Exhibit No.:	
Issue(s):	Billing Units, Revenue Allocation, Rate Design
Witness:	Nicholas Bowden
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2024-0319
Date Testimony Prepared:	June 28, 2024

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

DIRECT TESTIMONY OF NICHOLAS BOWDEN ON BEHALF OF UNION ELECTRIC COMPANY D/B/A AMEREN MISSOURI

St. Louis, Missouri
June, 2024

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

NICHOLAS BOWDEN

FILE NO. ER-2024-0319

I. INTRODUCTION

Q. Please state your name and business address.

A. Nicholas Bowden, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am employed by Ameren Missouri as Manager of Rates and Analysis.

Q. Please describe your educational background and employment experience.

A. I earned a Bachelor of Science in Economics from Bradley University in 2006, a Master of Science in Electricity, Natural Gas, and Telecommunications Economics from Illinois State University in 2008, and a Doctor of Philosophy in Energy Systems from the University of California, Davis in 2021. I was employed as an economic analyst with the Illinois Commerce Commission's ("ICC") Federal Energy Program from 2008 until 2012. My work at the ICC primarily involved interventions in Federal Energy Regulatory Commission dockets, but also included support for state jurisdictional policy and regulation. I was employed as a lecturer in the Department of Economics and a research associate with the Institute for Regulatory Policy Studies ("IRPS") at Illinois State University between 2011 and 2014. My work with the IRPS centered on the development of a national database of utility rates for the US Department of Energy. I joined Ameren Missouri in August of 2020 as an analyst in the Rates and Analysis group and was promoted to manager in the group in August of 2022.

Q. Have you sponsored testimony in other Missouri Public Service Commission ("Commission") proceedings?

A. Yes, I sponsored testimony in the Company's last two requests for review of electric rates, File No. ER-2021-0240 and File No. ER-2022-0337. In those proceedings, my testimony included the development of normalized billing units and revenues and addressed other miscellaneous program, rate, and tariff revisions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to:

1. Discuss the process used to develop normalized billing units and normalized revenues at current rates;

2. Discuss the allocation of the revenue requirement to customer classes and the design of rates;

3. Provide updated Rider EEIC Net Margin Revenue values; and

4. Discuss the interaction between RESRAM and this case.

Q. Are you sponsoring any schedules for presentation to the Commission in this proceeding?

A. Yes, I am sponsoring four schedules.

<u>Schedule NSB-D1</u> details the normalized billing units used to determine the normalized retail revenues and develop rates.

Schedule NSB-D2 details the allocation of the requested revenue requirement to customer classes.

Schedule NSB-D3 details the proposed rates.

Schedule NSB-D4 provides an illustrative RESRAM rate sheet.

III. NORMAL BILLING UNITS AND REVENUE

Q. Did you conduct the normalized billing unit and revenue analysis for this case?

A. Yes.

Q. What period of time does the analysis cover?

A. The analysis was conducted using the twelve months ending March 31, 2024.

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

A. A billing unit is a measurable phenomenon which drives electric power system cost and can be used in conjunction with filed rates to calculate customer bills. Billing units include, but are not limited to, electrical service connections (customer count), electrical energy consumption (kilowatt-hours, or "kWh"), electrical power demand (kilowatts, or "kW"), and reactive power demand (kilovolt-ampere reactive, or "kVar"). The billing units used to calculate a customer's bill depend on the customer's rate class, but virtually all customers' bills are determined by more than one billing unit. Billing units are typically normalized when rates are set.

Q. Why are billing units normalized?

A. Billing units are normalized for two related reasons. First, billing units are normalized in order to calculate the normalized revenue, the revenue the Company expects to earn under normal conditions at current rates. Second, normalized billing units are used to develop the rates proposed in this proceeding; rates that allow the Company an opportunity to collect its revenue requirement under normal conditions.

Q. What is the result of the billing unit analysis?

A. The billing unit analysis results in the normalized test year billing units and, when applied to current rates, the Company's normalized revenue. The normalized test year billing units are detailed in Schedule NSB-D1. The Company's normalized revenue in this case is $2,879,696,512. The Company's actual test year revenue, total revenue adjustments, and normalized revenue are summarized by customer class in Table 1.

Table 1. Normalized Revenue By Class

Customer Class	Actual Revenues (in Dollars)	Total Adjustments (in Dollars)	Normalized Revenue (in Dollars)
1M	1,413,600,734	46,055,916	1,459,656,650
2M	320,835,135	9,661,172	330,496,306
3M	579,949,740	8,860,821	588,810,561
4M	243,680,412	780,429	244,460,840
11M	215,165,108	-1,110,840	214,054,267
Lighting	41,963,091	168,805	42,131,896
MSD	84,790	1,202	85,992
*Total	2,815,279,008	64,417,504	2,879,696,512
Total may differ from sum of rows due to rounding.			

The difference between the Company's total revenue requirement, as calculated by Company witness Stephen Hipkiss, and normalized revenue is the difference between the Company's cost of providing electrical service to its customers and the revenue that the Company expects to earn in a normal year at current rates. Normalized billing units are used in conjunction with this difference to propose rates that fully cover the Company's costs under normal conditions.

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

A. The Company is making five adjustments to normalize billing units and consequently normalize revenues. The Company is also making three adjustments that do not impact billing units but result in direct adjustments to revenue. The five billing unit adjustments are as follows:

1. A weather normalization adjustment;
2. A days adjustment;
3. An energy efficiency adjustment;
4. A customer-owned solar adjustment; and
5. A growth adjustment.

The three direct revenue adjustments are as follows:

1. A rate annualization adjustment;
2. An economic development incentive adjustment; and
3. A community solar adjustment.

The revenue value of each billing unit adjustment is shown in Table 2 by customer class.

Table 2. Billing Unit Revenue Adjustments

Customer Class	Weather Adjustment (in Dollars)	Days Adjustment (in Dollars)	Energy Efficiency Adjustment (in Dollars)	Solar Adjustment (in Dollars)	Growth Adjustment (in Dollars)
1M	14,747,318	902,241	-3,378,974	-736,719	12,500,300
2M	3,134,531	410,030	-1,527,454	-222,148	2,877,366
3M	3,220,029	559,736	-2,359,323	-354,209	1,604
4M	-129,580	-828,260	-725,772	0	60,642
11M	-431,366	-895,909	-110,960	0	4,737,230
Lighting	0	0	0	0	103,456
MSD	0	0	0	0	0
*Total	20,540,931	147,838	-8,102,484	-1,313,076	20,280,598
**Total may differ from sum of rows due to rounding.*					

The value of each non-billing unit revenue adjustment is shown in Table 3 by customer class.

Table 3. Non-Billing Unit Revenue Adjustments

Customer Class	Rate Annualization Adjustment (in Dollars)	Economic Development Adjustment (in Dollars)	Community Solar Adjustment (in Dollars)
1M	20,465,360	0	1,556,390
2M	4,922,657	0	66,190
3M	9,032,678	-1,239,693	0
4M	3,683,363	-1,279,964	0
11M	1,296,992	-5,706,827	0
Lighting	65,349	0	0
MSD	1,202	0	0
*Total	39,467,602	-8,226,484	1,622,580
**Total may differ from sum of rows due to rounding.*			

Q. What is the starting point for the process of normalizing billing units?

A. The process of normalizing billing units starts with the actual metered and billed test year billing units. The test year billing units are extracted directly from the Company's billing system at the customer level by month. The customer level billing units are then aggregated across customers by rate class, or more precisely, by rate schedule within each rate class.[1]

Q. How are the aggregate monthly billing units used in your analysis?

A. First, the actual rate class or schedule level aggregate monthly billing units are used in conjunction with the rates applicable during the test year to calculate the actual revenues earned in the test year. Separate calculations are made for base rate revenue and rider revenue. Riders for the test year include the fuel adjustment clause ("FAC"), the energy efficiency investment charge ("EEIC"), and the renewable energy standard rate

[1] The importance of the distinction between rate class and rate schedule has become more evident with the addition of multiple distinct rate schedules within the residential class.

adjustment mechanism ("RESRAM"). The calculated base rate revenue is compared to the Company's recorded revenue minus the calculated rider revenue to check for data entry or aggregation errors. Ideally, the difference between the calculated base revenue and the recorded minus calculated rider revenue would be zero. However, there are a handful of practical reasons why the difference is unlikely to be zero. For example, recorded revenue is the sum of revenues generated from individual customer bills, while normalized revenue is calculated using the sum of individual customer billing units. On each customer bill, there are several charges, and each charge is rounded to the nearest penny. In the normalized revenue calculation, the single sum of billing units across customers is multiplied by applicable rates, and only that single result is rounded. Mathematical theory tells us that rounding individual customer level charges up and down should cancel out as the number of customers increases, but it is also true that in any given instance, we could experience a large deviation from that expectation.

Another source of deviation comes from the timing of rate changes, both rider rate and base rate changes. Despite the billing practice improvements associated with seasonal proration, our billing units are still defined as seasonally prorated primary month data and are not calendar month data. Rider and base rate changes, however, happen on specific calendar dates, and have always been applied on a prorated basis based on days before and after the rate change in each specific customer's billing period. Seasonally prorated billing units give us a way to estimate the proportion of billing units billed on either side of the first of each month, which we can use to prorate rate changes for a given primary month, but this estimate is based on observations of months that cross over the winter-summer seasonal boundary, and the proportion certainly changes across time. In addition to the deviations caused by the proration of intra-billing-period rate changes on customers' bills, deviations are also caused by the proration of first and final bills associated with customers initiating or terminating service. On first and final bills, customer charges and block sizes are prorated by the number of days billed over thirty days. The entering and exiting of customers within months is not captured in the calculation of revenues at this initial stage.

Once the historical billing units are assembled and verified, the process of making billing unit adjustments/normalizations begins. The combined effect of adjustments determines the normalized billing units. The combination of normalized billing units and current rates yields the Company's normalized revenue. Each adjustment is outlined in detail below.

Q. Are all billing units presented as class level aggregates?

A. Yes, but in two instances, large primary service and lighting service, greater detail is also provided. Large primary service billing units are provided at the customer account level, and lighting service is provided at the lighting-fixture-type level.

Q. What is the purpose of conducting the large primary service billing unit analysis at the customer account level?

A. We conduct the large primary service billing unit analysis at the customer account level because of three related facts. First, the number of customers is small enough to make the account level analysis feasible. Second, the Company communicates with these customers about their historic and future usage, and therefore has customer-specific information that can be used to inform the analysis. Third, each customer has significant electrical loads, such that changes in a single customer's electrical demand or energy consumption can have a non-negligible impact on the Company's electrical system and normalized revenues. In combination, these three facts allow the Company to make reasonable customer-specific adjustments to normalize billing units.

Q. What is the purpose of conducting the lighting service billing unit analysis at the lighting fixture level?

A. Unlike all other retail electric rates, retail rates for unmetered lighting service are defined on a dollar per fixture per month basis, and more than 90% of the Company's lighting service revenue comes from unmetered customers. While we can observe customer counts, implied kWh (rated watts × lighting hours × 1/1000), and recorded revenues at the class level using aggregate monthly data, we cannot calculate revenue using these monthly aggregates and tariffed rates. We cannot make this calculation, because revenue is determined by the monthly rate per fixture and the fixture count. Technically, fixture counts are the billing units for unmetered lighting service. Therefore, we retrieve monthly fixture counts in order to conduct the lighting service billing unit analysis. The fixture level data also allows us to embed the ongoing LED conversion of lighting fixtures in a pro-forma growth adjustment. Fixture counts are projected out to December 2024 using the fixture specific trends during the test year. Those trends capture both absolute growth in total fixture counts and the conversion of historic fixture types to LED fixtures. Generally speaking, we observe declines in the historic fixture types and offsetting increases in LED fixture types.

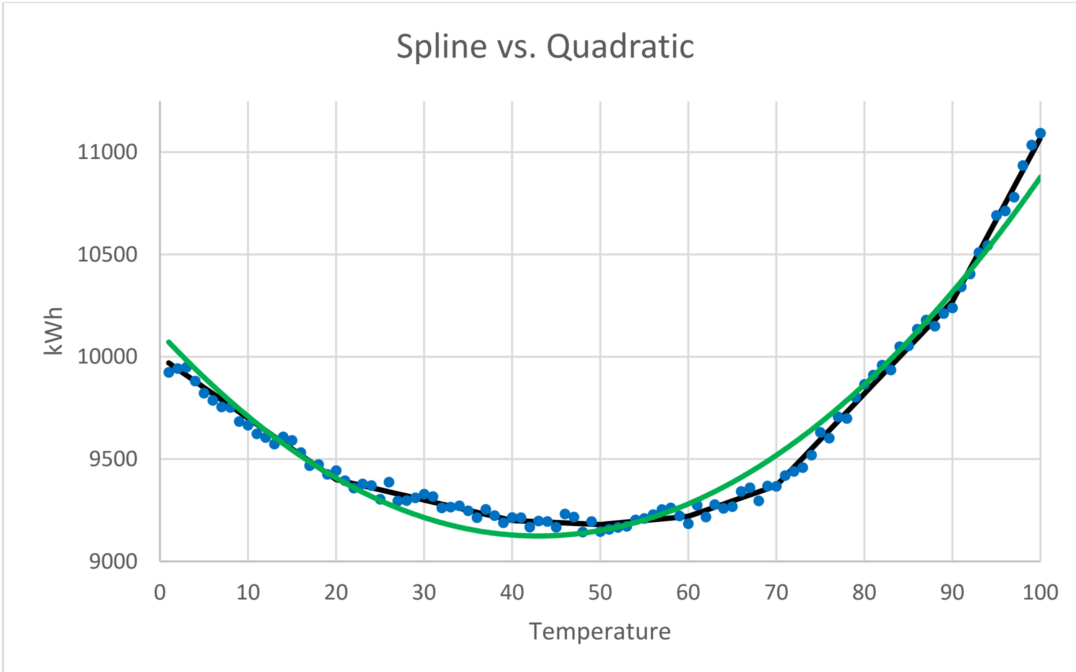
A. Billing Unit Revenue Adjustments

Q. How and why was the weather adjustment made?

A. The weather adjustment, or weather normalization, is made to remove the impact that test-year-specific weather conditions have on revenues through the weather's impact on billing units. The weather normalized billing units are a statistical estimate of the billing units that would have occurred during the test year under normal weather conditions. A thirty-year average (1994 to 2023) temperature is used to define normal daily weather conditions. The weather normalization adjustment exists when the weather in the test year deviates from normal weather. It is possible for test year weather to be equivalent to normal weather but, given the degree of variation in weather from year to year, the probability is effectively zero. The direction and magnitude of the adjustment are a function of the direction and magnitude of the monthly deviations of test year weather from normal weather and the way different customer class consumption responds to variation in weather at different times of the year. The weather adjustments are made using class- and month-specific weather adjustment ratios. The ratios are defined as the ratio of normal kWh to actual billed kWh for each class in each month. The class- and month-specific weather adjustment ratios are multiplied by the actual kWh billing units for that class and month to produce weather adjusted kWh billing units.

Actual billed kWh are observed and normal kWh are estimated for each class using statistical models of the relationship between weather and kWh. First, the relationship between daily weather and daily kWh is estimated using actual observed daily weather and kWh. Then, that relationship is used to adjust the observed daily kWh based on the difference between actual and normal daily weather conditions. The actual and normalized daily kWh are then aggregated to the monthly level to define the adjustment ratios described above. Our class-specific statistical models of the relationship between daily weather and daily kWh usage are estimated by ordinary least squares (a form of regression analysis) using day-of-week and month fixed effects and a temperature spline. The day-of-week and month fixed effects capture the predictable level differences in kWh usage that exist along these dimensions of time and are not related to the variation in daily temperature. For instance, there is a predictable difference between the level of kWh used on Saturdays and Sundays and the level of kWh used during the weekdays at an office building that is not related to the variation in daily temperature. Monthly fixed effects capture predictable variation in the level of kWh usage associated with environmental and behavioral factors that are seasonal, but independent of the variation in daily temperature. For instance, the level of kWh used during winter months, that is not related to the variation in daily temperature, is greater than spring or summer due to the increased hours of lighting. In addition to these level effects, we observe a predictable, non-linear relationship between daily temperature and daily kWh usage. The relationship might generally be characterized as parabolic, with the parabola opening upward, i.e., greater kWh usage at higher and lower temperatures and lower kWh usage in the middle of the range of temperatures, but the relationship is not symmetric around the minimum, so it is not technically parabolic. A temperature spline is our preferred modeling choice because it captures the non-linear nature of the relationship between temperature and kWh usage using a piecewise linear approximation rather than a quadratic approximation that would force symmetry on either side of the parabola's minimum. Figure 1 provides a stylistic illustration of the superiority of modeling a relationship with a piecewise linear spline relative to a quadratic when the data might generally be described as parabolic, but is, in fact, not symmetric around the minimum.

Figure 1. Regression Spline



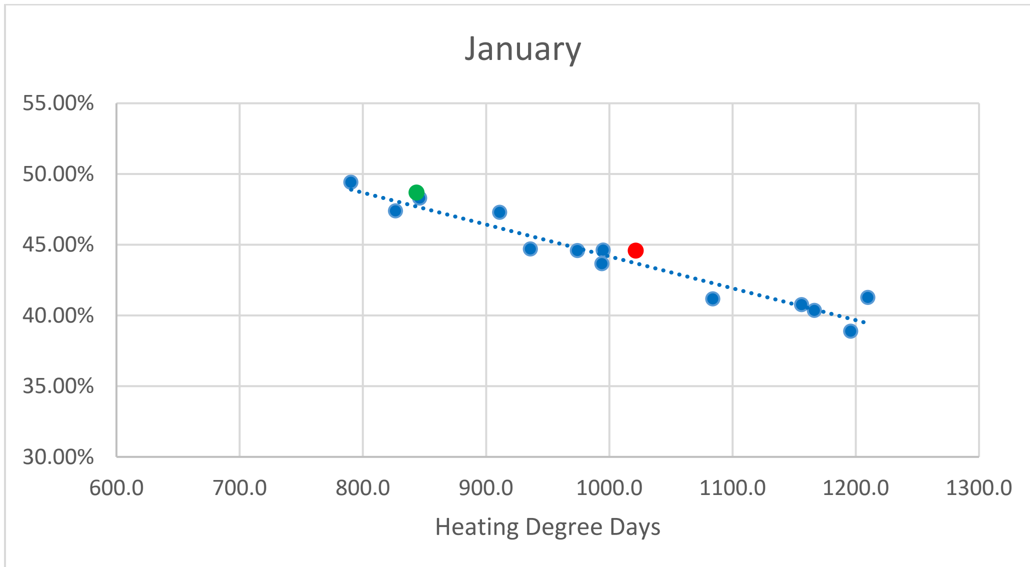
In Figure 1, the black line is a piecewise linear spline approximation of the blue points, which represent the observed **X** and **Y** variables (temperature and kWh usage). The green line in Figure 1 is a quadratic approximation of the blue points. It is clear in this illustration that the quadratic function systematically underestimates **Y** along some portions of the range of **X** and overestimates **Y** along other portions of **X**. On the other hand, the piecewise linear spline does not systematically underestimate or overestimate **Y** at any point along **X**. The class specific ordinary least squares models are estimated using two years of daily temperature values and kWh usage and produce parameters that describe the relationship between temperature and kWh usage, holding the day-of-week and month constant. The parameter values can then be used to estimate the kWh usage that would have occurred under normal weather conditions. Effectively, we hold kWh usage associated with each specific month and day-of-week combination constant and replace the observed quantity of kWh used associated with the test year temperature with the quantity of kWh associated with normal weather.

In addition to weather normalizing the total kWh billing unit using customer class- and month-specific weather adjustment ratios, we weather normalize the proportion of kWh consumed within block 1 and block 2 of the residential and small general service classes for each winter month.[2] We normalize the block 1 and block 2 proportions using a regression method subject to one additional logical constraint. First, historic data on the proportions of kWh consumed in block 1 is regressed on historic temperature data by month to develop a month-specific relationship between the proportion of kWh consumed in block 1 and temperature. The month-specific relationship and the difference between the monthly test year and normal temperature are then used to normalize the proportion of kWh consumed in block 1. The month-specific normalized proportion is then used to normalize the actual kWh within block 1 and, by consequence, block 2. Figure 2 illustrates how the regression method is used to normalize the proportion of kWh consumed in block 1. The proportion along the vertical axis in Figure 2 measures the percent of the total kWh consumed in block 1, and the horizontal axis measures heating degree days, an aggregate measure of weather in the month. The blue points represent historic data, and the red point represents the test year observation. The slope of the dotted blue line represents the estimate of the historic relationship between temperature (heating degree days) and the proportion of kWh consumed within block 1 in January. The green point represents the weather normalized proportion of kWh consumed in block 1 during January of the test year. The horizontal position of the green point is the normal temperature. The

[2] The block normalization applies to most residential rates. Specifically, Anytime Service, Anytime TOD, Evening Morning Savers, Overnight Savers Option B, and Smart Savers Option B.

process of normalizing the proportion of kWh consumed within block 1 moves the proportion parallel with the line (but not exactly on to it) until it reaches the normal temperature.

Figure 2. Residential and Small General Service Block Normalization



The normalization based on the outcome of the regression is subject to one additional logical constraint. The logical constraint has the potential to mitigate the size of the block normalization adjustment (the vertical distance between the red and green dots) prescribed by the regression. The logical constraint is as follows: the absolute value of kWh (not the proportion) in both blocks must move in the same direction as the total kWh did when it was weather normalized. For instance, if the total kWh increases because of weather normalization, then the absolute value of kWh in each block must also increase. The change in proportion in block 1 will be determined by which block increases by more. In some instances, the result prescribed by the regression could require one block to decrease in order to allow the other block to increase by enough given the value of the total weather normalized kWh. Table 4 illustrates the effect of the constraint when it binds the regression result.

Table 4. Block Normalization Logical Constraint

	January 2024	February 2024
Total Weather Normalization Direction	+	+
Block 1 Adjustment	0	0
Block 2 Adjustment	83,749,066	50,162,839
Regression Based Adjustment	-5.85%	-5.74%
Constrained Adjustment	-4.65%	-2.75%

In January 2024, weather normalization of total kWh resulted in an increase (+) in the total kWh. The regression-based normalization of block 1 kWh indicates that the proportion of kWh in block 1 to total kWh should decrease by 5.85%. However, the number of block 1 kWh would need to decrease for the block 1 proportion of total kWh to decrease by 5.85%. The constraint causes block 1 kWh to move in the same direction (or at least not move in the opposite direction) as the total adjustment, i.e., the change in block 1 kWh is 0. As a result, the constrained adjustment to the block 1 proportion is a decrease of 4.65% rather than a decrease of 5.85%. Similarly, in February 2024, the constraint results in a 2.75% decrease in the proportion rather than the 5.74% decrease prescribed by the regression alone.

Q. What is the result of the weather adjustment?

A. In aggregate, across the test year, the weather adjustment increases normalized revenues. The weather adjustment results in a total increase in revenue of $20,540,931, as shown in Table 2.

Q. How and why was the days adjustment made?

A. The Company's actual billing units for a given primary month do not necessarily represent kWh and kW that occurred exclusively during the similarly named calendar month. In fact, it is rare that a customer's primary month corresponds precisely to the calendar month with the same name. The lack of correspondence between primary month and calendar month is a result of the staggered reading of groups of meters, i.e., different customers have different billing cycles. Therefore, customers whose billing cycle straddles two calendar months will have billing units assigned to a single primary month by the Company's billing system, but truly have billing units which occurred in two different calendar months. The lack of correspondence between primary months and calendar months can result in customers whose billing year is more or less than a 365-day calendar year. Therefore, these customers' billing units need to be decreased or increased to reflect a normal 365-day year. The billing unit adjustment achieves this desired outcome. In addition to the deviation caused by the lack of correspondence between primary and calendar months, the test period used in this case includes a leap day, February 29, 2024. The leap day exists in both the primary and calendar year data and therefore requires an additional leap year adjustment.

Q. What is the result of the days adjustment?

A. In the proposed test year, the days adjustment, inclusive of the leap year adjustment, increases billing units for some classes and decreases them for other. In aggregate, the days adjustment increases revenue by $147,838 as shown in Table 2.

Q. How and why was the energy efficiency adjustment made?

A. The energy efficiency adjustment was made to annualize the impact of energy efficiency measures implemented throughout the test year. The energy efficiency adjustment is explicitly required by the terms of the Company's Demand Side Investment Mechanism that was approved by the Commission pursuant to the Missouri Energy Efficiency Investment Act ("MEEIA") and compensates the Company for the decrease in billing units and associated revenue that result from energy efficiency measures implemented during the test year through the Company's MEEIA programs.[3] The energy efficiency annualization adjustment is calculated using the energy efficiency measures installed during the test year. First, the energy efficiency measures installed in the test year are used, along with the measure-specific average kWh savings profiles and month of installation, to estimate the number of kWh actually saved during each month of the test year. A half month convention is used to estimate the savings in the month of installation. The half month convention is an assumption that all energy efficiency capacity was installed at the halfway point between the beginning and end of the month and is mathematically equivalent to assuming that the investments were made uniformly across the month. This estimate reflects energy efficiency savings that are already embedded in the test year kWh billing unit data, because the estimate reflects the savings that occurred and were not metered or billed during the test year, the actual test year energy efficiency savings. Next, the level of savings that would have been realized during the test year, assuming all measures were installed on April 1, 2023, is estimated for each month of the test year. This second estimate reflects the kWh billing units that the Company will not

[3] Please see Ameren Missouri 2019-21 MEEIA Energy Efficiency Plan, p. 50.

meter or bill going forward as a result of the energy efficiency measures installed in the test year; the annual energy efficiency savings. The positive monthly difference (annual – actual test year savings) between these two estimates is subtracted from the actual billing units so that normalized billing units reflect the total annual reductions in billing units that resulted from the energy efficiency measures installed in the test year. This monthly difference is the primary component of the energy efficiency annualization adjustment, but the adjustment also includes another, smaller component, the Demand Response Event Net Energy ("DRENE") component. DRENE kWh result when demand response events are called by the Company, and participating customers reduce kWh consumption. The kWh reductions that result from these events are reflected in billing units, but are not persistent energy savings like those that result from investments in energy efficiency measures. Therefore, DRENE kWh are added back to the test year billing units to reflect normal conditions. The DRENE kWh are added by reducing the annualized energy efficiency reductions as follows:

$$Energy\ Efficiency\ Adjustment = Annual\ Energy\ Efficiency\ Savings - Actual\ Test\ Year\ Energy\ Efficiency\ Savings - DRENE\ kWh$$

Q. What is the result of the energy efficiency adjustment?

A. The energy efficiency adjustment decreases kWh billing units for every class, because the energy efficiency component unambiguously reduced billing units and is large relative to the DRENE component. In total, the energy efficiency adjustment reduced kWh billing units by 90,442,460 kWh. The energy efficiency adjustment decreases the Company's revenue by $8,102,484, as shown in Table 2.

Q. How and why was the customer-owned solar adjustment made?

A. The customer-owned solar adjustment was made to annualize the impact of behind-the-meter solar installations made throughout the test year by the Company's customers, the majority of which were incentivized by the Company pursuant to Section 393.1670 RSMo. The solar adjustment reflects the decrease in billing units and associated revenue that occur because of customer solar generation installations during the test year. The solar adjustment is calculated using the behind-the-meter capacity installed during each month of the test year. First, the number of kWh generated by each solar installation, given their installation month and installed capacity, is estimated for each month of the test year. This estimate reflects actual test year behind-the-meter generation already embedded in the test year kWh billing unit data, because the estimate reflects the generation that occurred and displaces system-supplied energy that, as a result, was not billed during the test year. Next, the number of kWh that would have been generated during the test year, assuming all capacity was installed on April 1, 2023, is estimated for each month of the test year. The monthly difference between these two estimates is the preliminary estimate of the solar adjustment. This preliminary estimate of the solar adjustment is then further adjusted to reflect the fact that not all behind-the-meter solar generation will net against retail load, but rather some number of the kWh generated will be sold to the Company at its avoided cost rate under the Electric Power Purchases from Qualifying Net Metering Units tariff (Sheet No. 171). In order to reflect these sales in the solar adjustment, we estimate the probability that any kWh of behind-the-meter solar generation will be sold to the Company at avoided cost. We estimate this probability monthly using the ratio of the total behind-the-meter generation sold at avoided cost to the total behind-the-meter generation. The preliminary adjustment is multiplied by one minus this probability to determine the final solar adjustment.

Q. What is the result of the solar adjustment?

A. The solar adjustment unambiguously decreases kWh billing units for customer classes which have non-zero behind-the-meter solar capacity installed during the test year. The total solar adjustment for all classes of customers is 13,852,198 kWh for the test year and decreases the Company's revenue by $1,313,076.

Q. How and why was the growth adjustment made?

A. The growth adjustment was made to adjust billing units to the level we expect to observe at the time of true-up, December 31, 2024, in order to minimize the change in normalized revenues that will occur at the time of the true-up. Class-specific growth adjustments may be made using two component parts. The two components of the growth adjustment are pure customer count growth and inter-class class switching.

The pure growth component of the adjustment is made according to the following procedure for all but the large primary service class. First, a class-specific customer count forecast is made for December 31, 2024. Second, the difference between the forecasted customer count value and the test year customer count is calculated for each month. Third, the difference, or change, in customer count in each class is multiplied by the class average billing unit values, and that product is added to the test year billing unit values. For the large primary service class, growth adjustments include the addition or subtraction of specific customer loads, based on knowledge of customer-specific entry or exit from the system.

The switching component of the adjustment is made using different methods for different classes. In the past, the switching component was primarily focused on switching between the large primary service and small primary service customer classes. Switching between the large primary service and small primary service customer classes is done using customer-specific loads for customers who are known to have switched within the test year or whose intent to switch prior to December 31, 2024, is known. In this specific case, residential switching was included in the determination of billing units and normalized revenue. Residential switching is significant in the proposed test year for two reasons. First, an increased number of residential customers began adopting advanced time-of-use rate options. Second, the Company continued to implement a default residential rate policy whereby residential customers are switched to the Evening Morning Savers rate six months after receiving their advanced meter, unless they elect another rate option. For the residential class, the switching component is implemented prior to the pure growth component. The switching component is implemented by calculating the difference between the customer counts in each of the first eleven months of the test year and the customer count from the last month of the test year, March 2024. This difference is multiplied by the class average billing units and the product is added to the test year billing units. The switching component of the residential growth adjustment effectively normalizes the distribution of residential customers across the residential rate options to reflect distribution in the final month of the test year. After this normalization, the pure growth component is implemented.

Q. What is the result of the growth adjustment?

A. The growth adjustment resulted in increases in all class revenues. In total, the growth adjustment increases the Company's revenue by $20,280,598.

B. Non-Billing Unit Revenue Adjustments

Q. How and why was the rate annualization adjustment made?

A. The rate annualization adjustment was made because portions of the test year were not subject to current rates. The current rates went into effect on July 9, 2023, part way through the fourth month of the test year. The rate annualization adjustment was made to quantify the revenue impact of this change in rates and determine revenues that would have been expected had the rates that were effective on July 9, 2023, been in effect since April 1, 2023. This adjustment had no impact on billing units. The adjustment was made by first calculating revenues at actual test-year rates, and then calculating revenues as if current rates were in effect for the entire test year. The difference between these two revenues is the annualization adjustment.

Q. What is the result of the annualization adjustment?

A. The result of the annualization adjustment is an increase in revenue. In total, the annualization adjustment resulted in a $39,467,602 increase in revenues.

Q. How and why was the economic development incentive adjustment made?

A. The economic development incentive adjustment was made to account for base rate revenues that were not collected, because of discounts that were granted under the Company's economic development incentive provisions (Rider EDI at Sheet Nos. 86-86.5). Rider EDI was originally approved in compliance with Section 393.1640 RSMo.

(adopted by Senate Bill 564 in 2018 and subsequently amended by Senate Bill 745 in 2022), and allows customers meeting specific economic development criteria to receive a percentage discount on base rates. The value of the EDI discount is calculated as part of each applicable customer's monthly billing process, and therefore, the individual monthly value of the discount for each applicable customer can be retrieved from the Company's billing system. The value of the individual monthly discounts are aggregated across customers, including an annualization for customers who received discounts for less than twelve months of the test year, to determine the total annualized value of revenues that the Company will not collect as a result of the economic development incentive discounts. That total value is the economic development incentive adjustment.

Q. What is the result of the economic development incentive adjustment?

A. The economic development incentive adjustment decreases the Company's revenue by $8,226,484. The reduced level of revenues, $8,226,484, is allocated to each of the Company's customer classes through the application of a uniform percentage adjustment to the revenue requirement responsibility of each customer class as required by Section 393.1640 RSMo. The uniform percentage adjustment to the revenue requirement responsibility is outlined further in the section on rate design below.

Q. How and why was the Community Solar adjustment made?

A. The Community Solar adjustment was made to account for the Community Solar Pilot Program revenues that were collected by the Company. Community Solar Pilot Program customers subscribe to 100-kWh blocks of solar energy and pay the Community Solar Pilot Program's Total Solar Block Charge for each block of solar energy. The Community Solar adjustment is equal to the total number of 100-kWh blocks sold multiplied by the Total Solar Block Charge, i.e., total Community Solar Pilot Program revenue. The adjustment is equal to the total revenue because kWh that were metered but not billed at base rates due to solar block subscriptions were removed from the billing units used to calculate normalized revenue.

The total Solar Block Charge consists of two parts: the Solar Generation Charge and the Facilities Charge. The Solar Generation Charge is designed to cover the cost of the Community Solar Pilot Program solar generation resources. The Facilities Charge is designed to cover the cost of other Company assets beyond the solar generation resource needed to serve Community Solar Pilot Program customers. The revenues associated with each of the charges will receive different treatment in the rate design section discussed below.

Q. What is the result of the Community Solar adjustment?

A. A total of 134,362 100-kWh blocks were sold at the Total Solar Block Charge during the test year, 128,415 to residential customers and 5,947 to small general service customers. The Total Solar Block Charge during the test year equals $12.12 and $11.13 per block for residential and small general service customers, respectively. Therefore, the community solar adjustment increases the Company's revenue by $1,622,580. The portion of the adjustment associated with the Solar Generation Charge will be excluded from the general rate adjustment and distributed to all customer classes pro rata to offset revenue requirement allocations. The portion of revenue associated with the Facilities Charge will be subject to the rate adjustment, so the Facilities Charge adjustment prescribed by the stipulation and agreement in File No. EA-2016-0207 will be realized.

IV. REVENUE ALLOCATION AND RATE DESIGN

Q. Did you determine the revenue requirement allocation in this case?

A. Yes.

Q. What is the revenue requirement allocation result of the equal rate of return class cost of service study performed by Company witness Thomas Hickman?

A. Table 5 below summarizes the revenue requirement allocation necessary to give the Company an opportunity to earn an equal rate of return from each of its customer classes, based upon test year costs and pro forma adjustments made by Company witness Stephen Hipkiss.[4] A detailed summary of the class cost of service study can be found in Schedule TH-D2 attached to the direct testimony of Company witness Thomas Hickman.

Table 5 – Cost Based Revenue Requirements by Customer Class

Customer Class	Revenue Requirement ($Million)	Return on Rate Base
1M	$1,809.6	7.398%
2M	$373.0	7.398%
3M & 4M	$874.1	7.398%
11M	$218.0	7.398%
5M	$53.7	7.398%
6M	$4.6	7.398%
Total[5]	$ 3,333.0	7.398%

[4] The pro forma adjustment for the Renewable Solutions Program is of specific note here. This pro forma adjustment is calculated by Company witness Steven Wills and added to the normal revenues I calculate and present in Table 1 by Company witness Stephen Hipkiss in the calculation of the total revenue requirement and total revenue requirement adjustment. That requirement, inclusive of the Renewable Solutions Program pro forma revenue, is used by Company Witness Tom Hickman in his cost of service Study. The pro forma increase in normal revenue associated with the Renewable Solutions Program decreases the total revenue requirement adjustment proposed in this case.

[5] The difference between the total revenue requirement shown in Table 5 and the total revenue requirement shown in Table 8 is explained by the $7,037,224 pro forma adjustment for the Renewable Solutions Program calculated by Company witness Steven Wills.

Q. Why is an equal rate of return revenue requirement allocation an important reference point when designing rates?

A. An equal rate of return revenue requirement allocation implies that each classes' base rates produce revenue equal to their cost of service under normal conditions. These revenue requirement allocations are fair and promote the optimal use of electricity in the economy. Standard economic theory concludes that the greatest economic surplus is generated when the price of goods and services equal their cost of production. The cost of providing electrical service differs across customer classes. Revenue requirement allocations which reflect those differences promote the greatest surplus in the economy.

Q. What change in the current revenue requirement allocation would be necessary to achieve equal rate of return revenue requirement allocation?

A. Table 6 shows the equal rate of return revenue requirement allocation, the current revenue requirement allocation, and the revenue requirement changes required to move from the current allocation to the equal rate of return allocation in both millions of dollars and percentages.

Table 6 – Cost-Based Rate Changes by Customer Class

Customer Class	Equal Rate of Return Revenue Requirement	Current Revenue Requirement	Change Required in Dollars	Change Required in Percentage
1M	$1,809.6	$1,458.5	$351.1	24.1%
2M	$373.0	$330.5	$42.5	12.8%
3M & 4M	$874.1	$835.8	$38.3	4.6%
11M	$218.0	$219.8	-$1.8	-0.8%
5M	$53.7	$39.2	$14.5	37.0%
6M	$4.6	$3.0	$1.6	56.9%
Total	$ 3,333.0	$2,886.8[6]	$446.2	15.46%

[6] The difference between the current revenue requirement shown here in Table 6 and the current normal revenue shown above in Table 1 is explained by the $7,037,224 pro forma adjustment for the Renewable Solutions Program calculated by Company witness Steven Wills and added to normal revenue by company witness Stephen Hipkiss.

Q. Is the Company proposing revenue requirement allocations based strictly on equal rate of return revenue requirements in this case?

A. No. The Company is using the equal rate of return revenue requirements as a reference relative to the current revenue requirements, and the principles of stability and gradualism to make its revenue requirement allocation recommendation in this case.

Q. What is the Company's process for allocating the total revenue requirement adjustment requested in this case?

A. The total revenue requirement adjustment is allocated to the classes in this case according to the following process. A detailed summary of the allocation is attached as Schedule NSB-D2.

1. Subtract Low Income Charge and Community Solar Generation revenues from and add EDI discounts to the current total normal revenue to get the current base rate revenue requirements.

2. Make a revenue neutral shift to the current base rate revenue requirements.

3. Allocate the total revenue requirement adjustment plus Community Solar Generation revenues minus the absolute value of EDI discounts to the classes proportional to those classes' base rate revenue requirement post revenue neutral adjustment.[7] This type of allocation is often described as an equal percentage increase in the revenue requirement allocations.

[7] The Community Solar Generation Revenue is added from the total revenue requirement adjustment because it's inclusion in the total normal revenue decreased the total revenue requirement adjustment. The EDI discounts are subtracted from the total revenue requirement adjustment because their inclusion in total normal revenue increased the total revenue requirement adjustment.

4. Allocate the Community Solar Generation revenue and EDI discounts. The Community Solar Generation revenue is subtracted from class revenue requirements and the EDI discounts are added to the class revenue requirement, because they represent decreased and increased revenue responsibilities respectively.

5. Add Low Income Charge and Community Solar Generation revenues to and subtract EDI discounts from base rate revenue to get the total requested revenue requirement.

Q. Please describe the effects and treatment of the Community Solar Generation Revenue and EDI discounts in the process described above.

A. Community Solar Generation revenues increase and EDI discounts decrease normal total revenue relative to revenue that would be produced from base rates and normal billing units alone. Consequently, Community Solar Generation revenue decreases and EDI discounts increase the total revenue requirement adjustment requested in this case.

In step 1 of the revenue requirement allocation process, the effect of these revenues/discounts are removed from the normal total revenue, along with Low Income Charge revenue, to produce normal base rate revenue. The effect of these revenues\discounts is also removed from the total revenue requirement adjustment in step 2, and the impact of that removal is realized in step 3. The effect of these revenues\discounts need not be removed from the total revenue requirement adjustment to ensure recovery of the benefits and costs associated with these revenues and discounts, but it does allow for an explicit accounting for their effects on the requested base rate revenue targets used to develop rates in this case.

If the Community Solar Generation revenue and EDI discounts were not explicitly removed from the total revenue requirement adjustment and reallocated explicitly, then their respective decrease and increase effect on the requested target base rate revenue would be implicit and proportional to the allocation of the remainder of the total revenue requirement adjustment. Ultimately, the Community Solar Generation revenue and EDI discounts are allocated in equal proportion to the remaining revenue requirement adjustment but are done explicitly so their impact on the target base rate revenue is transparent in step 4.

The allocation of the increase in revenue requirement associated with EDI discounts is prescribed by law and the reallocation of the EDI discounts impact proportional to normal base rate revenues complies with the law.[8] The allocation of Community Solar Generation is not prescribed by law but follows the same proportional to normal base rate revenues for one simple reason. The cost associated with the Community Solar assets are included in the overall revenue requirement and are therefore implicitly included in the base rates of all customers' classes. Therefore, it is just and reasonable to allocate the associated benefits, the offsetting Community Solar Generation revenue, proportionally to all classes.

In step 5, Community Solar Generation revenue and EDI discounts are added to and subtracted from the base rate revenue respectively to reflect the impact their existence has on actual total revenue.

[8] Section 393.1640 RSMo, states that "the impact of the discounts provided for by this section shall be allocated to all the electrical corporation's customer classes, including the classes with customers that qualify for discounts under this section through the application of a uniform percentage adjustment to the revenue requirement responsibility of all customer classes."

Q. What, if any, revenue neutral revenue requirement adjustments are proposed in this case?

A. In this case, the Company recommends a 0.25% increase to the 1M current normal base rate revenue. One-third of the associated revenue is used to decrease the 4M current normal base rate revenue requirement and two-thirds is used to decrease the 11M current normal base rate revenue requirement. The reductions to 4M and 11M are roughly equal to a 0.5% and 1% decrease in their current normal base rate revenue requirement. Table 7 provides additional detail related to this revenue-neutral revenue requirement adjustment.

Table 7. Revenue Neutral Class Adjustments

Class	Current Normal Base Rate Revenue	Revenue-Neutral Adjustment	Revenue-Neutral Adjustment Base Rate Revenue	Percent Change
1M	1,456,717,634	3,641,794	1,460,359,428	0.25%
4M	245,723,941	-1,213,931	244,510,010	-0.49%
11M	219,581,006	-2,427,863	217,153,144	-1.11%

Q. Why are these revenue neutral adjustments made in this case?

A. These revenue neutral adjustments are made in this case because the movement towards the cost of service is fair and the size of the adjustment is reasonable. It is important to understand the percent change in Table 7 in the context of Table 6 above and Table 8 below. Table 6 indicates that the 11M class requires a 0.8% *decrease* to achieve an equal rate of return revenue requirement allocation. The 1.11% decrease in revenue requirement responsibility is applied prior to the allocation of the total revenue requirement adjustment in the case. In total, as shown in Table 8, the 11M class's proposed revenue requirement increase is 14.22%. In summary, the 11M class requires a 0.8% decrease to achieve cost of service in this case, but after the application of the revenue neutral adjustment, the recommended increase for the 11M class is 14.22%. Similarly, the 1M class requires a 24.1% increase to achieve cost of service, but after the revenue neutral adjustment, the 1M class's proposed increase is 15.77%. In light of these facts, the incremental movement towards the cost of service for the 1M, 4M, and 11M classes is fair and reasonable. Factors influencing the magnitude of revenue neutral adjustment are the absolute magnitude of the increase in the case and differing perspectives of fairness.

Q. Please summarize the Company's revenue requirement allocation proposal in this case.

A. The Company's revenue requirement allocation proposal in this case is summarized in Table 8.

Table 8 – Revenue Requirement Adjustments

Customer Class	Normalized Retail Revenues	Requested Revenue Requirement	Requested Revenue Adjustment	Percentage Increase
1M	1,459,656,650	1,689,782,220	230,125,070	15.77%
2M	330,496,306	381,686,865	51,190,559	15.49%
3M	588,810,561	680,101,832	91,291,271	15.50%
4M	244,460,840	280,981,595	36,520,754	14.94%
11M	214,054,267	244,488,305	30,434,038	14.22%
5M	39,182,322	45,260,353	6,078,030	15.51%
6M	2,949,574	3,406,241	456,667	15.48%
MSD	85,992	99,276	13,284	15.45%
Total	2,879,696,512	3,325,806,685	446,110,173[9]	15.49%

Q. Did you design the rates proposed in this case?

A. Yes.

[9] The total requested revenue requirement adjustment is $88,217 less than the stated total revenue requirement adjustment of $446,198,390 due to the practice of rounding of rates to 2 or 4 digits.

Q. Please explain what is meant by the term "rate design".

A. Rate design can be divided into two parts. First, rate design includes the determination of the charge types[10] associated with a rate schedule. Typical charge types include customer charges, demand (kW) charges, and energy (kWh) charges. These charges come in different flavors, including but not limited to declining block charges or time-of-use charges. Each of the charge types has an associated billing unit, a measurable feature of service, to which a rate can be applied. The combination of charge types associated with a rate schedule can be referred to as the rate structure.

Second, rate design includes the determination of the value of rates, which are applied to the billing unit associated with each charge type to produce charges on a customer's bill.

Q. Is the Company proposing to change the structure of any rate schedules?

A. Not at this time. Residential rate schedules were comprehensively restructured in File No. ER-2019-0335. Non-residential rate design is the ongoing subject of the Company's Non-Residential Rate Design (NRRD) working docket File No. EW-2023-0031.

Q. Please describe the Company's proposal to adjust rates in this case.

A. Generally, the Company is proposing to increase all rates within each rate schedule by an equal percentage. The percentage increase applied to each rate in each rate schedule is equal to the revenue requirement increase described above in Table 8. Detailed results of this process are attached as Schedule NSB-D3.

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[10] Elsewhere, I have used the term rate elements synonymously with charge types.

There are 4 exceptions to this general proposal.

1. Revenue neutral adjustments to time-of-day rate adjustments in the 3M, 4M, and 11M classes. These adjustments were motivated by the findings of a rate impact study conducted in the Company's NRRD working docket.

2. Evening-Morning Savers summer and winter on-peak adders are held constant. These adders are viewed as fixed features of the Evening-Morning Savers rate design, at least at this time.

3. Elimination of incremental time-of-day customer charges in the 2M, 3M, 4M, and 11M classes. These incremental customer charges were developed at a time when time-of-day rate selection induced incremental metering costs. With the roll-out of AMI, this incremental meter cost no longer exists.

4. The following 'uniform' rates are increased by a percentage equal to the total revenue requirement increase, so the uniform rates are equal across the two applicable classes. Those rates include 4M and 11M customer charge, Rider B discounts, and kVar rates.

V. EEIC Net Margin Revenue

Q. Were Rider EEIC Net Margin Revenue values updated to reflect rates proposed in the Company's filing?

A. Yes, the Rider EEIC Net Margin Revenue values were updated to reflect the rates proposed in the Company's filing.

VI. RIDER RESRAM REBASING

Q. Why is Rider RESRAM, which is a rider mechanism that establishes a rate outside of general rate cases, to be rebased in this case?

A. Rider RESRAM is designed to recover costs and distribute benefits associated with RES compliance. Rider RESRAM captures costs and benefits that occur between rate cases to ensure the Company and its customers are both made whole given the costs and benefits of RES compliance. The RESRAM is designed to be rebased in general rate proceedings. Rebasing moves RES costs and benefits currently included in the RESRAM rate into base rates.

Rebasing RESRAM may include two changes that impact the RESRAM rate: 1) the transfer of RESRAM eligible costs and benefits out of the RESRAM rate and into base rates, and 2) the establishment of values for the RESRAM Base Amount ("RBA") and the Monthly Base Amount ("MBA") components of the RESRAM rate. The values of RBA and MBA represent amounts of RESRAM eligible costs and benefits reflected in the RESRAM rate and base rates respectively.

Q. Did you submit a tariff sheet that rebases RESRAM filed in the direct case?

A. No. The timing of the annual RESRAM filing and the timing of a general rate proceedings make filing a tariff sheet rebasing RESRAM with the direct case impractical. The RESRAM rate is revised through an annual filing made by October 1st of each year. The annual filing has a four-month review period before the revised RESRAM rate takes effect on February 1st. Therefore, the RESRAM rate needs to be reset between the time this case is filed (June 28, 2024) and the time the resulting rates take effect (expected to be on or before June 1, 2025). Modifications to Rider RESRAM needed for rebasing cannot be filed with the other tariff sheet modifications initiating this case because, as is typical with general rate review filings, we expect all filed tariff sheets to be suspended. Suspension of the RESRAM tariff sheet would prevent the normal annual Rider RESRAM filing from occurring pursuant to its own schedule. Therefore, I have attached Schedule NSB-D4 to my testimony, an illustrative RESRAM rate sheet that shows the establishment of a new MBA based on the amount of RESRAM eligible costs and benefits reflected in the revenue requirement in the Company's direct filed case. When this case is resolved by Commission order, the Company will file the RESRAM rate sheet with an updated MBA, and an adjusted RBA and RESRAM rate consistent with the Commission's final order in this case as part of the compliance tariffs.

Q. What adjustment to the RESRAM rate and RBA will be required at the conclusion of this case?

A. The actual magnitude of the adjustments to the RESRAM rate and RESRAM RBA is not known at this time. In the anticipated October 2024 RESRAM rate filing, over- and under-recoveries and annual ongoing revenue requirements accumulated through July 2024 will be reflected in the RESRAM rate. The level of ongoing RESRAM revenue requirement included in the RESRAM rate and RBA as a result of that October 2024 filing, which is subsequently reflected in the base rate revenue requirement and MBA established by the Commission in this case, will need to be removed from the RESRAM rate and RBA in the compliance tariffs filed to implement the Commission's decision in this case.

Q. Will the RESRAM rate be zero when this rebasing occurs?

A. No. The portion of the RESRAM rate related to recovery of the ongoing revenue requirement associated with eligible RES investments and activities will be set to zero (assuming these costs and benefits are reflected in this case's revenue requirement). The portion of the RESRAM rate that reflects historical over- or under-recoveries from the previous Accumulation Period, RES Over/Under Recovery ("ROUR"), will remain in effect. Therefore, compliance tariffs would include a non-zero rate consistent with the recovery of ROUR from the Accumulation Period that ends in July of 2024.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Residential - Anytime Users	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	4,188,960	9.00	37,700,640
Low Income Charge	4,188,960	0.14	586,454
Energy Charge			
Summer kWh	1,557,552,010	0.1372	213,696,136
Winter kWh			
First 750 kWh	1,737,066,003	0.0934	162,241,965
Over 750 kWh	1,416,786,105	0.0627	88,832,489
Total Anytime Users kWh	4,711,404,118		
Total Anytime Users Revenue			503,057,684

Residential - Anytime TOD	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	60	9.00	540
Low Income Charge	60	0.14	8
Energy Charge			
Summer kWh			
Off Peak	24,942	0.0828	2,065
On Peak	5,166	0.353	1,824
Winter kWh			
First 750 kWh	49,844	0.0934	4,655
Over 750 kWh	35,164	0.0627	2,205
Total kWh	115,116		
Total Anytime TOD Revenue			11,297

Residential - Evening Morning Savers	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	8,947,308	9.00	80,525,772
Low Income Charge	8,947,308	0.14	1,252,623
Energy Charge			
Summer kWh	3,140,505,042	0.134	420,827,676
Summer Peak kWh	1,894,562,206	0.005	9,472,811
Winter kWh			
First 750 kWh	3,204,988,245	0.0919	294,538,420
Over 750 kWh	2,209,238,526	0.0616	136,089,093
Winter Peak kWh	2,833,695,435	0.0025	7,084,239
Total kWh	8,554,731,812		
Total Evening Morning Revenue			949,790,633

Residential - Overnight Savers	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	22,284	9.00	200,556
Low Income Charge	22,284	0.14	3,120
Energy Charge			
Summer kWh			
Off Peak	2,530,513	0.0644	162,965
On Peak	5,387,298	0.1617	871,126
Winter kWh			
Off Peak	4,390,494	0.0555	243,672
On Peak	8,210,055	0.091	747,115
First 750 kWh	460,037	0.0934	42,967
Over 750 kWh	284,182	0.0627	17,818
Total kWh	21,262,579		
Total Overnight Revenue			2,289,340

Residential - Smart Savers	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	15,084	9.00	135,756
Low Income Charge	15,084	0.14	2,112
Energy Charge			
Summer kWh			
Off Peak	1,653,841	0.0674	111,469
Intermediate Peak	2,779,656	0.1069	297,145
On Peak	613,669	0.3562	218,589
Winter kWh			
Off Peak	2,351,165	0.0558	131,195
Intermediate Peak	4,016,521	0.0684	274,730
On Peak	803,970	0.1907	153,317
First 750 kWh	612,152	0.0934	57,175
Over 750 kWh	443,786	0.0627	27,825
Total kWh	13,274,760		
Total Smart Revenue			1,409,313

Residential - Ultimate Savers	Billing Units	Current Rates	Current Revenue
Customer Charge			
Total Bills	13,476	9.00	121,284
Low Income Charge	13,476	0.14	1,887
Energy Charge			
Summer kWh			
Off Peak	4,977,274	0.0508	252,846
On Peak	702,385	0.3001	210,786
Winter kWh			
Off Peak	8,615,735	0.0449	386,847
On Peak	1,042,946	0.1632	170,209
Demand Charge			
Summer Demand	28,058	8.16	228,953
Winter Demand	50,202	3.37	169,182
Total kWh	15,338,341		
Total kW	78,260		
Total Ultimate Revenue			1,541,992

Community Solar Revenue	128,415	12.12	1,556,390
Total Residential Revenue			1,459,656,650

Small General Service	Billing Units	Current Rates	Current Revenue
Customer Charge			
One-phase	1,172,439	11.96	14,022,369
Three-phase	471,457	22.87	10,782,233
Limited Unmetered Service	88,085	6.34	558,456
TOD Bills			
One-phase	17,595	22.91	403,112
Three-phase	2,059	44.74	92,113
Overnight Bills			
One-phase	105	11.96	1,251
Three-phase	20	22.87	460
Low Income Charge	1,751,760	0.20	350,352
Total Bills	1,751,760		
Energy Charge			
Summer			
Summer kWh	1,089,920,938	0.1197	130,463,536
Off Peak	27,671,872	0.0726	2,008,978
On Peak	16,087,621	0.1779	2,861,988
Overnight Off Peak	0	0.0791	0
Overnight On Peak	0	0.1324	0
Winter			
Base	1,537,920,123	0.0894	137,490,059
Seasonal	477,801,616	0.0516	24,654,563
Off Peak	55,665,150	0.0535	2,978,086
On Peak	30,877,190	0.1172	3,618,807
Overnight Off Peak	104,224	0.0563	5,868
Overnight On Peak	230,435	0.0883	20,347
CellNet kWh	2,273,462	0.0517	117,538
Total kWh	3,238,552,631		
Total SGS Revenue			330,430,116

Community Solar Revenue	5,947	11.13	66,190
Total SGS Revenue			330,496,306

Large General Service	Billing Units	Current Rates	Current Revenue
Customer Charge			
Standard Bills	128,388	108.44	13,922,395
TOD Bills	696	21.08	14,672
Low Income Charge	128,388	2.11	270,899
Demand Charge (kW)			
Summer	8,018,101	6.19	49,632,043
Winter	14,604,472	2.30	33,590,285
Energy Charge			
Summer kWh			
First 150HU	1,038,383,740	0.1112	115,468,272
Next 200HU	1,118,967,542	0.0836	93,545,686
Over 350HU	448,427,484	0.0563	25,246,467
Off Peak	14,488,381	-0.0065	-94,174
On Peak	8,238,780	0.0114	93,922
Winter kWh			
Base Energy Charge			
First 150HU	1,697,867,048	0.0698	118,511,120
Next 200HU	1,807,877,873	0.0519	93,828,862
Over 350HU	768,141,201	0.0409	31,416,975
Seasonal Energy	357,910,289	0.0408	14,602,740
Off Peak	25,865,395	-0.0019	-49,144
On Peak	14,067,404	0.0035	49,236
Total kWh	7,300,235,136		
Total EDI Discount			-1,239,693
Total LGS Revenue			588,810,561

Small Primary Service			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Standard Bills	7,992	371.39	2,968,149
TOD Bills	239	21.08	5,038
Low Income Charge	7,992	2.11	16,863
Demand Charge (kW)			
Summer	2,834,971	5.34	15,138,744
Winter	5,037,989	1.94	9,773,698
Energy Charge			
Summer kWh			
First 150HU	409,045,780	0.1079	44,136,040
Next 200HU	493,755,152	0.0811	40,043,543
Over 350HU	348,538,750	0.0545	18,995,362
Off Peak	30,524,712	-0.0048	-146,519
On Peak	15,033,994	0.0084	126,286
Winter kWh			
Base Energy Charge			
First 150HU	668,605,372	0.0679	45,398,305
Next 200HU	800,536,074	0.0505	40,427,072
Over 350HU	577,956,004	0.0394	22,771,467
Seasonal Energy	168,200,102	0.0395	6,643,904
Off Peak	52,816,499	-0.0018	-95,070
On Peak	27,407,951	0.0031	84,965
Reactive Power (kvar)	1,198,900	0.40	479,560
Rider B 34.5/69 kV Discount	821,787	-1.24	-1,019,015
Rider B 138 kV Discount	5,160	-1.47	-7,586
Total kWh	3,592,420,390		
Total EDI Discount			-1,279,964
Total SPS Revenue			244,460,840

Large Primary Service			
	Billing Units	**Current Rates**	**Current Revenue**
Customer Charge			
Standard Bills	804	371.39	298,598
TOD	60	21.08	1,265
Low Income Charge	804	223.99	180,088
Demand Charge (kW)			
Summer	2,510,295	21.45	53,845,826
Winter	4,411,161	9.53	42,038,360
Energy Charge			
Summer kWh			
Energy	1,337,462,236	0.0364	48,683,625
Off Peak	81,008,617	-0.0035	-283,530
On Peak	39,976,461	0.0064	255,849
Winter kWh			
Energy	2,341,429,769	0.0333	77,969,611
Off Peak	150,709,381	-0.0018	-271,277
On Peak	72,997,422	0.0029	211,693
Reactive Power (kvar)	291,094	0.4	116,438
Rider B 34.5/69 kV Discount	1,928,765	-1.24	-2,391,669
Rider B 138 kV Discount	608,016	-1.47	-893,783
Total kWh	3,678,892,005		
Total EDI Discount			-5,706,827
Total LPS Revenue			214,054,267

Company Owned Lighting 5M	Billing Units	Current Rates	Current Revenue
100000 MH Direct	271	74.44	242,079
11000 MV Open Btm	50	10.59	6,354
140000 HPS Direct	4	75.06	3,603
20000 MV Direct	149	22.89	40,927
20000 MV Enclosed	1,418	17.43	296,589
25500 HPS Direct	1,820	23.81	520,010
25500 HPS Enclosed	3,360	18.33	739,066
27500 HP Enclosed	152	18.33	33,434
3300 MV Open Btm	823	10.57	104,389
3300 MV Post Top	29	23.45	8,161
34000 MH Direct	421	22.93	115,842
34200 HPS Direct	2	23.81	571
36000 MH Direct	1,574	22.93	433,102
47000 HPS Direct	61	37.67	27,574
50000 HPS Direct	1,662	37.67	751,290
50000 HPS Enclosed	819	33.12	325,503
54000 MV Direct	12	33.97	4,892
54000 MV Enclosed	42	29.42	14,828
5800 HPS Open Btm	36	10.92	4,717
6800 MV Enclosed	2,674	12.73	408,480
6800 MV Open Btm	4,321	11.11	576,076
6800 MV Post Top	4,632	24.36	1,354,026
9500 HPS Enclosed	2,685	13.26	427,237
9500 HPS Open Btm	7,772	11.64	1,085,593
9500 HPS Post Top	24,532	24.9	7,330,162
LED 100 W EQ Bracket	86,668	10.71	11,138,571
LED 250 W EQ Bracket	13,524	17.27	2,802,714
LED 400 W EQ Bracket	2,279	31.75	868,299
LED Direct-Large	545	71.89	470,161
LED Direct-Medium	4,366	36.06	1,889,256
LED Direct-Small	3,616	22.49	975,886
LED Post Top - All	27,179	23.77	7,752,538
Municipal Discount		-0.0385	-1,569,609
Total 5M Revenue			39,182,322

Customer Owned Lighting 6M

	Billing Units	Current Rates	Current Revenue
100W LED Energy Only	47	1.75	987
11000 MV Energy Only	24	4.93	1,420
11000 MV Enrg&Maint	26	7.49	2,337
12900 MH Enrg&Maint	53	7.45	4,738
162W LED Energy Only	8	2.84	273
180W LED Energy Only	82	3.15	3,100
196W LED Energy Only	28	3.43	1,152
20000 MV Energy Only	88	7.6	8,026
20000 MV Enrg&Maint	38	9.84	4,487
23W LED Energy Only	25	0.4	120
25500 HPS Enrg&Maint	339	7.38	30,022
25500 HPS Enrgy Only	26	5.14	1,604
26W LED Energy Only	29	0.46	160
27W LED Energy Only	10	0.47	56
3300 MV Enrg&Maint	1	4.3	52
3300 MV Enrgy Only	84	2.13	2,147
36W LED Energy Only	43	0.63	325
40W LED Energy Only	25	0.7	210
44W LED Energy Only	1	0.77	9
45W LED Energy Only	47	0.79	446
48W LED Energy Only	48	0.84	484
50000 HPS Enrg&Maint	44	10.59	5,592
50000 HPS Enrgy Only	1	8.07	97
54000 MV Energy Only	6	18.11	1,304
54000 MV Enrg&Maint	4	20.88	1,002
54W LED Energy Only	33	0.95	376
5500 MH Enrg&Maint	140	6.29	10,567
57W LED Energy Only	7	1	84
60W LED Energy Only	4	1.05	50
6800 MV Enrg&Maint	1,068	5.54	71,001
6800 MV Enrgy Only	121	3.46	5,024
6M Ltd LED 100 W EQ	11,787	3.24	458,279
6M Ltd LED 250 W EQ	119	4.2	5,998
6M Ltd LED 400 W EQ	10	7.41	889
70W LED Energy Only	13	1.23	192
72W LED Energy Only	36	1.26	544
75W LED Energy Only	182	1.31	2,861
80W LED Energy Only	204	1.4	3,427
85W LED Energy Only	50	1.49	894
9500 HPS Enrg&Maint	7,162	4.3	369,559
9500 HPS Enrgy Only	116	2	2,784
96W LED Energy Only	5	1.68	101
Fixture Revenue			1,002,778
Municipal Discount		-0.0385	-38,623
Total 6M Unmetered Revenue			964,155

Customer Owned Lighting 6M Metered			
	Billing Units	**Current Rates**	**Current Revenue**
Bills	20,096	8.15	163,782
Energy	37,681,342	0.0517	1,948,125
Billed Revenue			2,111,908
Municipal Discount		-0.0599	-126,489
Total 6M Metered Revenue			1,985,419

Total Lighting Revenue	42,131,896

MSD Horsepower Service			
	Billing Units	**Current Rates**	**Current Revenue**
	36,900	0.1942	85,992

Total Revenue	2,879,696,512

	1M	2M	3M	4M	5M	6M	11M	MSD		Total
Current Normal Total Revenue	1,459,656,650	330,496,306	588,810,561	244,460,840	39,182,322	2,949,574	214,054,267	85,992		2,879,696,512
Low Income Charge Revenue	1,846,204	350,352	270,899	16,863	0	0	180,088	0		2,664,406
Community Solar Generation Revenue	1,092,812	50,609	0	0	0	0	0	0		1,143,421
EDI Discounts	0	0	1,239,693	1,279,964	0	0	5,706,827	0		8,226,484
Current Normal Base Rate Revenue	1,456,717,634	330,095,345	589,779,355	245,723,941	39,182,322	2,949,574	219,581,006	85,992		2,884,115,170
Revenue-Neutral Adjustment	3,641,794			-1,213,931			-2,427,863			0
Revenue-Neutral Adjustment Base Rate Revenue	1,460,359,428	330,095,345	589,779,355	244,510,010	39,182,322	2,949,574	217,153,144	85,992		2,884,115,170
Remaining Revenue Adjustment Amount	222,344,175	50,258,023	89,795,705	37,227,394	5,965,628	449,082	33,062,228	13,093		439,115,326
Community Solar Generation Revenue Allocation	578,966	130,868	233,821	96,937	15,534	1,169	86,091	34		1,143,421
EDI Discount Allocation	4,165,445	941,545	1,682,253	697,426	111,761	8,413	619,395	245		8,226,484
Incremental EDI Discount Allocation	603,841	136,491	243,867	101,102	16,201	1,220	89,790	36		1,192,548
Base Rate Revenue Target	1,686,893,923	381,300,535	681,267,359	282,438,995	45,260,379	3,407,119	250,838,466	99,331		3,331,506,107
Requested Base Rate Revenue	1,686,843,204	381,285,904	681,262,418	282,435,416	45,260,353	3,406,241	250,825,080	99,276		3,331,417,890
Rounding Diff	-50,719	-14,632	-4,941	-3,580	-26	-878	-13,386	-55		-88,217
Low Income Charge	1,846,204	350,352	270,899	16,863	0	0	180,088	0		2,664,406
Community Solar Generation Revenue	1,092,812	50,609	0							1,143,421
EDI Discounts at Proposed Rates	0	0	1,431,485	1,470,684			6,516,863			9,419,032
Requested Total Revenue	1,689,782,220	381,686,865	680,101,832	280,981,595	45,260,353	3,406,241	244,488,305	99,276		3,325,806,685
Base Rate Revenue Change	230,125,570	51,190,559	91,483,062	36,711,475	6,078,030	456,667	31,244,073	13,284		447,302,721
Base Rate Revenue Percentage Change	15.76%	15.51%	15.51%	15.01%	15.51%	15.48%	14.39%	15.45%		15.51%
Total Revenue Change	230,125,570	51,190,559	91,291,271	36,520,754	6,078,030	456,667	30,434,038	13,284		446,110,173
Total Revenue Percent Change	15.77%	15.49%	15.50%	14.94%	15.51%	15.48%	14.22%	15.45%		15.49%

Residential - Anytime Users			
	Billing Units	Proposed Rates	Normal Revenue
Customer Charge			
Total Bills	4,188,960	$ 10.43	$ 43,690,853
Low Income Charge	4,188,960	$ 0.14	$ 586,454
Energy Charge			
Summer kWh	1,557,552,010	$ 0.1589	$ 247,495,014
Winter kWh			
First 750 kWh	1,737,066,003	$ 0.1082	$ 187,950,541
Over 750 kWh	1,416,786,105	$ 0.0725	$ 102,716,993
Total Anytime Users kWh	4,711,404,118		
Total Anytime Users Revenue			$ 582,439,856

Residential - Anytime TOD			
	Billing Units	Proposed Rates	Normal Revenue
Customer Charge			
Total Bills	60	$ 10.43	$ 626
Low Income Charge	60	$ 0.14	$ 8
Energy Charge			
Summer kWh			
Off Peak	24,942	$ 0.0959	$ 2,392
On Peak	5,166	$ 0.4088	$ 2,112
Winter kWh			
First 750 kWh	49,844	$ 0.1082	$ 5,393
Over 750 kWh	35,164	$ 0.0725	$ 2,549
Total kWh	115,116		
Total Anytime TOD Revenue			$ 13,080

Residential - Evening Morning Savers					
	Billing Units		Proposed Rates		Normal Revenue
Customer Charge					
Total Bills	8,947,308	$	10.43	$	93,320,422
Low Income Charge	8,947,308	$	0.14	$	1,252,623
Energy Charge					
Summer kWh	3,140,505,042	$	0.1555	$	488,348,534
Summer Peak kWh	1,894,562,206	$	0.0050	$	9,472,811
Winter kWh					
First 750 kWh	3,204,988,245	$	0.1067	$	341,972,246
Over 750 kWh	2,209,238,526	$	0.0716	$	158,181,478
Winter Peak kWh	2,833,695,435	$	0.0025	$	7,084,239
Total kWh	8,554,731,812				
Total Evening Morning Revenue				$	1,099,632,353

Residential - Overnight Savers					
	Billing Units		Proposed Rates		Normal Revenue
Customer Charge					
Total Bills	22,284	$	10.43	$	232,422
Low Income Charge	22,284	$	0.14	$	3,120
Energy Charge					
Summer kWh					
Off Peak	2,530,513	$	0.0746	$	188,776
On Peak	5,387,298	$	0.1873	$	1,009,041
Winter kWh					
Off Peak	4,390,494	$	0.0643	$	282,309
On Peak	8,210,055	$	0.1053	$	864,519
First 750 kWh	460,037	$	0.1082	$	49,776
Over 750 kWh	284,182	$	0.0725	$	20,603
Total kWh	21,262,579				
Total Overnight Revenue				$	2,650,566

Residential - Smart Savers	Billing Units	Proposed Rates	Normal Revenue
Customer Charge			
Total Bills	15,084	$ 10.43	$ 157,326
Low Income Charge	15,084	$ 0.14	$ 2,112
Energy Charge			
Summer kWh			
Off Peak	1,653,841	$ 0.0779	$ 128,834
Intermediate Peak	2,779,656	$ 0.1238	$ 344,121
On Peak	613,669	$ 0.4125	$ 253,139
Winter kWh			
Off Peak	2,351,165	$ 0.0646	$ 151,885
Intermediate Peak	4,016,521	$ 0.0792	$ 318,108
On Peak	803,970	$ 0.2208	$ 177,517
First 750 kWh	612,152	$ 0.1082	$ 66,235
Over 750 kWh	443,786	$ 0.0725	$ 32,174
Total kWh	13,274,760		
Total Smart Revenue			$ 1,631,452

Residential - Ultimate Savers	Billing Units	Proposed Rates	Normal Revenue
Customer Charge			
Total Bills	13,476	$ 10.43	$ 140,555
Low Income Charge	13,476	$ 0.14	$ 1,887
Energy Charge			
Summer kWh			
Off Peak	4,977,274	$ 0.0588	$ 292,664
On Peak	702,385	$ 0.3476	$ 244,149
Winter kWh			
Off Peak	8,615,735	$ 0.0520	$ 448,018
On Peak	1,042,946	$ 0.1890	$ 197,117
Demand Charge			
Summer Demand	28,058	$ 9.45	$ 265,148
Winter Demand	50,202	$ 3.90	$ 195,789
Total kWh	15,338,341		
Total kW	78,260		
Total Ultimate Revenue			$ 1,785,326

Community Solar Revenue	128,415	12.69	$ 1,629,586
Total Residential Revenue			$ 1,689,782,220

Small General Service			
	Billing Units	Proposed Rates	Normal Revenue
Customer Charge			
One-phase	1,172,439	$ 13.82	$ 16,203,105
Three-phase	471,457	$ 26.42	$ 12,455,907
Limited Unmetered Service	88,085	$ 7.32	$ 644,779
TOD Bills			
One-phase	17,595	$ 13.82	$ 243,169
Three-phase	2,059	$ 26.42	$ 54,395
Overnight Bills			
One-phase	105	$ 13.82	$ 1,446
Three-phase	20	$ 26.42	$ 531
Low Income Charge	1,751,760	$ 0.20	$ 350,352
Total Bills	1,751,760		
Energy Charge			
Summer kWh			
Summer kWh	1,089,920,938	$ 0.1384	$ 150,845,058
Off Peak	27,671,872	$ 0.0840	$ 2,324,437
On Peak	16,087,621	$ 0.2056	$ 3,307,615
Overnight Off Peak	0	$ 0.0914	$ -
Overnight On Peak	0	$ 0.1529	$ -
Winter kWh			
Base	1,537,920,123	$ 0.1033	$ 158,867,149
Seasonal	477,801,616	$ 0.0597	$ 28,524,756
Off Peak	55,665,150	$ 0.0619	$ 3,445,673
On Peak	30,877,190	$ 0.1355	$ 4,183,859
Overnight Off Peak	104,224	$ 0.0650	$ 6,775
Overnight On Peak	230,435	$ 0.1020	$ 23,504
CellNet kWh	2,273,462	$ 0.06	$ 135,726
Total kWh	3,238,552,631		
Total Revenue			$ 381,618,237
Community Solar Revenue	5,947	11.54	$ 68,628
Total SGS Revenue			$ 381,686,865

Large General Service					
	Billing Units		Proposed Rates		Normal Revenue
Customer Charge					
Standard Bills	128,388	$	125.27	$	16,083,165
TOD Bills	696	$	-	$	-
Low Income Charge	128,388	$	2.11	$	270,899
Demand Charge (kW)					
Summer	8,018,101	$	7.15	$	57,329,419
Winter	14,604,472	$	2.66	$	38,847,895
Energy Charge					
Summer kWh					
First 150HU	1,038,383,740	$	0.1285	$	133,432,311
Next 200HU	1,118,967,542	$	0.0966	$	108,092,265
Over 350HU	448,427,484	$	0.0650	$	29,147,786
Off Peak	14,488,381	$	(0.0079)	$	(114,458)
On Peak	8,238,780	$	0.0114	$	93,922
Winter kWh					
Base Energy Charge					
First 150HU	1,697,867,048	$	0.0806	$	136,848,084
Next 200HU	1,807,877,873	$	0.0600	$	108,472,672
Over 350HU	768,141,201	$	0.0471	$	36,179,451
Seasonal Energy	357,910,289	$	0.0471	$	16,857,575
Off Peak	25,865,395	$	(0.0022)	$	(56,904)
On Peak	14,067,404	$	0.0035	$	49,236
Total kWh	7,237,575,177				
Total EDI Discount				$	(1,431,485)
Total LGS Revenue				$	680,101,832

Small Primary Service					
	Billing Units	Proposed Rates		Normal Revenue	
Customer Charge					
Standard Bills	7,992	$	426.93	$	3,412,025
TOD Bills	239	$	-	$	-
Low Income Charge	7,992	$	2.11	$	16,863
Demand Charge (kW)					
Summer	2,834,971	$	6.14	$	17,406,721
Winter	5,037,989	$	2.23	$	11,234,714
Energy Charge					
Summer kWh					
First 150HU	409,045,780	$	0.1240	$	50,721,677
Next 200HU	493,755,152	$	0.0932	$	46,017,980
Over 350HU	348,538,750	$	0.0625	$	21,783,672
Off Peak	30,524,712	$	(0.0055)	$	(167,886)
On Peak	15,033,994	$	0.0084	$	126,286
Winter kWh					
Base Energy Charge					
First 150HU	668,605,372	$	0.0781	$	52,218,080
Next 200HU	800,536,074	$	0.0581	$	46,511,146
Over 350HU	577,956,004	$	0.0453	$	26,181,407
Seasonal Energy	168,200,102	$	0.0454	$	7,636,285
Off Peak	52,816,499	$	(0.0019)	$	(100,351)
On Peak	27,407,951	$	0.0031	$	84,965
Reactive Power (kvar)	1,198,900	$	0.4609	$	552,573
Rider B 34.5/69 kV Discount	821,787	$	(1.43)	$	(1,175,155)
Rider B 138 kV Discount	5,160	$	(1.69)	$	(8,721)
Total kWh	3,466,637,234				
Total EDI Discount				$	(1,470,684)
Total SPS Revenue				$	280,981,595

Large Primary Service					
	Billing Units		Proposed Rates		Normal Revenue
Customer Charge					
Standard Bills	804	$	426.93	$	343,252
TOD	60	$	-	$	-
Low Income Charge	804	$	223.99	$	180,088
Demand Charge (kW)					
Summer	2,510,295	$	24.51	$	61,527,329
Winter	4,411,161	$	10.90	$	48,081,650
Energy Charge					
Summer kWh					
Energy	1,337,462,236		0.0416	$	55,638,429
Off Peak	81,008,617		-0.0037	$	(299,732)
On Peak	39,976,461		0.0064	$	255,849
Winter kWh					
Energy	2,341,429,769		0.038	$	88,974,331
Off Peak	150,709,381		-0.0017	$	(256,206)
On Peak	72,997,422		0.0029	$	211,693
Reactive Power (kvar)	291,094		0.4609	$	134,165
Rider B 34.5/69 kV Discount	1,928,765	$	(1.43)	$	(2,758,134)
Rider B 138 kV Discount	608,016	$	(1.69)	$	(1,027,547)
Total kWh	3,678,892,005				
Total EDI Discount				$	(6,516,863)
Total LPS Revenue				$	244,488,305

Company Owned Lighting 5M			
	Billing Units	Proposed Rates	Normal Revenue
100000 MH Direct	271	$ 85.99	$ 279,639
11000 MV Open Btm	50	$ 12.23	$ 7,338
140000 HPS Direct	4	$ 86.70	$ 4,162
20000 MV Direct	149	$ 26.44	$ 47,275
20000 MV Enclosed	1,418	$ 20.13	$ 342,532
25500 HPS Direct	1,820	$ 27.50	$ 600,600
25500 HPS Enclosed	3,360	$ 21.17	$ 853,574
27500 HP Enclosed	152	$ 21.17	$ 38,614
3300 MV Open Btm	823	$ 12.21	$ 120,586
3300 MV Post Top	29	$ 27.09	$ 9,427
34000 MH Direct	421	$ 26.49	$ 133,827
34200 HPS Direct	2	$ 27.50	$ 660
36000 MH Direct	1,574	$ 26.49	$ 500,343
47000 HPS Direct	61	$ 43.51	$ 31,849
50000 HPS Direct	1,662	$ 43.51	$ 867,763
50000 HPS Enclosed	819	$ 38.26	$ 376,019
54000 MV Direct	12	$ 39.24	$ 5,651
54000 MV Enclosed	42	$ 33.98	$ 17,126
5800 HPS Open Btm	36	$ 12.61	$ 5,448
6800 MV Enclosed	2,674	$ 14.70	$ 471,694
6800 MV Open Btm	4,321	$ 12.83	$ 665,261
6800 MV Post Top	4,632	$ 28.14	$ 1,564,134
9500 HPS Enclosed	2,685	$ 15.32	$ 493,610
9500 HPS Open Btm	7,772	$ 13.45	$ 1,254,401
9500 HPS Post Top	24,532	$ 28.76	$ 8,466,484
LED 100 W EQ Bracket	86,668	$ 12.37	$ 12,864,998
LED 250 W EQ Bracket	13,524	$ 19.96	$ 3,239,268
LED 400 W EQ Bracket	2,279	$ 36.68	$ 1,003,125
LED Direct-Large	545	$ 83.04	$ 543,082
LED Direct-Medium	4,366	$ 41.64	$ 2,181,603
LED Direct-Small	3,616	$ 25.98	$ 1,127,324
LED Post Top - All	27,179	$ 27.46	$ 8,956,024
Municipal Discount		-0.0385	$ (1,813,089)
Total 5M Revenue			$ 45,260,353

Customer Owned Lighting 6M	Billing Units	Proposed Rates	Normal Revenue
100W LED Energy Only	47	$ 2.02	$ 1,139
11000 MV Energy Only	24	$ 5.69	$ 1,639
11000 MV Enrg&Maint	26	$ 8.65	$ 2,699
12900 MH Energy Only	0	$ 4.10	$ -
12900 MH Enrg&Maint	53	$ 8.61	$ 5,476
162W LED Energy Only	8	$ 3.27	$ 314
180W LED Energy Only	82	$ 3.64	$ 3,582
196W LED Energy Only	28	$ 3.96	$ 1,331
20000 MV Energy Only	88	$ 8.78	$ 9,272
20000 MV Enrg&Maint	38	$ 11.37	$ 5,185
23W LED Energy Only	25	$ 0.46	$ 138
25500 HPS Enrg&Maint	339	$ 8.52	$ 34,659
25500 HPS Enrgy Only	26	$ 5.94	$ 1,853
26W LED Energy Only	29	$ 0.53	$ 184
27W LED Energy Only	10	$ 0.55	$ 66
3300 MV Enrg&Maint	1	$ 4.97	$ 60
3300 MV Enrgy Only	84	$ 2.46	$ 2,480
36W LED Energy Only	43	$ 0.73	$ 377
40W LED Energy Only	25	$ 0.81	$ 243
44W LED Energy Only	1	$ 0.89	$ 11
45W LED Energy Only	47	$ 0.91	$ 513
48W LED Energy Only	48	$ 0.97	$ 559
50000 HPS Enrg&Maint	44	$ 12.23	$ 6,457
50000 HPS Enrgy Only	1	$ 9.32	$ 112
54000 MV Energy Only	6	$ 20.92	$ 1,506
54000 MV Enrg&Maint	4	$ 24.12	$ 1,158
54W LED Energy Only	33	$ 1.09	$ 432
5500 MH Enrg&Maint	140	$ 7.27	$ 12,214
5500 MH Energy Only	0	$ 2.43	$ -
57W LED Energy Only	7	$ 1.15	$ 97
60W LED Energy Only	4	$ 1.21	$ 58
6800 MV Enrg&Maint	1,068	$ 6.40	$ 82,022
6800 MV Enrgy Only	121	$ 4.00	$ 5,808
6M Ltd LED 100 W EQ	11,787	$ 3.74	$ 529,001
6M Ltd LED 250 W EQ	119	$ 4.85	$ 6,926
6M Ltd LED 400 W EQ	10	$ 8.56	$ 1,027
70W LED Energy Only	13	$ 1.41	$ 220
72W LED Energy Only	36	$ 1.45	$ 626
75W LED Energy Only	182	$ 1.52	$ 3,320
80W LED Energy Only	204	$ 1.62	$ 3,966
85W LED Energy Only	50	$ 1.72	$ 1,032
9500 HPS Enrg&Maint	7,162	$ 4.97	$ 427,142
9500 HPS Enrgy Only	116	$ 2.31	$ 3,216
96W LED Energy Only	5	$ 1.94	$ 116
Fixture Revenue			$ 1,158,233
Municipal Discount		-0.0599	$ (44,611)
Total 6M Unmetered Revenue			$ 1,113,622

Customer Owned Lighting 6M Metered					
	Billing Units	Proposed Rates		Normal Revenue	
Bills	20,096	$	9.41	$	189,103
Energy	37,681,342	$	0.06	$	2,249,576
Billed Revenue				$	2,438,679
Municipal Discount			-0.0599	$	(146,061)
Total 6M Metered Revenue				$	2,292,619

Total Lighting Revenue	$	48,666,593

MSD Horsepower Service					
	Billing Units	Proposed Rates		Normal Revenue	
	36,900	$	0.2242	$	99,276

RIDER RESRAM

RENEWABLE ENERGY STANDARD RATE ADJUSTMENT MECHANISM

RESRAM Rate Schedule

Accumulation Period Ending: 07/31/2024

1.	Actual RES Costs Incurred in AP (ARC)		$xxxx
2.	RES Expenses Recovered in AP (RCR) =(RBA + sum of monthly MBAs)	=	$xxxx
3.	RES Over/Under Recovery (ROUR)=	=	$xxxx
	3.1 Interest	+	$xxxx
	3.2 (Over)/Under Recovered Costs (ARC-RCR)	+	$xxxx
4.	RES Revenue Requirement (RRR)	+	$0
5.	True-Up (T)	+	$xxxx
6.	Ordered Adjustment (OA)	±	$xxxx
7.	Total RESRAM Recoveries(TRR)=(ROUR+RRR+T+OA)	=	$xxxx
8.	Estimated Recovery Period Sales (S_{RP})	÷	xx,xxx,xxx,xxx kWh
9.	TRR_{RATE} = MIN of((TRR/S_{RP}),(RAC))	=	$(x.xxxxx)/kWh
10.	$RESRAM_{RATE}$ = TRR_{RATE} + ROA[1]	=	$(x.xxxxx)/kWh
11.	Required Offset Amount (ROA)	**+**	$x.xxxxx/kWh
12.	**$RESRAM_{RATE}$ (applicable for the first 6 months if ROA is greater than $0.00000)**	**=**	**$(x.xxxx)/kWh**

*A negative RESRAM Rate represents a per kWh credit that would be applied to a customer's bill.

Recovery Period for Above RESRAM Rate
February 1, 2024 to January 31, 2025

Current RBA = $0

Base Amount File No. ER-2024-0319 = -$10,740,897

[1] If ROA is equal $0.00000, The $RESRAM_{RATE}$ stated in this Line 10 shall apply for the entire Recovery Period. If ROA is greater than $0.00000, the $RESRAM_{RATE}$ shall be the value shown on line 12 for the first 6 months and, thereafter, the value shown on Line 10.

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 Adjust Its Revenues for Electric Service.	)))	Case No. ER-2024-0319

AFFIDAVIT OF NICHOLAS BOWDEN

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

Nicholas Bowden, being first duly sworn states:

My name is Nicholas Bowden, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

/s/ Nicholas Bowden
Nicholas Bowden

Sworn to me this 26th day of June, 2024.