COST CATEGORY: **Avoided Energy**

COST DESCRIPTION: Avoided energy costs provide benefit to the utility by reducing the amount of energy the utility would otherwise need to produce. This distributed energy is consumed at the point of generation and any excess energy is delivered to the grid.

QUANTIFICATION: For the residential class, all distributed generation occurs in the form of net metering. Of that, 98.5% of the generation is solar with the remaining 1.5% as wind. Under net metering the Company tracks two data points concerning the customer generation, the energy delivered by the utility to the customer and the energy delivered by the customer generator to the grid. There is currently no specific tracking of energy produced and consumed on-site by the customer generator. Therefore, to determine the total generation achieved by customer net metering systems, an engineering calculation must be used. For this analysis, the Company used the PVWatts[3] calculator provided by the National Renewable Energy Laboratory ("NREL"). To facilitate calculation, the Company established that all customer generation would be evaluated as solar.[4] This would streamline the calculation and it is not expected to impact the estimation of avoided cost.

Using PVWatts, the Company modeled the AC generation capability of the entire population of residential net metered systems under the default parameters[5] of the calculator based on a typical meteorological year ("TMY3") data for Kansas City International Airport. Using the 2017 annual net metering report[6], the Company reported a total of 2,219.94 kW of customer generation capacity. Of that capacity, 1,413.57 kW was associated with residential customers. According to the engineering calculation of the PVWatts system, the population of residential net metered systems is expected to produce the following levels of monthly energy.

Table 1. Estimated kWh Output Based on Current Kansas Solar Penetration

Month	Energy Produced (PVWatts kWh)
Oct-16	174,981
Nov-16	138,963
Dec-16	135,862
Jan-17	153,236
Feb-17	137,887
Mar-17	189,099
Apr-17	186,642
May-17	194,405

[3] http://pvwatts.nrel.gov/

[4] This total represents approximately 9.9 kW of wind generation. Since no production estimation models are readily available for residential scale wind, these systems were modeled as if they were solar.

[5] NREL PVWatts Default values: Standard Module Type, Panel Losses of 14%, Fixed array with 39.3-degree tilt, at azimuth of 180 degrees, DC to AC ratio of 1.1, and Inverter efficiency of 96%.

[6] Filed March 1, 2018 under Docket 12-KCPE-665-CPL

Jun-17	186,660
Jul-17	194,898
Aug-17	196,175
Sep-17	184,666
Total	**2,073,474**

For the purpose of presentation and subsequent valuation, the monthly production estimated by PVWatts was associated with the months of the test year in Table 1.

VALUATION: To establish the value for the residential customer energy, the Company considered and accepted that the value is defined by Kansas statutes. Within the Kansas Net Metering Easy Connect Act, particularly KS Stat § 66-1266 (2017), the value of energy from customer systems is set at 100% of the utility's monthly system average cost of energy per kilowatt hour. This value is applied to energy received from all net metering systems and parallel generation systems within the Kansas jurisdiction.

In providing administration to the net metering and parallel generation tariffs, the Company calculates its monthly system average cost of energy per kilowatt hour. Those rates generally include fuel operating expenses, purchased power, station non-fuel operations, and production expenses. For the test period associated with this study, the rates were as follows:

Table 2. Average Cost of Energy (per kWh) (per KS Stat § 66-1266 (2017))

Month	Rate (Ave System)
Oct-16	0.03110
Nov-16	0.03330
Dec-16	0.02920
Jan-17	0.02600
Feb-17	0.02490
Mar-17	0.02270
Apr-17	0.02000
May-17	0.02760
Jun-17	0.02850
Jul-17	0.02810
Aug-17	0.02900
Sep-17	0.02740

IDENTIFIED AVOIDED COST: To determine the avoided cost of the energy quantified the Company multiplies the estimated kWh production from the residential net metered systems by the utility's monthly system average cost of energy per kilowatt hour. The product of this multiplication represents the avoided cost of energy.

Table 3. Estimated Value of Energy Received

Month	Energy Produced (PVWatts kWh)	Rate (Ave System)	Estimated Value
Oct-16	174,981	0.03110	$5,442
Nov-16	138,963	0.03330	$4,627
Dec-16	135,862	0.02920	$3,967
Jan-17	153,236	0.02600	$3,984
Feb-17	137,887	0.02490	$3,433
Mar-17	189,099	0.02270	$4,293
Apr-17	186,642	0.02000	$3,733
May-17	194,405	0.02760	$5,366
Jun-17	186,660	0.02850	$5,320
Jul-17	194,898	0.02810	$5,477
Aug-17	196,175	0.02900	$5,689
Sep-17	184,666	0.02740	$5,060
Total	**2,073,474**		**$56,391**

As an alternate view, the avoided cost of energy for the test year period may be expressed as an average per kWh value.

Avoided Cost of Energy (per kWh) = Total Estimated Value ($) ÷ Total kWh

$0.02720 per kWh = $56,391 ÷ 2,073,474

ADDITIONAL OBSERVATIONS:

- The recommendation to utilize the annual average system cost to value energy produced from DG sources was introduced within the 16-GIME-403-GIE docket by Commission Staff witness Dr. Robert Glass. On page 6, paragraph 14 of his Initial Comments, the statutory requirement was plainly stated. The Company considered and accepted this position.

- Absent the statutory provisions defining average system cost, the Company believes the value for avoided energy would be lower, approaching the marginal cost of energy or a market-based cost of energy.

- Certain generalizations were used to complete this determination of avoided cost. In particular, reliance on the engineering calculation to determine energy production may be suitable for current levels of production and at the current point in the lifecycle of DG, particularly solar photovoltaic systems.

  - As the penetration levels of DG increase and the installed systems begin to age, it would become increasingly important to utilize some other method to determine the actual energy produced. It is likely to become practical to require installation of production meters to precisely measure this energy.
  - Increased number of DG systems will introduce higher levels of diversity to the DG “fleet”, meaning the systems will become less homogeneous and less suitable for generalized calculations like those used here.
  - Concerning age, it is reasonable to expect that system performance will begin to degrade as photocell surfaces become cloudy and components wear out. Further, particularly for residential systems that may not benefit from regular maintenance, it is reasonable to expect that photocells will fail and not be replaced. Generalized calculations presume all systems are operational at full capability. This assumption may not prove reliable into the future.

- Future determinations of avoided energy may need to be revised to address changes in technology. In particular, deployment of Smart Inverters may change the way this element of avoided cost is defined. Today, solar photovoltaic systems produce energy only. When Smart Inverters are deployed, solar photovoltaic systems could be used to provide valuable, energy-related services such as voltage support, power factor compensation, or event ride-through capabilities. These services provide benefit to the grid, but would result in reduced measured energy output from the customer’s system. Quantification and valuation methodologies would need to be expanded to include these elements. Further, substantial DG and Smart Inverter proliferation would benefit from remote sensing and remote coordination/control at the utility level to help mitigate power quality issues associated with high levels of DG saturation. Thus, the utility may need to incur additional control systems costs.

- From another perspective, the energy produced by DG sources can contribute to a negative effect for non-DG customers. As current utility cost recovery is dependent on energy sales, reductions in sales can have the effect of increasing the average price paid for energy. That condition is not incorporated in this evaluation, but under high DG penetration levels and if the dependence on volumetric sales cannot be addressed, there may need to be a consideration of the impact in the determination of avoided cost. More specifically, if there is high penetration of DG and the Company must deploy higher levels of fast-start generation or rely more heavily on the hourly energy market for supporting the DG, it is reasonable to expect the costs to provide energy will increase. To the extent this increase is driven by DG, it may be appropriate to reflect this increase as an offset, or reduction to the calculation of avoided cost.

COST CATEGORY: **Avoided Generation Capacity**

COST DESCRIPTION: Avoided Generation Capacity Costs are avoided expenditures attributed to DG additions that would otherwise be required by a utility to meet capacity requirements.

QUANTIFICATION: To quantify the avoided capacity provided by DG, the amount of currently installed DG capacity in the KCP&L-KS jurisdiction was determined. The Company then developed an estimate of the effect the installed DG capacity has on the peak load observed for KCP&L-KS.

Using the 2017 annual net metering report[7], the Company reported a total of 2,219.94 kW of customer DG capacity. Of that, **1,413.57 kW, or 1.414 MW,** was associated with residential customers.

To determine the effect or coincidence of production from the DG capacity on the system loads, the Company used the PVWatts[8] calculator provided by the NREL to obtain the hourly production estimated for the 1,413.57 kW of identified DG capacity. This production was compared to load data obtained from Company load research sources for KCP&L-KS. Aligning the hours, the Company compared the capacity factor attributable to DG generation to the system load factor. Figure 1 details that result for the annual system coincident peak ("CP") day, observed on July 21, 2017, and for the six highest peak days in July.

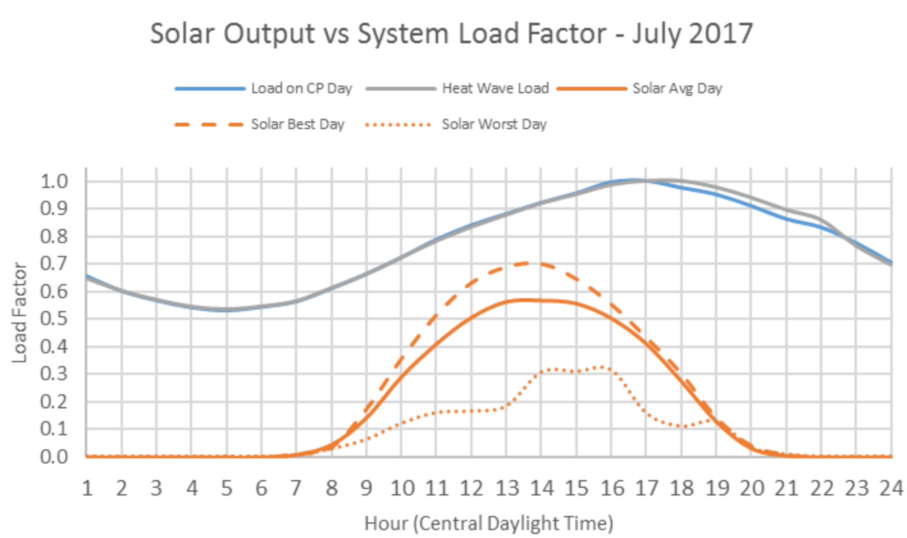

Figure 1

Two lines, the "Load on CP Day" and "Heat Wave Load", represent the measured customer load factor during the system peak day and the six days with the highest daily peaks and highest daily maximum temperatures in the month. On the vertical axis, a comparison of the load factors is presented. The system peak hour for each line was

[7] Filed March 1, 2018 under Docket 12-KCPE-665-CPL
[8] http://pvwatts.nrel.gov/

assigned a load factor of 1.0, and the other hours were assigned a factor based on a ratio of the hourly load to the peak load.

The "Solar Average Day" line represents the capacity factor for solar expressed as the ratio of the average hourly alternating current ("AC") output divided by the installed direct current ("DC") capacity. The AC output measures the usable energy delivered by the system, while the DC value expresses the capacity rating of the solar panels. For purposes of this analysis, the solar output was determined using the default settings of PVWatts for the installed DG systems. Two additional lines, "Solar Best Day" and "Solar Worst Day" reflect the hourly output for the July days with the highest and lowest production estimated by PVWatts. For the purpose of identifying the effective capacity factor for the DG capacity, the Company considered the four hours, starting with hour ending 16 (4pm) and produced an average value for that four-hour period. This period is thought to capture the peak and allow for a level of variability in aligning the data. The resulting average capacity factor for the "Solar Average" line in this period was **33.33%**. For comparison, the capacity factor for the "Solar Best Day" in that same period was 36% and the "Worst Solar Day" was 15%. Under higher DG penetrations, use of the "Worst Solar Day" capacity factor would be appropriate. However, under these smaller penetrations and to allow for some generalizations within the calculation process, the Solar Average is used here.

Using these values, the Company quantified the capacity provided by DG systems to be:

$$\text{DG Capacity} \times \text{DG Capacity Factor} = \text{Capacity Provided}$$

$$\mathbf{1{,}413.57\ kW \times 33.33\% = 471.14\ kW\ (0.471\ MW)}$$

This calculation does not account for any variation, positive or negative, in production due to system installation (orientation, tilt, photocell type, inverter capability, or system losses), conditions of equipment (panel age, inverter settings), or other elements associated with individual installations (shading, wiring interconnection).

VALUATION: Company research would indicate there are no less than five methods commonly used to establish the value of capacity.[9] Those methods commonly used are:

- Simple avoided generator ("CT") - Assumes DG avoids construction of a new CT. also known as the Cost of New Entry ("CONE") of a Combustion Turbine.
- Weighted avoided generator - Assumes DG avoids a mix of generators based on avoided fuel.
- Capacity market value - Uses cost of capacity in restructured markets. The cost of capacities in these types of markets generally represent a short-term perspective such as in the PJM capacity market where capacity is priced and auctioned in one-year blocks. In markets without capacity elements, competitively bid capacity procurements could serve as an equivalent source.
- Screening curve - Uses system load and generation data to estimate avoided generation mix based on capacity factor.

[9] Paul Denholm, Robert Margolis, Bryan Palmintier, Clayton Barrows, Eduardo Ibanez, Lori Bird, and Jarett Zuboy (2014). Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System. NREL Report No. NREL/TP- 6A20-62447. Golden CO: National Renewable Energy Laboratory. Page 32

- <u>Complete valuation of DG versus alternative technologies</u> - Estimates the type or mix of generators avoided in subsequent years using a capacity-expansion model.

In reviewing the environment around DG, including the amount of generation, the generation characteristics of common DG systems, and the time frame associated with the analysis, the Company identified the market-based rate method as the appropriate means to value capacity under these short-term perspectives. The Company does acknowledge that the simple avoided generator method of CONE method has merit, but believes that it would be more representative of the equivalent cost and term of capacity agreements under higher penetrations of DG (levels approaching 100MW, a common size for capacity procurement) or if valuation methods are revised to consider long-term or forward-looking cost projections. It would be reasonable to expect the methodology used to value capacity to change as levels of DG penetration also change.

To determine the market-based rate for capacity, the Company turned to a recent request for proposal (RFP) to procure capacity, issued by Great Plains Energy ("GPE"). Issued in December 2017, this RFP provided an opportunity for capacity producers to competitively bid to provide capacity service to the GPE companies. Reviewing the range of responses received, the Company determined that **$2.00/kW-month** was representative. This rate is not reflective of the low bid received, but provided a liberal value, selected to provide some recognition of the perceived increased value of DG capacity near the load.

IDENTIFIED AVOIDED COST: To calculate the annual avoided cost the Company used the following equation:

Capacity Provided × Capacity Value = Avoided Cost of Capacity

471.14kW × ($2.00/kW-month × 12 months) = $11,307.36

ADDITIONAL OBSERVATIONS:

- The KCP&L-KS jurisdiction currently does not need capacity to satisfy customer loads.

- Utilities normally build or otherwise procure capacity in relatively large increments (≈100MW). As such, it is common to have excess capacity at any given time.

- In estimating the capacity factor for DG generation, the Company utilized an average level of production as estimated by PVWatts. For this effort, particularly given the limited amount of DG generation installed, this approach was deemed appropriate. However, the Company recognizes that if a relatively high level of DG penetration were incorporated on the Company's generation system in the future and absent data from production metering, use of the lower, "Worst Day Solar" capacity factor assumption would be prudent to ensure sufficient capacity resources are deployed to meet Southwest Power Pool-mandated capacity responsibility. This change would better parallel other system planning approaches and recognize capacity factors more in-line with known utility scale alternatives.

- As DG penetrations increase the avoided cost of generation capacity will be reduced.[10]

- Estimated capacity factors can vary dramatically from day to day. Using data from PVWatts assuming the system peak month in July, shows an average DG-based capacity factor of 19% with variations in daily capacity factors ranging from 9% to 22%. Figure 2 details these results.

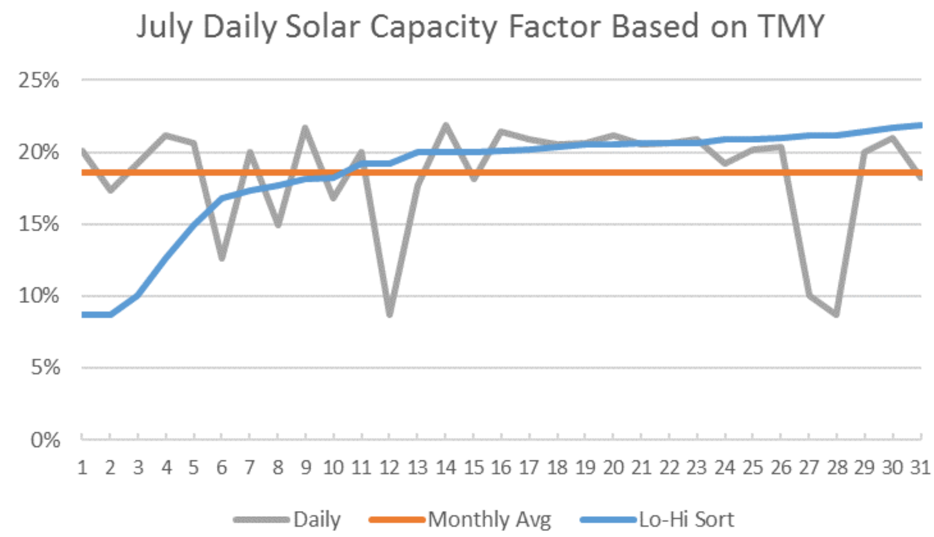

Figure 2

- It has been observed that orienting solar panels in a more westerly direction can result in higher levels of generation during the later afternoon/early evening peak hours, better aligning with the system peak usage period, but reducing the overall annual energy produced by the systems. However, as noted in the discussion of Distribution Costs, the adjusted peak does not last through the customer's demand peak usage.

- The analysis completed here does not address considerations for reserve capacity costs or benefits associated with deferral of capacity. As higher levels of DG are deployed, particularly levels approaching the normal capacity of utility peaking generation, these factors may become more relevant and may be included in the determination of avoided capacity.

- The value of capacity can vary depending on the application. Different values are currently used within resource planning and in evaluation of demand side measures such as energy efficiency or demand response. While these different values for capacity are related, one should not expect to see identical values between applications as the considerations for term, size, and other factors are unique to each.

[10] "Changes in the Economic Value of Variable Generation with Increasing Penetration Levels: A Pilot Study of California", Andrew Mills and Ryan Wiser, Lawrence Berkeley National Laboratory, CREPC/SPSC Pre-Meeting Webinar, March 21, 2012.

DISTRIBUTED GENERATION AVOIDED COST ANALYSIS

COST CATEGORY: **Avoided Transmission and Distribution Line Losses**

COST DESCRIPTION: Costs associated with a reduction in-line current relating to I^2R losses. Transmission and Distribution (T&D) losses are the energy expended on the lines and transformers due to current flow through line and wire impedance. These losses are calculated by multiplying the square of the current flow through the line by the line resistance, hence I^2R.

QUANTIFICATION: To estimate the avoided line losses as a result of DG, the Company determined the amount of installed DG capacity in the KCP&L-KS jurisdiction. Using the 2017 annual net metering report[11], the Company reported a total of 2,219.94 kW of customer DG capacity. Of that, **1,413.57 kW, or 1.414 MW,** was associated with residential customers.

To estimate the DG avoided line losses, the Company used the PVWatts[12] calculator provided by the NREL to obtain the annual energy production estimated for the 1,413.57 kW of identified DG capacity. Default NREL suggested input values were assumed for this calculation.[13] The estimated annual output range was identified as 1,982,656 kWh to 2,145,009 kWh, with a nominal value of 2,073,474 kWh. This nominal output was then multiplied by a combined T&D loss factor of 1.077325 for the KCP&L Kansas system, calculated in a *Loss Study for the KCP&L, MPS, and SJLP Systems – Year 2013* by Siemens Industry, Inc. The resulting product is the total demand plus losses. Subtracting the DG output then leaves the total avoided losses per year, 160,331 kWh of avoided losses.

Output for a solar capacity of 1,413.57 kW = **2,073,474 kWh /year**

KCP&L Kansas System Loss Factor = **1.077325**

Demand Output = Loss Factor x Output for a solar capacity of 1,414 kW = **2,233,805 kWh/year**

Avoided Losses due to Solar DG = Demand Output - Output for solar capacity of 1,413.57 kW = **2,233,805 kWh/year - 2,073,474 kWh/year = 160,331 kWh/year**

VALUATION: To establish the value for avoided T&D line losses due to DG, the Company used a marginal combined loss rate. This method is outlined in section five of NREL's *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. As identified in the Avoided Energy section of this report, the KCP&L-KS system wide average cost of energy for DG solar in the test year period is **$0.02720/kWh**.

The Company's existing design standards account for line losses, in terms of voltage drop and current limits. Because of this, there is no additional valued benefit beyond that of the average cost of energy. However, as technologies that can influence performance, such as Smart Inverters, continue to advance and the prevalence of DG in our territory continues to grow, there could be added benefits in the future. At that time, a more advanced method of valuation could be considered.

[11] Filed March 1, 2018 under Docket 12-KCPE-665-CPL
[12] http://pvwatts.nrel.gov/
[13] see footnote #5

IDENTIFIED AVOIDED COST: To determine the avoided cost of T&D line losses, the KCP&L-KS Avoided Line Losses were multiplied by the average energy cost of $0.02720/kWh.

Average Cost of Energy × KCP&L-KS Avoided Line Losses = Total Estimated Value ($)

$0.02720/kWh × 160,331 kWh = $4,361.00

ADDITIONAL OBSERVATIONS:

- KCP&L made the assumption that the PVWatts calculator provides accurate estimation of solar output for the Kansas jurisdiction. It was also assumed that the solar panels' efficiency has not degraded over time.

- The above estimate considers only the net loss savings associated with customer DG offsetting their own usage. No estimation was included to quantify potential added losses due to reverse current flow on the utility system as a result of excess generation. Examples of additional losses with excess DG are: additional transformer losses due to reverse current flow and additional secondary losses due to excessive generation. Similar findings were the result of a comparable study conducted by Xcel Energy "…total line losses with [DG] might be expected to be higher than total line losses that would occur in the absence of [DG]. This effect is caused by higher electrical current flows across sections of the Company's 120-volt secondary delivery system than would exist without 120-volt interconnected generation." [14]

- A more exact quantification of avoided losses could be completed with the individual premise location data including associated DG generation metering (as opposed to net metering only) and computer loss modeling. Substantial investment in metering, computer loss modeling, and data integration would be required to complete such a comprehensive study. Further, implementations of this nature require data preparation and complex system integration schemes.

[14] *"Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System," rep., May 2013. Page iii.*

DISTRIBUTED GENERATION AVOIDED COST ANALYSIS

COST CATEGORY: **Avoided Distribution Infrastructure Costs**

COST DESCRIPTION: Avoided costs associated with maintaining existing or building new distribution infrastructure associated with DG.

QUANTIFICATION: Savings on distribution infrastructure improvement costs due to DG requires four key qualifiers to be met:

1) The DG capacity is not greater than the customer load;
2) The distribution system infrastructure is not existing and thus can be constructed (sized) with the DG offset;
3) The DG is uninterrupted;
4) The DG peak occurs during the peak customer demand period.

Complications with each of these requirements are noted below.

Assuming future DG sizing is standard in accordance with existing Schedule NM[15], the existing infrastructure (wires and transformers) generally supports DG additions (DG output does not exceed customer usage). Infrastructure upgrade situations often occur where multiple DG sites are connected to one distribution transformer. These transformers sometimes require upsizing to accommodate situations where customer loads are low but generation is high. This situation has been particularly identified in the spring and fall (low customer loads) where multiple solar DG sites cumulatively contribute more capacity than the original transformer size. Additionally, "back-feeding" transformers not designed for reverse flow can cause increased losses due to the impedance characteristics of a transformer's primary and secondary coil.

As new customer growth occurs, infrastructure expansions and improvements must be made to keep the system operational. Unfortunately, intermittent DG sources do not allow utilities to consider the DG system in the design, and are not able to remove or downsize existing assets when DG is later installed. This means utility infrastructure must be designed, built, and maintained to support full peak demand.

As previously mentioned, utilities must design the distribution infrastructure to ensure reliable service during all conditions, and especially during peak usage situations. DG dependent infrastructure must be supported by uninterrupted generation. Without reliable and efficient energy storage devices, Solar DG cannot provide reliable uninterrupted service. Figure 3[16], following, illustrates that distribution infrastructure must be designed for Solar Generation Worst Day production, in the case of solar DG.

Further, Figure 3, illustrates the challenge with DG generation peaks not coincident with customer demand peak usage. Peak solar generation (12 p.m. – 3 p.m.) occurs prior to

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[15] Net Metering for Renewable Energy Sources-Schedule NM. Filed with the Kansas Corporation Commission and effective on July 17th, 2014.

[16] Customer load data acquired from KCP&L-KS Residential General Use customer energy profile, provided by KCP&L Regulatory Department. Solar generation data acquired from Figure 3-145 of the KCP&L Green Impact Zone SmartGrid Demonstration Final Technical Report, DOE-KCP&L-0000221. Page 578.

the hours of peak residential demand (6 p.m. – 9 p.m.). Thus, DG dependent infrastructure cannot rely on solar to support its peak demand.

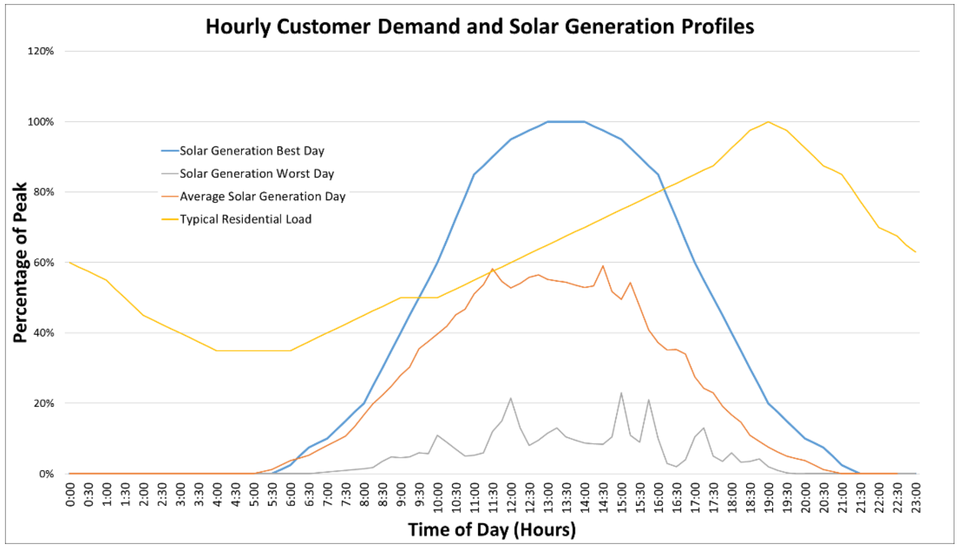


Figure 3

VALUATION: The valuation approach used for this study is that DG capacity is limited to current hosting capacity, outlined in section eight of NREL's *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*. Current DG and storage systems do not offset the customer demand peaks with certainty. Thus, until all four key qualifiers are capable of being satisfied, utilities are still required to build distribution infrastructure to ensure peak loads are met. No distribution infrastructure savings are present.

As technologies continue to advance and the prevalence of DG and efficient storage in our territory continues to grow, there could be a benefit observed in the future. At that time, a more advanced method of valuation could be considered, such as the Average Deferred Investment for Peak Reduction, mentioned in NREL's document noted above.

IDENTIFIED AVOIDED COST: Due to the intermittent nature of current DG sources, and the need to maintain a full capacity distribution source, there are no measurable avoided costs.

ADDITIONAL OBSERVATIONS:

- Another concern with net generation is its effect on distribution system protection schemes. These protection schemes are typically not intended to operate in reverse flow, though some have the appropriate settings to allow for it. In the case of fuses and many reclosers, operation in reverse power flow situations can lead to miscoordination and the potential for a dangerous extended fault. Additionally, DG can dramatically increase available fault current on distribution systems leading to a higher arc flash potential.

- Excessive voltage fluctuations can occur due to large changes in DG energy production. These fluctuations can cause significant, additional wear on voltage support devices such as capacitors, voltage regulators, and load tap changers, which are designed to automatically respond to voltage fluctuations. This could lead to noticeably shorter life expectations for these types of equipment, as well as additional labor hours spent inspecting devices for signs of eminent failure.

DISTRIBUTED GENERATION AVOIDED COST ANALYSIS

COST CATEGORY: **Avoided Transmission Infrastructure Costs**

COST DESCRIPTION: Avoided Transmission Infrastructure Costs are costs associated with expanding transmission infrastructure to meet demand and reliability needs.

QUANTIFICATION: KCP&L is currently forecasting load to remain relatively flat, thus transmission projects are aimed at improving reliability, no transmission expansion projects deigned to respond to load growth are planned. Additionally, examination of the output of solar generation absent storage solutions provides limited reduction to peak load, resulting in no change to required transmission capacity.

VALUATION: In the event of a large increase in the amount of residential DG on the KCP&L system, it is possible that the benefits could be calculated using locational marginal prices from Southwest Power Pool's Integrated Marketplace, as suggested in the NREL document. However, because locational marginal prices are, as named, location specific, absent a quantification of avoided cost, the value cannot be identified or reasonably estimated.

IDENTIFIED AVOIDED COST: Due to no observed reduction in cost and no current valuation, the identified avoided cost is zero.

ADDITIONAL OBSERVATIONS:

- Currently DG penetration levels are not at high enough values to have an impact on transmission. With the current data and KCP&Ls load projections, the Company is unable to identify any avoided transmission costs associated with DG.

- Intermittent DG placed at a specific location could, in fact, result in an increase in congestion, and thus costs, to the system. As Ashley Brown and Jillian Bunyan state in their paper *Valuation of Distributed Solar: A Qualitative View*, "…it is improbable that solar DG actually saves any investment in transmission capacity."

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG

AVAILABILITY:

Any Customer-Generator operating or adding generation powered by Renewable Energy Resources or taking service under an interconnection agreement connecting to KCP&L's distribution system after XXX XX, XXX (effective date of rates in this case) must take service under this rate schedule.

For electric service to a single-occupancy private residence. Single-phase electric service through one meters for ordinary domestic use for all customers who request to be served under this rate. The Company reserves the right in all instances to designate whether a Customer-Generator is or is not a residential customer.

Three-phase electric service for the operation of cooling and air conditioning equipment for domestic use. For three-phase, built-up central plant air conditioning systems of at least 25 tons single-unit cooling capacity, service is available under this schedule only if permitted by the Company, with the Company exercising sole discretion in the case of each Customer-Generator. The availability of three-phase Residential Service for such air conditioning systems also shall be contingent upon the Customer-Generator paying the full cost of the required three-phase line extension prior to construction of the extension.

Single-phase electric service through a single or separately metered circuit for space heating purposes in the residence. Single metered electric space heating equipment shall be of a size and design sufficient to heat the entire residence. Electric space heating equipment may be supplemented by wood burning fireplaces, wood burning stoves, active or passive solar heating, and used in conjunction with fossil fuels where the combination of energy sources results in a net economic benefit to the Customer-Generator. Electric space heating equipment shall be permanently installed and thermostatically controlled.

Customers currently served under two meter heat rates shall be required to convert their metering from two meters to a single meter or agree to provisions to combine the readings from the two meters when billed under this schedule.

Not available for Temporary, Seasonal, Standby, or Resale Service.

TERM OF CONTRACT:

Contracts under this schedule shall be for a period of not less than one year from the effective date thereof.

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG (Continued)

DEFINITIONS:

1. Customer-Generator: The owner and operator of a facility which:

   A. Is powered by a Renewable Energy Resource;
   B. Is located on a premise owned, operated, leased, or otherwise controlled by the Customer-Generator;
   C. Is interconnected and operates in parallel phase and synchronization with the Company facilities and is in compliance with the Company standards;
   D. Is intended primarily to offset part or all of the Customer-Generator's own electrical energy requirements; and
   E. Contains a mechanism, approved by the Company that automatically disables the unit and interrupts the flow of electricity back onto the Company's electric lines in the event that service to the Customer-Generator is interrupted.

2. Renewable Energy Resources: Net renewable generation capacity produced from wind, solar thermal sources, photovoltaic cells and panels, dedicated crops grown for energy production, cellulosic agricultural residues, plant residues, methane from landfills or from wastewater treatment, clean and untreated wood products such as pallets, hydroelectric sources (existing hydropower, new hydropower, not including pumped storage, that has a name plate rating of 10 megawatts or less), fuel cells using hydrogen produced by one of the above-named renewable energy sources; and other sources of energy, not including nuclear power, that become available, and that are certified as renewable by the rules and regulations of the Kansas Corporation Commission.

RATE: 2RSDG

Single-phase and Three-phase service will be cumulated for billing under this schedule.

		Summer Season	Winter Season
1.	Customer Charge (Per month)	$14.00	
2.	Demand Charge Per KW of Billing Demand per month	$9.000	$2.000
3.	Energy Charge (Per kWh) All Energy	$0.08683	$0.06704

Issued: May 1, 2018
Month Day Year

Effective: ____
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

DEMAND SERVICE FOR RESIDENTIAL DISTRIBUTED GENERATION
Schedule RDG (Continued)

MINIMUM MONTHLY BILL:

Minimum Monthly Bill:

1. Customer Charge; plus
2. Any additional charges for line extensions, if applicable.

SUMMER AND WINTER SEASONS:

The Summer Season is four consecutive months, beginning and effective May 16 and ending September 15, inclusive. The Winter Season is eight consecutive months, beginning and effective September 16 and ending May 15. Customer bills for meter reading periods including one or more days in both seasons will reflect the number of days in each season.

DETERMINATION OF MONTHLY BILLING DEMAND:

The Monthly Billing Demand shall be defined as the maximum fifteen (15) minute demand, measured in KW, during the peak period within the billing month. The peak period shall be the daily hours of 4:00 p.m. through 8:00 p.m. Central Time, excluding weekends, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

ADJUSTMENTS AND SURCHARGES:

The rates hereunder are subject to adjustment as provided in the following schedules:

- Energy Cost Adjustment (ECA)
- Energy Efficiency Rider (EER)
- Property Tax Surcharge (PTS)
- Tax Adjustment (TA)
- Transmission Delivery Charge (TDC)

REGULATIONS:

Subject to Rules and Regulations filed with the State Regulatory Commission.

Issued: May 1, 2018
Month Day Year

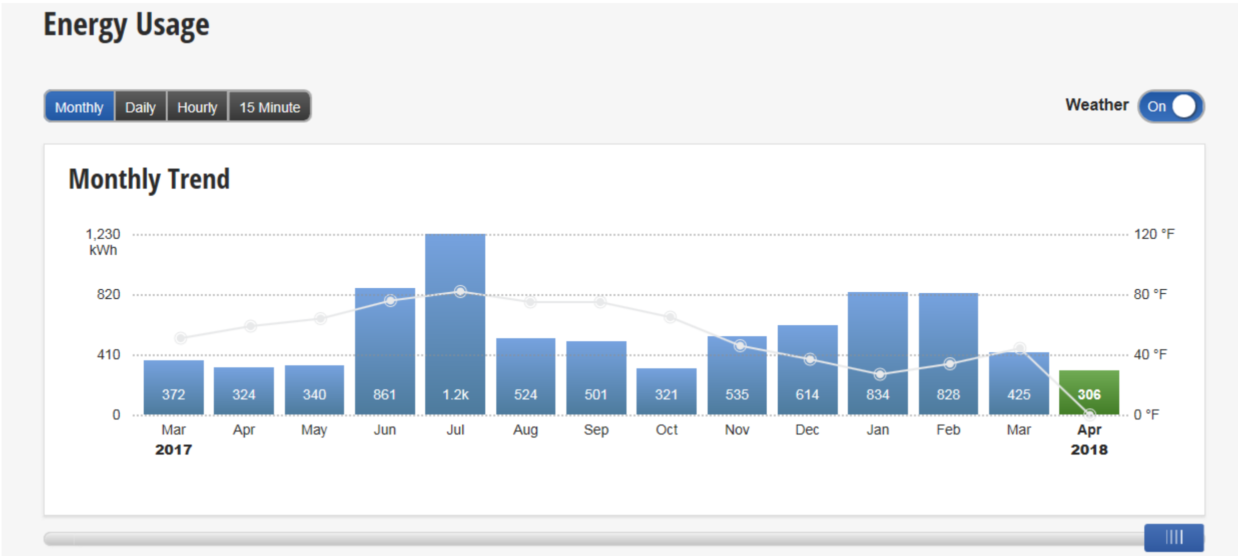
Effective: ______
Month Day Year

By: /s/ Darrin R. Ives Vice President
Title

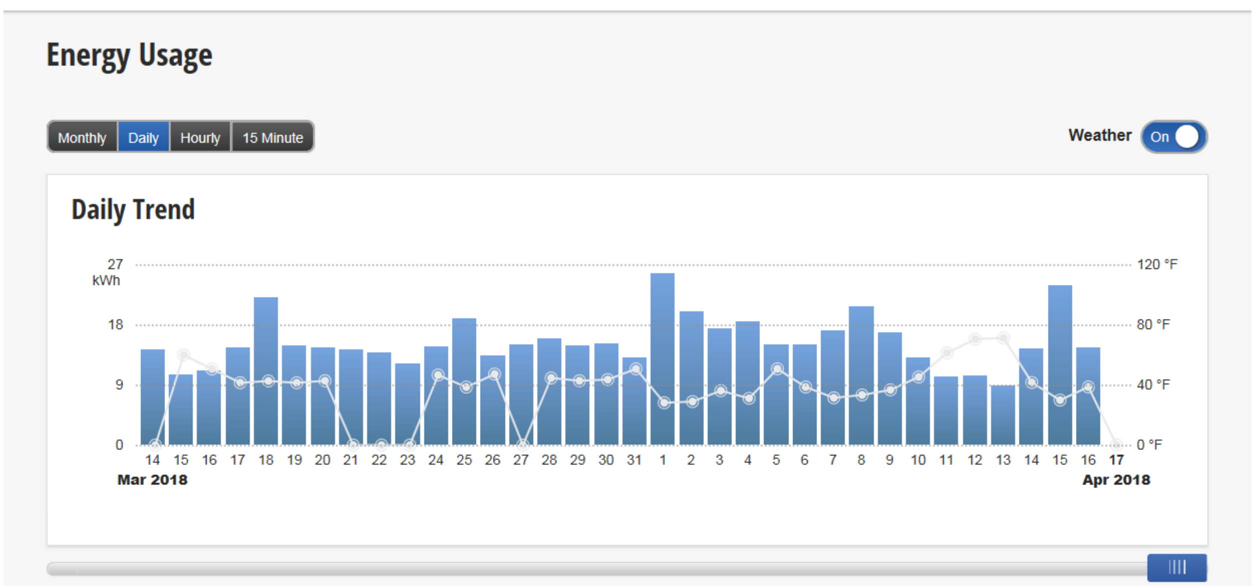
Customer Portal – Energy Use Display Examples

The following energy usage displays will be available in the updated Customer Portal, available to customers. Views other than monthly require the customer to have an advanced meter. Data will be accessible on a four to eight-hour latency.

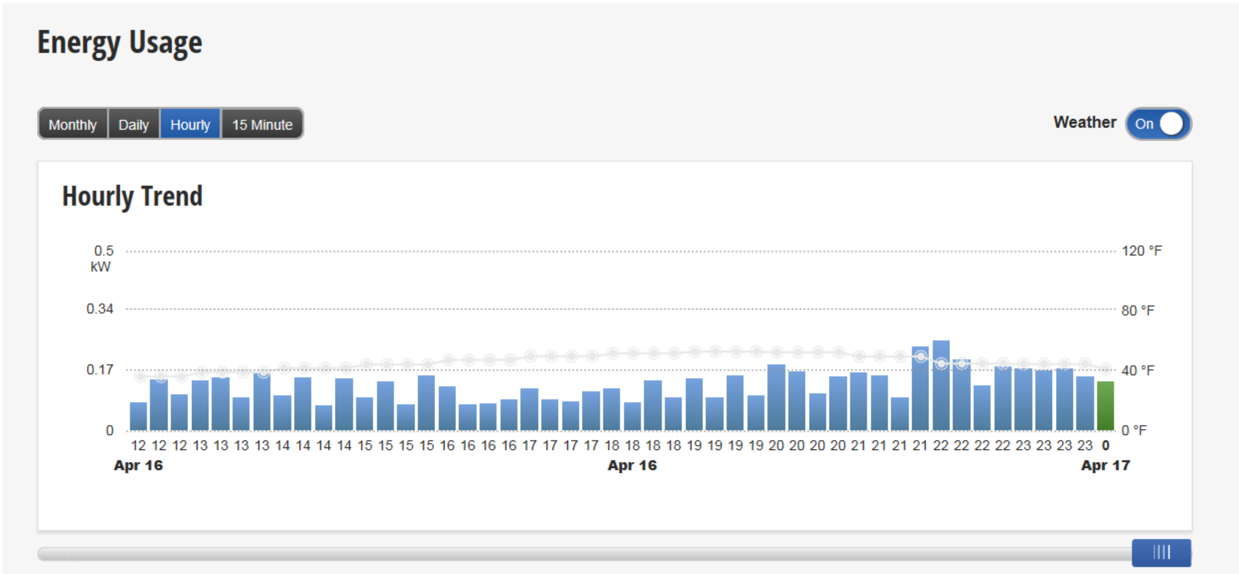
Monthly view



Daily View



Hourly View



15-minute View