Exhibit No.:	
Issue(s):	Rate Design, CCOS, Grid Access Charge, Street Lighting Rates, Underutilized Infrastructure Tariff
Witness:	William R. Davis
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2016-0179
Date Testimony Prepared:	July 1, 2016

MISSOURI PUBLIC SERVICE COMMISSION

File No. ER-2016-0179

DIRECT TESTIMONY

OF

WILLIAM R. DAVIS

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
July 2016

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DIRECT TESTIMONY

OF

WILLIAM R. DAVIS

FILE NO. ER-2016-0179

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William ("Bill") R. Davis. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am the Senior Manager of Energy Services Strategy and Development for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Please describe your educational background and employment history.

A. I received a Bachelor of Science in Economics from Illinois State University in 2002. I subsequently received a Master of Science in Economics with an emphasis in regulatory economics from Illinois State University in 2003. I completed several internships during my college career, including an internship with Illinois Power Company. Upon completion of my master's degree, I began working full-time for Caterpillar, Inc., at its corporate headquarters in Peoria, Illinois, as an Advanced Quantitative Analyst in the Business Intelligence Group, with the primary duties of performing economic and sales analyses.

In May 2005, I joined Ameren Services Company as a Load Research and Forecasting Specialist in the Corporate Planning Department. My duties included electricity and natural gas sales forecasting, load research, weather normalization, and various other sales analyses. In September 2007, I became a Senior Load Research Specialist and then moved to the Resource Planning Group in March of 2009. In October 2011, I became a Senior Corporate Planning Analyst. In that position, I was responsible for Ameren Missouri's 2011 Integrated Resource Plan and the 2012 Missouri Energy Efficiency Investment Act ("MEEIA") filing. In March 2013, I was promoted to Manager of Economic Analysis and Pricing, where I was responsible for the Company's rate design, class cost of service, and various other regulatory matters. I was promoted to my current position on May 1, 2016, where I am responsible for energy efficiency planning, the evaluation of the Company's energy efficiency programs, as well as the development of new energy services opportunities.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony discusses: a) the revenue increase being proposed for the Company's electric retail rate classes; b) the design and development of rates for the individual customer classes; c) the development and results of a class cost of service study; d) the introduction of a new pilot program designed to better utilize under-utilized infrastructure; e) the quantification of lost fixed costs caused by the recent drop in electricity consumption at the New Madrid aluminum smelter; and f) the introduction of a new Standby Service Rider for large customers with on-site generation.

Q. Please summarize your testimony.

A. I recommend the Missouri Public Service Commission ("Commission") approve the Company's filed tariff sheets, a copy of which are provided in Schedule WRD-1, that effectuate the requested rate increase of $206.4 million. The tariffs reflect the five basic proposals below:

1) The use of a three-step process for the development of respective class revenue requirements similar to the process used to set the rates approved by the Commission's order in the Company's last electric rate case to move rates closer to cost of service.

2) With few exceptions, the charges within each customer class will be increased by the same percentage as the class total.[1]

3) The implementation of an energy grid access charge for Residential and Small General Service classes to reflect the basic cost of making the grid available to customers.

4) A new economic re-development pilot program designed to target discounts toward projects that enhance the utilization of existing infrastructure and does so in a collaborative way with interested stakeholders from this rate case.

5) A new Standby Service Rider for large customers with on-site generation.

[1] After adjusting for the pre-MEEIA energy efficiency charges and certain charges to maintain consistency between rate classes.

III. CLASS REVENUE PROPOSAL

Q. What is generally meant by the term "cost of service study"?

A. A cost of service study determines a utility's aggregate or total annual revenue requirement necessary to recover its operating and maintenance expenses and taxes, depreciation of its plant, and a fair return on the utility's net investment in property and plant. An electric jurisdictional cost of service study (total revenue requirement), prepared and filed by Company witness Laura Moore, provided the total rate base and expense items that formed the starting point for the class cost of service study I am sponsoring.

Q. Please explain what is meant by "class cost of service."

A. The Company currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service. The non-residential customer group is differentiated by customer size and the voltage level at which the Company provides service. The current customer classes are Residential, Small General Service ("SGS") and Large General Service ("LGS") (all of which have their service delivered at a low secondary voltage level); Small Primary Service ("SPS") and Large Primary Service ("LPS") (delivery at a high voltage level); Large Transmission Service ("LTS") and Industrial Aluminum Smelter Service ("IAS") (delivery at a "transmission" voltage level);[2] Company-Owned Lighting Service; and Customer-Owned Lighting Service. A class cost of service study provides a basis for allocating and/or assigning the Company's total jurisdictional cost of providing electric

[2] A customer meeting the LTS or IAS class requirements will only take service as a member of one or the other of these two classes, depending on whether they meet the IAS class requirements, which are based on the Commission's order in the Company's last rate case.

service to these customer classes in a manner that reflects cost causation. The results of a class cost of service study with equalized rates of return are often referred to as "class revenue requirements." A detailed explanation about the Company's class cost of service study can be found later in my testimony.

Q. What would the base revenue requirement for each service classification be if rates were set based purely on the class cost of service study?

A. The table below summarizes the class base revenue requirements necessary to give the Company an opportunity to achieve an equal rate of return from each of its customer classes, based upon test year figures with the pro forma adjustments made by Ms. Moore. A more detailed summary can be found in Schedule WRD-2.

Table 1 – Cost-Based Base Revenue Requirements by Customer Class ($MM)[3]

Customer Class	Base Revenue Requirement	Return on Rate Base
Residential Service	$1,467.1	7.713%
Small General Service[4]	$319.8	7.713%
Large General and Small Primary Service	$814.7	7.713%
Large Primary Service	$218.3	7.713%
Company-Owned Lighting	$36.2	7.713%
Customer-Owned Lighting	$8.3	7.713%
Total	**$2,864.4**	**7.713%**

Q. Why are equal rates of return for all customer classes an appropriate starting point when designing electric utility rates?

A. There are several reasons why reflecting equal rates of return for all customer classes is an appropriate starting point in the consideration of rate design. First

[3] Excludes the Low-Income Pilot Program. Also note that this and other tables exclude the large transmission service/industrial aluminum smelter class since as discussed below, their billing units have been set to zero.
[4] Includes St. Louis Metropolitan Sewer District.

and foremost is the consideration of equity and fairness to all electric customers. Purely from a cost perspective, and ignoring all other factors, to overcharge one customer class in order to subsidize another class is not fair. A second important consideration in support of equal class rates of return is the goal of encouraging cost-effective utilization of electricity by customers. To make appropriate decisions regarding the most efficient and effective use of electricity, including decisions regarding the acquisition of equipment that uses electricity, customers require correct and appropriate price signals from the Company's electric rates. Equal rates of return for all customer classes promote such price signals. A third consideration is that of competition. Cost-based electric rates permit the Company to compete effectively with alternative fuels, co-generation, and other electric providers for new commercial and industrial customers.

Q. Once the annual cost-based revenue requirements are developed for all of the Company's service classifications, would the design of specific rates for each class be the next and final step in the overall rate development process?

A. If one were to base class rates solely on class cost of service and ignore other relevant factors, the response would be yes. However, the results of the Company's class cost of service study produced the revenue increases by customer class shown in the table below.

Table 2 – Cost-Based Rate Increases by Customer Class

Customer Class	Cost of Service Increase
Residential Service	16.9%
Small General Service[5]	3.3%
Large General and Small Primary Service	-3.4%
Large Primary Service	4.2%
Company-Owned Lighting	-1.1%
Customer-Owned Lighting	120%
Total	**7.8%**

Q. Is the Company proposing that these strictly cost-based class revenue requirements be utilized in developing class rates in the case?

A. No, the Company is proposing some departure from class revenue requirements or rate design being established solely on the basis of equal class rates of return as shown in its class cost of service study.

Q. What is the Company's proposal for allocating the revenue increase requested in this case?

A. The Company is proposing to use a three-step process similar to that used to set rates per the Commission's order from the Company's last rate case and similar to that which underlies previous settlements in prior Company rate cases.

<u>Step 1</u> is to increase/decrease the current base retail revenue[6] on a revenue-neutral basis to various classes of customers. The Residential class receives a positive 0.50% adjustment with nearly all of it applied as an offsetting negative adjustment to the Large General and Small Primary classes to be allocated on current base retail revenues[7] (a negative 0.73% adjustment for each class). In addition, the Customer-Owned Lighting

[5] Includes St. Louis Metropolitan Sewer District.
[6] Excludes Pre-MEEIA program costs.
[7] Excluding Pre-MEEIA program costs.

class receives a positive 10% adjustment with an equal offsetting negative adjustment to the Company-Owned Lighting class (a negative 1.0% adjustment). Finally, a small portion, $150,000, of the Residential revenue-neutral shift will be applied directly as a reduction to Company-Owned post-top style lights (resulting in a total revenue neutral reduction of 1.4% for Company-Owned Lighting).

Step 2 is to assign directly to applicable customer classes the portion of the revenue increase/decrease that is attributable to Energy Efficiency ("EE") programs from pre-MEEIA program costs. The pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of pre-MEEIA program costs.

Step 3 is to determine the amount of revenue increase awarded to Ameren Missouri that is not associated with the EE revenue from pre-MEEIA revenue requirement assigned in Step 2, by subtracting the total amount in Step 2 from the total increase awarded to Ameren Missouri. This amount will be allocated to customer classes as an equal percent of current base revenues after making the adjustment in Step 1, with the exception that the Customer-Owned Lighting class receives no increase from this step.[8]

Q. Please summarize the Company's proposed rate increase.

A. The table below summarizes the proposed class revenue requirements necessary to give the Company an opportunity to achieve its jurisdictional rate of return, based upon test year figures.

[8] In Step 1, the Customer-Owned Lighting class received a 10% increase.

Table 3 – Proposed Rate Increases by Customer Class

Customer Class	Normalized Retail Revenues*	Proposed Base Revenue Requirement*	Required Base Revenue Adjustment**	Percentage Increase
Residential Service	$1,255,462,780	$1,359,483,065	$104,020,285	8.29%
Small General Service	$309,645,053	$333,870,544	$24,225,491	7.82%
Large General Service	$603,408,285	$645,685,579	$42,277,294	7.01%
Small Primary Service	$239,989,465	$256,730,304	$16,740,838	6.98%
Large Primary Service	$209,571,770	$225,964,945	$16,393,175	7.82%
Company-Owned Lighting	$36,570,811	$38,895,085	$2,324,274	6.36%
Customer-Owned Lighting	$3,785,618	$4,161,916	$376,297	9.94%
Metropolitan Sewer District	$76,826	$82,892	$6,066	7.90%
Total	**$2,658,510,609**	**$2,864,874,329**	**$206,363,720**	**7.76%**

* Revenue includes Low-Income Pilot Program Charges.
**Targeted increase from Company witness Laura Moore testimony is $206,402,505; however, rate rounding resulted in a difference of $-38,785.

Q. Please explain the Company's proposal to allocate the revenue increase in this three-step process rather than based solely on class cost of service study results.

A. While using the results of a given class cost of service study is an important starting point in developing class revenue targets and rate design, no one class cost of service study yields "the" perfect result since class cost of service studies are estimates. That is not to say that all class cost of service studies are equally valid; instead, it means there is a reasonable range around the point estimates produced by the Company's class cost of service study. Other factors – such as revenue stability, rate stability, effectiveness in yielding total revenue requirements, public acceptance, and value of service – can then be considered when determining class revenue requirements and designing rates. Those additional considerations drove the specific revenue neutral shifts included in the Company's three-step process proposal.

For the Lighting class, it is apparent that the Customer-Owned Lighting class has rates that are well below its cost of service, while the Company-Owned Lighting class has rates that are above its cost of service. Starting a transition to rates that more closely match the underlying costs is necessary for the Customer-Owned Lighting class, but such adjustments need to be done gradually in order to avoid rate shock. The 10% shift to the Customer-Owned Lighting class is a significant shift for that particular class in terms of percentage but a relatively small amount of dollars compared to the base revenues of other classes.

Q. How does the Company's proposal compare to historical allocation of rate increases approved by the Commission?

A. First, the multi-step process is consistent with the Commission order in the Company's last rate case. Second, the revenue neutral shifts are reasonable compared to the types of shifts that have been approved in the past. The table below shows the percentage increase/decrease compared to the overall system average for the Company's last six rate cases as well as the Company's proposal in this rate case. It is clear that the Residential class has consistently been given above-average increases and that Large General Service and Small Primary Service classes have been given modestly below-average increases. Large Primary and Small General Service have seen increases very close to average. With the notable exception of Large Transmission Service, the individual class rate increases in the table below have generally been consistent with moving rate classes closer to cost-based rates. In this case, I have presented a more granular class cost of service study that separates the two lighting classes, which supports the proposed revenue-neutral shift between the lighting classes.

Table 4 - Class Increases As A Difference From Average

File No.	Total Increase	RES	SGS	LGS	SPS	LPS	LTS	LTG-Cust.	LTG-Comp.	MSD
ER-2007-0002	**2.1%**	1.1%	0.7%	-0.9%	1.0%	0.7%	-7.5%	0.0%	0.0%	0.0%
ER-2008-0318	**7.8%**	0.4%	-0.1%	-0.1%	-0.1%	0.2%	-1.7%	0.2%	0.2%	0.2%
ER-2010-0036	**10.4%**	1.5%	1.7%	-0.5%	-0.5%	1.5%	-10.3%	-10.4%	-10.4%	-10.4%
ER-2011-0028	**7.1%**	2.1%	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	11.1%	4.3%	0.0%
ER-2012-0166	**10.1%**	0.8%	-1.3%	-0.2%	0.4%	-0.3%	-3.5%	6.1%	0.7%	-3.5%
ER-2014-0258	**4.5%**	1.1%	0.0%	0.0%	0.0%	0.7%	-9.6%	0.8%	0.8%	0.8%
Average Shift		**1.2%**	**-0.1%**	**-0.6%**	**-0.2%**	**0.1%**	**-5.7%**	**1.3%**	**-0.7%**	**-2.2%**
ER-2016-0179	**7.8%**	0.5%	0.1%	-0.8%	-0.8%	0.1%	0.00%	-1.4%	2.2%	0.1%

IV. OVERALL RATE DESIGN PROPOSALS

Q. Please explain your use of the term “rate design.”

A. Generically speaking, my use of the term “rate design” refers both to the process of establishing the specific charges (e.g. monthly customer charges, dollars per kilowatt of demand and/or cents per kilowatt-hour energy charges) for each customer class, as well as to the actual structure of an individual class rate. The rate design, or structure, of a given class rate may range in complexity from a simple structure consisting of a monthly customer charge and a flat charge per kilowatt-hour (such as the Company’s summer Residential rate), to a more complex set of customer, demand, energy, and reactive charges (such as the Company’s SPS, LPS and LTS/IAS rates). In all instances, however, the charges within a specific rate classification are established such that the application of these individual charges to the total annual customer class electrical usage is expected to result in the collection of the targeted annual revenue requirement of each of the Company’s retail rate classes.

Q. Please describe the Company's rate design proposals in this case.

A. For the most part, the Company is proposing to increase the existing charges within each customer class by the same percentage. The significance of implementing a rate increase in this fashion is that it ensures all customers within each class experience the same rate increase as the customer class as a whole.[9] There are four exceptions to this proposed methodology: 1) the pre-MEEIA energy efficiency costs are explicitly accounted for in each customer class; 2) certain non-residential charges require the same increases across comparable rate classes to maintain consistency; 3) the revenue neutral reduction for Company-Owned Lights includes a specific amount to be only applied to rates for post-top lights; and 4) the implementation of an energy grid access charge for the Residential and Small General Service classes. It is noteworthy that with the implementation of an energy grid access charge, the Company is proposing to keep the Residential customer charge at $8 per month. I describe these four specific proposals in detail below plus some other miscellaneous tariff changes; however, because the energy grid access charge is a new billing element, I have separated that discussion into its own subsection of my testimony.

Q. Why is it important to separately adjust the pre-MEEIA energy efficiency charges?

A. The pre-MEEIA energy efficiency charges are being amortized over several years but no new costs are being accumulated; therefore, eventually those charges will completely disappear from customer bills. Because these costs are declining over time and have been accounted for separately in past rate cases, it is appropriate to continue isolating the charges associated with pre-MEEIA costs.

[9] Assuming all other factors are held constant.

Q. Please describe what charges you are proposing to keep consistent across rate classes.

A. The four charges below need to remain consistent for SPS, LPS, and LTS/IAS because those costs are effectively the same regardless of the customer class. After increasing these four charges by 7.77%, the remaining charges were increased by each respective class' average increase (after excluding pre-MEEIA energy efficiency charges).

1) The monthly customer charge
2) The additional Time-of-Day monthly customer charge[10]
3) The Rider B credits (customer-owned substation discounts)
4) The Reactive charge

Q. Why should post-top style lights within the Company-Owned Lighting class receive a below-average rate increase?

A. As previously mentioned, the Company is proposing a special revenue neutral shift to Company-Owned post-top style lights. It is important to note that post-top style rates will be increasing, but will be increased 2% below the system average increase. Also, while the Company has just begun transitioning horizontal enclosed and open bottom style lights to Light Emitting Diodes ("LEDs"), the post-top style lights do not currently have a cost-effective LED alternative. Yet, the post-top style lights are 37% of the total Company-Owned Lighting revenues. Upon investigation into the price premium for post-top style lights, it became apparent that the price premium in rates has

[10] This incremental customer charge for Time-of-Day will also be the same for the LGS customer class.

gotten out of line with the current underlying cost differential. For instance, a customer who chooses a 100 watt High Pressure Sodium post-top style light currently pays $10.58 more per month compared to the rate for the standard horizontal enclosed 100 watt High Pressure Sodium style light. However, using the current cost of new comparable lights, the implied extra monthly charge should only be $6.30. Considering this price differential analysis, the relatively large amount of revenues that post-top style lights represent within Company-Owned Lighting, the fact that there are not currently cost-effective LED alternatives for post-top style lights, and the fact that most other lights are already transitioning to a lower rate, the Company believes targeted rate relief for post-top style lights is appropriate at this time.

Q. Please describe the other tariff changes Ameren Missouri is proposing in this case.

A. The Company is proposing a few "clean-up" tariff changes. These changes include adjustments to the Fuel Adjustment Clause ("FAC"), Company-Owned lighting service, Customer-Owned lighting service, and Limited Unmetered Service. Each of these changes is described further below.

Q. What changes is the Company proposing for the FAC?

A. Ms. Barnes outlines a few changes to the FAC in her testimony; however, I am sponsoring the FAC tariff change to eliminate the adjustment related to load reductions for rate classifications 12(M) and 13(M) (the so-called "N Factor"). The N Factor portions of the FAC were originally approved in File No. ER-2010-0036, yet the first use of the N Factor was not until June of 2015.[11] The N Factor was developed to

[11] Although first used in June of 2015, an amount for the N Factor was not reflected in rates until the June 2016 billing month.

recognize the significant financial impact to the Company in the event of material reductions in the electricity consumption at the New Madrid aluminum smelter. Recent events at the New Madrid aluminum smelter have resulted in the shutdown of all three of its pot lines and the billing units in this rate case have been adjusted to reflect a zero load at the smelter. Since the N Factor is triggered by load reductions at the smelter, an N Factor is inappropriate and meaningless when the load used to set rates is zero. Accordingly, the FAC tariff has been modified to reflect the elimination of the N Factor.

Q. What changes is the Company proposing for Company-Owned Lighting Service?

A. The specific changes proposed are related to LED street lights, which include combining the "horizontal enclosed" and "open bottom" distinction into a single category called "bracket mounted." As a result of the Company's investigation into specific product offerings and specifications, it was determined that a single LED product better replaced the outmoded "horizontal enclosed" and "open bottom" descriptions associated with the previous lighting technology; just as the LED pricing options had already moved away from lumens as a distinguishing attribute. The only overlap associated with this change is with the 100 watt equivalent LED replacement, and the new pricing is based on the lower-priced offering previously referred to as "open bottom" to ensure all customers will receive lower charges compared to the obsolete non-LED lighting options.

Q. What changes is the Company proposing for Customer-Owned Lighting Service?

A. Currently in the Customer-Owned Lighting tariff there is a $6.71 monthly charge for all accounts whether the account is for metered lighting or unmetered lighting. Intuitively, it is logical that a metered account should have a higher monthly fixed charge than an unmetered account because a portion of the monthly charge should cover the cost of metering. Therefore, I am proposing the elimination of the monthly *account-level* fixed charge for unmetered accounts. Because unmetered Customer-Owned Lighting charges are already established as a fixed charge per light per month, the revenues (~$12,000) from the unmetered monthly account-level charge will be spread across the various unmetered lighting charges. This results in a consistent approach with the Company-Owned Lighting tariff where there is no monthly account-level charge for unmetered lighting; instead, monthly bills are based on the number of and type of lights.

The Company is also proposing to revise its unmetered Customer-Owned LED rates. Currently, there are a few lumen/watt-based buckets available for unmetered Customer-Owned LED lighting but we know that LED lighting technologies are advancing and it will be difficult to design the proper buckets of watt ranges when customers can choose any light style with any level of wattage rating. Therefore, instead of listing various buckets of watt ranges and making sure the tariff keeps up with the evolution of lighting technology, the Company is proposing a cents-per-watt-per-month charge. This approach allows a customer to choose whatever light wattage he/she desires and the rate will be "right-sized" accordingly to the expected energy consumption. Following this approach, the base rate for unmetered LED Customer-Owned Lighting service would be 1.68 cents per watt per month.

Additionally, the Company is proposing to add wording in the tariff that explains the Company's intent to phase out maintenance service for Customer-Owned lighting in the future, but not prior to June 1, 2022. This timeline should give the Company and its customers enough time to find suitable solutions to transition away from increasingly obsolete lighting technologies. The primary drivers for phasing out customer-owned lighting maintenance service include: 1) the Company is already transitioning most of the Company-Owned lights to LEDs; 2) the economics of LEDs continue to improve; and 3) as the Company transitions to LEDs, it will no longer be carrying materials to provide maintenance service for non-LED lights.

Finally, the Company is eliminating a pair of obsolete unmetered Customer-Owned Lighting options; specifically, the 16,000 lumen High Pressure Sodium light and the 42,000 lumen Mercury Vapor light. There are no active lights of these types in operation and both of these options are only available for grandfathered fixtures, so no customers will be affected by the removal of these lighting types from the tariff.

Q. Is the Company proposing any other changes for Customer-Owned Lighting Service?

A. Yes. One additional change relates to a unique situation within the Customer-Owned Lighting class. Currently there are grandfathered customer-owned mercury vapor/high pressure sodium lights that were installed directly on Company-owned distribution poles containing energized cables. The Company provides routine maintenance on these lights (e.g., bulb and photocell replacement) while the Company is fully reimbursed by the customer for the full cost of new lighting fixtures upon fixture replacements. In an effort to remedy the grandfathered situation of customer-owned lights on Company-owned distribution poles, eliminate the need for the Company to maintain outdated lights that it is phasing out, and to support the adoption of LED street lights, the Company is proposing to add an option whereby, upon a normal maintenance trip, the old customer-owned light can be replaced with a Company-owned LED lighting fixture. Upon such conversion to LED, the converted light will be grandfathered to the customer-owned LED energy-only rate and be assessed a monthly charge that varies depending on the wattage of the replacement LED fixture to cover the cost of the Company-owned LED. Approximately 15,000 unmetered Customer-Owned lights could qualify for this LED conversion option, which represents nearly 75% of the unmetered Customer-Owned taking Energy and Maintenance service.[12]

Q. Please elaborate on the changes related to Limited Unmetered Service that the Company is proposing.

A. Currently, in the Company's Measurement of Service section of its tariffs (specifically sheet 129) there is a provision that allows certain types of loads to be billed without needing a meter. The Company's proposal is to move the Limited Unmetered Service section to the Small General Service tariff. Because Limited Unmetered Service is billed as Small General Service, it seems logical that the service option should be specified directly in the Small General Service tariff.

As part of the move, the Company is also proposing to implement an explicit monthly charge for Limited Unmetered Service as opposed to relying on the monthly charge specified in the Customer-Owned Lighting tariff. To determine the monthly

[12] As mentioned earlier in testimony, it is the Company's intent to eliminate maintenance service for Customer-Owned lighting which means the opportunity to convert 75% of the lights taking this maintenance service to LEDs would be a major step toward the Company's ability to eliminate this service offering and do so in a way that is also beneficial to its customers.

charge for Limited Unmetered Service, the Company's class cost of service model was modified to exclude all metering costs and then the calculated customer charge from that model was compared to the calculated customer charge from a class cost of service model with all costs. Because Limited Unmetered Service should not pay for metering costs, the difference between the model with and without metering costs determines the "discount" associated with not needing a meter. In this case, that difference is $5.27 per month; therefore, the Company is proposing a Limited Unmetered Service monthly customer charge of $5.48 which is $5.27 less than the proposed single-phase customer charge for Small General Service. The proposed monthly customer charge for Limited Unmetered Service is $1.23 lower than the current monthly customer charge of $6.71.

Finally, the Company is proposing to modify the last sentence in that section of the tariff addressing what qualifies for Limited Unmetered Service. The proposed change eliminates the explicit limitation for only "lighting, Wi-Fi, and CATV power boosters" which opens up the possibility for other unmetered applications (like trickle chargers on emergency tornado sirens) but also keeps the more important limitations on maximum size, the requirement that loads be constant over a pre-determined operating schedule, and the requirement that loads can be reasonably estimated by Company.

V. ENERGY GRID ACCESS CHARGE

Q. What is an energy grid access charge?

A. An energy grid access charge is a fixed monthly charge designed to cover a portion of the distribution system costs that are unrelated to the amount of demand or usage on the system. In other words, there are costs necessary to construct a basic power grid and those costs are the same to serve customers whether a customer uses 1 kWh or

1,000 kWh. A more detailed description of the study performed to define these minimum distribution system costs is contained below in a subsection to the Cost of Service Study section of my testimony.

Q. Is Ameren Missouri proposing to implement such an access charge?

A. Yes.

Q. How is an energy grid access charge different than the customer charge?

A. The customer charge can traditionally be thought of as reflecting the basic costs of metering and billing customers (e.g., monthly meter reading, billing, postage, customer accounting and customer service expenses, investment in meters and service lines), whereas the energy grid access charge is designed to reflect the minimum costs related to accessing the grid itself (e.g., distribution poles, line transformers, wires).

Q. What is Ameren Missouri's proposal for implementing an energy grid access charge?

A. At this time, Ameren Missouri is proposing to implement a $4.89 per month energy grid access charge for Residential and Small General Service customers. The cost of service analysis outlined further below supports an energy grid access charge as high as $14.68. However, as a means to balance immediate bill impacts, the Company is proposing to phase in the charge over the next three rate cases, which limits the request in this case to $4.89 per month.

Q. Will adding an energy grid access charge reduce the volumetric rates ($/kWh) charged to Residential and Small General Service customers?

A. The volumetric rates will be lower than they would have been but for the energy grid access charge. Because a portion of class revenue will be collected through the energy grid access charge, a correspondingly lower amount of revenue needs to be collected through the volumetric charges. However, with the requested overall increase, the volumetric rates will still increase, which means the price signal to use energy efficiently will still be strengthened even with the adoption of the requested energy grid access charge.

Q. How can an energy grid access charge be beneficial to customers?

A. An energy grid access charge promotes fairness between customers within a class. As a recent example, the Commission and Commission Staff recently expressed concerns about the cost of energy efficiency for customers who do not participate in the energy efficiency programs. The costs to non-participating customers include the program costs, the incentive component, and the throughput disincentive component. The throughput disincentive component is effectively designed to cover fixed system costs that base rates do not cover because of the lower sales caused by energy efficiency, essentially shifting the payment of revenues to cover those fixed costs from participating customers to non-participating customers. In the Company’s most recent energy efficiency plan proceeding, parties recognized that the significant drop in avoided cost estimates and rising program costs to achieve energy efficiency savings were creating upward pressure on rates. These two factors contributed to heightened sensitivity about the impact to non-participants because the calculated net benefits of energy efficiency were not as great as they had been earlier, because of lower avoided cost estimates and higher program costs. Irrespective of avoided cost estimates and overall program costs, the Commission can reduce the cost burden on non-participants by reducing the amount of fixed costs that are collected in the volumetric component of rates.

Q. How does an energy grid access charge relate to reducing throughput disincentive recoveries in the Company's energy efficiency rider?

A. The throughput disincentive is driven by two fundamental factors: 1) the regulatory lag caused by using historical billing units for setting prospective rates; and 2) the level of fixed costs that are collected via volumetric charges. Imagine, at one end of the spectrum, if a fixed monthly charge was calculated to cover all of the fixed costs. In that case, the throughput disincentive would be entirely eliminated and zero dollars of throughput disincentive would flow through the Company's energy efficiency rider. That is one extreme, but the Company's rate design is nearer to the other extreme since its monthly fixed charge is based on just 10% of the overall fixed costs leaving 90% of the fixed costs to be covered by the volumetric charges. This inflates the throughput disincentive that must be reflected in energy efficiency rider charges. In short, instituting an energy grid access charge will reduce the costs of energy efficiency to non-participants by directly reducing the throughput disincentive and as a consequence reducing the energy efficiency charges they pay.[13] This would produce a more equitable balance of cost responsibility between energy efficiency participants and non-participants.

Q. Does the throughput disincentive represent the full amount of fixed cost responsibility that is shifted to non-participants?

[13] The throughput disincentive calculation in the Company's recently approved Energy Efficiency Investment Charge ("EEIC") rider reflects the net margin rates approved in rate cases; therefore, the relevant throughput disincentive impacts associated with the implementation of an energy grid access charge will be captured by the EEIC rider.

A. No. The throughput disincentive is a relatively small portion of the fixed cost responsibility because it only represents the shifting of costs that happens between rate cases. Once a rate case is adjudicated, when new rates are effectuated, the shifting of fixed costs is made permanent and on-going because the billing units (kWh and/or kW) used to set base rates are lower, thus driving up the volumetric rates.

Q. Have you quantified the costs savings to Residential non-participants from instituting an energy grid access charge as Ameren Missouri is proposing?

A. Partially, yes. Looking solely at the Company's most recently approved energy efficiency plan, implementing a $4.89 per month energy grid access charge would reduce the cost burden to non-participants by $13.6 million.[14] This analysis only considers the implications of the Company's most recently approved energy efficiency plan although all subsequently approved energy efficiency plans would materially add to this estimate. In addition, this analysis excludes the effects of naturally occurring energy efficiency and the adoption of distributed generation. In short, this quantification is very conservative.

Q. Conversely, if the volumetric rate does not go up by as much as with the addition of an energy grid access charge, would that reduce the incentive for customers to participate in the Company's energy efficiency programs?

A. For several reasons, it is my opinion that the impact is so small that it will not change the incentive for program participation. First, on average, the customers who participate in the Company's most recently approved energy efficiency plan are expected to benefit by 7.15 times the cost of participation if there is no energy grid access charge.

[14] Lifetime net present value.

This means that a participating customer enjoys $7.15 in benefits for every $1 spent. With a $4.89 per month energy grid access charge, the benefits for participants would still be a very healthy $6.81 for every $1 spent. Furthermore, I estimate that a slightly lower volumetric rate would only increase the average payback of energy efficiency by 25 days from an average payback of roughly 455 days. I find it highly unlikely that participating customers will decide not to invest in energy saving equipment because the payback period went up by 25 days.

Q. Are there any other standard metrics that summarize the trade-offs between participants and non-participants?

A. Yes, there are four common tests used when evaluating the economics of energy efficiency programs, including the test that MEEIA designates as the preferred cost-effectiveness test, the Total Resource Cost ("TRC") test. The other cost-effectiveness tests are the Utility Cost Test ("UCT"), Participant Cost Test (“PCT”), and the Ratepayer Impact Measure (“RIM”) Test, which at one time was known as the Non-Participant Test.

Q. How does an energy grid access charge affect the results of those tests?

A. *An energy grid access charge has no impact on the TRC or UCT test results at all.* However, the analysis further below of the RIM and PCT highlights the benefit of implementing an energy grid access charge.

Q. Please address why there is no impact on the TRC and UCT test results.

A. Both of these tests consider the total avoided costs (e.g., avoided energy, avoided capacity, and avoided transmission and distribution costs) as benefits. The TRC compares those benefits to the total costs of the energy efficiency program which include both the customer costs and the utility costs. The UCT compares those benefits to only the utility's costs to implement the programs. It is noteworthy that the TRC and UCT do not consider any changes in bill savings because those savings represent a transfer between participants and non-participants, which effectively "cancel out" in the TRC and UCT tests. The implementation of an energy grid access charge will not affect the avoided cost benefits or direct program costs, which is why it would not affect the TRC or UCT.

Q. Please address the impacts on the RIM and PCT test results.

A. Implementing an energy grid access charge will improve the RIM test results and degrade the PCT results. The PCT considers the incremental costs of more efficient end-uses (like a more efficient air conditioner) compared to the total bill savings and the rebates the participants would receive if they implemented measures necessary to qualify for the rebates from a participant perspective. From a participant perspective, if the PCT is above 1, then the benefits are greater than the costs. The RIM test compares the avoided cost benefits to the cost of the program, including the program administration costs, the rebates to customers, and the fixed cost portion of participant bill savings. The relationship between these tests is that the fixed cost bill savings are a benefit in the PCT but are a cost in the RIM. In the case where an energy grid access charge is implemented, the PCT is degraded because the decrease in the volumetric charge will reduce the fixed cost bill savings (but not the avoided cost benefits). Since more fixed costs would be collected through the proposed energy grid access charge, there would be less fixed costs that need to be recovered from others on the system which, in turn, improves the RIM test.

Q. Have you done any analysis to quantify the impact to the PCT and RIM tests associated with implementing an energy grid access charge?

A. Yes. The table below shows a comparison of the PCT and RIM tests for all of the Company's MEEIA residential programs with ("$4.89") and without ("$0") an energy grid access charge. Notice that the PCT still shows a strong benefit/cost relationship. Both tests change by approximately 5% (+5.0% RIM vs. -4.8% PCT).

Also, I would note that under both scenarios – i.e., with or without an energy grid access charge – customers will still incur additional costs for every unit of energy consumed; and, conversely, customers will still experience bill savings for every unit of energy not used.

Table 5 - Comparison of Residential PCT and RIM

	PCT		**RIM**	
Program	**$0**	**$4.89**	**$0**	**$4.89**
Lighting	~ ∞	~ ∞	0.55	0.58
Efficient Products	2.86	2.74	0.74	0.77
HVAC	4.67	4.45	0.99	1.04
Low Income	4.14	3.98	0.45	0.47
Energy Efficiency Kits	27.58	26.23	0.61	0.64
Home Energy Reports	∞	∞	0.55	0.58
Portfolio Total	**7.15**	**6.81**	**0.76**	**0.80**

The table above demonstrates that a more equitable balance of cost responsibility between energy efficiency participants and non-participants can be reached without severe impacts to the financial attractiveness of energy efficiency.

VI. ECONOMIC RE-DEVELOPMENT

Q. What is Ameren Missouri proposing in this rate case related to economic re-development and efficient infrastructure utilization?

A. The Company is proposing a new pilot program designed to target discounts toward projects that enhance the utilization of existing infrastructure and do so in a collaborative way with interested stakeholders from this rate case.

Q. Please provide a summary of the proposed pilot?

A. The pilot is designed to partner with local governmental agencies where those agencies have designated specific sites for re-development. The Company's intent is to get engaged early in the re-development process such that there is an opportunity to offer discounts to prospective re-developers or end-users of the re-developed sites. By being engaged while the re-development plans are being created, there is an opportunity for the electric service discounts being offered by the Company to influence to re-development plans and to re-position vacant and/or underutilized properties for adaptive economic re-use to support job creation and community re-investment. Each prospective project site will also be analyzed with the intent to only offer discounts to sites where re-development would result in more efficient utilization of the Company's existing infrastructure. The proposed pilot also includes the creation of a collaborative of interested stakeholders from this case that would serve as the voting and decision-making body for all discounts awarded under the pilot. The pilot also includes a $10 million cap on discounts awarded and the pilot itself has a five-year term. The expectation is that the discounts approved by the collaborative will not be imputed when setting rates in a future rate proceeding.

Q. What is unique about the proposed pilot compared to the Company's existing economic development tariffs?

A. There are four unique aspects of the proposed pilot that make it different than the Company's two other economic development tariffs:

1) A voting collaborative of interested parties from this rate case will be the decision makers about when to award discounts and how much should be awarded to a particular project.

2) The focus of the pilot is to encourage more efficient utilization of the Company's system and this tariff can apply to load anywhere in the Company's service territory.

3) The intent is to develop new partnerships with local government agencies, and because of these new partnerships, discounts may be awarded to the re-developer of a property and/or the end-user of a re-developed property.

4) There are fewer restrictions on qualifications, types of discounts, levels of discounts, and terms of discounts. Each project will be analyzed on a case-by-case basis and the collaborative will review and decide whether to approve discount packages.

Q. What is the significance of having a voting collaborative in the Company's proposed pilot?

A. In the Company's last rate case and even in a workshop after that rate case, there has been a lot of discussion about economic development and efficient system utilization. Through those discussions it became apparent that determining opportunities for more efficient utilization can be a complicated matter. In addition, some parties, and some Commissioners, expressed frustration that the Company's economic development riders were not being utilized enough. Therefore, the Company has married these two issues into a pilot program. The program significantly increases the flexibility of discount offerings and also incorporates a case-by-case analysis of system utilization associated with potential projects. It is important that interested parties in this case have an opportunity to be engaged in this new process to gain first-hand knowledge about economic development challenges, challenges in analyzing system utilization, and challenges in determining discount packages. Ameren Missouri expects this to be an excellent learning experience for all involved, including the Company.

Q. How will the Commission receive feedback about the activities of this pilot?

A. The pilot's tariff requires that the Company submit an annual report to the Commission describing all of the activities of the pilot.

VII. LOST FIXED COSTS FROM LOAD LOSSES AT THE NEW MARDID ALUMINUM SMELTER

Q. Please provide some historical context about the New Madrid aluminum smelter.

A. For many years (decades, as I understand it) the New Madrid aluminum smelter had taken service from Associated Electric Cooperative, Inc. ("AECI") under a cost-based contract. Once that contract expired, the New Madrid smelter was unable to secure continued cost-based service from AECI and the New Madrid smelter was then able to acquire its electricity under a market-based contract with a power marketing company. In June of 2005, the Commission determined that it was in the public interest for Ameren Missouri's service territory to be expanded in order to allow the New Madrid aluminum smelter to become a retail customer of Ameren Missouri, at the cost-based rates to be set by the Commission. At full load, the New Madrid aluminum smelter was Ameren Missouri's largest customer and represented about 10% of the Company's retail electricity sales.

Q. Please provide a summary of recent events at the New Madrid aluminum smelter.

A. In February of 2014, Noranda filed what it characterized as a rate design complaint case seeking a heavily-discounted electricity rate for the New Madrid aluminum smelter. In August of 2014, the Commission decided that a discounted rate was not justified and denied the request. In July of 2014, the Company filed a rate case (File No. ER-2014-0258) and, as part of its direct testimony filed in December of 2014, Noranda again requested a discounted electricity rate for the New Madrid aluminum smelter. During the rate case, the Company presented evidence showing that over Noranda's operational history as an Ameren Missouri customer, Noranda had not on average operated at "full load" and evidence showing for the trued-up test year in that case that Noranda was experiencing a significantly downward trend in its load. As a consequence, Ameren Missouri argued that billing units for the rate class under which Noranda takes service be set for ratemaking purposes at a level to reflect a normalized Noranda load (using a three-year historical average), just as many elements of the cost of service are normalized. In its April 2015 Order in File No. ER-2014-0258, the Commission granted a discounted rate for Noranda, but declined to set the billing units for Noranda at a normalized level and instead set the billing units at a level that represented "full load" (essentially the maximum electricity consumption) at the New

Madrid aluminum smelter. After that Order, electricity consumption at the New Madrid smelter continued to decline and in June 2015, for the first time ever, the mechanism in the Company's FAC (known as the N Factor and discussed above) was triggered. The N Factor only offsets a small part of the negative impact on Ameren Missouri from lower Noranda loads. From June 2015 through December 2015, electricity consumption at the smelter continued to decline. In January 2016, after a failure of a piece of equipment owned and operated by Noranda, two of the three pot lines at the New Madrid aluminum smelter were abruptly and unexpectedly shut down, causing molten aluminum to solidify in the pots and rendering those pot lines inoperable. In February 2016, Noranda took the additional extraordinary step of filing for bankruptcy and shortly thereafter, in March 2016, its third pot line was idled, bringing electricity consumption at the smelter down to a very small fraction of load used to set rates in the Company's last rate case. In June 2016, Noranda Aluminum Holding Corporation announced its intent to auction its upstream business operations, which include the plant in New Madrid with the intent of finalizing the sale in September 2016.

Q. Given the recent extreme reduction in electricity consumption at the New Madrid aluminum smelter, have you calculated the lost fixed costs associated with that load loss?

A. Yes. I followed a similar approach to what has been used in the past for determining lost fixed costs by excluding the fuel adjustment clause charges, excluding the net base energy cost charges, and I have also accounted for the partial coverage of those costs by the N Factor clause.[15] From April 2015 through May 2016, the

[15] Consistent with the approach used in File No. EU-2012-0027 and also with how lost fixed costs are determined for the Company's energy efficiency rider.

Company's lost fixed costs were $23.9 million associated with load reductions at the New Madrid aluminum smelter. The Company expects its lost fixed costs to grow by another $57.6 million from June 2016 through late May 2017 (the likely timeframe until rates will become effective from this case), bringing the total to $81.5 million.

Q. Is Ameren Missouri seeking to recover the lost fixed costs from the recent load loss at the New Madrid aluminum smelter?

A. Yes. The failure of Noranda's piece of equipment, resulting in the loss of two pot lines, followed by its bankruptcy filing, idling of the third pot line and the impending sale of its assets are all extraordinary events that are not likely to recur and which have caused significant financial harm to Ameren Missouri. Consequently, deferral of the lost fixed costs and recovery through an amortization through future rates is appropriate. Ameren Missouri witness Laura Moore has included one-tenth of the above-calculated sum in the revenue requirement to reflect a ten year amortization of those costs.

VIII. CLASS COST OF SERVICE STUDY

Q. Please summarize the results of the Company's class cost of service study.

A. The table below is a summary of the class cost of service study indicating the return on rate base ("RORB") currently being earned on the service being provided to the Company's major retail customer classes. A more detailed summary can be found in Schedule WRD-3.

Table 6 – Summary of Class Cost of Service Study

Customer Class	Actual RORB	Target RORB
Residential Service	2.69%	7.713%
Small General Service[16]	7.04%	7.713%
Large General and Small Primary Service	9.73%	7.713%
Large Primary Service	6.52%	7.713%
Company-Owned Lighting	8.66%	7.713%
Customer-Owned Lighting	-14.81%	7.713%
Total	**5.41%**	**7.713%**

Q. What general conclusions can be drawn from the information contained in the table above?

A. The Residential class is providing a below average rate of return while the LGS, SPS, and Company-Owned Lighting are providing rates of return well above average. Customer-Owned lighting rates are providing a negative rate of return. Overall, as is suggested by the filing of this case, the Company's return on its rate base is inadequate.

Q. Please describe the method used to equalize rates of return for each customer class, as reflected in your Schedule WRD-2.

A. The total net original cost rate base of each customer class was multiplied by the Missouri electric test year return on rate base proposed by the Company of 7.713% to obtain the required total net operating income for each class. This net operating income was then added to the operating expenses for each class to obtain the total operating revenue for each class required for equal class rates of return. The resulting cost of service of each customer class is set forth on line 6 of Schedule WRD-2.

[16] Includes Metropolitan St. Louis Sewer District

Q. How are the results of the class cost of service study used?

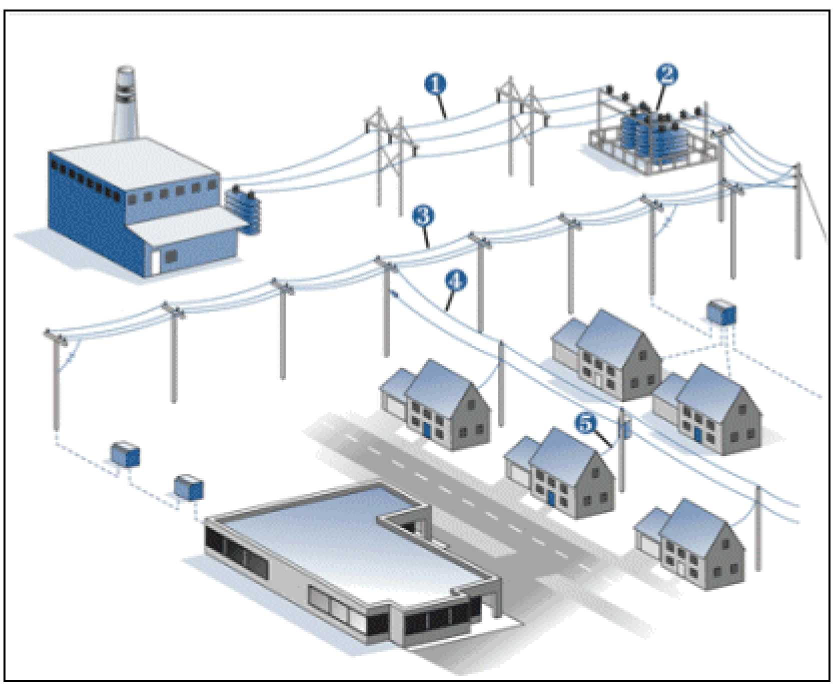
A. The results of the study are utilized as the starting point of revenue allocation and rate design.

i. <u>Class Cost of Service Concepts</u>

Q. As background for additional discussion on the class cost of service study the Company is sponsoring in this case, please provide a general description of the various facilities utilized by the Company in producing and delivering electricity to its customers.

A. The figure below is a simplified diagram illustrative of the Ameren Missouri electric system showing how power flows from the generating station and is then transmitted and distributed to the home of a residential customer. Other customers receiving service at higher voltage levels are also served from various points on the same system.

Figure 1 – Simplified Diagram of Electrical System



1 Electrical power is produced at the Company's generating stations at voltage levels ranging from 11,000 to 23,750 volts. To achieve transmission operating economies, this voltage is raised, or stepped up, by power transformers at the generating station sites to voltages generally ranging from 138,000 to 345,000 volts for transmission to the Company's bulk substations, which are strategically located throughout its service area.

- The Company's only LTS customer was served[17] at 161,000 volts via a unique transmission service arrangement.

2 At a substation, the electricity's voltage is lowered so that it can travel over the distribution system. Although this diagram does not show this level of detail, there are two main classes of substations: bulk substations and distribution substations. The bulk substations are used to lower the voltage but still keep the voltage relatively high (usually 34,500 or 69,500 volts) while the distribution substations lower the voltage even further (4,160 to 13,800 volts) to distribute power closer to customer premises.

- The Company serves 84 customers at voltages above the 13,800 volt level. These are referred to as "high voltage" or Rider B customers.
- Approximately 730 large non-residential customers receive service at 4,160 to 13,800 volts and are referred to as "primary" voltage customers.

3 Main distribution power lines, typically 3-phase circuits, bring electricity into communities.

4 Local distribution power lines serve neighborhoods and individual customers.

5 Service lines carry electricity from pole-mounted or pad-mounted transformers - which lowers the voltage again - to customer premises.

- Residential customers are served at either 120 or 240 volts depending upon the customer's service entrance panel size and connected appliances.
- Non-residential customers on the Company's SGS or LGS rates are served at voltages from 120 to 480 volts due to the wide variety of electrical consuming devices utilized by such customers.

Q. In your description of the Ameren Missouri generation, transmission, and distribution system are you using the term "lines" in a general sense?

[17] The New Madrid aluminum smelter was idled in the first quarter of 2016 and normalized retail revenues have been calculated to reflect zero usage.

A. Yes. Those "lines" may be overhead conductors or underground cables. Overhead “lines” include all poles, towers, insulators, cross arms, and all other hardware associated with such installations. Underground "lines" include direct buried cable, as well as that installed in single or multi-duct conduit, and other associated hardware.

Q. Please explain the steps in performing a class cost of service study.

A. The three major steps to develop a class cost of service study are:

1. Functionalization – the process of assigning the Company’s total revenue requirement to specified utility functions, i.e., production, transmission, distribution, etc. This step is done mainly in the jurisdictional cost of service utilizing the Federal Energy Regulatory Commissions (“FERC”) Uniform System of Accounts Manual.

2. Classification – is a further refinement of the functionalized revenue requirement. Cost classification identifies the various elements of functionalized revenue, on a cost-causative basis, as demand-related, energy-related, or customer-related.

3. Allocation – is the process of allocating the classified costs among the Company’s customer rate classes. Demand-related distribution costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident, or individual customer non-coincident kilowatt demands. Energy-related costs are allocated to the customer classes on the basis of their respective energy (kilowatt-hour) requirements at the generation level of the Company's system, which includes applicable system energy losses. The use of this common point on the Company's system to allocate such costs ensures that each customer class will be

assigned the appropriate portion of the Company's total incurred variable fuel and purchased power costs. Customer-related costs are normally allocated on the basis of the number of customers associated with each rate class. In some instances involving non-residential customer multiple or advanced metering installations, weighting factors may also be used. In addition, where specific costs can be identified as being attributable to one or more specific customer classes, such as credit and collection expenses, a direct assignment of such costs will be made.

ii. <u>Functionalization and Classification</u>

Q. Please describe the components of costs and revenues that are contained in the class cost of service study that the Company is filing in this case.

A. A traditional cost of service study incorporates the aggregate jurisdictional (Missouri or FERC) accounting and financial data normally submitted to a regulatory commission by a utility in support of a request for an adjustment in its overall rate levels. Such a study is required to determine the level of revenues necessary for the Company to recover its operating and maintenance expenses through rates, depreciation applicable to its investment in utility plant, property taxes, income and other taxes, and provide a fair rate of return to the Company's investors. The Company's class cost of service study allocates, or distributes, these total jurisdictional costs to the various customer classes in a cost-based manner that fairly and equitably reflects the cost of the service being provided to each customer class.

Q. What major categories of costs were examined in the development of the class cost of service study?

A. A detailed analysis was made of all elements of the Company's Missouri jurisdictional rate base investment and expenses during the test year for the purpose of allocating such items to the Company's present customer classes. This analysis consisted of classifying the various elements of costs into their customer-related, energy-related, and demand-related cost categories.

Q. Why are the Company's costs classified into these three categories?

A. It is generally accepted within the industry that the costs in each of these categories result from different cost causation factors and hence should be allocated among the various customer classes by different methodologies which consider such cost causation.

Q. What are customer-related costs?

A. Customer-related costs are the minimum costs necessary to make electric service available to the customer, regardless of the extent to which such service is utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting and customer service expenses, investment in meters and service lines, as well as a portion of line transformers and other distribution system facilities. The customer components of the distribution system are those costs necessary to simply provide reliable and safe service to a customer, without the consideration of the amount of the customer's electrical use.

Q. What are energy-related costs?

A. Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, interchange power costs, and a portion of production plant maintenance expenses.

Q. What are demand-related costs, the third category of costs to which you referred?

A. Demand-related costs are rate base investment and related operating expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. During such peak periods, this usage is expressed in terms of the customer's maximum power consumption, commonly referred to as kilowatts of demand. As defined, demand-related costs include those costs in excess of the aforementioned customer and energy-related costs. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant.

iii. <u>Minimum Distribution System Study</u>

Q. What is a Minimum Distribution System Study?

A. The distribution system is commonly classified into both demand and customer-related costs. However, many of the distribution system components need to be apportioned between the customer and demand-related classifications. In order to do so one must determine how much of the distribution system is needed to make service available versus how much of the distribution system is needed to meet the maximum demand requirements of each customer class. The Minimum Distribution System Study is the analytical process that apportions the distribution system into the customer and demand-related classifications.

Q. What approach is the Company using to apportion the distribution system between the customer and demand-related classifications?

A. In this case, the Company has used the "Minimum-Size Method" which is outlined in the National Association of Regulatory Utility Commissioners ("NARUC") January 1992 cost allocation manual.

Q. In prior cases the Company has used the "Zero-Intercept Method," how does the Minimum-Size Method relate?

A. Both the Minimum-Size Method and the Zero-Intercept Method are outlined in the NARUC cost allocation manual. Both methodologies also yield similar overall results and because the Company is not asking for purely cost-based rates, either approach supports the Company's proposals in this case. However, I believe the Minimum-Size Method is more intuitive and simpler to execute than the Zero-Intercept Method.

Q. What is the process to develop a Minimum-Size Distribution System Study?

A. As prescribed by the NARUC Electric Utility Cost Allocation Manual, the Minimum-Size Distribution System Study involves determining the minimum size pole, conductor, cable, and transformer that is currently installed or used by the Company. This equipment clearly would be consistent with the safety codes and any other requirements the Company designs for and would take into account the impact of snow and ice, minimum electrical clearances, etc. The average book cost for that minimum standard item of equipment normally determines the customer-related cost of all installed units, except legacy smaller units still in service which are included at their actual lower cost. Also included in the minimum-size distribution system costs are safety/reliability equipment like protective relays and lightning arrestors as well and other basics like land and fencing--essentials necessary for providing electrical service regardless of customer usage characteristics.

Q. How was the customer-related cost of FERC Account 364 – poles, towers, and fixtures – determined using the minimum-size method?

A. First, the average installed book cost of the minimum height pole currently being installed for the Company's distribution system was determined.[18] Then, the average book cost was multiplied by the number of poles to find the customer-related cost component. There are some poles installed in special situations or legacy poles that are less expensive, and these are included at their lower cost. Required fencing and land rights are also included as customer-related costs.

Q. How was the customer-related cost of FERC Account 365 – overhead conductors and devices – determined?

A. The current minimum size conductor being installed was determined and then multiplied by the number of circuit miles to determine the customer-related cost component for this account. As with the pole account, there is some legacy wiring that is smaller and less expensive than our current standards allow, and this wiring is included at its installed (lower) cost in the customer component. Again, protective equipment such as lightning arrestors, re-closers, and switches are also included in the customer component. While many of the circuits are three-phase circuits (three wires carrying

[18] A 40-foot wood distribution pole is the minimum height pole currently being installed according to Ameren Missouri's Standards Group.

current, one neutral) the minimum size standard cost is that of a one-phase circuit (one current carrying conductor, one neutral).

Q. How was the customer-related cost of FERC Accounts 366 and 367 – underground conduits, conductors and devices – determined?

A. For Account 367 (underground conductors and devices) the average minimum size primary cable cost was determined and then multiplied by the number of circuit miles to determine the customer-related cost components for these accounts. The secondary voltage cable was also included at the lesser of actual installed or minimum primary cable cost. The excess larger cable was allocated at the minimum size cost. Account 366 (underground conduits) used the same customer-related percentage as Account 367.

Q. How was the customer-related cost of FERC Account 368 – line transformers – determined?

A. The cost of a minimum size overhead and underground transformer currently being installed was determined and then multiplied by the number of transformers of each type in the plant account to determine the current cost of the minimum-size system. For this account, the cost differential is significantly different between transformers served by overhead lines and those served by underground lines. The current cost of the minimum-size system was divided by the current cost of the entire plant account to determine the customer-related percentage to be applied to the embedded cost of this plant account.

iv. Cost Allocations

Q. After the Company's costs are categorized into one of the three major classifications, how are they allocated to the various rate classes?

A. Customer-related costs are normally allocated on the basis of the number of customers associated with each rate class. In some instances involving non-residential customer multiple metering installations, weighting factors may also be used. In addition, where specific costs can be identified as being attributable to one or more specific customer classes, such as credit and collection expenses, a direct assignment of such costs will be made. Energy-related costs are allocated to the customer classes on the basis of their respective energy (kilowatt-hour) requirements at the generation level of the Company's system, which includes applicable system energy losses. Demand-related distribution costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident, or individual customer non-coincident kilowatt demands. Demand-related transmission costs are allocated to customer classes on a 12 coincident peak ("CP") basis, as that methodology is consistent with the method utilized to assign cost responsibility of the demands of the Ameren operating companies and all of the other utilities participating in the Midcontinent Independent System Operator, Inc. ("MISO"), per MISO's Attachment O Rate Formulae in MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff on file at the FERC. Demand-related production costs are allocated on the basis of the Average and Excess ("A&E") Demand Method referenced in the NARUC cost allocation manual. As not all customers have demand meters, customer class and individual customer kilowatt demand data is obtained from the Company's on-going load research program.

Q. After the determination of customer, energy and demand allocation factors for the various components of the Company's costs, what was the next step in the completion of the Company's class cost of service study?

A. The next step was to apply the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The aggregation of such cost allocations indicates the total annual costs, or annual revenue requirement, at equalized rates of return associated with serving a particular customer class. The operating revenues of each customer class minus its total operating expenses provide the resulting net operating income for each class. This net operating income divided by the rate base allocated to each class will indicate the percentage rate of return being earned by the Company from a particular customer class.

Q. Please describe how costs and expenses were allocated to the customer classes.

A. The original cost and depreciation reserves of the major functional components of the Company's electric rate base were allocated to customer classes as described below. The resulting dollar amount (in thousands) allocated to each class is shown in Schedules WRD-2 and WRD-3.

(1) Production Plant. Production plant was allocated to each customer class on the basis of the Four Non-Coincident Peak (“4 NCP”) Average and Excess Demand allocation factors for each customer class at the Company's generating stations.

Non-coincident peak demand is the customer class' maximum load at any time of the study period regardless of the time of occurrence or magnitude of the Company's system peak. The four non-coincident peak demands are the average of the customer class' four maximum monthly loads.

(2) Transmission Plant. Transmission line and substation investment was allocated to each customer class on the basis of the Twelve Coincident Peak ("12 CP") demands of each class at their point of input to the Company's transmission system. Coincident peak demand is the customer class' load at the time of occurrence of the Company's system peak. The twelve coincident peak demands are the customer class' twelve monthly loads at the time of the Company's twelve monthly system peaks. Such 12 CP allocation is consistent with the development of the Ameren system transmission revenue requirement, under the MISO Attachment O Rate Formulae in the Open Access Transmission, Energy and Operating Reserve Markets Tariff on file at the FERC.

(3) Distribution Plant. The Company's Distribution Plant was allocated to each customer class based upon the results of an analysis of the functions performed by the facilities in Distribution Plant Accounts 360-369. This analysis determined the breakdown of each account based on its customer-related and demand-related components. The demand-related component was further broken down by high voltage primary, primary voltage and secondary voltage demand-related functions. High voltage primary is 34.5 kilovolts up to 69 kilovolts, primary distribution voltage is above 600 volts up to 34.5 kilovolts, while secondary distribution voltage is 600 volts or less.

The portion of the Distribution Plant accounts classified as customer-related costs was derived using the Minimum-Size Method described above. The remaining, or demand-related, portion of the Company's Distribution Plant accounts were split among the high voltage primary, primary voltage and secondary voltage levels on the basis of a review of the functional utilization of various equipment and hardware in such accounts. For all distribution accounts, with the exception of Account 369, Services, the demand-related investment in each account was allocated to each customer class on the basis of the non-coincident peak demand of each class at the appropriate high voltage, primary and secondary voltage levels.

The demand-related investment in Account 369, Services, was allocated to each customer class on the basis of the sum of the maximum demand of all customers in the class at the secondary level. The maximum individual customer demand was used to reflect the fact that the maximum demand of individual customers dictates the sizing of their service facilities.

Distribution Account 370, Meters, was allocated to each of the customer classes by allocation factors that weigh the results of multiplying the current cost of the typical metering arrangement for each customer class by the number of meters used in serving that class. All metering cost is classified as customer-related.

Account 371-1, Installation on Customer's Premises Substation Equipment, was allocated to the Primary class on the basis of such customers’ historical use of these facilities.

Account 373, Street Lighting & Signal Systems, was directly assigned to the Company-Owned Lighting class.

(4) General Plant. The balance in this account was allocated to each customer class on the basis of the proportion of labor expense allocated to each class.

(5) Accumulated Reserves for Depreciation. Because such reserves are functionalized by type of plant, these reserves were allocated on the same basis as the allocation of the various plant accounts, as described above.

(6) Materials & Supplies. This component consists of fuel inventories and general materials and supplies related to power plants, transmission facilities and distribution facilities. Fuel inventories and the power plants and transmission facilities materials are directly related to the generation and transmission of energy and were therefore allocated on the basis of the energy allocation factor. The local distribution materials were allocated on the basis of the composite allocation of Distribution Plant, as previously described.

(7) Cash Working Capital. This item is related primarily to operating expenses and was therefore allocated to each customer class in proportion to the total operating expenses allocated to each class.

(8) Customer Advances for Construction and Deposits. This component of rate base was assigned to each customer class on the basis of an analysis of the sources of such deposits in Missouri.

(9) Total Accumulated Deferred Income Taxes. This component is related primarily to investment in property and was therefore allocated to each customer class on the basis of allocated gross plant.

Q. As generation (production) plant comprises more than half of the Company's total plant investment, please summarize the most common cost allocation methodologies employed within the electric utility industry for the allocation of generation plant.

A. The most common and generally accepted methodologies used for the allocation of generation plant can be grouped into the following three categories:

Coincident Peak – Costs are allocated on the basis of the relative customer class demands at the time of occurrence of the company's system peak during the period of study (referred to as the "CP" method). One or more system peak hours, or a number of monthly or seasonal system peaks, are normally used in applying the CP methodology. For instance, transmission costs are allocated using a “12 CP” method, which is based on averaging the test year’s monthly coincident peaks.

Non-Coincident Peak – Costs are allocated on the basis of the maximum peak demand of each customer class at any time during the study period, without regard to the time of occurrence or magnitude of the company's coincident system peaks (referred to as the "NCP" method). As with the CP method, the NCP methodology can employ one or more customer class peaks in its application. As a simple example, consider street lighting; the summer street lighting non-coincident peak occurs at night when the street lights are active, yet street lighting demand is zero at the time of the summer system coincident peak (usually at 4 p.m. or 5 p.m.).

Average and Excess - Costs are allocated based upon a weighting of average class demand throughout the year (kilowatt-hours ÷ 8,760 hours) and class "excess" demand(s) (referred to as the "A&E" method). The excess demand(s) used in this determination are the class NCP demand(s) in excess of the average class demand during the study period. As with the CP and NCP methodologies, this method can also employ the use of one or more customer class NCP demands to determine class excess demands. Average class demands are weighted by the Company's annual system load factor (“LF”) (LF = average demand ÷ peak demand) and excess class demands are weighted by the complement of the load factor (1.0 – LF) in the development of cost allocation factors using this methodology.

Q. Which cost allocation methodology is the Company using for production plant in its class cost of service study in this case?

A. The Company is utilizing the 4 NCP version of the A&E demand methodology for allocating production plant in this case.

Q. From a generation perspective, what were the considerations associated with the Company's election to utilize the A&E demand allocation methodology for production plant in this case?

A. Two major factors associated with generation capacity planning prompted the use of the A&E demand cost allocation methodology. Generally, system peak demands and, to a somewhat lesser extent, excess customer demands, are the motivating factors which influence the amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type of capacity (base, intermediate, or peaking) that the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt-hours, that will be required to be generated by such capacity, i.e., the generation unit's utilization factor. A cost allocation methodology that gives weight to both: a) class peak demands and b) class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt-hours divided by total hours in the year (8,760), and the excess NCP demands of each class. As indicated earlier, the Company's A&E cost allocation study used both the 4 NCP and average class demands in the determination of class <u>excess</u> demands.

Q. Is there also quantitative support for the Company's selection of the 4 NCP version of the A&E demand allocation methodology for production plant?

A. Yes. The 4 NCP version of the A&E methodology, which uses the four maximum non-coincident monthly peak demands for each customer class during the test year, was selected due to the fact that 14 of the 16 maximum 4 NCP monthly demands for the Company's major (i.e., non-lighting) customer classes occurred during the Company's summer peak demand months of June - September. The use of the 4 NCP demand option, rather than a lesser number of monthly NCP demands, also prevents the demand allocator for any customer class from being unduly influenced by any extreme demand in a given month.

Q. How did you allocate the electric test year operating and maintenance expenses to the customer classes?

A. With very few exceptions, operating and maintenance expenses were allocated to the customer classes on the same basis as the related investment in plant was allocated. This type of allocation employs the familiar and widely used "expenses follow plant" principle of cost allocation. For example, the allocator for Transmission Lines was used to allocate Transmission Line expenses. The only exceptions to this procedure are as follows:

(1) <u>Production Expenses</u>. This item consists of two categories: (a) fixed, which includes standard operating and maintenance ("O&M") crews, nuclear

support staff and a portion of non-labor production plant O&M expenses; and (b) variable, which includes fuel, fuel handling, interchange power costs, and the remaining portion of non-labor production plant O&M expenses. The fixed portion of production expenses was allocated on the same basis as Production Plant, while the variable portion was allocated using a variable allocator based on the megawatt-hours required at the generator to provide service to each respective customer class.

(2) Customer Accounts Expenses. An analysis of Account 903, Customer Records and Collection Expenses, indicated that approximately 24% of such expenses are devoted to credit and collection activities. Therefore, this portion of Account 903 and all of Account 904, Uncollectible Accounts, were allocated to each customer class on the basis of the annual level of collection activities applicable to each customer class. The remaining 76% of Account 903 expense was allocated to each customer class utilizing a weighted billing and customer accounts administration allocation factor. Account 902, Meter Reading Expenses, was allocated to each class by weighting the results of applying the monthly contract meter reading cost per meter to the respective number of meters in each customer class. Account 901, Supervision, was allocated to each class on the basis of the composite allocation of all other Customer Accounts Expenses.

(3) Customer Service & Sales Expenses. These expenses were allocated to each customer class using the composite allocation of Customer Accounts Expenses.

(4) Interest on Customer Surety Deposits. These expenses were allocated to each customer class on the basis of the previously allocated Customer

Advances and Deposits, since advances and deposit accounts are typically representative of where surety deposits are booked.

(5) Administrative and General ("A&G") Expenses. With the exception of property insurance expense, A&G expenses were allocated to the customer classes on the basis of the class composite distribution of previously allocated labor expense. Property insurance expense was allocated using a composite allocator based on gross production, transmission, distribution, and general plant.

Q. How did you allocate off-system sales revenues?

A. Off-system sales revenues were allocated to each class using each class' variable production allocation factor based on the megawatt-hours required at the generator to provide service to each respective customer class. This allocation is consistent with the Commission's Report and Order in File No. ER-2010-0036.

Q. How did you allocate the test year depreciation expenses?

A. Since depreciation expenses are functionalized and are directly related to the Company's original cost investment in plant, depreciation expense within each function was allocated to each customer class on the basis of the previously allocated original cost production, transmission, distribution and general plant.

Q. How did you allocate the test year real estate and property taxes?

A. Real estate and property tax expenses are directly related to the Company's original cost investment in plant, so these expenses were allocated to customer classes on the basis of the sum of the previously allocated production, transmission, distribution and general plant investment.

Q. How did you allocate the test year income taxes?

A. Income tax expense is directly related to the Company's net operating income as a proportion of its net rate base investment, i.e., rate of return on its net original cost rate base. As a result, income taxes were allocated to each class on the basis of the net original cost rate base allocated to each customer class.

Q. How did you allocate the revenue requirement associated with energy efficiency to the various affected customer classifications?

A. Costs associated with the Company's energy efficiency efforts were split into two categories: 1) program costs reflected as regulatory assets from energy efficiency programs implemented before January 1, 2013; and 2) costs associated with energy efficiency implemented on and after January 1, 2013. The revenue requirement associated with energy efficiency in category 1 was directly assigned to the respective rate classes based on utilization of the programs. The revenue requirement associated with category 2 expenses was excluded from the class cost of service study because all of those costs are collected through the Company's Energy Efficiency Investment Charge Rider.

IX. BILLING UNITS

Q. Please explain what is meant by the term "billing unit."

A. A billing unit is a quantity of electric customers (or number of lights for lighting service), usage (kilowatt-hours), demand (kilowatts), or reactive demand (kilovar) data to which filed rates are applied in determining customers' bills. Depending on a customer's rate class, two or more of these components are used to bill virtually all customers. The weather normalized billing units developed for this case are a compilation of the individual customer billing units that occurred during the study period, adjusted to reflect normal weather. The study period is the test year consisting of the twelve months ending March 31, 2016. The weather normalized billing units were further adjusted for anticipated customer growth to December 31, 2016.

Q. What was the result of the billing units analysis?

A. The analysis provides the normal billing units to be used to develop proposed rates. The study shows that test year retail revenues should be reduced by $88.7 million to reflect normalized conditions. The resulting normalized retail revenues were utilized by Ms. Moore in her cost of service study and are summarized in the table below. The detailed rate elements used to develop the normalized retail revenues by rates class are attached in Schedule WRD-4.

Table 7 – Normalized Billing Units

Customer Class	Calculated Retail Revenues*	Normalized Retail Revenues*	Total Adjustment
Residential Service	$1,243,789,926	$1,255,462,780	$11,672,854
Small General Service	$305,108,073	$309,645,053	$4,536,980
Large General Service	$587,482,563	$603,408,285	$15,925,722
Small Primary Service	$235,951,593	$239,989,465	$4,037,872
Large Primary Service	$209,722,931	$209,571,770	($151,162)
Large Transmission Service**	$124,866,054	$0	($124,866,054)
Company-Owned Lighting	$36,431,618	$36,570,811	$139,193
Customer-Owned Lighting	$3,738,820	$3,785,618	$46,799
Metropolitan Sewer District	$75,802	$76,826	$1,024
Total	**$2,747,167,381**	**$2,658,510,609**	**($88,656,772)**

* Revenue includes Low-Income Pilot Program Charges
** Includes the Industrial Aluminum Smelter classification

Q. What adjustments is the Company making to normalize the billing units?

A. There are four primary adjustments: 1) a rate increase adjustment that reflects the fact that rates increased during the test year; 2) weather normalization to reflect normal weather conditions; 3) a 365-day adjustment; and 4) a growth adjustment to capture expected customer growth through December 2016. The table below summarizes each adjustment and each adjustment is described further below.

Table 8 – Billing Unit Adjustments

Customer Class	Rate Increase Adjustment	Weather Adjustment	365-Day Adjustment	Dec. 2016 Growth Adjustment	Total Adjustment
Residential Service	$10,787,178	($2,842,371)	($209,221)	$3,937,268	$11,672,854
Small General Service	$2,684,901	($307,723)	($344,522)	$2,504,323	$4,536,980
Large General Service	$4,996,904	$1,553,550	($1,032,948)	$10,408,216	$15,925,722
Small Primary Service	$1,997,653	($907,392)	($1,015,497)	$3,963,108	$4,037,872
Large Primary Service	$1,171,344	($980,110)	($342,395)	$0	($151,162)
Large Transmission Service*	($1,617,317)	$0	$0	($123,248,737)	($124,866,054)
Company-Owned Lighting	$456,014	$0	$0	($316,821)	$139,193
Customer-Owned Lighting	$46,799	$0	$0	$0	$46,799
Metropolitan Sewer District	$1,024	$0	$0	$0	$1,024
Total	**$20,524,500**	**($3,484,046)**	**($2,944,584)**	**($102,752,642)**	**($88,656,772)**

* Includes the Industrial Aluminum Smelter classification

Q. What was the initial step in the development of the Company's billing units for each customer class?

A. Existing Company reports contain aggregate kilowatt-hour sales and revenues on a monthly basis for the Residential, Small General Service, Large General Service, Small Primary Service, Large Primary Service, and Large Transmission Service/Industrial Aluminum Smelter rate classes. More detailed monthly billing units were retrieved from the Company's Data Warehouse which can be priced at the Company's latest approved rates to calculate customer revenues. The Data Warehouse stores individual customer data which can be queried to provide summaries of billing data both by revenue month, which is the month for which the data was reported, and the primary month, which is the month the data should have been reflected in customer bills. After assembling the billing data in the proper primary month, the rates in effect during the test year for each specific rate class were applied to the billing units for each class. This results in the "Calculated Retail Revenues" for each class.

Q. Do the revenues calculated from this process exactly match the revenues reported on the Company's books for the same time period?

A. While the comparison of calculated revenue and reported revenue match closely, there will always be some difference between the two. The difference results from billing adjustments that are made to a number of accounts each month due to corrected and pro-rated billings.

Q. Were all of the rate classes analyzed using the billing unit reports?

A. No, individual customer data was used for the Large Primary Service class. This was done because the Large Primary Service class contains 66 customers that are generally the largest customers, so it is important to thoroughly review each customer's billing data.

Q. After verifying the billing units associated with the Company's reported revenues, how were the revenues adjusted to reflect the mid-test year rate increase?

A. New rates from File No. ER-2014-0258 went into effect on May 30, 2015; so with a test year of 12 months ending March 2016, the revenue from the billing months of April 2015, May 2015, and part of June 2015 need to be adjusted to reflect those new rates. The adjustments to April 2015 and May 2015 were a result of comparing revenues under the then-current rates to the rates approved in File No. ER-2014-0258; while the June 2015 partial adjustment was based on a comparison of actual billed revenues under File No. ER-2014-0258 rates compared to calculated revenues under File No. ER-2014-0258 rates.

Q. How were the billing units and revenues adjusted to reflect normal weather?

A. Weather adjustment ratios for each billing month were applied to adjust the monthly reported sales to weather normalized sales. An additional weather normalization step was taken for the Residential and Small General Service classes to normalize the percentage of kilowatt-hours billed in the first block of the winter declining block rates. For the other rate classes, the kilowatt-hours in all of the rate blocks were adjusted by the weather ratios and the resulting units were priced at the rates as a result of File No. ER-2014-0258.

Q. How were the billing units and revenues adjusted to a 365-day test year?

A. The Company compares calendarized test-year sales[19] to the billed test-year sales. Because the calendarized test-year sales cover 365 days, the difference from the billed test-year allows the Company to adjust the billing units to a standard calendar year.

[19] The Company uses the statistical usage models from its weather normalization to estimate daily usage based on billing data, and the estimated daily usage is then aggregated into calendar months.

Q. How were the billing units adjusted for customer growth?

A. The weather normalized billing units were adjusted for customer growth by multiplying the monthly usage per customer by the customer counts as of March 2016, and then again using forecasted customer counts for December 2016, the end of the proposed true-up period.[20] It is noteworthy that because of the recent idling (and bankruptcy filing) of the New Madrid aluminum smelter, the billing units have been normalized to reflect zero revenues from the Large Transmission Service and Industrial Aluminum Smelter Service classifications.[21]

Q. How else were the normalized billing units used?

A. The normalized revenues and billing units are used in the development of the Company's proposed rates in this case.

Q. Does the Company intend to revise its billing units and associated test year revenue to reflect a more recent twelve-month period as this case progresses?

A. Yes. In the Company's last several cases, both the Company and Commission Staff moved the test year billing units forward in order to reflect a more current twelve-month period. The Company anticipates that rather than relying on the twelve months ended March 2016 data, a more current period (e.g., twelve months ended July 2016) will be utilized to allow the most current usage information possible to be used to set rates in this case. Updating and weather normalizing usage through July 2016 would also likely include annualization adjustments for the energy savings associated with the Company's energy efficiency programs following the terms of its Energy

[20] A similar process is used for individual light types within the Lighting Service classifications.
[21] The Keeping Current Low-Income Pilot Program tariff has also been changed to reflect a reduction in funding associated with the amount contributed by Noranda which is $18,000 (12 months * $1,500 per month).

Efficiency Investment Charge Rider and the Commission-approved stipulation in File No. EO-2015-0055. The final adjustment would be to update the billing units for actual customer growth to December 2016. This is also true for the Company's LED street lighting conversion. The Company anticipates updating its billing units for the LED street lighting conversion to capture and annualize the amount of LED street lights installed through December of 2016.

X. ENERGY EFFICIENCY RIDER UPDATE

Q. Does the outcome of this rate case impact the Company's EEIC Rider?

A. Yes. The throughput disincentive is a common term used in the energy efficiency realm to describe the financial losses that the Company experiences related to the lower sales caused by administering its energy efficiency programs. In each rate case, two things happen that relate to the throughput disincentive recovery mechanism associated with the Company's most recently approved plan: 1) the margin rates for each rate class will change; and 2) a portion of the lower sales associated with the Company's energy efficiency programs will be incorporated into base rates. The Company's EEIC Rider necessitates the formalization of these two factors.

Q. What are the new margin rates to be used in Rider EEIC?

A. The table below is a copy of the new rates that will be updated in Rider EEIC.

Table 9 – Proposed Net Margin Rates in Rider EEIC

	Service Classifications				
Month	**1(M)Res $/kWh**	**2(M)SGS $/kWh**	**3(M)LGS $/kWh**	**4(M)SPS $/kWh**	**11(M)LPS $/kWh**
January	0.046615	0.051423	0.041326	0.032592	0.022981
February	0.048909	0.052795	0.043663	0.034426	0.025636
March	0.051054	0.055339	0.044589	0.034846	0.025034
April	0.053222	0.057800	0.045251	0.034576	0.024971
May	0.055832	0.059580	0.045948	0.035680	0.025414
June	0.108580	0.097180	0.085785	0.064718	0.038172
July	0.108580	0.097180	0.083861	0.064199	0.039335
August	0.108580	0.097180	0.083820	0.064699	0.038788
September	0.108580	0.097180	0.084412	0.064280	0.039015
October	0.050982	0.056241	0.043317	0.033543	0.024170
November	0.054323	0.057716	0.044022	0.033712	0.023931
December	0.049395	0.054672	0.042713	0.033117	0.023350

Q. Is Ameren Missouri proposing an energy efficiency annualization to billing units and re-basing adjustment for Rider EEIC?

A. Not at this time. The filed test year ends March 2016 which was also the first month of the Company's newly approved energy efficiency plan. There were no energy savings in March to report but there will likely be the need for an annualization to billing units and a re-basing adjustment as part of the true-up in this case.

XI. STANDBY SERVICE RIDER

Q. Why is Ameren Missouri filing a new Standby Service Rider?

A. At the request of the Missouri Division of Energy in the Company's last rate case, the Company reached an agreement titled *Nonunanimous Stipulation and Agreement Regarding Supplemental Service Issues*[22] ("Supplemental Service Stipulation"), wherein it agreed to work with interested stakeholders to develop a new Standby Service Rider and file it by December 31, 2015. Ultimately the signatories to

[22] File No. ER-2014-0258, March 5, 2015.

the Supplemental Service Stipulation agreed it was acceptable to delay the filing of the Standby Service Rider and include it as part of this rate case.

Q. What is the basic purpose of a Standby Service Rider?

A. The basic purpose of a Standby Service Rider is to accurately recover the allocated embedded costs associated with providing the type of service necessary for customers with on-site electrical generation and/or storage. In short, standby rates should allow self-supplying customers access to utility services without unfairly creating costs for other customers.

Q. Please provide a brief overview of the new Standby Service Rider being proposed.

A. There are several main components of the new Standby Service Rider. The service applies to Large General, Small Primary, and Large Primary services where a customer has on-site generation and/or storage with rated capacity of more than 100 kilowatts. The tariff delineates between supplemental and standby service with each of the components being separated out on the customer's bill. Supplemental service represents the electric service provided by the Company to the customer to supplement normal operation of the customer's on-site parallel distributed generation and/or storage in order to meet the customer's full service requirements. Standby service generally represents the service supplied to the premises by the Company in place of the service that is normally self-supplied by the customer's on-site electrical generation and/or storage. In the proposed tariff, "standby" occurs in the event of the customer exceeding his/her Supplemental Contract Capacity. Standby Service may be needed on either a scheduled (maintenance service) or unscheduled (backup service) basis.

The customer must designate the anticipated maximum net load on the Company's system which is known as the Supplemental Contract Capacity. In addition, the customer must designate the expected capacity utilization of his/her generation and/or storage system which is known as Standby Contract Capacity. The Standby Contract Capacity may reflect a load shedding plan, if the customer has plans to reduce its demand at the time of an outage of its generating equipment. The tariff also includes provisions that allow customers to schedule maintenance outages for their equipment. In addition, the tariff specifies that the maintenance and standby charges only apply when the customer's metered load exceeds the Supplemental Contract Capacity which means the customer will only pay standby charges when the metered load on the utility's system exceeds the levels already expected.

Q. Does the proposed Standby Service Rider meet the terms of the Supplemental Service Stipulation from the Company's last rate case?

A. Yes, the Supplemental Service Stipulation listed several key concepts to incorporate, all of which are factored into the new Standby Service Rider. Below is a summary of how each concept was addressed.

1) Definitions for supplementary power, backup power, and maintenance power – The new Standby Service Rider includes these definitions and reflects the feedback of stakeholders. Also, the Standby Service Rider specifies that the charges for each of these services will be billed separately so customers can easily understand how much of each of those services were used.

2) Unbundled rates for services – The new Standby Service Rider includes several unbundled charges including an Administration Charge, Transmission

and Generation Access Charge, Facilities Charge, Daily Standby Charge, Daily Back-up Charge, Energy Charges, and Voltage Discounts.

3) The customer's generator availability – The Transmission and Generation Access Charge represents a 95% reduction to the underlying cost of the service based on expected generator availability. In addition, the tariff includes multiple opportunities for flexibility with regard to the amount and timing of scheduled maintenance as well as incorporating the expected usage of the generator in determining the contract standby capacity.

4) Maintenance scheduling – The new Standby Service Rider provides for maintenance scheduling as well as differentiated charges for maintenance service. In addition, the tariff includes multiple opportunities for flexibility with regard to the amount and timing of scheduled maintenance.

5) Seasonally differentiated charges – Most of the charges in the new Standby Service Rider are seasonally differentiated. In fact, even the Supplemental Contract Capacity and the Standby Contract Capacity are seasonally differentiated.

6) Time differentiated charges – There are two main places in the new Standby Service Rider where time differentiated charges are apparent. First, consistent with traditional billing for the relevant service classifications, off-peak demands receive a 50% discount. This time differentiation of demands is a material factor for this service because if a generator has a scheduled or an unscheduled outage during an off-peak period, it is entirely possible no standby charges would apply.

Second, energy charges for unscheduled outages (a/k/a backup service) are billed using higher on-peak rates and lower off-peak rates.[23]

7) Charges differentiated by voltage level – Charges in the new Standby Service Rider reflect differences in voltage just as standard tariff rates do, including the voltage discounts available to customers taking standard service.

Q. Was the proposed Standby Service Rider developed solely by Ameren Missouri?

A. No, the Company hosted a series of collaborative meetings with interested stakeholders. In those meetings, several iterations of the tariff were shared and discussed as well as supporting and requested quantitative analysis. Workshops were held on July 29, 2015, October 20, 2015, November 10, 2015 and January 21, 2016. Participants in the workshops included the signatories to the Supplemental Service Stipulation, and included many other interested groups, including: Midwest Cogeneration Association; Environmental Law Counsel, P.C.; Renew Missouri, Missouri Office of Administration; Lambert-St. Louis International Airport; Veolia Energy North America; University of Illinois at Chicago – Energy Resource Center; Washington University; Brightergy; Missouri Energy Initiative; Kansas City Power & Light Company; and The Empire District Electric Company. Beyond the workshops, numerous one-on-one conversations were held with various participants.

Q. How does the proposed Standby Service Rider impact customers currently taking Supplemental Service under Rider E from the Company?

A. There is only one customer receiving Supplemental Service under the Company's Rider E tariff and that customer has been taking service under the terms of

[23] These charges only apply if the load exceeds the supplemental contract capacity.

the Company's Supplemental Service for decades. Because of these circumstances, the Company is proposing to grandfather the current Supplemental Service tariff (Rider E) for this one customer until such a time as the customer makes material changes to its generation, while the new Standby Service Rider will apply to all new eligible self-generating customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Annual Revenues for Electric Service.	)))	File No. ER-2016-

AFFIDAVIT OF WILLIAM R. DAVIS

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

William Davis, being first duly sworn on his oath, states:

1. My name is William R. Davis. I am employed by Ameren Missouri as Sr. Manager, Energy Services Strategy and Development in the Energy Efficiency and Renewables Department.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company, d/b/a Ameren Missouri, consisting of 65 pages and Schedule(s) Schedule WRD 1-4, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

William R Davis
William R. Davis

Subscribed and sworn to before me this 30th day of June, 2016.

Beckie J Eaves
Notary Public

My commission expires: 2-21-18

BECKIE J. EAVES
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis City
My Commission Expires: February 21, 2018
Commission Number: 14938572

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RATES

* Indicates Change.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$8.00
** Energy Grid Access Charge – per month	$4.89
Low-Income Pilot Program Charge – per month	$0.03
Energy Charge - per kWh	12.54¢
Energy Efficiency Program Charge – per kWh	0.09¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$8.00
** Energy Grid Access Charge – per month	$4.89
Low-Income Pilot Program Charge – per month	$0.03
Energy Charge - per kWh	
First 750 kWh	8.91¢
Over 750 kWh	5.95¢
Energy Efficiency Program Charge – per kWh	0.05¢

Optional Time-of-Day Rate (Pilot)

Customer Charge - per month	$8.00
** Energy Grid Access Charge – per month	$4.89
Low-Income Pilot Program Charge – per month	$0.03
Energy Charge - per kWh (1)	
Summer (June-September billing periods)	
All On Peak kWh	31.37¢
All Off Peak kWh	7.84¢
Winter (October-May billing periods)	
First 750 kWh	8.91¢
Over 750 kWh	5.95¢
Energy Efficiency Program Charge – per kWh	
Summer (June-September billing periods)	0.09¢
Winter (October-May billing periods)	0.05¢

(1) On-peak and Off-peak hours applicable herein are:

Peak hours - 2:00 P.M. to 7:00 P.M., Monday through Friday.

Off-peak hours – 7:00 P.M. of Monday through Thursday to 2:00 P.M. of the following day, and from 7:00 P.M. Friday to 2:00 P.M. Monday.

* Indicates Change. **Indicates Addition.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd.)

Fuel and Purchased Power Adjustment (Rider FAC). Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC). Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions or the low-income exemption provisions of Section 393.1075, RSMo.

*Payments. Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Term of Use. Initial period one (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	
Single Phase Service	$10.75
Three Phase Service	$21.49
Limited Unmetered Service	$5.48
Energy Grid Access Charge(4) – per month	$4.89
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh	11.40¢
Energy Efficiency Program Charge(3) – per kWh	0.03¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	
Single Phase Service	$10.75
Three Phase Service	$21.49
Limited Unmetered Service	$5.48
Energy Grid Access Charge(4) – per month	$4.89
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge - per kWh	
Base Use	8.50¢
Seasonal Use(1)	4.90¢
Energy Efficiency Program Charge(3) – per kWh	0.02¢

Optional Time-of-Day Rate

Customer Charge - per month	
Single Phase Service	$21.55
Three Phase Service	$43.07
Limited Unmetered Service	$5.48
Energy Grid Access Charge(4) – per month	$4.89
Low-Income Pilot Program Charge – per month	$ 0.05
Energy Charge(2) - per kWh	
Summer (June-September billing periods)	
All On Peak kWh	16.93¢
All Off Peak kWh	6.90¢
Winter (October-May billing periods)	
All On Peak kWh	11.15¢
All Off Peak kWh	5.12¢
Energy Efficiency Program Charge(3) – per kWh	
Summer (June-September billing periods)	0.03¢
Winter (October-May billing periods)	0.02¢

(1) The winter seasonal energy use shall be all kWh in excess of 1,000 kWh per month and in excess of the lesser of a) the kWh use during the preceding May billing period, or b) October billing period, or c) the maximum monthly kWh use during any preceding summer month.

(2) On-peak and Off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

(3) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

(4) Not applicable to customers receiving Limited Unmetered Service.

* Indicates Change.

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd.)

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC). Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

*Payments Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Term of Use One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment Any license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE (Cont'd.)

6. **OPTIONAL TIME-OF-DAY (TOD) SERVICE (Cont'd.)**

a. Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

b. Customer electing this TOD option, shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

c. Any customer canceling this TOD option cannot thereafter resume billing under said option for a period of one year following the last billing period on the TOD option.

d. Premises with 120 volt 2-wire service, or meter locations which would make monthly meter readings unusually difficult to obtain, do not qualify for this TOD option.

*7. **LIMITED UNMETERED SERVICE**

Where service is required for electrical loads which are constant over a predetermined operating schedule and can be reasonably estimated by Company, Company may at its sole discretion waive the metering requirement for the limited types of load referred to herein. In such instances Company would calculate monthly billing for these loads under Service Classification No. 2(M). Additionally, all other provisions of Service Classification 2(M) shall apply to these loads. Service supplied under the provisions of this paragraph is limited to loads of 5 kVA or less at any one service delivery point.

8. **GENERAL RULES AND REGULATIONS

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

* Indicates Addition. ** Indicates Reissue.

SERVICE CLASSIFICATION NO. 3(M)
LARGE GENERAL SERVICE RATE

*RATE BASED ON MONTHLY METER READINGS

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$98.91
Low-Income Pilot Program Charge - per month	$ 0.50
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	11.07¢
Next 200 kWh per kW of Billing Demand	8.33¢
All Over 350 kWh per kW of Billing Demand	5.60¢
Demand Charge - per kW of Total Billing Demand	$ 5.17
Energy Efficiency Program Charge - per kWh (1)	0.07¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$98.91
Low-Income Pilot Program Charge - per month	$ 0.50
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	6.98¢
Next 200 kWh per kW of Base Demand	5.17¢
All Over 350 kWh per kW of Base Demand	4.07¢
Seasonal Energy Charge - Seasonal kWh	4.07¢
Demand Charge - per kW of Total Billing Demand	$ 1.92
Energy Efficiency Program Charge - per kWh (1)	0.04¢

(1) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $21.95 per month

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh(June-September billing periods)	+1.31¢	-0.74¢
Winter kWh(October-May billing periods)	+0.40¢	-0.22¢

(2) On-peak and off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

* Indicates Change.

SERVICE CLASSIFICATION NO. 3(M)
LARGE GENERAL SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd.)

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC). Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

* Payments Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Term of Use One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

SERVICE CLASSIFICATION NO. 4(M)
SMALL PRIMARY SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$337.28
Low-Income Pilot Program Charge - per month	$ 0.50
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	10.72¢
Next 200 kWh per kW of Billing Demand	8.07¢
All Over 350 kWh per kW of Billing Demand	5.41¢
Demand Charge - per kW of Total Billing Demand	$ 4.29
Reactive Charge - per kVar	40.00¢
Energy Efficiency Program Charge - per kWh (1)	0.07¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$337.28
Low-Income Pilot Program Charge - per month	$ 0.50
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	6.75¢
Next 200 kWh per kW of Base Demand	5.02¢
All Over 350 kWh per kW of Base Demand	3.92¢
Seasonal Energy Charge - Seasonal kWh	3.92¢
Demand Charge - per kW of Total Billing Demand	$ 1.55
Reactive Charge - per kVar	40.00¢
Energy Efficiency Program Charge - per kWh (1)	0.04¢

(1) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month	$21.95 per month	
Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh(June-September billing periods)	+0.95¢	-0.54¢
Winter kWh(October-May billing periods)	+0.35¢	-0.19¢

(2) On-peak and Off-peak hours applicable herein shall be as specified within this service classification.

* Indicates Change.

SERVICE CLASSIFICATION NO. 4(M)
SMALL PRIMARY SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd.)

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC). Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

* Payments Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Term of Use One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

SERVICE CLASSIFICATION NO. 5(M)
STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED

* **RATE PER UNIT PER MONTH LAMP AND FIXTURE**

The Light Emitting Diode (LED) offerings under section A. below will be made available to customers beginning on or about April 1, 2016.

* A. LED bracket mounted luminaire on existing wood pole:

Identification	Rate
100W Equivalent (1)	$10.59
250W Equivalent (1)	$17.16
400W Equivalent (1)	$31.74

(1) The equivalent wattage represents the rating of the high pressure sodium lamp that the LED replaces.

* The High Pressure Sodium and Mercury Vapor offerings under sections B. and C. below will only be available for new installations through on or about March 31, 2016. After such time, Company will replace these existing fixtures, upon failure, with an LED fixture under section A.

** B. Standard horizontal burning, enclosed luminaire on existing wood pole:

High Pressure Sodium		Mercury Vapor	
Lumens	Rate*	Lumens	Rate*
9,500	$13.25	6,800	$13.25
25,500	$19.14	20,000	$19.14
50,000	$34.13	54,000	$34.13

** C. Standard side mounted, hood with open bottom glassware on existing wood pole:

High Pressure Sodium		Mercury Vapor	
Lumens	Rate*	Lumens	Rate*
5,800	$10.73	3,300	$10.73
9,500	$11.72	6,800	$11.72

** D. Standard post-top luminaire including standard 17-foot post:

High Pressure Sodium		Mercury Vapor (1)	
Lumens	Rate*	Lumens	Rate*
9,500	$24.30	3,300	$22.97
		6,800	$24.30

*Indicates Change. **Indicates Reissue.

SERVICE CLASSIFICATION NO. 5(M)
STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)

** E. Pole-mounted, direction flood luminaire; limited to installations accessible to Company basket truck:

High Pressure Sodium		Metal Halide		Mercury Vapor (1)	
Lumens	Rate*	Lumens	Rate*	Lumens	Rate*
25,500	$24.30	34,000	$24.30	20,000	$24.30
50,000	$38.43	100,000	$76.82	54,000	$38.43

(1) Mercury Vapor lamps and fixtures are limited to customers served under contracts initiated prior to September 27, 1988. Company will continue to maintain these lamps and fixtures so long as parts are economically available.

** F. All poles and cable, where required to provide lighting service:

The installation of all standard poles and cables shall be paid for in advance by customer, with all subsequent replacements of said facilities provided by Company.

** G. Former Subsidiary Company lighting units provided under contracts initiated prior to April 9, 1986, which facilities will only be maintained by Company so long as parts are available in Company's present stock:

Lamp and Fixture	*Per Unit Monthly Rate
11,000 Lumens, Mercury Vapor, Open Bottom	$11.72
140,000 Lumens, H.P. Sodium, Directional	$76.82

Term of Contract Minimum term of three (3) years where only standard facilities are installed; ten (10) years where post-top luminaires are installed.

Discount for Franchised Municipal Customers A 10% discount will be applied to bills rendered for lighting facilities served under the above rates and currently contracted for by municipalities with whom the Company has an ordinance granted electric franchise as of September 27, 1988. The above discount shall only apply for the duration of said franchise. Thereafter, the above discount shall apply only when the following two conditions are met: 1) any initial or subsequent ordinance granted electric franchise must be for a minimum term of twenty (20) years and 2) Company must have a contract for all lighting facilities for municipal lighting service provided by Company in effect.

*Indicates Change. ** Indicates Reissue.

SERVICE CLASSIFICATION NO. 5(M)
STREET AND OUTDOOR AREA LIGHTING – COMPANY-OWNED (Cont'd.)

** Payments Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

Fuel and Purchased Power Adjustment (Rider FAC) The kilowatt-hours for lighting service provided under the terms of this Service Classification shall be subject to the provisions of Company's Fuel and Purchased Power Adjustment Clause (Rider FAC). The kilowatt-hour consumption of each lamp, whose operating hours are determined by a photoelectric control, shall be determined from the manufacturer's rated wattage multiplied by the number of hours of operation for the month, in accordance with the following schedules:

* LED (Watts)	* LED (Watts)
100W Equivalent	48
250W Equivalent	88
400W Equivalent	195

Lamp Size (Lumens)	Rating (Watts)
H. P. Sodium	
5,800	70
9,500	120
16,000	202
25,500	307
50,000	482
140,000	1000
Mercury Vapor	
3,300	127
6,800	207
11,000	294
20,000	455
42,000	700
54,000	1080
Metal Halide	
34,000	450
100,000	1100

Billing Month	Burning Hours
January	408
February	347
March	346
April	301
May	279
June	255
July	272
August	298
September	322
October	368
November	387
December	417

*Indicates Change. **Indicates Addition.

SERVICE CLASSIFICATION NO. 6(M)
STREET AND OUTDOOR AREA LIGHTING – CUSTOMER-OWNED

* **MONTHLY RATE FOR METERED SERVICE**

Customer Charge Per Meter	$7.38 per month
Energy Charge	4.99¢ per kWh

* **RATE PER UNIT PER MONTH FOR UNMETERED SERVICE**

H.P. Sodium	Energy & Maintenance(1)	Energy Only(2)
9,500 Lumens, Standard	$ 4.02	$ 1.95
25,500 Lumens, Standard	$ 6.99	$ 4.98
50,000 Lumens, Standard	$10.10	$ 7.83
Metal Halide		
5,500 Lumens, Standard	$ 5.81	N/A
12,900 Lumens, Standard	$ 6.96	N/A
Mercury Vapor	(3)	
3,300 Lumens, Standard	$ 4.02	$ 2.06
6,800 Lumens, Standard	$ 5.23	$ 3.35
11,000 Lumens, Standard	$ 7.08	$ 4.78
20,000 Lumens, Standard	$ 9.38	$ 7.37
54,000 Lumens, Standard	$20.04	$17.53

Light Emitting Diodes (LED)	Energy Only
Energy Charge – per rated wattage per month	1.68¢

*(1) Company will furnish electric energy, furnish and replace lamps, and adjust and replace control mechanisms, as required. In conjunction with the Company's conversion of its Company-Owned lights to LED, Company anticipates eliminating 6(M) Energy & Maintenance service in the future but not prior to 6/1/2022. Customers remaining on Energy & Maintenance at that time will be transitioned to Energy Only service.

(2) Limited to lamps served under contracts initiated prior to September 27, 1988.

(3) Maintenance of lamps and fixtures limited to customers served under contracts prior to November 15, 1991.

N/A Not Available.

Term of Contract One (1) year, terminable thereafter on three (3) days' notice.

Discount For Franchised Municipal Customers A 10% discount will be applied to bills rendered for lighting facilities served under the above rates and currently contracted for by municipalities with whom the Company has an ordinance granted electric franchise as of September 27, 1988. The above discount shall only apply for the duration of said franchise.

* Indicates Change.

SERVICE CLASSIFICATION NO. 6(M)
STREET AND OUTDOOR AREA LIGHTING – CUSTOMER-OWNED (Cont'd.)

Discount For Franchised Municipal Customers (Cont'd.) Thereafter, the above discount shall apply only when the following two conditions are met: 1) any initial or subsequent ordinance granted electric franchise must be for a minimum term of twenty (20) years and 2) Company must have a contract for all lighting facilities for municipal lighting service provided by Company in effect.

Fuel and Purchased Power Adjustment (Rider FAC) The kilowatt-hours for lighting service provided under the terms of this Service Classification shall be subject to the provisions of Company's Fuel and Purchased Power Adjustment Clause (Rider FAC). The kilowatt-hour consumption of each lamp, whose operating hours are determined by a photoelectric control, shall be determined from the manufacturer's rated wattage multiplied by the number of hours of operation for the month, in accordance with the following schedules:

Lamp Size (Lumens)	Rating (Watts)
*H. P. Sodium	
9,500	120
25,500	307
50,000	482
*Mercury Vapor	
3,300	127
6,800	207
11,000	294
20,000	455
54,000	1080
Metal Halide	
5,500	122
12,900	206

Billing Month	Burning Hours
January	408
February	347
March	346
April	301
May	279
June	255
July	272
August	298
September	322
October	368
November	387
December	417

*Light Emitting Diodes (LED)
Based on the rated wattage of individual customer lights.

** Payments Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change. **Indicates Addition.

SERVICE CLASSIFICATION NO. 6 (M)
STREET AND OUTDOOR AREA LIGHTING – CUSTOMER-OWNED (Cont'd.)

3. GENERAL PROVISIONS (Cont'd.)

e. Customer shall furnish to Company, without cost to Company and on forms suitable to it, or customer shall reimburse Company for all costs incurred in obtaining all rights, permits and easements necessary to permit the installation and maintenance of Company's facilities on, over, under and across both public and private property where and as needed by Company in providing service hereunder.

f. Customer shall notify Company immediately if any changes are made in customer's installation.

g. Company may refuse to make the initial connection or may discontinue service to any installation if there is any engineering, construction, safety, legal or practical reason for doing so.

h. In case of destruction or damage of customer's property hereunder due to highway accidents, storm damage or other similar causes or where replacement of equipment other than as provided above is required, Company, upon receipt of either written or verbal instructions from customer, may at its option, effect the necessary repairs or replacement of the damaged equipment to place it in normal operating condition. Such repairs will be made with parts supplied by customer or, where applicable, with suitable standard items carried in Company stores. Customer shall reimburse Company for such work at the Company's current Productive man-hour rate including applicable overhead for all labor expended and 1.2 times all direct costs or charges incurred by Company for all materials and any related items. All charges and payments hereunder shall be in addition to the monthly charge for normal maintenance.

*i. For unmetered service, Company shall have the right to verify or audit the type and/or rated wattage of lights installed.

*** 4. LIMITED LED CONVERSION OPTION AND GRANDFATHERING PROVISION**

Customer-owned horizontal enclosed or open bottom lights which were installed on Company distribution poles and billed under this Service Classification on or before July 31, 2016 are eligible for participation in a LED lighting conversion program.

If customer elects this LED conversion option, the Company will replace existing fixtures, upon failure of the bulb, and/or the lighting fixture or apparatus with an equivalent LED fixture. The Company will install, own and operate and maintain the LED fixture, mast, and wiring. Customer shall continue to receive service under this Service Classification 6(M) subject to being billed the following applicable monthly charges:

* Indicates Addition.

SERVICE CLASSIFICATION NO. 6 (M)
STREET AND OUTDOOR AREA LIGHTING – CUSTOMER-OWNED (Cont'd.)

* 4. **LIMITED LED CONVERSION OPTION AND GRANDFATHERING PROVISION (Cont'd.)**

The monthly unmetered energy-only 6(M) LED rate plus,

$2.76 per month for a 100 watt equivalent LED fixture;

$3.58 per month for a 250 watt equivalent LED fixture;

$6.32 per month for a 400 watt equivalent LED fixture.

In addition, all other applicable charges under this Service Classification 6(M) shall apply.

If customer requests, in writing, the termination of all or a portion of converted LEDs under this provision within ten years of the installation of the LED being terminated, customer shall pay in advance to Company $100.00 per fixture for both the removal costs associated therewith and the loss of the remaining life value of such facilities. If said request for termination is made after the above ten year in-service period, and customer requests a new lighting installation within twelve months after the removal of the prior terminated lighting facilities, customer shall pay the amount specified earlier in this paragraph for all facilities previously removed prior to Company making any new lighting installation.

** 5. **GENERAL RULES AND REGULATIONS**

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to service supplied under this Service Classification.

* Indicates Addition. ** Indicates Reissue.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE

***RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$337.28
Low-Income Pilot Program Charge – per month	$ 50.00
Energy Charge – per kWh	3.68¢
Demand Charge - per kW of Billing Demand	$ 21.98
Reactive Charge - per kVar	40.00¢
Energy Efficiency Program Charge – per kWh (1)	0.02¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$337.28
Low-Income Pilot Program Charge – per month	$ 50.00
Energy Charge – per kWh	3.26¢
Demand Charge - per kW of Billing Demand	$ 9.98
Reactive Charge - per kVar	40.00¢
Energy Efficiency Program Charge – per kWh (1)	0.01¢

(1) Not applicable to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

Optional Time-of-Day Adjustments

Additional Customer Charge - per month $21.95 per month

Energy Adjustment - per kWh	On-Peak Hours(2)	Off-Peak Hours(2)
Summer kWh(June-September billing periods)	+0.71¢	-0.40¢
Winter kWh(October-May billing periods)	+0.33¢	-0.17¢

(2) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

* Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE (Cont'd.)

RATE BASED ON MONTHLY METER READINGS (Cont'd.)

Fuel and Purchased Power Adjustment (Rider FAC). Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC). Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

* Payments. Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

Term of Use. One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

SERVICE CLASSIFICATION NO. 12(M)
LARGE TRANSMISSION SERVICE RATE

*RATE BASED ON MONTHLY METER READINGS

Summer Rate (Applicable during four (4) monthly billing periods of June through September)

Customer Charge – per month	$337.28
Low-Income Pilot Program Charge – per month	$1,500.00
Demand Charge – per kW of Billing Demand	$16.20
Energy Charge – per kWh	3.076¢
Reactive Charge – per kVar	40.000¢

Winter Rate (Applicable during eight (8) monthly billing periods of October through May)

Customer Charge – per month	$337.28
Low-Income Pilot Program Charge – per month	$1,500.00
Demand Charge – per kW of Billing Demand	$6.19
Energy Charge – per kWh	2.708¢
Reactive Charge – per kVar	40.000¢

Optional Time-of-Day Adjustments

Additional Customer Charge – per month $21.95

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh (June-September Billing Periods)	+0.71¢	-0.40¢
Winter kWh (October-May Billing Periods)	+0.32¢	-0.17¢

(1) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

Fuel and Purchased Power Adjustment (Rider FAC) Applicable to all metered kilowatt-hours (kWh) of energy.

Energy Efficiency Investment Charge (Rider EEIC) Applicable to all metered kilowatt-hours (kWh) of energy excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

*Energy Line Loss Rate Compensation for customer's energy line losses from use of the transmission system(s) outside Company's control area shall be in the form of energy solely supplied by Company to the transmission owner(s) and compensated by payment at a monthly rate of $0.0416 per kWh after appropriate Rider C adjustment of meter readings.

* Indicates Change.

SERVICE CLASSIFICATION NO. 12(M)
LARGE TRANSMISSION SERVICE RATE (Cont'd.)

* 3. **PAYMENTS**

Bills are due and payable within twenty-one (21) days from date of bill and become delinquent thereafter.

4. **CONTRACT TERM**

A customer taking service under this rate shall agree to an initial Contract Term of 15 years. The Contract Term shall be extended in one-year increments unless or until the contract is terminated at the end of the Contract Term or any annual extension thereof by a written notice of termination given by either party or received not later than five years prior to the date of termination. During the Contract Term, a customer taking service under this rate agrees that Company shall be the exclusive supplier of power and energy to customer's premises, and waives any right or entitlement by virtue of any law, including but not limited to Section 91.026 RSMo as it now exists or as amended from time to time, statute, rule, regulation, or tariff, to purchase, acquire or take delivery of power and energy from any other person or entity.

5. **TAX ADJUSTMENT**

Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

6. **RATE APPLICATION**

This rate shall be applicable, at customer's request, to any customer that 1) meets the Rate Application conditions of the Large Primary Service rate, 2) can demonstrate to Company’s satisfaction that such energy was routinely consumed at a load factor of 95% or higher or that customer will, in the ordinary course of its operations, operate at a similar load factor, 3) if necessary, arranges and pays for transmission service for the delivery of electricity over the transmission facilities of a third party, 4) does not require use of Company’s distribution system or distribution arrangements that are provided by Company at Company’s cost, excepting Company’s metering equipment, for service to customer, and 5) meets all other required terms and conditions of the rate.

7. **CHARACTER OF SERVICE SUPPLIED**

Company will supply a standard three-phase alternating current transmission service voltage. The appropriate adjustments under Rider C will apply; however, there will be no adjustments under Rider B.

* Indicates Change.

SERVICE CLASSIFICATION NO. 13(M)
INDUSTRIAL ALUMINUM SMELTER (IAS) SERVICE RATE

AVAILIBILITY

This rate is only available for electricity consumed at Noranda Aluminum, Inc.'s ("Noranda") aluminum smelting facility in New Madrid County, which immediately prior to the inception of this Service Classification No. 13(M) received service under Service Classification No. 12(M) – Large Transmission Service.

* **RATE BASED ON MONTHLY METER READINGS**

Summer Rate (Applicable during four (4) monthly billing periods of June through September)

Low-Income Pilot Program Charge – per month	$1,500.00
Energy Charge – per kWh	4.756¢

Winter Rate (Applicable during eight (8) monthly billing periods of October through May)

Low-Income Pilot Program Charge – per month	$1,500.00
Energy Charge – per kWh	3.232¢

FUEL AND PURCHASED POWER ADJUSTMENT (RIDER FAC)

Applicable to all metered kilowatt-hours of energy.

The FAR applicable to this Service Classification for all kWh of energy consumed by Noranda prior to the effective date of this rate schedule shall be FAR_{TRAN} (as calculated under Rider FAC applicable to that period).

The FAR applicable to this Service Classification for all kWh consumed by Noranda on and after the effective date of this rate schedule and prior to the date a positive or negative FAR_{IAS} is in effect under Rider FAC, will be the lesser of FAR_{TRAN} (as calculated under the Rider FAC applicable to that period) or $0.00200 per kWh. Thereafter, FAR_{IAS} shall be applicable to all kWh consumed by Noranda.

TERM OF USE

This Service Classification has an initial term of three (3) years and shall remain in effect after the expiration of said term until such time that the Commission orders otherwise in a Company general rate proceeding. However, effective with any order of the Missouri Public Service Commission finding that Noranda failed to materially comply with the terms and conditions applicable to Noranda's option to take service under this Service Classification, as set forth in the Commission's Order in Case No. ER-2014-0258, the rate under this Service Classification shall no longer be available to Noranda and Noranda shall instead take service under the Company's Service Classification 12(M)- Large Transmission Service.

OTHER PROVISIONS

The provisions in paragraphs 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 12 in Service Classification 12(M), Large Transmission Service Rate, shall also apply; provided that use of this optional rate shall not cause a change in the term of the existing contract between Noranda and Company.

* Indicates Change.

MISCELLANEOUS CHARGES

A. Reconnection Charges per Connection Point

Sheet No. 79, Par. B-3 (Annually Recurring Service)	$30.00
Sheet No. 145, Par. I (Reconnection of Service)	$30.00

* B. Supplementary Service Minimum Monthly Charges

Sheet No. 78, Par. C-3

Charges applicable during 4 monthly billing periods of June through September	Primary Service Rate
Customer Charge per month, plus	$337.28
Low-Income Pilot Program Charge – per month	$50.00
All kW @	$21.98

Charges applicable during 8 monthly billing periods of October through May	Primary Service Rate
Customer Charge per month, plus	$337.28
Low-Income Pilot Program Charge – per month	$50.00
All kW @	$9.98

C. Service Call Charge

Customer's reporting service problems may be charged a $50.00 fee for a service call, if it is determined the problem is within the customer's electrical system.

Tax Adjustment Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

* Indicates Change.

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RIDERS

* Indicates Addition.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 11(M), 12(M), and 13(M).

* Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation and emissions costs and revenues, net of off-system sales revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)), and the amount of those costs recovered in base rates (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing no later than sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

Ninety five percent (95%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 95\% \pm I \pm P \pm T]/S_{RP}$$

Where:

ANEC = FC + PP + E – OSSR

FC = Fuel costs and revenues associated with the Company’s generating plants. These consist of the following:

1. For fossil fuel plants:
   A. the following costs and revenues (including applicable taxes) reflected in Federal Energy Regulatory Commission (FERC) Account 501 for: coal commodity, gas, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs, fuel oil adjustments included in commodity and transportation costs, oil costs, ash disposal costs and revenues, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and
   B. the following costs and revenues reflected in FERC Account 502 for: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and powder activated carbon; and
   C. the following costs and revenues reflected in FERC Account 547, excluding fuel costs related to the Company’s landfill gas generating plant known as Maryland Heights Energy Center. Such costs and revenues include natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation, fuel losses, hedging, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; and
2. The following costs and revenues in FERC Account 518 (Nuclear Fuel Expense)for: nuclear fuel commodity expense, waste disposal expense, and nuclear fuel hedging costs.

PP = Purchased power costs and revenues and consists of the following:

1. The following costs and revenues for purchased power reflected in FERC Account 555, excluding all charges under Midwest Independent Transmission System Operator, Inc. ("MISO") Schedules 10, 16, 17 and 24 (or any successor to those MISO Schedules), and excluding generation capacity charges for contracts with terms in excess of one (1) year. Such costs and revenues include:

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

A. MISO costs or revenues for MISO’s energy and operating reserve market settlement charge types and capacity market settlement clearing costs or revenues associated with:
   i. Energy;
   ii. Losses;
   iii. Congestion management:
      a. Congestion;
      b. Financial Transmission Rights; and
      c. Auction Revenue Rights;
   iv. Generation capacity acquired in MISO's capacity auction or market; provided such capacity is acquired for a term of one (1) year or less;
   v. Revenue sufficiency guarantees;
   vi. Revenue neutrality uplift;
   vii. Net inadvertent energy distribution amounts;
   viii. Ancillary Services:
      a. Regulating reserve service (MISO Schedule 3, or its successor);
      b. Energy imbalance service (MISO Schedule 4, or its successor);
      c. Spinning reserve service (MISO Schedule 5, or its successor);and
      d. Supplemental reserve service (MISO Schedule 6, or its successor); and
   ix. Demand response:
      a. Demand response allocation uplift; and
      b. Emergency demand response cost allocation (MISO Schedule 30, or its successor);

B. Non-MISO costs or revenues as follows:
   i. If received from a centrally administered market (e.g. PJM/SPP), costs or revenues of an equivalent nature to those identified for the MISO costs or revenues specified in subpart A of part 1 above;
   ii. If not received from a centrally administered market:
      a. Costs for purchases of energy; and
      b. Costs for purchases of generation capacity, provided such capacity is acquired for a term of one (1) year or less; and

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

C. Realized losses and costs (including broker commissions and fees) minus realized gains for financial swap transactions for electrical energy that are entered into for the purpose of mitigating price volatility associated with anticipated purchases of electrical energy for those specific time periods when the Company does not have sufficient economic energy resources to meet its native load obligations, so long as such swaps are for up to a quantity of electrical energy equal to the expected energy shortfall and for a duration up to the expected length of the period during which the shortfall is expected to exist; and

*2. One and 86/100 percent (1.86%) of transmission service costs reflected in FERC Account 565. Such transmission service costs include:

A. MISO costs and revenues associated with:
   - i. network transmission service (MISO Schedule 9 or its successor);
   - ii. point-to-point transmission service (MISO Schedules 7 and 8 or their successors);
   - iii. System control and dispatch, (MISO Schedule 1 or its successor);
   - iv. Reactive supply and voltage control (MISO Schedule 2 or its successor);
   - v. MISO Schedule 11 or its successor;
   - vi. MISO Schedules 26, 26A, 37 and 38 or their successors; and
   - vii. MISO Schedule 33;
   - viii. MISO Schedules 41, 42-A, 42-B, 45 and 47;

B. Non-MISO costs associated with:
   - i. network transmission service;
   - ii. point-to-point transmission service;
   - iii. System control and dispatch; and
   - iv. Reactive supply and voltage control.

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

E = Costs and revenues for SO_2 and NO_X emissions allowances in FERC Accounts 411.8, 411.9, and 509, including those associated with hedging.

* OSSR = Costs and revenues in FERC Account 447 for:

1. Capacity;
2. Energy;
3. Ancillary services, including:
   A. Regulating reserve service (MISO Schedule 3, or its successor);
   B. Energy Imbalance Service (MISO Schedule 4, or its successor;
   C. Spinning reserve service (MISO Schedule 5, or its successor); and
   D. Supplemental reserve service (MISO Schedule 6, or its successor);
4. Make-whole payments, including:
   A. Price volatility; and
   B. Revenue sufficiency guarantee; and
5. Hedging.

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

For purposes of factors FC, E, and OSSR, “hedging” is defined as realized losses and costs (including broker commissions and fees associated with the hedging activities) minus realized gains associated with mitigating volatility in the Company’s cost of fuel, off-system sales and emission allowances, including but not limited to, the Company’s use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.

* Costs and revenues not specifically detailed in Factors FC, PP, E, or OSSR shall not be included in the Company's FAR filings; provided however, in the case of Factors PP or OSSR the market settlement charge types under which MISO or another centrally administered market (e.g., PJM or SPP) bills/credits a cost or revenue need not be detailed in Factors PP or OSSR for the costs or revenues to be considered specifically detailed in Factors PP or OSSR; and provided further, should the MISO or another centrally administered market (e.g. PJM or SPP) implement a market settlement charge type or schedule not listed in the FAC Charge Type Table included in this Rider (a “new charge type”):

A. The Company may include the new charge type cost or revenue in its FAR filings if the Company believes the new charge type cost or revenue possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be, subject to the requirement that the Company make a filing with the Commission as outlined in B below and also subject to another party’s right to challenge the inclusion as outlined in E. below;

B. The Company will make a filing with the Commission giving the Commission notice of the new charge type no later than 60 days prior to the Company including the new charge type cost or revenue in a FAR filing. Such filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements;

C. The Company will also provide notice in its monthly reports required by the Commission's fuel adjustment clause rules that identifies the new charge type costs or revenues by amount, description and location within the monthly reports;

D. The Company shall account for the new charge type costs or revenues in a manner which allows for the transparent determination of current period and cumulative costs or revenues; and

* Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

E. If the Company makes the filing provided for in B above and a party challenges the inclusion, such challenge will not delay approval of the FAR filing. To challenge the inclusion of a new charge type, a party shall make a filing with the Commission based upon that party’s contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. A party wishing to challenge the inclusion of a charge type shall include in its filing the reasons why it believes the Company did not show that the new charge type possesses the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be, and its filing shall be made within 30 days of the Company’s filing under B above. In the event of a timely challenge, the Company shall bear the burden of proof to support its decision to include a new charge type in a FAR filing. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P; and

F. A party other than the Company may seek the inclusion of a new charge type in a FAR filing by making a filing with the Commission no less than 60 days before the Company’s next FAR filing. Such a filing shall give the Commission notice that such party believes the new charge type should be included because it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR, as the case may be. The party’s filing shall identify the proposed accounts affected by such change, provide a description of the new charge type demonstrating that it possesses the characteristics of, and is of the nature of, the costs or revenues listed in factors PP or OSSR as the case may be, and identify the preexisting market settlement charge type(s) which the new charge type replaces or supplements. If a party makes the filing provided for by this paragraph F and a party (including the Company) challenges the inclusion, such challenge will not delay inclusion of the new charge type in the FAR filing or delay approval of the FAR filing. To challenge the inclusion of a new charge type, the challenging party shall make a filing with the Commission based upon that party’s contention that the new charge type costs or revenues at issue should not have been included, because they do not possess the characteristics of the costs or revenues listed in Factors PP or OSSR, as the case may be. The challenging party shall make its filing challenging the inclusion and stating the reasons why it believes the new charge type does not possess the characteristic of the costs or revenues listed in Factors PP or OSSR, as the case may be, within 30 days of the

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

filing that seeks inclusion of the new charge type. In the event of a timely challenge, the party seeking the inclusion of the new charge type shall bear the burden of proof to support its contention that the new charge type should be included in the Company’s FAR filings. Should such challenge be upheld by the Commission, any such costs will be refunded (or revenues retained) through a future FAR filing in a manner consistent with that utilized for Factor P.

Should FERC require any item covered by factors FC, PP, E or OSSR to be recorded in an account different than the FERC accounts listed in such factors, such items shall nevertheless be included in factor FC, PP, E or OSSR. In the month that the Company begins to record items in a different account, the Company will file with the Commission the previous account number, the new account number and what costs or revenues that flow through this Rider FAC are to be recorded in the account.

B = BF x S_{AP}

*NBEC = the normalized value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), and emissions costs and revenues (consistent with the term E), less revenues from off-system sales (consistent with the term OSSR). The normalized values referred to in the prior sentence shall be those values used to determine the revenue requirement in the Company’s most recent rate case.

*BF = NBEC divided by corresponding normalized retail kWh used to determine the revenue requirement in the Company’s most recent rate case, as adjusted for applicable losses. The BF applicable to June through September calendar months (BF_{SUMMER}) is $0.01679 per kWh. The BF applicable to October through January calendar months ($BF_{WINTER-1}$) is $0.01739 per kWh and applicable to February to May calendar months ($BF_{WINTER-2}$) is $0.01587.

*S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the most recent kWh data for the retail component of the Company’s load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company’s load settled at its MISO CP node (AMMO.UE or successor node).

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

S_{RP} = Applicable RP estimated kWh representing the expected retail component of the Company's load settled at its MISO CP node (AMMO.UE or successor node) plus the metered net energy output of any generating station operating within its certificated service territory as a behind the meter resource in MISO, the output of which served to reduce the Company’s load settled at its MISO CP node (AMMO.UE or successor node).

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews (“P”), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings (“T”) provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company’s short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P = Prudence disallowance amount, if any, as defined below.

T = True-up amount as defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below is calculated as:

$$FAR = FAR_{RP} + FAR_{(RP-1)}$$

where:

FAR = Fuel Adjustment Rate applied to retail customer usage on a per kWh basis starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under– or over-collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component for the under- or over-collection during the Accumulation Period immediately preceding the Accumulation Period that ended immediately prior to the application filing for FAR_{RP}.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

FAR DETERMINATION (Cont'd.)

*The Initial Rate Component For the Individual Service Classifications shall be determined by multiplying the FAR in accordance with the foregoing by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0545
Primary Voltage Service (VAF_{PRI})	1.0234
Transmission Voltage Service (VAF_{TRAN})	1.0327

Customers served by the Company under Service Classification No. 13(M), Industrial Aluminum Smelter (IAS) Service shall be capped such that their FAR_{IAS}, adjusted for applicable voltage service, does not exceed $0.00200/kWh, with FAR_{IAS} to be determined as follows:

FAR_{IAS} = the lesser of $0.00200/kWh or the Initial Rate Component For Transmission Customers

Where the Initial Rate Component for Transmission Customers is greater than $0.00200/kWh, then a Per kWh FAR Shortfall Adder shall apply to each of the respective Initial Rate Components to be determined as follows:

Per kWh FAR Shortfall Adder = (((Initial Rate Component For Transmission Customers– FAR_{IAS}) x S_{IAS}) / (S_{RP} – S_{RP-IAS}))

Where:

S_{IAS} = Estimated Recovery Period IAS kWh sales at the retail meter

S_{RP-IAS} = Estimated Recovery Period IAS kWh sales at the Company’s MISO CP Node (AMMO.UE or successor node)

The FAR Applicable to the Individual Service Classifications shall be determined as follows:

FAR_{SEC} = Initial Rate Component For Secondary Customers + (Per kWh FAR Shortfall Adder x VAF_{SEC})

FAR_{PRI} = Initial Rate Component For Primary Customers + (Per kWh FAR Shortfall Adder x VAF_{PRI})

FAR_{TRAN} = Initial Rate Component For Transmission Customers + (Per kWh FAR Shortfall Adder x VAF_{TRAN})

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

TRUE-UP

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in T above. Interest on the true-up adjustment will be included in I above.

*Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Service Provided On The Effective Date Of This Tariff Sheet And Thereafter)

TRUE-UP (Cont'd.)

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in P above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in I above.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

*FAC CHARGE TYPE TABLE

MISO Energy & Operating Reserve Market Settlement Charge Types and Capacity Market Charges and Credits

DA Asset Energy Amount;
DA Congestion Rebate on Carve-out GFA;
DA Congestion Rebate on Option B GFA;
DA Financial Bilateral Transaction Congestion Amount;
DA Financial Bilateral Transaction Loss Amount;
DA Loss Rebate on Carve-out GFA;
DA Loss Rebate on Option B GFA;
DA Non-Asset Energy Amount;
DA Ramp Capability Amount;
DA Regulation Amount;
DA Revenue Sufficiency Guarantee Distribution Amount;
DA Revenue Sufficiency Guarantee Make Whole Payment Amount;
DA Spinning Reserve Amount;
DA Supplemental Reserve Amount;
DA Virtual Energy Amount;
FTR Annual Transaction Amount;
FTR ARR Revenue Amount;
FTR ARR Stage 2 Distribution;
FTR Full Funding Guarantee Amount;
FTR Guarantee Uplift Amount;
FTR Hourly Allocation Amount;
FTR Infeasible ARR Uplift Amount;
FTR Monthly Allocation Amount;
FTR Monthly Transaction Amount;
FTR Yearly Allocation Amount;
FTR Transaction Amount;
Net Revenue from Voluntary Capacity Auction;
Net Purchase for Voluntary Capacity Auction;
RT Asset Energy Amount;
RT Congestion Rebate on Carve-out GFA;
RT Contingency Reserve Deployment Failure Charge Amount;
RT Demand Response Allocation Uplift Charge;
RT Distribution of Losses Amount;
RT Excessive Energy Amount;
RT Excessive\Deficient Energy Deployment Charge Amount;
RT Financial Bilateral Transaction Congestion Amount;
RT Financial Bilateral Transaction Loss Amount;
RT Loss Rebate on Carve-out GFA;
RT Miscellaneous Amount;
RT Ramp Capability Amount;
Real Time MVP Distribution;
RT Net Inadvertent Distribution Amount;
RT Net Regulation Adjustment Amount;
RT Non-Asset Energy Amount;
RT Non-Excessive Energy Amount;
RT Price Volatility Make Whole Payment;
RT Regulation Amount;
RT Regulation Cost Distribution Amount;
RT Resource Adequacy Auction Amount;
RT Revenue Neutrality Uplift Amount;
RT Revenue Sufficiency Guarantee First Pass Dist Amount;
RT Revenue Sufficiency Guarantee Make Whole Payment Amount;
RT Spinning Reserve Amount;
RT Spinning Reserve Cost Distribution Amount;
RT Supplemental Reserve Amount;
RT Supplemental Reserve Cost Distribution Amount;
RT Virtual Energy Amount;

MISO Transmission Service Settlement Schedules

MISO Schedule 1 (System control & dispatch);
MISO Schedule 2 (Reactive supply & voltage control);
MISO Schedule 7 & 8 (point to point transmission service);
MISO Schedule 9 (network transmission service);
MISO Schedule 11 (Wholesale Distribution);
MISO Schedules 26, 26A, 37 & 38 (MTEP & MVP Cost Recovery);
MISO Schedule 33 (Black Start Service);
MISO Schedule 41 (Charge to Recover Costs of Entergy Strom Securitization);
MISO Schedule 42A (Entergy Charge to Recover Interest);
MISO Schedule 42B (Entergy Credit associated with AFUDC);
MISO Schedule 45 (Cost Recovery of NERC Recommendation or Essential Action);
MISO Schedule 47 (Entergy Operating Companies MISO Transition Cost Recovery);

MISO Charge Types Which Appear On MISO Settlement Statements Represent Administrative Charges And Are Specifically Excluded From The FAC

DA Market Administration Amount;
DA Schedule 24 Allocation Amount;
FTR Market Administration Amount;
Schedule 10 - ISO Cost Recovery Adder;
RT Market Administration Amount;
RT Schedule 24 Allocation Amount;
RT Schedule 24 Distribution Amount;
Schedule 10 - FERC - Annual Charges Recovery;

* Indicates Addition.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)
*FAC CHARGE TYPE TABLE (Cont'd.)

PJM Market Settlement Charge Types

Auction Revenue Rights;
Balancing Operating Reserve;
Balancing Operating Reserve for Load Response;
Balancing Operating Reserve for Load Response;
Balancing Spot Market Energy;
Balancing Transmission Congestion;
Balancing Transmission Losses;
Capacity Resource Deficiency;
Capacity Transfer Rights;
Day-ahead Economic Load Response;
Day-Ahead Load Response Charge Allocation;
Day-ahead Operating Reserve;
Day-ahead Operating Reserve for Load Response;
Day-ahead Spot Market Energy;
Day-ahead Transmission Congestion;
Day-ahead Transmission Losses;
Demand Resource and ILR Compliance Penalty;
Emergency Energy;
Emergency Load Response;
Energy Imbalance Service;
Financial Transmission Rights Auction;
Generation Deactivation;
Generation Resource Rating Test Failure;
Inadvertent Interchange;
Incremental Capacity Transfer Rights;
Interruptible Load for Reliability;
Load Reconciliation for Inadvertent Interchange;
Load Reconciliation for Operating Reserve Charge;
Load Reconciliation for Regulation and Frequency Response Service;
Load Reconciliation for Spot Market Energy;
Load Reconciliation for Synchronized Reserve;
Load Reconciliation for Synchronous Condensing;
Load Reconciliation for Transmission Congestion;
Load Reconciliation for Transmission Losses;
Locational Reliability;
Miscellaneous Bilateral;
Non-Unit Specific Capacity Transaction;
Peak Season Maintenance Compliance Penalty;
Peak-Hour Period Availability;
PJM Customer Payment Default;
Planning Period Congestion Uplift;
Planning Period Excess Congestion;
Ramapo Phase Angle Regulators;
Real-time Economic Load Response;
Real-Time Load Response Charge Allocation;
Regulation and Frequency Response Service;
RPM Auction;
Station Power;
Synchronized Reserve;
Synchronous Condensing;
Transmission Congestion;
Transmission Losses;

PJM Transmission Service Charge Types

Black Start Service;
Day-ahead Scheduling Reserve;
Direct Assignment Facilities;
Expansion Cost Recovery;
Firm Point-to-Point Transmission Service;
Internal Firm Point-to-Point Transmission Service;
Internal Non-Firm Point-to-Point Transmission Service;
Load Reconciliation for PJM Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service Offset;
Non-Firm Point-to-Point Transmission Service;
Non-Zone Network Integration Transmission Service;
Other Supporting Facilities;
PJM Scheduling, System Control and Dispatch Service Refunds;
PJM Scheduling, System Control and Dispatch Services;
Qualifying Transmission Upgrade Compliance Penalty;
Reactive Services;

* Indicates Addition.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

***FAC CHARGE TYPE TABLE (Cont'd.)**

PJM Transmission Service Charge Types (Cont'd.)

Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund;
Load Reconciliation for Reactive Services;
Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service;
Network Integration Transmission Service;
Network Integration Transmission Service (exempt);
Reactive Supply and Voltage Control from Generation and Other Sources Service;
Transmission Enhancement;
Transmission Owner Scheduling, System Control and Dispatch Service;
Unscheduled Transmission Service;

PJM Charge Types Which Appear On The Settlement Statements Represent Administrative Charges Are Specifically Excluded From The FAC

Annual PJM Building Rent;
Annual PJM Cell Tower;
FERC Annual Charge Recovery;
Load Reconciliation for FERC Annual Charge Recovery;
Load Reconciliation for North American Electric Reliability Corporation (NERC);
Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding;
Load Reconciliation for Reliability First Corporation (RFC);
Market Monitoring Unit (MMU) Funding;
Michigan - Ontario Interface Phase Angle Regulators;
North American Electric Reliability Corporation (NERC);
Organization of PJM States, Inc. (OPSI) Funding;
PJM Annual Membership Fee;
PJM Settlement, Inc.;
Reliability First Corporation (RFC);
RTO Start-up Cost Recovery;
Virginia Retail Administrative Fee;

* Indicates Addition.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (Cont'd.)

(Applicable To Calculation of Fuel Adjustment Rate for the Billing Months of XXXXXX 2017 through XXXXX 2017)

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending:

1.	Actual Net Energy Cost = (ANEC) (FC+PP+E-OSSR)		$
2.	(B) = (BF x S_{AP})	-	$
	2.1 Base Factor (BF)		$/kWh
	2.2 Accumulation Period Sales (S_{AP})		kWh
3.	Total Company Fuel and Purchased Power Difference	=	$
	3.1 Customer Responsibility	x	95%
4.	Fuel and Purchased Power Amount to be Recovered	=	$
	4.1 Interest (I)	-	$
	4.2 True-Up Amount (T)	+	$
	4.3 Prudence Adjustment Amount (P)	±	$
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$0.00000/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$0.00000/kWh
9.	Fuel Adjustment Rate (FAR)	=	$0.00000/kWh

Initial Rate Component For the Individual Service Classifications

10.	Secondary Voltage Adjustment Factor (VAF_{SEC})		1.0545
11.	Initial Rate Component for Secondary Customers		$0.00000/kWh
12.	Primary Voltage Adjustment Factor (VAF_{PRI})		1.0234
13.	Initial Rate Component for Primary Customers		$0.00000/kWh
14.	Transmission Voltage Adjustment Factor (VAF_{TRAN})		1.0327
15.	Initial Rate Component for Transmission Customers		$0.00000/kWh

FAR Applicable to the Individual Service Classifications

16.	FAR for Industrial Aluminum Smelter Service (FAR_{IAS}) (The lesser of $0.00200/kWh or Line 15)		$0.00000/kWh
17.	Difference (Line 15 – Line 16)	=	$0.00000/kWh
18.	Estimated Recovery Period Metered Sales for IAS (S_{IAS})		0 kWh
19.	FAR Shortfall Adder (Line 17 x Line 18)		$0
20.	Per kWh FAR Shortfall Adder (Line 19 / (Line 6 – S_{RP-IAS}))	=	$0.00000/kWh
21.	FAR for Secondary Customers (FAR_{SEC}) (Line 11 + (Line 20 x Line 10))	=	$0.00000/kWh
22.	FAR for Primary Customers (FAR_{PRI}) (Line 13 + (Line 20 x Line 12))	=	$0.00000/kWh
23.	FAR for Transmission Customers (FAR_{TRAN}) (Line 15 + (Line 20 x Line 14))	=	$0.00000/kWh

*Indicates Change.

RIDER B

DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP

Where a customer served under rate schedules 4(M) or 11 (M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:

*1. A monthly credit of $1.28/kW of billing demand for customers taking service at 34.5 or 69kV.

*2. A monthly credit of $1.52/kW of billing demand for customers taking service at 115kV or higher.

*Indicates Change.

RIDER E

SUPPLEMENTARY SERVICE

A. DEFINITION

Where the service supplied by Company is available in the event of failure or shutdown of customer's private plant service or any other source of electrical energy or motive power through electrical or mechanical means or by means of operational procedure, or where the service in effect serves to relieve, sustain or augment any other source of power, such service shall constitute Supplementary Service.

*** B. AVAILABILITY**

Supplementary Service will be supplied whenever, in the opinion of the Company, it will have capacity available for the supply of such service during the term of the proposed Electric Service Agreement. This Rider is limited to those customers receiving service prior to July 31, 2016. After July 31, 2016 all new customers or those customer(s) on Rider E who experience a significant change to the customer's generating equipment shall have Supplementary Service supplied under Standby Service.

C. RATE FOR SERVICE

1. Supplementary Service will be delivered to customer under the Primary Service Rate at a primary service voltage to be selected by Company. All provisions of the Primary Service Rate under which supplementary service is to be supplied shall remain in effect, except as hereinafter specifically provided.

2. Electric service actually used each month shall be charged for under the applicable rate specified in customer's Electric Service Agreement.

3. The monthly bill to be paid by customer, whether or not any electric service is actually used, shall in no case be less than the minimum charge specified in the applicable rate or the amount based on the Contract Demand (as hereinafter defined) computed on the schedule of charges set forth on Sheet No. 63, Miscellaneous Charges, whichever is greater.

D. GENERAL PROVISIONS

1. Contract Demand is defined as the higher of either:

   a. The number of kilowatts mutually agreed upon by Company with customer as representing customer's maximum service requirements under all conditions of use, and such demand shall be specified in customer's Electric Service Agreement; or

   b. The maximum demand established by customer in use of Company's service.

* Indicates Change.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE
For MEEIA Cycle 2 Plan

APPLICABILITY

This Rider EEIC – Energy Efficiency Investment Charge (Rider EEIC) is applicable to all kilowatt-hours (kWh) of energy supplied to customers served under Company's Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 11(M), and 12(M), excluding kWh of energy supplied to "opt-out" or "low-income" customers.

* Ameren Missouri will work with Community Action Agencies to establish a mechanism by which these agencies can provide information regarding which customers are recipients of Low Income Home Energy Assistance Program (LIHEAP) assistance, regardless of the fuel source for which the assistance was applicable. An Ameren Missouri low-income customer who has received assistance from Missouri Energy Assistance (a.k.a. LIHEAP), Winter Energy Crisis Intervention Program, or Summer Energy Crisis Intervention Program and (i) whose account has not automatically been exempted from Rider EEIC, or (ii) who has been charged Rider EEIC charges and whose account has not been credited for said charges, may provide the Company, via facsimile to **866.297.8054**, via email to **myhomeamerenmissouri@ameren.com**, or via regular mail to **Ameren Missouri, P.O. Box 790352, St. Louis, MO 63179-0352**

a. documentation of the assistance received in the form of:
   i. a copy of the Division of Social Services Family Support Division ("DSSFSD") form EA-7 energy assistance payment notice received by the low-income customer, or
   ii. a copy of the DSSFSD LIHEAP Energy Assistance direct payment check received by the low-income customer, or
   iii. a copy of the Contract Agency energy crisis intervention program ("ECIP") payment notification letter received by the low-income customer, or
   iv. a printout of the low-income customer's DSSFSD LIHEAP EA E1RG System Registration screen identifying the supplier, benefit amount and payment processing date.

b. Upon receipt of the documentation, the Company will credit the low-income customer's account for:
   i. energy efficiency investment charges, and
   ii. any municipal charges attributable to said EEIC charges, that were previously charged to the low-income customer within twelve billing months following the documented receipt of energy assistance; provided that the low-income customer shall not be entitled to any credit, nor shall Company credit the low-income customer, for energy efficiency investment charges and associated municipal charges incurred and billed prior to the June 2015 commencement of the low-income exemption.

c. Upon receipt of the documentation, for the remainder of the twelve months following the documented receipt of energy assistance, the Company will exempt such low-income customer from any Rider EEIC charges thereafter imposed. The exemption will be evidenced on the low-income customer's bill as an EEIC charge, followed by a credit.

Charges passed through this Rider EEIC reflect the charges approved to be billed from the implementation of the Missouri Energy Efficiency Investment Act (MEEIA) 2016-18 Plan and any remaining unrecovered balances from the MEEIA 2013-15 plan. Those charges include:

* Indicates Change.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA Cycle 2 Plan

ENERGY EFFICIENCY INVESTMENT RATE (EEIR) DETERMINATION

The EEIR during each applicable EP is a dollar per kWh rate for each applicable Service Classification calculated as follows:

EEIR = [NPC + NTD + NEO + NOA]/PE

Where:

NPC = Net Program Costs for the applicable EP as defined below,

NPC = PPC + PCR

* PPC = Projected Program Costs is an amount equal to Program Costs projected by the Company to be incurred during the applicable EP, including Company's Energy Efficiency Department's internal labor cost and associated benefits.

* PCR = Program Costs Reconciliation is equal to the cumulative difference, if any, between the PPC revenues billed resulting from the application of the NPC component of the EEIR and the actual Program Costs, including Company's Energy Efficiency Department's internal labor cost and associated benefits, incurred through the end of the previous EP (which will reflect projections through the end of the previous EP due to timing of adjustments). Such amounts shall include monthly interest charged at the Company's monthly short-term borrowing rate. Any remaining PCR balance from MEEIA Cycle 1 shall be rolled into the PCR calculation starting February 2017.

NTD = Net Throughput Disincentive for the applicable EP as defined below,

NTD = PTD + TDR

PTD = Projected Throughput Disincentive is the Company's TD projected by the Company to be incurred during the applicable EP. For the detailed method for calculating the TD, see Sheet 91.6.

TDR = Throughput Disincentive Reconciliation is equal to the cumulative difference, if any, between the PTD revenues billed during the previous EP resulting from the application of the NTD component of the EEIR and the Company's TD through the end of the previous EP (which will reflect projections through the end of the previous EP due to timing of adjustments). Such amounts shall include monthly interest charged at the Company's monthly short-term borrowing rate. Any remaining TDR balance from MEEIA Cycle 1 shall be rolled into the TDR calculation starting February 2017.

NEO = Net Earnings Opportunity for the applicable EP as defined below,

NEO = EO + EOR

EO = Earnings Opportunity is equal to the Earnings Opportunity Award monthly amortization multiplied by the number of billing months in the applicable EP.

* Indicates Change.

RIDER EEIC
ENERGY EFFICIENCY INVESTMENT CHARGE (Cont'd.)
For MEEIA Cycle 2 Plan

TD DETERMINATION (Cont'd.)

c. For Measures under the –Business Custom Incentive Program, Business New Construction Incentive Program, and Business Retro-Commissioning Program, the ME will be the annual value attributable to the installations reported monthly by the program implementer.

CM = Current calendar month.

CAS = Cumulative sum of MAS of all prior calendar months for each End Use Category for the MEEIA 2016-18 Plan.

PM = Prior calendar month.

RB = Rebasing Adjustment. The RB shall equal the CAS applicable as of the date used for MEEIA normalization when base rates are adjusted in any general electric rate case or otherwise resulting in new retail electric rates becoming effective during the accrual and collection of TD pursuant to this MEEIA 2016-18 Plan. In the event base rates are adjusted by more than one general electric rate case or otherwise resulting in new rates becoming effective during the accrual and collection of TD pursuant to this MEEIA 2016-18 Plan occurs, the RB adjustment shall include each and every prior RB adjustment calculation.

LS = Load Shape. The LS is the monthly load shape percent (%) for each End-Use Category (attached as Appendix E to the Stipulation).

*NMR = Net Margin Revenue. NMR values for each applicable Service Classification are as follows:

	Service Classifications				
Month	1(M)Res $/kWh	2(M)SGS $/kWh	3(M)LGS $/kWh	4(M)SPS $/kWh	11(M)LPS $/kWh
January	0.046615	0.051423	0.041326	0.032592	0.022981
February	0.048909	0.052795	0.043663	0.034426	0.025636
March	0.051054	0.055339	0.044589	0.034846	0.025034
April	0.053222	0.057800	0.045251	0.034576	0.024971
May	0.055832	0.059580	0.045948	0.035680	0.025414
June	0.108580	0.097180	0.085785	0.064718	0.038172
July	0.108580	0.097180	0.083861	0.064199	0.039335
August	0.108580	0.097180	0.083820	0.064699	0.038788
September	0.108580	0.097180	0.084412	0.064280	0.039015
October	0.050982	0.056241	0.043317	0.033543	0.024170
November	0.054323	0.057716	0.044022	0.033712	0.023931
December	0.049395	0.054672	0.042713	0.033117	0.023350

* Indicates Change.

RIDER SSR

STANDBY SERVICE RIDER

APPLICABILITY

Applicable to each customer not currently served by Rider E, at a single premises with behind the meter on-site parallel distributed generation and/or storage system(s) with a capacity over 100 kilowatts (kW), as a modification to standard electric service supplied under either the tariffed rate schedules of Large General Service 3(M), Small Primary Service 4(M), or Large Primary Service 11(M). Customers with emergency backup, solar or wind generation that is not integrated with a storage system are excluded from this Rider.

DEFINITIONS

DISTRIBUTED GENERATION AND/OR STORAGE - Customer's private on-site generation and/or storage that:

1. is located behind the meter on the customer's premises,
2. has a rated capacity of greater than 100 kW,
3. operates in parallel with the Company's system, and
4. adheres to applicable interconnection agreement entered into with the Company.

SUPPLEMENTAL SERVICE - Electric service provided by the Company to customer to supplement normal operation of the customer's on-site parallel distributed generation and/or storage in order to meet the customer's full service requirements.

STANDBY SERVICE - Service supplied to the premises by the Company in the event of the customer exceeding its Supplemental Contract Capacity. Standby Service may be needed on either a scheduled or unscheduled basis. Standby Service comprises capacity and associated energy during the time it is used.

1. BACKUP SERVICE - Unscheduled Standby Service.
2. MAINTENANCE SERVICE - Scheduled Standby Service.

BACK-UP SERVICE - The portion of Standby Contract Capacity and associated energy used without advance permission from the Company. The customer must notify the Company within thirty (30) minutes of taking Back-up Service for amounts over five (5) megawatts (MW). For Back-up Service billed, the customer shall be charged the daily standby demand charge for back-up service and back-up energy charges associated with Standby Service. The rates for these charges as well as the monthly fixed charges are stated in this Rider. Back-up Service charges will be shown and calculated separately on the customer bill.

MAINTENANCE SERVICE - The portion of Standby Contract Capacity used with advance permission from the Company. The customer must schedule Maintenance Service with the Company not less than six (6) days prior to its use. Unless otherwise agreed to by the Company, Maintenance Service shall be limited to not more than six (6) occurrences and not more than sixty (60) total and partial days during twelve (12) consecutive billing periods (based on billing dates). Maintenance Service may be available during all months and shall not be greater than the seasonal Standby Contract Capacity.

RIDER SSR

STANDBY SERVICE RIDER (Cont'd.)

DEFINITIONS (Cont'd.)

MAINTENANCE SERVICE (Cont'd.) - The scheduling of Maintenance Service may be restricted by the Company during times associated with system peaking conditions or other times as necessary. For Maintenance Service billed, the customer shall be charged the daily standby demand charge for maintenance service associated with Standby Service Demand. The rates for these daily demand charges as well as the monthly fixed charges are stated in this Rider. Energy charges for Maintenance Service associated with the Standby Service will be billed as standard energy charges per the applicable tariffed rate schedule. Maintenance Service charges will be shown and calculated separately on the customer bill.

SUPPLEMENTAL CONTRACT CAPACITY - The customer must designate and contract by season the maximum amount of demand, in kW, taken at the premises through the billing meter that may be billed on the applicable standard tariffed rate. The Supplemental Contract Capacity shall insofar as possible estimate the historic or probable loads of the facility as adjusted for customer generation and shall be mutually agreeable to customer and Company.

STANDBY CONTRACT CAPACITY - The higher of:

1. The number of kilowatts mutually agreed upon by Company with customer as representing the customer's maximum service requirements under all conditions of use less Supplemental Contract Capacity, and such demand shall be specified in customer's Electric Service Agreement. Such amount shall be seasonally designated and shall not exceed the nameplate rating(s) of the customer's own generation. The amount of Standby Contract Capacity will generally consider the seasonal (summer or winter billing periods) capacity ratings and use of the generator(s), or may be selected based on a Company approved load shedding plan.

2. The maximum demand established by customer in use of Company's service less the Supplemental Contract Capacity.

SUPPLEMENTAL DEMAND - The lesser of:

1. Supplemental Contract Capacity or
2. The Total Billing Demand in this Rider.

STANDBY SERVICE DEMAND - The Total Billing Demand as determined in this Rider in excess of the Supplemental Contract Capacity.

TOTAL BILLING DEMAND - Total Billing Demand for purposes of this Rider during shall be the maximum 15 minute demand established during peak hours or 50% of the maximum 15 minute demand established during off-peak hours, whichever is greater, but in no event less than 100 kW for Large General Service or Small Primary Service, nor less than 5,000 kW for Large Primary Service.
Peak and off-peak hours are defined as follows:

Peak hours: 10:00 A.M. to 10:00 P.M.,
Monday through Friday

RIDER SSR

STANDBY SERVICE RIDER (Cont'd.)

DEFINITIONS (Cont'd.)

Off-peak hours: All other hours including the entire 24 hours of the tariffed holidays as defined in the base tariff. All times stated above apply to the local effective time.

GENERAL PROVISIONS

The contract term shall be one (1) year, automatically renewable, unless usage, plant modifications or additional generation requires a change to Supplemental Contract Capacity or Standby Contract Capacity.

The Company will install and maintain the necessary suitable meters for measurement of service rendered hereunder. The Company may inspect generation logs or other evidence that the customer's generator is being used in accordance with the provisions this Rider.

Power production equipment at the customer site shall not commence parallel operation until after inspection by the Company and a written interconnection agreement is executed. The sale of excess energy to the Company may be included in the interconnection or other agreement.

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 addition to the charges in the applicable rate schedule, customers taking service under this Rider will be subject to the applicable Administrative Charge, Generation and Transmission Access Charges, and the Facilities Charge each month contained herein.

In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this Rider.

In the event a customer adds distributed generation and/or storage after investments are made by the Company in accordance with the net revenue test described in 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.

Fuel and Purchased Power Adjustment (Rider FAC). Applicable to all billed kilowatt-hours (kWh) of energy under this Rider.

Energy Efficiency Investment Charge (Rider EEIC). Applicable to all billed kilowatt-hours (kWh) of energy under this Rider excluding kWh of energy supplied to customers that have satisfied the opt-out provisions of Section 393.1075, RSMo.

RIDER SSR

STANDBY SERVICE RIDER (Cont'd.)

STANDBY RATE			
	Large General Service	**Small Primary Service**	**Large Primary Service**
Standby Fixed Charges			
Administrative Charge	$199.00/month	$199.00/month	$199.00/month
Generation and Transmission Access Charge per month per kW of Contracted Standby Demand	$0.70/kW	$0.70/kW	$0.87/kW
Facilities Charge per month per kW of Contracted Standby Demand: Summer Winter	 $3.87/kW $0.92/kW	 $2.99/kW $0.55/kW	 $2.99/kW $0.55/kW
Daily Standby Demand Rate – Summer			
Per kW of Daily Standby Service Demand: Back-Up Maintenance	 $0.04/kW $0.02/kW	 $0.04/kW $0.02/kW	 $1.21/kW $0.60/kW
Daily Standby Demand Rate - Winter			
Per kW of Daily Standby Service Demand: Back-Up Maintenance	 $0.02/kW $0.01/kW	 $0.02/kW $0.01/kW	 $0.57/kW $0.29/kW
Back-Up Energy Charges – Summer			
kWh in excess of Supplemental Contract Capacity On-Peak Off-Peak	 12.45¢/kWh 10.40¢/kWh	 11.74¢/kWh 10.25¢/kWh	 4.41¢/kWh 3.30¢/kWh
Back-Up Energy Charges – Winter			
kWh in excess of Supplemental Contract Capacity On-Peak Off-Peak	 7.42¢/kWh 6.80¢/kWh	 7.14¢/kWh 6.60¢/kWh	 3.60¢/kWh 3.10¢/kWh
High Voltage Facilities Charge Discount			
Facilities Charge Credit per month per kW of Contracted Standby Demand @ 34.5 or 69kV @ 115kV or higher	 N/A N/A	 $1.28/kW $1.52/kW	 $1.28/kW $1.52/kW

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GENERAL RULES & REGULATIONS (Cont'd.)

*Indicates Change.

GENERAL RULES AND REGULATIONS

IV. MEASUREMENT OF SERVICE (Cont'd.)

*** C. MULTIPLE METERED ACCOUNT BILLING**

Where more than one meter is installed for metering the premises of an individual account in accordance with paragraphs A and B above, the sum of each watthour meter's kilowatt-hour usage and each demand meter's individual maximum non-simultaneous kilowatt demand will be used for billing purposes. Under all circumstances involving multiple metered accounts, any alternating current watthour meter registering zero usage in a given billing month shall be subject to the monthly charge for three phase meters, specified in paragraph B of this Section IV, during each month of zero usage.

*** D. METER INSPECTIONS AND TESTING**

Company's meters shall be inspected and tested for accuracy in accordance with applicable Missouri Public Service Commission Rules. If customer requests a meter test within 12 months of any previous testing of such meter, a standard charge based on meter type will be assessed for meters found to have an average meter error of 2 percent or less.

* Indicates Reissue.

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PILOTS, VARIANCES AND PROMOTIONAL PRACTICES

* Indicates Addition.

PILOTS, VARIANCES, AND PROMOTIONAL PRACTICES

D. KEEPING CURRENT LOW-INCOME PILOT PROGRAM

PURPOSE

The purpose of the Keeping Current Low-Income Pilot Program (Program) is to provide electric bill payment assistance to customers meeting the eligibility requirements while assessing the delivery methods used in the Program and the impacts on revenues and costs. This Program is provided pursuant to the Stipulation and Agreement Regarding Ameren Missouri's Keeping Current Program approved by the Missouri Public Service Commission (MoPSC) in Case No. ER-2012-0166.

AVAILABILITY

Availability of this Program shall be limited to customers on the Residential Service Rate 1(M) who a) have an income level at or below 125% of the Federal Poverty Level (FPL) for the heating provisions or b) up to 135% of the FPL who use electricity for cooling and are either elderly, disabled, or with a chronic medical condition, or live in households with children five (5) years of age or younger. No customer with an arrearage that includes a theft of service charge shall be eligible to participate in the Program.

DEFINITIONS

Collaborative – Signatories to the Stipulation and Agreement Regarding Ameren Missouri's Keeping Current Program in Case No. ER-2012-0166 which include the Company, MoPSC Staff, Office of the Public Counsel (OPC), Missouri Industrial Energy Consumers (MIEC), AARP and Consumers Council of Missouri.

PROVISIONS

* Pursuant to the Order issued by the MoPSC in Case No. ER-2016-0179, the Company will provide $500,000 annually, in twelve monthly installments each Program year, to finance the Program. An additional amount of approximately $563,000 will be collected through the Low-Income Pilot Program Charge in the Company's 1(M), 2(M), 3(M), 4(M), 11(M), and 12(M) tariffs and contributed to the Program. The Program will be implemented through the Company's existing Keeping Current Agencies in cooperation with the Collaborative.

Credits will be provided through Monthly Heating Bill Credits and/or Monthly Arrearage Bill Credits and/or Keeping Cool Bill Credits as listed below to customers meeting the income limits above and the general qualifications listed below as well as the qualifications for each provision:

1. Customer must be registered with a designated Keeping Current Agency.
2. Customer will apply for weatherization and LIHEAP assistance.

* Indicates Change.

PILOTS, VARIANCES AND PROMOTIONAL PRACTICES

F. VOLUNTARY ELECTRONIC BILL RENDERING AND PAYMENT PROGRAM

* **AVAILABILITY**

This program will be made available on a voluntary basis to customers who are billed under Service Classifications No. 1(M) or No. 2(M) provided customer has access to an electronic device capable of downloading Internet content.

* **GENERAL DESCRIPTION**

This program will permit the Company to deliver to program participants, including participants in the Company's Budget Bill Plan, an electronic image of a bill through the use of the Internet, instead of mailing or hand delivery of a bill. As part of the enrollment process, the customer will choose a login identification number and a password as a means to prevent others from viewing the customer's bills. Customers participating in this program will have to affirmatively elect the discontinuation of mailed or hand delivered bills.

Company will provide the customer's account data to CheckFree ("vendor") or its successor, which will in turn format this data into a bill layout. This electronic bill layout may not exactly resemble the customer's paper bill layout.

The Company or the designated vendor will present the bill to the customer via the Internet and, also, provide the customer a means to pay the bill via the Internet. However, customers may continue to pay the bill via all payment options available to those not participating in the program.

** **ELECTRONIC BILL CREDIT**

Customers participating in this program will have a forty-cent ($0.40) per month credit applied to their bills.

TERM

Customers may terminate participation in this program at any time.

* Indicates Change. **Indicates Addition.

ECONOMIC REDEVELOPMENT AND EFFICIENT INFRASTRUCTURE UTILIZATION PILOT

PURPOSE

The purpose of this Economic Redevelopment and Efficient Infrastructure Utilization Pilot ("Pilot") is to encourage redevelopment of certain sites in the Company's service territory. Projects eligible for service under this Pilot shall be designed to provide more efficient utilization of Company's existing infrastructure in a manner beneficial to the electric delivery system, and which may also provide socio-economic benefits to the areas in which they locate.

DEFINITIONS

"Collaborative" – Ameren Missouri ("Company"), Missouri Public Service Commission Staff ("Staff"), Office of the Public Counsel ("OPC") and other intervening parties in File No. ER-2016-0179 who have provided the Company with a written request to be a Collaborative member, provided, that a Collaborative member may choose to resign as a member at any time.

AVAILABILITY

This Pilot is available to any city, village, incorporated town, or county ("Governmental Entity")or other entity created by such Governmental Entity, to encourage the redevelopment of blighted or conservation areas.

Discounts under this Pilot are available for a redevelopment project provided that:

1) The Governmental Entity makes a determination that the proposed redevelopment area is classified as "blighted" or a "conservation" area in accordance with either Chapter 353 Urban Redevelopment Corporations (CH 353 RSMO); Tax Increment Financing (99.800-99.865 RSMO); Land Clearance for Redevelopment Authority (LCRA) (99.300-99.660 RSMO); or Community Improvement District (CID) (67.1401-67.1475 RSMO) and

2) The Governmental Entity makes a determination that but for the adoption of the redevelopment plan, the redevelopment area would not reasonably be anticipated to be developed, and

3) The Governmental Entity approves a redevelopment plan including a description of the designated redevelopment area (including boundaries), proposed redevelopment projects and uses therein, and

4) The Governmental Entity adopts an ordinance approving the designation of the redevelopment boundaries, the redevelopment plan and proposed redevelopment projects.

5) The Governmental Entity or authorized entity has submitted the above information to the Company and has received written acknowledgement from the Company that the identified redevelopment area meets the availability criteria of this Pilot.

ECONOMIC REDEVELOPMENT AND EFFICIENT INFRASTRUCTURE UTILIZATION PILOT (Cont'd.)

PROVISIONS

The Company is responsible to actively work with Governmental Entities or other authorized entity to identify eligible projects. Such projects and relevant information about each project shall be presented by the Company to the other members of the Collaborative. Decisions made by the Collaborative shall be based on voting by the members present at the meeting when decisions are being made. Collaborative members shall be notified at least 48 hours in advance of any meeting in which voting will take place. Meetings may occur in person or by telephone. A majority vote of a quorum of Collaborative members attending the meeting shall approve an action.

Upon request by a Governmental Entity or other authorized entity for discounts under this Pilot, the Company shall present a package of proposed electric rate discounts to the Collaborative for approval. If any discounts are approved by the Collaborative the Company shall submit an explanation of the approved discounts to the Governmental Entity or other authorized entity so that those discounts can be incorporated into the decision-making about redevelopment execution plans.

This Pilot is subject to the following limitations:

1) This Pilot is available for premises that are either unoccupied or otherwise dormant (e.g. vacant land and/or buildings) for a minimum period of one hundred-twenty (120) days.
2) Expansion of electric service to existing customers within a redevelopment is also eligible for discounts under this Pilot, but such discounts are only applicable to the incremental electric load.
3) Service under this Pilot is limited to loads which in the Collaborative’s judgment utilize existing infrastructure in a manner which is beneficial to the local electric service delivery system.
4) As a general rule, this Pilot is not intended for electric service to a customer that results merely from load shifted from one location on Company’s system to a qualifying site; however, exceptions to this rule may be granted by the Collaborative.
5) This Pilot shall expire on the earlier of June 1, 2022 or the date on which the funding cap is reached.

DISCOUNTS

1) Discounts may be provided in the form of: a) reduced rates for electric service to those customers in the redevelopment area or b) discounted facility and/or relocation charges associated with modifications to local distribution facilities.
2) The Company shall present each eligible project to the Collaborative with an assessment of its impact on the local distribution system and a recommended discount scheme based on the circumstances of that specific project. The Collaborative will determine the final discounts offered for each project as well as the terms of such discounts.
3) The total discounts awarded under this Pilot shall not exceed $10 million.

ECONOMIC REDEVELOPMENT AND EFFICIENT INFRASTRUCTURE UTILIZATION PILOT (Cont'd.)

TERMS AND CONDITIONS

Customers participating in this Pilot will be ineligible for participation in any other economic development, economic retention, or similar tariff of the Company.

Notwithstanding the above, this Pilot shall immediately become void, and the Company shall have no further obligations or liabilities hereunder, if any term or terms of this Pilot are determined to be discriminatory or otherwise unlawful by a court of competent jurisdiction. The expectation is that the discounts approved by the Collaborative will not be imputed when setting rates in future general rate proceedings.

REPORTING AND EVALUATION

The Company shall file, in the Commission's Electronic Filing Information System ("EFIS"), an annual report summarizing the activities conducted under this Pilot. Such report shall include the following information: a physical description of each project evaluated, the infrastructure assessment performed for each project, the status of each project, the amount of capital investment associated for each project area, the amount of temporary and full-time jobs expected for each project area, a qualitative description of socio-economic benefits expected for each project, an assessment of the economic benefit expected for all other Company customers, and any other information that the Collaborative deems relevant.

AMEREN MISSOURI
CLASS RATE OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED MARCH 2016

	TITLE: SUMMARY EQUAL ROR ($000's)	MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LIGHTING COMPANY OWNED	LIGHTING CUST. OWNED
1	BASE REVENUE	$ 2,864,350	$ 1,467,076	$ 319,821	$ 814,698	$ 218,263	$ 36,167	$ 8,325
2	OTHER REVENUE	$ 84,601	$ 44,736	$ 9,370	$ 23,237	$ 5,707	$ 1,337	$ 214
3	LIGHTING REVENUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 525,489	$ 212,311	$ 55,558	$ 193,296	$ 61,561	$ 1,782	$ 981
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 3,474,440	$ 1,724,123	$ 384,749	$ 1,031,231	$ 285,531	$ 39,286	$ 9,520
7								
8	TOTAL PROD., T&D, CUSTOMER, AND A&G EXP.	$ 2,001,082	$ 941,179	$ 216,772	$ 633,773	$ 187,170	$ 16,691	$ 5,496
9	TOTAL DEPR. AND AMMOR. EXPENSES	$ 532,300	$ 285,514	$ 60,432	$ 141,573	$ 34,432	$ 8,928	$ 1,421
10	REAL ESTATE AND PROPERTY TAXES	$ 151,461	$ 81,920	$ 17,479	$ 39,399	$ 9,597	$ 2,664	$ 403
11	INCOME TAXES	$ 214,781	$ 113,053	$ 24,512	$ 58,877	$ 14,765	$ 2,987	$ 587
12	PAYROLL TAXES	$ 19,846	$ 10,340	$ 2,216	$ 5,479	$ 1,416	$ 297	$ 98
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,919,470	$ 1,432,006	$ 321,412	$ 879,101	$ 247,380	$ 31,567	$ 8,004
17								
18	NET OPERATING INCOME	$ 554,970	$ 292,117	$ 63,337	$ 152,130	$ 38,150	$ 7,719	$ 1,516
19								
20	GROSS PLANT IN SERVICE	$ 16,976,734	$ 9,175,591	$ 1,956,940	$ 4,422,920	$ 1,078,043	$ 297,616	$ 45,623
21	RESERVES FOR DEPRECIATION	$ 7,461,799	$ 4,116,234	$ 860,268	$ 1,861,138	$ 448,118	$ 156,483	$ 19,559
22								
23	NET PLANT IN SERVICE	$ 9,514,935	$ 5,059,357	$ 1,096,672	$ 2,561,782	$ 629,926	$ 141,133	$ 26,065
24								
25	MATERIALS & SUPPLIES - FUEL	$ 317,381	$ 128,230	$ 33,556	$ 116,745	$ 37,181	$ 1,076	$ 592
26	MATERIALS & SUPPLIES -LOCAL	$ 206,340	$ 136,892	$ 24,391	$ 30,970	$ 4,905	$ 8,698	$ 484
27	CASH WORKING CAPITAL	$ 34,400	$ 16,180	$ 3,726	$ 10,895	$ 3,218	$ 287	$ 94
28	CUSTOMER ADVANCES & DEPOSITS	$ (27,473)	$ (11,689)	$ (8,245)	$ (6,552)	$ -	$ (987)	$ (0)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (2,850,326)	$ (1,541,637)	$ (328,928)	$ (741,452)	$ (180,604)	$ (50,126)	$ (7,579)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 7,195,256	$ 3,787,332	$ 821,172	$ 1,972,389	$ 494,626	$ 100,082	$ 19,655
32								
33	RATE OF RETURN	7.713%	7.713%	7.713%	7.713%	7.713%	7.713%	7.713%
34								
35								
36	IMPLIED COST-BASED RATE INCREASE	7.77%	16.9%	3.3%	-3.4%	4.2%	-1.1%	119.9%

AMEREN MISSOURI
CLASS RATE OF RETURN ANALYSIS
TEST YEAR: 12 MONTHS ENDED MARCH 2016

TITLE: SUMMARY CURRENT ROR RESULTS ($000'S)

		MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE G.S. / SMALL PRIMARY	LARGE PRIMARY	LIGHTING COMPANY OWNED	LIGHTING CUST. OWNED
1	BASE REVENUE	$ 2,657,947	$ 1,255,086	$ 309,643	$ 843,330	$ 209,532	$ 36,571	$ 3,786
2	OTHER REVENUE	$ 84,601	$ 44,736	$ 9,370	$ 23,237	$ 5,707	$ 1,337	$ 214
3	LIGHTING REVENUE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	SYSTEM, OFF-SYS SALES & DISP OF ALLOW	$ 525,489	$ 212,311	$ 55,558	$ 193,296	$ 61,561	$ 1,782	$ 981
5	RATE REVENUE VARIANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL OPERATING REVENUE	$ 3,268,037	$ 1,512,133	$ 374,571	$ 1,059,863	$ 276,800	$ 39,690	$ 4,980
7								
8	TOTAL PROD, T&D, CUST, AND A&G EXP	$ 2,001,082	$ 941,179	$ 216,772	$ 633,773	$ 187,170	$ 16,691	$ 5,496
9	TOTAL DEPR AND AMMORT EXPENSES	$ 532,300	$ 285,514	$ 60,432	$ 141,573	$ 34,432	$ 8,928	$ 1,421
10	REAL ESTATE AND PROPERTY TAXES	$ 151,461	$ 81,920	$ 17,479	$ 39,399	$ 9,597	$ 2,664	$ 403
11	INCOME TAXES	$ 173,800	$ 91,455	$ 19,836	$ 47,647	$ 11,947	$ 2,442	$ 475
12	PAYROLL TAXES	$ 19,846	$ 10,340	$ 2,216	$ 5,479	$ 1,416	$ 297	$ 98
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,878,489	$ 1,410,408	$ 316,735	$ 867,871	$ 244,562	$ 31,021	$ 7,892
17								
18	NET OPERATING INCOME	$ 389,549	$ 101,725	$ 57,836	$ 191,992	$ 32,238	$ 8,669	$ (2,912)
19								
20	GROSS PLANT IN SERVICE	$ 16,976,734	$ 9,175,591	$ 1,956,940	$ 4,422,920	$ 1,078,043	$ 297,616	$ 45,623
21	RESERVES FOR DEPRECIATION	$ 7,461,799	$ 4,116,234	$ 860,268	$ 1,861,138	$ 448,118	$ 156,483	$ 19,559
22								
23	NET PLANT IN SERVICE	$ 9,514,935	$ 5,059,357	$ 1,096,672	$ 2,561,782	$ 629,926	$ 141,133	$ 26,065
24								
25	MATERIALS & SUPPLIES - FUEL	$ 317,381	$ 128,230	$ 33,556	$ 116,745	$ 37,181	$ 1,076	$ 592
26	MATERIALS & SUPPLIES -LOCAL	$ 206,340	$ 136,892	$ 24,391	$ 30,970	$ 4,905	$ 8,698	$ 484
27	CASH WORKING CAPITAL	$ 34,400	$ 16,180	$ 3,726	$ 10,895	$ 3,218	$ 287	$ 94
28	CUSTOMER ADVANCES & DEPOSITS	$ (27,473)	$ (11,689)	$ (8,245)	$ (6,552)	$ -	$ (987)	$ (0)
29	ACCUMULATED DEFERRED INCOME TAXES	$ (2,850,326)	$ (1,541,637)	$ (328,928)	$ (741,452)	$ (180,604)	$ (50,126)	$ (7,579)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 7,195,256	$ 3,787,332	$ 821,172	$ 1,972,389	$ 494,626	$ 100,082	$ 19,655
32								
33	RATE OF RETURN	5.41%	2.69%	7.04%	9.73%	6.52%	8.66%	-14.81%

SCHEDULE WRD-3

Weather Normalized-12 months ending March 2016 Forecasted Growth to December 2016			
Residential Class			
	Billing Units	Rates	Revenue
Customer Charge			
Summer Bills	4,183,694	$8.00	$33,469,548
Winter Bills	8,387,335	$8.00	$67,098,677
TOD Bills	480	$8.00	$3,836
Access Charge			
Summer Bills	4,183,694		
Winter Bills	8,387,335		
TOD Bills	480		
Low Income Charge	12,571,508	$0.03	$377,145
Total Bills	12,571,508		
Energy Charge			
Summer kWh	4,435,407,718	$0.1208	$535,797,252
On-peak	41,354	$0.3021	$12,493
Off-peak	188,390	$0.0755	$14,223
Energy Eff kwh	4,435,633,332	$0.0010	$4,435,633
Winter kWh			
First 750 kWh	4,623,436,366	$0.0858	$396,690,840
Over 750 kWh	3,709,655,849	$0.0573	$212,563,280
On-peak	0	$0.0000	$0
Off-peak	0	$0.0000	$0
Energy Eff Charge	8,333,085,352	$0.0006	$4,999,851
Total kWh	12,768,729,677		
		Total	$1,255,462,780
		Total	$1,255,462,780
		Low Income Charge	$377,145
		Total less Low Inc	$1,255,085,635

Weather Normalized-12 months ending March 2016			
Forecasted Growth to December 2016			
Small General Service Class			
	Billing Units	Rates	Revenue
Customer Charge			
Summer Bills			
Limited Unmetered Service	3,016	$10.19	$30,733
One-phase	367,122	$10.19	$3,740,969
Three-phase	152,298	$20.38	$3,103,828
Winter Bills			
Limited Unmetered Service	6,032	$10.19	$61,466
One-phase	734,002	$10.19	$7,479,482
Three-phase	305,072	$20.38	$6,217,374
TOD Bills			
Limited Unmetered Service	68,921	$6.71	$462,463
One-phase	10,163	$20.43	$207,634
Three-phase	1,452	$40.84	$59,289
6M		$6.71	$0
Access Charge			
Summer Bills	519,419		
Winter Bills	1,039,075		
TOD Bills	11,615		
Low Income Charge	1,579,157	$0.05	$78,958
Total Bills	1,628,820		
Energy Charge			
Summer kWh	1,139,509,845	$0.1081	$123,181,014
On-peak	12,366,350	$0.1605	$1,984,799
Off-peak	22,092,838	$0.0654	$1,444,872
Energy Eff Charge	1,172,494,286	$0.0004	$468,998
Winter kWh			
Base	1,688,639,623	$0.0806	$136,104,354
Seasonal	429,806,503	$0.0465	$19,986,002
On-peak	23,568,902	$0.1057	$2,491,233
Off-peak	43,406,981	$0.0485	$2,105,239
Energy Eff Charge	2,181,731,259	$0.0002	$436,346
Total kWh	3,359,391,042	Total	$309,645,053
		Total	$309,645,053
		Low Income Charge	$78,958
		Total less Low Inc	$309,566,095

Weather Normalized-12 months ending March 2016 Forecasted Growth to December 2016			
Large General Service			
	Billing Units	Rates	Revenue
Customer Charge			
Summer Bills	42,290	$92.35	$3,905,525
Winter Bills	84,459	$92.35	$7,799,773
TOD Bills	388	$112.72	$43,700
Low Income Charge	127,137	$0.50	$63,568
Demand Charge (kW)			
Summer	8,529,011.90	$4.83	$41,195,127
Winter	15,787,327.20	$1.79	$28,259,316
Energy Charge			
Summer kWh			
First 150HU	1,141,221,926	$0.1034	$118,002,347
Next 200HU	1,252,694,918	$0.0778	$97,459,665
Over 350HU	522,107,462	$0.0523	$27,306,220
On-peak	4,594,412	$0.0122	$56,052
Off-peak	9,415,429	-$0.0069	-$64,966
Energy Eff	2,843,088,287	$0.0008	$2,274,471
Winter kWh			
Base Energy Charge			
First 150HU	1,954,789,919	$0.0651	$127,256,824
Next 200HU	2,105,899,549	$0.0483	$101,714,948
Over 350HU	867,480,713	$0.0380	$32,964,267
Seasonal Energy	345,260,038	$0.0380	$13,119,881
On-peak	9,074,758	$0.0037	$33,577
Off-peak	19,052,439	-$0.0021	-$40,010
Energy Eff	5,144,999,758	$0.0004	$2,058,000
Total kWh	8,189,454,524		$603,408,285
		Total	$603,408,285
		Low Income Charge	$63,568
		Total less Low Inc	$603,344,716

Weather Normalized-12 months ending March 2016			
Forecasted Growth to December 2016			
Small Primary Service			
	Billing Units	Rates	Revenue
Customer Charge			
Summer Bills	2,592	$312.98	$811,178
Winter Bills	5,211	$312.98	$1,630,948
TOD Bills	220	$333.35	$73,212
Low Income Charge	8,022	$0.50	$4,011
Demand Charge (kW)			
Summer	2,952,050.28	$4.00	$11,808,201
Winter	5,296,748.07	$1.45	$7,680,285
Energy Charge			
Summer kWh			
First 150HU	425,434,558	$0.1000	$42,543,456
Next 200HU	523,039,769	$0.0753	$39,384,895
Over 350HU	384,040,875	$0.0505	$19,394,064
On-peak	13,981,066	$0.0089	$124,431
Off-peak	28,984,854	-$0.0050	-$144,924
Energy Eff	1,213,282,368	$0.0008	$970,626
Winter kWh			
First 150HU	719,288,239	$0.0630	$45,315,159
Next 200HU	878,081,788	$0.0468	$41,094,228
Over 350HU	641,104,716	$0.0366	$23,464,433
Seasonal Energy	147,826,764	$0.0366	$5,410,460
On-peak	23,818,081	$0.0033	$78,600
Off-peak	47,347,288	-$0.0018	-$85,225
Energy Eff	2,177,312,636	$0.0005	$1,088,656
Total kWh	3,718,816,709		
Reactive Charge	1,414,269	$0.37	$523,279
Rider b			
115 kV	4,540.36	-$1.41	-$6,402
69 kV	927,818.73	-$1.19	-$1,104,104
Rider EDR			-$70,000
			$239,989,465
		Total	$239,989,465
		Low Income Charge	$4,011
		Total less Low Inc	$239,985,454

Weather Normalized-12 months ending March 2016			
Forecasted Growth to December 2016			
Large Primary Service			
	Billing Units	Rates	Revenue
Customer Charge			
Bills	744	$312.98	$232,857
TOD	48	$333.35	$16,001
Low Income Charge	792	50	$39,600
Demand Charge (kW)			
Summer	2,457,413.90	$20.37	$50,057,521
Winter	4,438,400.90	$9.25	$41,055,208
Energy Charge			
Summer kWh			
Energy	1,394,780,677	$0.0341	$47,562,021
On Peak	38,598,050	$0.0066	$254,747
Off-Peak	79,972,270	-$0.0037	-$295,897
Energy Eff Charge	660,200,096	$0.0003	$198,060
Winter kWh			
Energy	2,423,107,619	$0.0302	$73,177,850
On Peak	68,677,229	$0.0031	$212,899
Off-Peak	146,098,357	-$0.0016	-$233,757
Energy Eff Charge	1,099,351,205	$0.0002	$219,870
Total kWh	3,817,888,295		
Reactive Charge	427,937	$0.37	$158,337
Rider b			
115 kV	621,262.10	-$1.41	-$875,980
69 kV	1,855,099.00	-$1.19	-$2,207,568
			$209,571,770
		Total	$209,571,770
		Low Income Charge	$39,600
		Total less Low Inc	$209,532,170

Weather Normalized-12 months ending March 2016			
Forecasted Growth to December 2016			
Company Owned Lighting 5M			
Description CSS Code	**Monthly Rate**	**December 2016 Quantity**	**Annual Revenue**
LED 100W Equivalent	$9.92	15,489	$1,843,811
LED 250W Equivalent	$16.07	2,691	$518,932
LED 400W Equivalent	$29.73	459	$163,753
9500 HPS Enclosed	$12.41	15,277	$2,275,051
25500 HPS Enclosed	$17.93	12,110	$2,605,588
50000 HPS Enclosed	$31.97	2,533	$971,760
6800 MV Enclosed	$12.41	6,547	$974,979
20000 MV Enclosed	$17.93	3,123	$671,945
54000 MV Enclosed	$31.97	67	$25,704
5800 HPS Open Btm	$10.05	114	$13,748
9500 HPS Open Btm	$10.98	50,054	$6,595,115
3300 MV Open Btm	$10.05	2,393	$288,596
6800 MV Open Btm	$10.98	13,387	$1,763,871
9500 HPS Post Top	$22.99	42,908	$11,837,459
3300 MV Post Top	$21.73	96	$25,033
6800 MV Post Top	$22.99	8,929	$2,463,333
25500 HPS Direct	$22.76	3,551	$969,849
50000 HPS Direct	$36.00	3,729	$1,610,928
34000 MH Direct	$22.76	5,393	$1,472,936
100000 MH Direct	$71.96	994	$858,339
20000 MV Direct	$22.76	299	$81,663
54000 MV Direct	$36.00	24	$10,368
11000 MV Open Btm	$10.98	144	$18,973
140000 HPS Direct	$71.96	15	$12,953
		190,326	**$38,074,686**
		Discount	3.9498%
			$36,570,811

Weather Normalized-12 months ending March 2016			
Forecasted Growth to December 2016			
Customer Owned Lighting 6M			
Description CSS Code	**Count**	**Monthly Rate**	**Annual Revenue**
Metered service (cust cha	1,484	$6.71	$119,492
Energy charge (per kWh)	63,619,950	$0.0454	$2,888,346
Unmetered service (cust c	150	$6.71	$12,078
9500 HPS Enrg&Maint	16,222	$3.61	$702,737
25500 HPS Enrg&Maint	830	$6.28	$62,549
50000 HPS Enrg&Maint	70	$9.07	$7,619
5500 MH Enrg&Maint	169	$5.22	$10,586
12900 MH Enrg&Maint	39	$6.25	$2,925
3300 MV Enrg&Maint	7	$3.61	$303
6800 MV Enrg&Maint	3,110	$4.70	$175,404
11000 MV Enrg&Maint	26	$6.36	$1,984
20000 MV Enrg&Maint	40	$8.43	$4,046
54000 MV Enrg&Maint	4	$18.00	$864
9500 HPS Enrgy Only	223	$1.75	$4,683
25500 HPS Enrgy Only	205	$4.47	$10,996
50000 HPS Enrgy Only	1	$7.03	$84
3300 MV Enrgy Only	86	$1.85	$1,909
6800 MV Enrgy Only	122	$3.01	$4,407
11000 MV Energy Only	24	$4.29	$1,236
20000 MV Energy Only	88	$6.62	$6,991
54000 MV Energy Only	21	$15.75	$3,969
2500 LED Energy Only	3	$0.60	$22
5000 LED Energy Only	0	$1.06	$0
4250 LED Energy Only	19	$1.28	$292
12500 LED Energy Only	0	$2.73	$0
19000 LED Energy Only	0	$3.94	$0
			$4,023,521
	Realized Municpal Discount		5.9128%
			$3,785,618

Weather Normalized-12 months ending March 2016			
Forecasted Growth to December 2016			
MSD Horsepower Service			
		Amount of Bill at	
		.1735 per	
Connected	Current	Horsepower	
Horsepower	Rate	Per Month	Annual
36,900.0	0.1735	$ 6,402	$ 76,826