Public Version

Exhibit No.:	
Issue:	Annualized/Normalized Revenues, CCOS, Tariffs, Rate Design, AMI
Witness:	Marisol E. Miller
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Evergy Missouri Metro
Case No.:	ER-2022-0129
Date Testimony Prepared:	January 7, 2022

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2022-0129

DIRECT TESTIMONY

OF

MARISOL E. MILLER

ON BEHALF OF

EVERGY MISSOURI METRO

Kansas City, Missouri
January 2022

TABLE OF CONTENTS

DIRECT TESTIMONY

OF

MARISOL E. MILLER

Case No. ER-2022-0129

Q: Please state your name and business address.

A: My name is Marisol E. Miller. My business address is 1200 Main, Kansas City, Missouri 64105.

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

A: I am employed by Evergy Metro, Inc. I serve as Senior Manager – Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Evergy Missouri Metro.

Q: What are your responsibilities?

A: My general responsibilities are to provide support for the Company's regulatory activities in the Missouri and Kansas jurisdictions. Specifically, my duties include oversight of class cost of service, tariff management, load analysis, and rate design. I also manage certain analytical activities for the department including rate change implementation, billing determinant calculation, and retail revenue calculation.

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

A: I hold a Master of Business Administration degree from Rockhurst University with an emphasis in Management. I also was awarded a Bachelor of Science in Business Administration Magna Cum Laude with an emphasis in Business Finance and Banking/Financial Markets from the University of Nebraska at Omaha. In addition to those academic credentials, the Institute of Internal Auditor's ("IIA") and the Association of Certified Fraud Examiners ("ACFE") have certified me as a Certified Internal Auditor and Certified Fraud Examiner respectively.

I've worked in various roles in Financial Analysis, Financial Reporting, and Internal Auditing. I joined KCP&L (now Evergy) in August of 2006 working as a Senior/Lead Internal Auditor. I led various projects of increasing complexity and most notably was the on-site Internal Auditor for the approximately $2 billion Comprehensive Energy Plan Iatan 2 Construction project.

I have worked in the Regulatory Affairs Department since 2011 holding various positions covering areas including Integrated Resource Planning ("IRP"), Missouri Energy Efficiency Investment Act ("MEEIA")/Demand-Side Management ("DSM"), compliance reporting for multiple areas in transmission and delivery, and rate case support.

Q: Have you previously testified in a proceeding before the Missouri Public Service Commission ("Commission" or "MPSC") or before any other utility regulatory agency?

A: Yes, I provided written testimony before the Kansas Corporation Commission ("KCC") and provided written testimony and testified in proceedings before the MPSC.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

I. Highlight and explain changes impacting rates resulting from rate studies and planning. These changes include:

a. Seasonal Alignment

b. Real Time Pricing ("RTP") Alternative

c. Rate Clean Up

i. Residential

1. Eliminate frozen 2 Meter Heat Rate (1RS2A) and transition customers to 1 Meter Heat Rate (1RS6A).

2. Eliminate Residential Other Rate (1RO1A) and transition customers to Residential Standard (1RS1A).

3. Eliminate frozen Time of Day (TOD) Rate (1TE1A) and transition customers to Residential Standard (1RS1A).

4. Remove frozen Multi-occupancy provision from the Residential Standard and Residential 1 Meter heat rate calculation (subset of 1RS1A and 1RS6A) and transition customers to the standard commercial rate based on best fit (1SGSE or 1MGSE).

ii. Non-Residential

1. Eliminate frozen 2 Meter Heat Rates (1SGHE, 1MGHE, 1LGHE) and transition customers to 1 Meter All Electric Rates based on best fit (1SGAE, 1MGAE, 1LGAE).

2. Eliminate the frozen Two Part Time of Use provision and transition customers to the base (1SGSE) rate.
3. Remove the special Facilities Demand calculation for certain customers on the Large General Service, Medium General Service, and Small General Service tariffs (subset of rates 1SGSE, 1MGSE and 1LGSE) and use the standard facilities demand calculation within the general service rates (1SGSE, 1MGSE, 1LGSE).

d. Studies underway with potential plans for the future
   i. Bright Lines
   ii. Hours Use

II. Explain and support the Company's annualized/normalized revenues.

III. Explain the Electric Class Cost of Service ("CCOS") Study.

IV. Explain and support the Company's Electric Rate Design.

I. CHANGES RESULTING FROM RATE STUDIES

Q: Were there any studies completed that impact change to revenues or rate design proposed in this case?

A: Yes. The Company performed a number of studies as part of commitments made in the last general rate case that provided insight into the value of rate consolidation and simplification. The proposals included herein are also part of a broader Rate Modernization Plan ("Rate Plan") that will expand programs and rates offered to our customers. For more details on the Company's Rate Plan goals and objectives, as well as the studies and commitments completed, please see the Direct testimony of Company witnesses Bradley D. Lutz and Kimberly Winslow. My testimony will focus on the proposals resulting from those studies and reviews.

Q: What proposals are being made as part of this filing that resulted from studies or planning?

A: The following proposals are being made in this filing resulting from studies:

- Seasonal Date Alignment (All Customers)
- Real Time Pricing ("RTP") alternative (Commercial & Industrial Customers) (frozen)
- Elimination of certain Rates or rate provisions
  - Residential
    - 2 Meter Heat Rate (frozen) and 2 Meter Electric Heating and Electric Water Heating provision (frozen)
    - Residential Other
    - Time of Day (frozen)
    - Multiple Occupancy provision in the Residential Tariff (frozen)
  - Commercial & Industrial
    - 2 Meter Heat Rate (frozen)
    - Two Part-Time of Use provision (frozen)
    - Special Facilities Demand treatment for certain customers (frozen)

Q: Are there other rate changes that you will discuss in your testimony?

A: Yes, I will also discuss studies that are currently underway that explore a potential future change that would impact our Commercial & Industrial classes. The two studies cover the calculation of Hours Use utilized in the energy charge calculation and the establishment of "bright lines" for demands. The intention in discussing these studies now is to collect feedback to inform a future case where these study results will be used to propose potential changes to the energy charge calculation and class demand thresholds.

Q: Can you provide a bit of background and detail on each proposal starting with the proposal for seasonal alignment?

A: Yes. The Company agreed to complete a study to explore the potential alignment of summer and winter seasons of the Evergy Missouri Metro and Evergy Missouri West utilities. Currently, the Missouri Metro jurisdiction defines the summer season as beginning May 16 through September 15 and winter season as September 16 through May 15. The results of the study showed benefit to alignment. We are proposing changing the summer season and winter season for Missouri Metro to better align with the Missouri West jurisdiction or June 1 through September 30 and October 1 through May 31, respectively.

Q: What analysis was performed in the Study?

A: Multiple analyses were completed to support this change including customer bill impact and revenue. These are all outlined in the Direct Testimony of Company Witness Bradley D. Lutz.

Q: Are there test year revenue impacts to the Seasonal alignment proposal?

A: Yes, on a weather normalized customer growth adjusted basis, the change would result in a decrease in test year revenues of approximately $352,083.

Q: How was this calculated?

A: Utilizing the test year billing determinants, the Company recalculated billed revenue actuals utilizing the new defined seasonal periods and then applied weather normalization, customer growth, and the other adjustments typical in adjusted test year billed revenues.

The $352,083 represents the difference between normalized revenues with the current seasonal definitions and normalized revenues with the new seasonal definitions. The tables below outline the change in revenue by class and in total.

Table 1- Seasonal Alignment Test Year Revenue Impact by Class and Total [1]

Class	Before Change	After Change	Diff	Diff %
RES	$341,159,142.81	$341,072,261.89	-$86,880.92	-0.0255%
SGS	$68,617,737.48	$68,558,084.73	-$59,652.76	-0.0869%
MGS	$121,656,929.77	$121,612,062.48	-$44,867.29	-0.0369%
LGS	$180,373,757.71	$180,236,999.24	-$136,758.46	-0.0758%
CCN	$74,563.92	$74,563.92	$0.00	0.0000%
LPS	$121,482,208.12	$121,458,284.64	-$23,923.47	-0.0197%
Lighting	$9,930,634.83	$9,930,634.83	$0.00	0.0000%

Table 2- Seasonal Alignment Test Year Revenue Impact Total Impact

Normalized, Annualized Revenue Impact	
Before Change	$843,294,974.64
After Change	$842,942,891.74
Total Change	-$352,082.90
Total Change %	-0.04%

Q: Was there anything else considered regarding seasonal alignment?

A: While not directly related to seasonal alignment across jurisdictions, the Company did consider historical stakeholder interest in the creation of shoulder seasons. In the System Peak Analysis performed as part of the Seasonal Study, there was an observed increase in February for both MO Metro and MO West jurisdictions. The Company believes this to be related to the extreme cold weather event impacting the entire Midwest region in that

[1] CCN and Lighting classes would not be impacted by a change in seasons. While the change outlined are reflective of expected test year revenue differences resulting from the seasonal redefinition, it was not reflected in the Direct filing test year revenues and therefore will not reconcile to billed revenues filed in Direct. The Company expects to update revenues to reflect new season at True Up.

period. Given the extreme nature of the cold weather event, no adjustment to create a shoulder season was proposed as part of this rate case. The Company is a summer peaking utility and believes that price signals should emphasize the summer period as the "peak" and should reflect that acknowledgement through price signals offered through higher pricing in the summer. The creation of a shoulder season based on an occasional day or two of increased load or based on an extreme weather event will only serve to confuse customers or thwart the effectiveness of price signals appropriately emphasizing the summer season as appropriate for a summer peaking utility. Still, in an effort to be cognizant of stakeholder concerns, the Company will continue to monitor customer loads and system peak data to determine if such an adjustment in the future is merited.

Q: What are you proposing in the area of Real Time Pricing ("RTP")?

A: The Company worked with consulting firm, Concentric Energy Advisors, to design a rate option that leveraged real world examples in the industry, offered price signals that aligned with market pricing, and that worked with Evergy's billing system. The result was an hourly rate that melds the predictability of static time variant rates with a reflection of market energy price fluctuations. The rate will offer flexibility and predictability that will allow customers to modify their operations to take advantage of reduced cost hours. This offering is a result of a rate case commitment in the last general rate cases. For more details on the commitment and background, please see the Direct Testimony of Company witness Bradley D. Lutz.

Q: What is the recommendation and what analysis has been performed to support the plan?

A: Utilizing the current Class Cost of Service study, functionalized costs were identified for use in a time-sensitive model for replacement of the RTP tariff. Costs which vary by season (summer versus non-summer) and day type (weekday versus weekend) were identified for temporal allocation. Excess production demand costs were slated for allocation to hours within 90% of System peak, and Energy-related costs were slated for allocation based on locational marginal prices. Average production demand costs, which also possess a time element, were slated for application to all hours. Though Transmission demand costs are not temporal, they are covered in normal rates by the regular demand charge and were thus also slated for application equally to all hours. Distribution demand costs and Customer-related costs were deemed non-temporal. These costs are currently handled via the Facilities Demand Charge (variable by kW) and Customer Charge (per customer), respectively, within the normal general service tariff rates, and were thus treated accordingly in this proposed rate design and excluded from the hourly considerations. Next, system hourly cost patterns were identified. Prior year day-ahead locational marginal price ("LMP") data was analyzed to identify high and low-cost hours by season and day type. System hourly load data was also analyzed to identify the hours that are the drivers of peak demand and associated costs. Utilizing these findings, the identified time-variable costs were allocated by hour. Once the various functional costs were allocated to the different temporal and non-temporal components, rates were designed to be revenue neutral for each rate class. The resulting structure is composed of three distinct components: hourly energy charge variable by season and day type; facilities demand charge; and customer charge. This new structure continues to preserve the time-based components inherent in the current RTP rate structure, establishes appropriate price signals for efficient usage while providing a means for customers to modify usage to reduce costs, and will work with the Company's billing system. The new rate will be available on a limited basis to customers meeting specific load requirements typical of current Large Power Service and Large General Service customers. It is intended that the rate will be broadened further to allow for greater participation in a future case leveraging learnings from this initial offering. See the following table for the pricing related to this proposal, Schedule MEM-3 for RTP Alternate report, and new tariff Time-Related Pricing ("TRP") filed in this case.

Large General Service – level rates:

Table 3 – Time Related Pricing

Customer Charge ($/month)	
0-24 KW	**$125.12**
25-199 KW	**$125.12**
200-999 KW	**$125.12**
1000 KW or above	**$1,068.21**

Facilities Charge ($/kW)	
Secondary	**$3.579**
Primary	**$2.967**

Hourly Energy Charge ($/kWh)

Hour Ending	Summer Weekday	Non-Summer Weekday	Summer Weekend	Non-Summer Weekend
1	$0.04317	$0.05756	$0.03942	$0.06713
2	$0.03918	$0.05501	$0.03659	$0.06411
3	$0.03727	$0.05467	$0.03486	$0.06125
4	$0.03657	$0.05553	$0.03410	$0.06200
5	$0.03949	$0.06084	$0.03486	$0.06586
6	$0.04558	$0.07272	$0.03719	$0.07186
7	$0.05184	$0.09535	$0.03914	$0.07860

8	$0.05559	$0.09816	$0.04316	$0.08781
9	$0.06132	$0.09535	$0.04753	$0.09859
10	$0.06448	$0.09864	$0.05017	$0.10728
11	$0.07077	$0.09331	$0.05347	$0.10260
12	$0.07976	$0.08869	$0.05934	$0.09590
13	$0.08805	$0.08533	$0.06513	$0.09119
14	$0.11254	$0.08426	$0.06962	$0.08753
15	$0.14331	$0.08087	$0.08647	$0.08642
16	$0.18869	$0.07961	$0.09209	$0.08685
17	$0.21493	$0.08375	$0.09523	$0.09190
18	$0.19287	$0.09358	$0.08996	$0.10578
19	$0.14224	$0.09541	$0.08084	$0.10712
20	$0.11473	$0.09198	$0.07414	$0.10355
21	$0.08018	$0.08999	$0.05300	$0.09848
22	$0.06005	$0.07731	$0.04883	$0.08614
23	$0.05205	$0.06718	$0.04339	$0.07546
24	$0.04607	$0.05769	$0.03930	$0.06500

Large Power Service – level rates:

Customer Charge ($/month)	**$1,210.14**

Facilities Charge ($/kW)	
Secondary	**$4.053**
Primary	**$3.359**
Substation	**$1.014**
Transmission	**$0.000**

Hourly Energy Charge ($/kWh)

Hour Ending	Summer Weekday	Non-Summer Weekday	Summer Weekend	Non-Summer Weekend
1	$0.04290	$0.04875	$0.03567	$0.05211
2	$0.03850	$0.04657	$0.03295	$0.04983
3	$0.03639	$0.04629	$0.03128	$0.04767
4	$0.03563	$0.04702	$0.03056	$0.04824
5	$0.03885	$0.05154	$0.03128	$0.05115
6	$0.04556	$0.06166	$0.03353	$0.05568
7	$0.05247	$0.08092	$0.03539	$0.06077
8	$0.05660	$0.08330	$0.03926	$0.06771
9	$0.06293	$0.08091	$0.04345	$0.07585
10	$0.06641	$0.08371	$0.04599	$0.08240
11	$0.07335	$0.07918	$0.04915	$0.07887

12	$0.08327	$0.07524	$0.05479	$0.07381
13	$0.09242	$0.07238	$0.06035	$0.07026
14	$0.10658	$0.07148	$0.06466	$0.06750
15	$0.12304	$0.06859	$0.07056	$0.06666
16	$0.14620	$0.06752	$0.07568	$0.06699
17	$0.15070	$0.07104	$0.07839	$0.07080
18	$0.13198	$0.07941	$0.07314	$0.08127
19	$0.10534	$0.08096	$0.06427	$0.08228
20	$0.08981	$0.07805	$0.05786	$0.07959
21	$0.07292	$0.07636	$0.04870	$0.07576
22	$0.06153	$0.06556	$0.04470	$0.06645
23	$0.05270	$0.05694	$0.03948	$0.05840
24	$0.04610	$0.04886	$0.03555	$0.05051

Q: Can you provide some background on what is being proposed for grandfathered/frozen rates and why?

A: The Company completed a study exploring the consolidation of the MO Metro and MO West rates which was filed on October 31, 2020. The objective of the study was to outline the current state of operations, costs, and rates, the potential obstacles with immediate rate consolidation given the current state, and finally, the steps contemplated to consolidate rates properly. Because of concern with the impact to customers, a careful, incremental process and plan was outlined to ensure minimal impact and to allow time for customer adjustment. The proposals for the elimination of grandfathered rates represents a portion of Steps 1, 2, 3 of that plan.

Q: For the elimination of grandfathered rates and rate clean up, what analysis was performed to support those proposals?

A: The Company completed various analyses to understand the impact of the proposals to determine feasibility. The following steps were performed:

- Identified full list of frozen rates/rate provisions
- Determined the number of customers on each and how long the rate had been frozen

- Pulled test year actual[2] billing determinants for all customers in a given frozen rate/provision
- Performed best fit analysis to determine the best rate for each customer
- Performed bill impact analysis comparing the current rate and the new using test year
- Finalized recommendations
- Developed an approach to contact and educate impacted customers

Q: Are you proposing elimination of all frozen rates at this time?

A: No. The following frozen rates are not being proposed for elimination at this time:

- The non-residential, 1 Meter all electric rates which have been grandfathered since June 1, 2008.
- Frozen lighting rates with active customers.

Q: Why aren't all grandfathered/frozen rates being proposed for elimination at this time?

A: The Company is not proposing elimination of the Non-residential 1 Meter all electric rate this time as the rate is being used as a transition for the elimination of the non-residential, 2 Meter Heat rates. All frozen, non-LED lighting rates with active customers are not being eliminated at this time due to the need for customer coordination/fieldwork. However, switch outs are continuing to take place when repairs or customer requests occur.

[2] All bill impact analysis and corresponding analysis that utilizes billing determinants actuals (kwh, kw, and customer count) will be based calculated on an actual basis with no adjustment for weather or growth. Only customers with a full 12 months of data in the test year were analyzed.

Q: Starting with the Residential Class, why is the Company proposing the elimination of the 2 Meter Heat rates?

A: The Company's Rate Plan moves away from end use rates. The 2 Meter Heat rate was frozen on January 1, 2007 and the 2 Meter Electric Heating and Electric Water Heating provision was frozen on July 9, 1996. Given the number of customers on this rate is down to 9,619, plus the length of time since freezing the rate, the time seems right to seek elimination. Customers would be moved to the 1 Meter all electric rate.

Q: If the Company is moving away from the end use rates as part of the Rate Plan, why are these customers being proposed to be moved to the 1 Meter All Electric rate?

A: The move to a 1 Meter All Electric rate is considered to be an interim step until most/all end use rates are eliminated. The Company anticipates a proposal in a future rate case where the 1 Meter All Electric rate will be frozen/eliminated. Until that time, the Company will continue to monitor these customers and determine how the general use rates can be designed and/or modified to provide benefit to these customers in such a way that minimizes overall customer impact and fits with Rate Plan efforts. These rates/provisions have been frozen for well over a decade and electric heating customers who established service since 2007 have been subject to standard rates.

Q: What were the results of the customer bill impact analysis?

A: Based on review of 6,481 customers with 12 months of actual usage for the 12 months ending June 30, 2021, approximately 90% of customers could experience an annual bill impact of less than 5%, with almost 75% of those customers experiencing an increase of

0%[3] or less. Of the 164 customers who were impacted by more than 10%, 111 are impacted by less than $10/mo.

Q: What is the Company proposing for the Residential Other rate and why?

A: The Company proposes elimination of the Residential Other rate and moving those customers to the Residential Standard rate. The Residential Other rate provides electric service to Residential customers who have dedicated well pumps, barns, machine sheds, detached garages, etc. and whose corresponding usage would not currently qualify under any other Residential rate. The Company views this usage as largely an extension of Residential usage and believe it should be covered as part of the Residential General use tariff. This will require modification of the tariff language to allow for this change. Those proposed changes are reflected in the tariffs supporting this rate case filing.

Q: What were the results of the customer bill impact analysis?

A: Based on review of 147 customers with 12 months of actual usage for the 12 months ending June 30, 2021, 100% of customers could experience a bill decrease ranging from 5% to 35%[4].

Q: What is the Company proposing for the frozen Time of Day Service rate and why?

A: Since this rate was frozen in 2015, new TOU rate offerings have been made available that leverage recent analysis and industry best practice, and given the limited participation of just 26 customers, the Company is proposing elimination of the rate and moving these customers to the Residential Standard rate. It is the Company's intention to inform these

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[3] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.
[4] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.

customers on the latest TOU rate offerings available to them but will allow them to make the choice to move to the optional TOU rates available.

Q: What were the results of the customer bill impact analysis?

A: Based on review of 21 customers with 12 months of actual usage for the 12 months ending June 30, 2021, approximately 75% of customers could experience a bill decrease ranging from 0-5%[5] and no customer was impacted by more than approximately 6%. Should customers move to another TOU rate, this potential bill change ignores any potential customer behavior or usage changes that would further influence bill change/savings.

Q: What is the Company proposing for the frozen multiple occupancy provision of the Residential rate and why?

A: The Residential Service tariff includes a provision frozen since 1981 that allows single metered multiple occupancy residential buildings to take service under the Residential tariff. This represents a stark difference when compared to Evergy's other jurisdictions that bill these kinds of customer on commercial rates. Given the small number of customers on this rate, 22, the Company proposes alignment with other jurisdictions and to move these customers to C&I rates.

Q: What were the results of the customer bill impact analysis?

A: Two rate codes include the multi-occupancy provision (or have customers that utilize the calculation). One rate code captures 16 of the 22 total customers. Of those 16 customers with 12 months of actual usage for the 12 months ending June 30, 2021, potential bill impacts range from -17% to +11.99%[6] or -$140.02 to +$346.80 annually. These premises all have four or less apartments each with average usage just over 12,000 kWh annually.

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[5] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.
[6] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.

The second rate code has 6 customers. Of the 5 customers with 12 months of actual usage for the 12 months ending June 30, 2021, these customers will potentially experience bill impacts ranging from -1.31% to +30%[6]. It should be noted that these multi-unit complexes all have ten or more apartments each and have usage which exceeds an average of 80,000 kWh annually.

Q: For the Non-Residential Classes, why is the Company proposing the elimination of the 2 Meter Heat rates?

A: The Company's Rate Plan moves away from end use rates. The 2 Meter Heat rate was frozen on July 9, 1996. Given the number of customers on this rate is down to 16 for the Large General Service, 55 for the Medium General Service, and 116 for Small General Service, the time seems right to seek elimination. Customers would be moved to the 1 Meter All Electric rate.

Q: If the Company is moving away from the end use rates as part of the Rate Plan, why are these customers being proposed to be moved to the 1 Meter All Electric rate?

A: Like the proposal for the Residential Class, the move to the 1 Meter All Electric rate is considered to be an interim step until most/all end use rates are eliminated. The Company anticipates a proposal in a future rate case where the 1 Meter All Electric rate will be eliminated. Until that time, the Company will continue to monitor these customers and determine how the general use rates can be designed and/or modified to provide benefit to these customers in such a way that minimizes overall customer impact and fits with Rate Plan efforts.

Q: The C&I All Electric Rates are frozen. Is it the intention for these customers to be moved to a frozen rate?

A: Yes. This move is being done intentionally, but again only as an interim step. Eventually, in a future rate case, after communication and education, these customers would be moved to a standard rate.

Q: What were the results of the customer bill impact analysis to move customers from the 2 Meter Heat rate to the 1 Meter All Electric rate?

A: For Large General Service class, the 15 customers in in this class with 12 months of actual usage for the 12 months ending June 30, 2021 showed a change ranging from a 9.3% decrease to a 3.94%[7] increase in their annual bills. 93% of customers would experience an increase of 2% or less with 60% of those customers experiencing a bill decrease. In the Medium General Service class, the 49 customers in in this class with 12 months of actual usage for the 12 months ending June 30, 2021 showed a change ranging from a 15.2% decrease to a 7.9%[7] increase in their annual bills. 57% of customers could see a change of 1% or less with 71% of those customers experiencing a bill decrease. In the Small General Service class, the 111 customers in the Small General Service Class with 12 months of actual usage for the 12 months ending June 30, 2021 showed a change ranging from an 14.6% decrease to a 34.58%[7] increase in their annual bill.

Q: This filing also includes a proposal to eliminate the frozen TPP TOU provision. Please explain what is being proposed and why?

A: This tariff was frozen on October 8, 2015 and there are only two small general service customers utilizing this tariff. It is an outdated provision with no recent analysis to support

[7] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.

its continued viability. In alignment with the Company's Rate Plan that includes rate simplicity and jurisdictional alignment, the Company seeks to eliminate the tariff and bill these customers on their current base rate which is the standard small general service rate – 1SGSE.

Q: **What were the results of the customer bill impact analysis?**

A: The two customers using the TPP provision had a range of impacts from -15.7% to 61.2%[8][9]

Q: Lastly for C&I, the filing includes a proposal to change the method for calculating Facilities Demand calculation for certain customers. Can you explain what is being proposed?

A: In the Evergy Missouri Metro jurisdiction, there is a provision in each of the Commercial & Industrial rate tariffs that outlines a special method of calculating the Facilities Demand for Schools and Churches. The provision allows Schools or Churches in specified rate schedules receiving service prior to July 9, 1996 to have their Facilities Demand be based on an outdated, pre-determined peak period instead of the standard facilities demand calculation. This provision has been frozen to new customers since 1996 and approximately 600 customers are grandfathered to this special provision. The Company is proposing eliminating this special calculation for grandfathered Schools and Churches where Facilities Demand is limited to an outdated predetermined peak period.

Q: Why are you seeking to eliminate this special provision?

A: As part of Rate Plan that include objectives around rate simplification and jurisdictional alignment, the Company is seeking to eliminate this special provision to align more closely to its other classes and jurisdictions where Schools and Church customers are treated

[8] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.
[9] Customer impacts were based on actual loads.

consistently with other similar C&I customers. Since this tariff was frozen, any new School or Church receiving service in the Missouri Metro jurisdiction is treated consistently with any other C&I customer whose facilities demand would be calculated based on the highest monthly maximum demand and subject to the 11-month ratchet.

Q: Was there billing impact analysis performed to determine the impact of this change to effected Schools and Churches?

A: Yes. To determine the billing impact of the change in Facilities Demand, the Company recalculated the Facilities Demand comparing the highest monthly maximum demand and applying the 11-month ratchet, as would be calculated for a typical customer in those classes[10]. The results were as follows:

- For the Medium General Service Class, the 146 customers in the Medium General Service Class with 12 months of actual usage for the 12 months ending June 30, 2021 showed a change ranging 0% to 9.59%[11] with 54% of customers experiencing an increase of 5% or less.
- For the Small General Service Class, the 400 customers in the Small General Service Class with 12 months of actual usage for the 12 months ending June 30, 2021 showed a change ranging 0% to 27%[11] with 78% of customers experiencing an increase of 0%.

Q: What is the aggregate revenue impact to these proposals?

A: Table 4 below shows the aggregated impact of each proposal and the movement of customers from eliminated rates to standard rates and the change in customer count, kwh, and calculated revenue based on those specific customers moved by rate code. For

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[10] Eleven of the Schools and Churches in the Facilities Demand analysis are also included in the 2-Meter Heat analysis. The Facilities Demand customer bill impact for the eleven customers was calculated using their best fit All-Electric rate determined in the 2-meter heat analysis.

[11] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.

example, for rate code 1TE1A 26 customers and 308,548 kwh were moved to 1RS1A. The actual revenue impact for this movement resulted in a change in actual revenue from $40,586 (1TE1A) to $41,759 (1RS1A). Table 5 below shows the aggregated impact of all proposals on weather normalized test year revenues. The total aggregated impact of the proposals results in a reduction in test year revenues of approximately $165,539.

Table 4- Aggregated Revenue Impact for Each Proposal (Actual Revenues)

Aggregate Impact of Grandfathered Rate Clean Up

Actuals Test Year Revenue

Rate Class	Proposal	MO Metro Rates	Total Revenue (Before Changes)	Customer/ Bill Count	Customer Count Change (+/-)	Adj Customer Count	Energy Total (KWH)	Switchers (+/-)	Energy Total (KWH)	Total Revenue (excluding FAC & DSIM)
Res	TOD to Standard Rate	1TE1A	$ 40,586	26	(26)	-	308,548	(308,548)	-	$ -
Res		1RS1A	$ -	-	26	26	-	308,548	308,548	$ 41,759
Res	2-Meter Heat to 1-Meter Heat Rate	1RS2A	$ 14,753,251	9,619	(9,619)	-	135,664,704	(135,664,704)	-	$ -
Res		1RS6A	$ -	-	9,619	9,619	-	135,664,704	135,664,704	$ 14,656,841
Res	Other to Standard Rate	1RO1A	$ 154,011	172	(172)	-	863,890	(863,890)	-	$ -
Res		1RS1A	$ -	-	172	172	-	863,890	863,890	$ 116,747
Res	Residential Standard Multi-Unit to SGS Standard	1RS1A	$ 30,316	16	(16)	-	197,392	(197,392)	-	$ -
Res	Residential 1-Meter Heat Multi-Unit to MGS Standard	1RS6A	$ 62,175	6	(6)	-	491,012	(491,012)	-	$ -
	Residential Total		***$15,040,340***	*9,839*	*(22)*	*9,817*	*137,525,545*	*(688,403)*	*136,837,142*	***$ 14,815,347***
Non Res	Residential Standard Multi-Unit to SGS Standard	1SGSE	$ -	-	16	16	-	197,392	197,392	$ 31,576
Non Res	Residential 1-Meter Heat Multi-Unit to MGS Standard	1MGSE	$ -	-	6	6	-	491,012	491,012	$ 75,459
Non Res	2 Meter Heat Rate - 1 Meter Heat Rate Small	1SGHE	$ 336,121	116	(116)	0	2,786,947	(2,786,947)	-	$ -
Non Res		1SGAE	$ -	-	111	111		2,124,641	2,124,641	$ 283,451
Non Res		1MGAE	$ -	-	5	5		662,306	662,306	$ 80,105
Non Res	2 Meter Heat Rate - 1 Meter Heat Rate Medium	1MGHE	$ 1,294,430	55	(55)	0	12,294,876	(12,294,876)	-	$ -
Non Res		1MGAE	$ -	-	46	46	0	11,831,110	11,831,110	$ 1,244,777
Non Res		1SGAE	$ -	-	9	9	0	463,766	463,766	$ 66,485
Non Res	2 Meter Heat Rate - 1 Meter Heat Rate Large	1LGHE	$ 2,334,185	16	(16)	0	23,926,783	(23,926,783)	-	$ -
Non Res		1LGAE	$ -	-	3	-3	0	4,878,059	4,878,059	$ 432,152
Non Res		1MGAE	$ -	-	13	-13	0	19,048,724	19,048,724	$ 1,846,400
Non Res	Two-Part Time of Use 1SGSE to Standard 1SGSE*	1SGSE	$ 25,994	2		2	190,938			$ 46,464
Non Res	Church and School On-Peak Facilities Demand	1SGSE	$ 891,623	394			5,813,493			$ 917,399
Non Res	Church and School On-Peak Facilities Demand	1SGAE	$ 20,784	6			139,594			$ 22,338
Non Res	Church and School On-Peak Facilities Demand	1MGAE	$ 276,923	5			2,605,923			$ 292,544
Non Res	Church and School On-Peak Facilities Demand	1MGSE	$ 2,083,005	141			16,103,518			$ 2,183,401
	Non Residential Total		***$ 7,263,064***	*735*	*22*	*179*	*63,862,072*	*688,404*	*39,697,009*	***$ 7,522,551***
	GRAND TOTAL		***$ 22,303,405***	***$ 10,574***	***$ -***	***$ 9,996***	***$ 201,387,616***	***$ 0***	***$ 176,534,151***	***$ 22,337,898***

Table 5-Aggregated Weather Normalized Test Year Revenue Impact for All Proposals- By Class

Aggregate Impact of Grandfathered Rate Clean Up
WN/CG Test Year Revenues

Rate Class	MO Metro Rates	Total Revenue (Before Changes)*	Customer /Bill Count**	Customer Count Change (+/-)	Adj Customer Count	Starting Energy Total (KWH)	Switchers (+/-)	Final Adj Energy Total (KWH)	Total Revenue (excluding FAC & DSIM)*
Residential Class	1RS1A	$ 243,347,244	189,413	185	189,598	1,840,396,715	1,005,285	1,841,402,000	$ 243,478,658
	1RS6A	$ 79,939,562	58,619	9,811	68,430	692,721,403	139,733,326	832,454,729	$ 94,928,917
	1RS2A	$ 15,158,161	9,817	(9,817)	-	140,238,638	(140,238,638)	-	$ -
	1TE1A	$ 41,519	27	(27)	-	316,727	(316,727)	-	$ -
	1RO1A	$ 158,374	175	(175)	-	891,235	(891,235)	-	$ -
Residential Total		*$ 338,644,861*	*258,051*	*(22)*	*258,028*	*2,674,564,719*	*(707,989)*	*2,673,856,729*	*$ 338,407,574*
Small General Service	1SGSE	$ 65,789,948	25,986	16	26,002	519,193,278	202,167	519,395,446	$ 65,822,313
	1SGAE	$ 1,030,966	284	123	407	8,968,521	2,648,459	11,616,980	$ 1,389,158
	1SGHE	$ 344,280	119	(119)	-	2,851,438	(2,851,438)	-	$ -
Small General Service Total		$ 67,165,194	26,389	21	26,409	531,013,237	(812)	531,012,425	$ 67,211,471
Medium General Service	1MGSE	$ 104,278,010	4,850	6	4,856	963,493,653	486,468	963,980,122	$ 104,352,842
	1MGAE	$ 10,745,487	259	64	323	109,235,233	31,329,725	140,564,958	$ 13,893,539
	1MGHE	$ 1,285,123	55	(55)	-	12,205,704	(12,205,704)	-	$ -
Medium General Service Total		$ 116,308,619	5,164	15	5,179	1,084,934,590	19,610,489	1,104,545,079	$ 118,246,381
Large General Service	1LGAE	$ 34,938,778	132	3	135	405,506,916	4,888,075	410,394,992	$ 35,373,564
	1LGHE	$ 2,347,076	16	(16)	-	23,989,387	(23,989,387)	-	$ -
Large General Service Total		$ 37,285,854	148	(13)	135	429,496,303	(19,101,312)	410,394,992	$ 35,373,564
Non Residential Total		*$ 220,759,668*	*31,700*	*22*	*31,723*	*2,045,444,131*	*508,365*	*2,045,952,496*	*$ 220,831,416*
GRAND TOTAL		*$ 559,404,528*	*289,751*	*(0)*	*289,751*	*4,720,008,850*	*(199,624)*	*4,719,809,226*	*$ 559,238,990*

Q: Do Tables 4 and 5 reflect all proposals that have been adjusted for and reflected in the test year revenues in this filing?

A: No, while Table 4 includes all rate clean up and jurisdictional alignment proposals described in this testimony, Table 5 only reflects the proposals that were adjusted for in the test year reflected in the Direct Filing. The test year determinants and revenues filed as part of this case reflect all proposals included in this testimony except:

- the Seasonal change for Missouri Metro (See Seasonal Alignment Test Year Revenue Impact by Class and Total Table on pg 7, for expected revenue impact),
- the Facilities Demand Adjustment for Schools & Churches in the C&I rates, and
- the TPP TOU Rate provision elimination.

Q: When does the Company expect to make these changes to the test year to reflect the three proposals above that were not reflected in its test year determinants and revenues in the Direct filing?

A: The Company plans to make these revenue and billing determinant changes not already reflected in the test year, by True Up.

Q: Is there anything else to add with regard to these proposals and the rate clean up being done to facilitate jurisdictional alignment?

A: Yes. Given the expansive nature of the proposed changes and the number of customers being moved and impacted, implementation will be more arduous, requiring careful planning and consideration to ensure minimal customer impact. The Company is expecting that full implementation of these changes and the elimination of rates may not be a completed by the effective date of rates and may require extra time. The Company is still working through various implementation scenarios and is still assessing the expected timeline or how much extra time might be needed, but at this point, it is not expected to be extensive. The Company expects to share implementation plans and needs as the rate case evolves.

Q: What about new plans you are introducing around Hours Use?

A: Like the jurisdictional alignment work described above, the review of Hours Use is part of the Rate Plan that includes rate clean up and jurisdictional alignment and is in response to stakeholder and customer feedback communicating interest in this charge being simplified to ease understanding and to enable more active management and monitoring by the customer. The Company worked with Concentric Energy Advisors to review the calculation of the energy charge. The Company is introducing the results of that review in this case to inform a future case where these study results will be used to propose potential changes to the energy charge calculation.

Q: What is the recommendation and what analysis has been performed to support the plan?

A: First, a cross jurisdictional review of existing rate classes and rate structures/pricing, including the calculation of the energy charge and demand charge was performed in order to assess differences and similarities. Second, cost data from Class Cost of Service study[12] and billing determinants (energy and demand) from the test year in this rate case was obtained. Using that data, the "unraveling" of the hours use calculation began and a determination of the customer impacts was ascertained. Given those impacts, in a future rate case, the Company will be proposing a multi-step plan to move from the hours use calculation to a more standard and more transparent energy charge calculation. The proposal will include the flattening of energy charges and the redistribution of some demand costs back into the demand charge. This retains the intended price signaling which exists within the current hours use structure, but in a more straightforward manner. The plan will need to be executed over multiple rate cases due to the potential impact to customers. The table below summarizes the proposed C&I rate structures:

[12] The Class Cost of Service study from the 2018 rate case was the most recent CCOS study available at the time of the Hours Use review.

Table 6- Summary of Future Changes to the Hours Use Rate Structure

Rate Class	Missouri West	Missouri Metro
Large Power Service	- Summer/winter flat demand charge - Summer/winter flat energy charge - Removed Base/Seasonal demand and energy distinction - *No phase-in required*	- Summer/winter flat demand charge - Summer/winter flat energy charge - Assumes customers will remain on off-peak rider under proposed rates. - Removed blocked demand charge - *Three-step phase-in proposed*
Large General Service	- Summer/winter flat demand charge - Summer/winter flat energy charge - Removed Base/Seasonal demand and energy distinction - *Two-step phase-in proposed*	- Summer/winter flat demand charge - Summer/winter flat energy charge - *Three-step phase-in proposed*
Medium General Service	- Not applicable	- Summer/winter flat demand charge - Summer/winter flat energy charge - *Three-step phase-in proposed*
Small General Service	- Summer/winter flat demand charge - Summer/winter flat energy charge - Removed Base/Seasonal demand and energy distinction - *Three-step phase-in proposed*	Secondary Voltage - Summer/winter flat energy charge - Summer/winter demand charge applied to demand in excess of 25kW - *Three-step phase-in proposed* Primary Voltage - Summer/winter flat energy charge - Summer/winter flat demand charge - *Three-step phase-in proposed*

For more details on the proposal and all analysis performed, please see Schedule MEM-4 for the complete Hours Use Report.

Q: If Evergy is not proposing it in this case, why is it being discussed?

A: Unlike the jurisdictional alignment proposals discussed earlier, the Hours Use study explores a possible avenue for simplification, but with a focus on jurisdictional alignment. Currently, Evergy's Kansas Central jurisdictions calculates the Energy charge in a manner that veers away from the Missouri Metro, Missouri West, and Kansas Metro jurisdictions and offers a flat seasonal differentiated Energy Charge. The Company took inspiration from this method in its undertaking of the Study. Our goal in this rate case is to introduce the concepts being explored to change the calculation of the Energy Charge and determine a path for formal proposal of a change to be included in a future rate case. As such, we hope to collect formal feedback and impressions from stakeholders in this case to help inform how we might modify the proposals being considered to address broader considerations.

Q: What are Bright Lines?

A: Bright Lines, in utility tariff application, are thresholds which define the utility classes. These thresholds could be expressed in terms of energy usage, demand or capacity, or some other measure of a customer's power usage. Based upon where a customer's pertinent determinants fall within said thresholds and/or similarities in load profiles, customer are grouped into a given class over another. In Evergy's Kansas Central jurisdiction existing application, Bright Lines are based upon customer Non-Coincident Peak (NCP) demands. As part of the Rate Plan that includes jurisdictional alignment, the Company is exploring Bright Lines to bring some consistency to how rate classes are defined across its jurisdictions, as well as minimize rate switching across classes.

Q: What is the recommendation and what analysis has been performed to support it?

A: After examining actual revenues in the test year, best-fit Bright lines were determined across jurisdictions, utilizing maximum NCP demand as the defining criteria. These best-fit lines were determined by established maximums that would minimize customer rate switching. An analysis keeping class counts static was done, as well as a more finite analysis keeping absolute switchers to a minimum. Comparing these lines across all three jurisdictions, it was concluded that all three legacy KCP&L jurisdictions were hovering around the 30-200-1,000 maximum demand lines for Small, Medium and Large General

Service classes, respectively. After establishing these baselines, individual customer impacts were investigated using actual test year data for MO West and MO Metro. The largest one or two rates in each class of each jurisdiction (summing at least 90% of all customers in that class) were evaluated and their results extrapolated to arrive at full class impacts. Based on test year actuals, MO West could experience an increase in total actual revenues of $232,331, and MO Metro could experience an increase in total revenues of $5,626,214. For purposes of revenue effects, no revenue addition was posited for the movement of MO West customers into a new Medium Service class. Average annual customer impacts ranged from -$119.45 to $29.56 for MO West classes, and -$1076.50 to $718.45 for MO Metro classes. With a focus on minimal upfront customer impacts, and an eye toward finitely defining classes for better cost allocations, rate design, and other class-based considerations, as well as a nod toward jurisdictional alignment, the proposal of Bright Line maximum demands of 30 kW (Small) – 200 kW (Medium) – 1,000 kW (Large) is promoted for implementation in a future rate case. Several factors can impact this proposal including the results of this rate case filing, the timing and frequency of future rate cases, significant change in load profiles, and many other unforeseeable. Evergy wishes to alert the Commission now of its intentions of formally proposing this change in a future rate case filing.

Q: Can you provide more detail on the analysis performed to support this recommendation?

A: The following steps and analysis were performed:

1. Pull Test Year data for all customers currently in the Small, Medium, Large, and Power classes in all jurisdictions.

- Monthly kWh (actuals)
- Monthly kW (actuals)

2. Identify maximum, minimum, and average energy and demand values, by customer.
3. Calculate load factor by customer (based on maximum of energy and demand).
4. Leverage bright lines experience in Kansas Central jurisdiction specific to how Bright Lines were defined.
5. Graph maximum, minimum, and average demands by class, in an attempt to see any patterns, alignments, or natural divisions in and between classes.
6. Evaluated the impact (switchers) of setting existing and new max demand thresholds across jurisdictions/classes to determine cross jurisdictional feasibility with the goal of minimizing impacts.
7. Using actuals, ran individual bill impacts for impacted customers (customers likely to switch) and calculated change to revenue and bills. Any impacts associated with new classes (Medium for MO West) were assumed to be revenue neutral or 0.

Q: If Evergy is not proposing Bright Lines in this case, why is it being discussed?

A: Similar to Hours Use, the Company hopes to collect stakeholder impressions and feedback to determine a path for formal proposal in a change to be included in a future rate case. We hope that feedback provided during this rate case can help inform how we might modify the proposals being considered to address broader considerations.

Q: Are there other new rates that you have not included in your discussion above?

A: My testimony mainly covered those rates resulting from the specific studies that were performed. There are other new rates or customers programs that are being included in this filing that are covered in the Direct testimonies of Company witnesses Bradley D. Lutz, Kimberly Winslow, and Ryan Hledik.

II. ANNUALIZED/NORMALIZED REVENUES

Q: Were the retail revenues included in this filing prepared by you or under your supervision?

A: Yes, they were.

Q: Will you describe the method used in developing the revenues for this case?

A: Both the weather-normalized kWh sales and customer growth levels by rate class (i.e. Residential, Small General Service, Medium General Service and Large General Service) were developed by Company witness Albert R. Bass, Jr. Mr. Bass explains those figures and other adjustments, including adjustments for COVID, in his Direct Testimony. The test year used by the Company in this case was the 12 months ending June 30, 2021, which we expect will be updated for known and measurable changes through May 31, 2022. The monthly bill frequencies for the 12 months ending June 30, 2021, that contain the billing units for each of the billing blocks for the various rate components, were developed under my supervision. These bill frequencies were developed by collecting the actual usage and customer counts billed in each month of the test period and applying them to the existing rate structures[13]. By applying the existing rates to the usage in each of the billing blocks, the revenues were reproduced, providing a basis for determining the overall revenues to be used in this case. The Company determined monthly revenues by applying the normalized sales and customer levels for each month represented in the test period to the corresponding

[13] These actual determinants would reflect the migration of customers that were moved from frozen rates being proposed for elimination in this rate case filing to standard rates with the exception of those changes that will be made at True Up.

billing frequency. The normalized sales and customer levels from this were then multiplied by the rates that took effect on December 6, 2018 to obtain the weather normalized and customer growth adjusted monthly revenues available. The sum of the monthly revenues was compared to the actual revenues for the test year ending June 30, 2021 to determine the revenue adjustment contained in the Summary of Adjustments attached to the Direct Testimony of Company witness Ronald A. Klote as Schedule RAK-4 (adjustment no. R-20).

Q: Were all class revenues developed as described above?

A: Yes, except for the Large Power Class. The Large Power class revenues generally followed the methodology outlined above but were developed on an individual customer basis. Customer growth was accounted for by the annualization of usage for new customers switching (or starting new service) to the Large Power Class or customers leaving the Large Power Class (either due to switching or stopping service) through the end of the test year period.

Q: Have there been any operational change(s) that would impact the calculation of test year revenues?

A: Yes. Historically and in the last general rate case, the Company relied on hourly load research for purposes of determining weather normalization. This hourly load research was prepared utilizing a sample of customers to determine hourly loads by class. As of December 2020, the Company discontinued load research.

Q: Why did the Company discontinue load research?

A: The Company implemented Advanced Metering Infrastructure ("AMI") metering and completed implementation of those meters in all Missouri jurisdictions in early 2020. In order to leverage the benefits of AMI technology and broaden the data set used for weather normalization and rate design, it was decided to transition from using a load research sample to full utilization of AMI data available.

Q: Is AMI data better than load research data?

A: The Company's load research data was relied upon for many years to support various analysis requiring customer load analysis and to support general rate cases. Stakeholder feedback was consistently very positive with regards to load research data, methodology and the analysis. However, the Company would be remiss to not maximize utilization of a broader data set. For more information on how AMI data was utilized in weather normalization, please see the Direct testimony of Company witness, Albert R. Bass, Jr.

Q: The Company has several riders in place to recover particular costs. How will these mechanisms affect the requested increase in this case?

A: The Demand-Side Investment Mechanism ("DSIM") is separate from the revenue requirement requested in this case and thus the associated DSIM revenues have been removed from the total revenues available. The fuel adjustment clause ("FAC") rider base amount has been re-based within the current revenue requirement. In addition to my testimony on the FAC, please see the Direct Testimony of Linda Nunn for the primary details concerning the continuation of the FAC in this case.

III. ELECTRIC CLASS COST OF SERVICE STUDY

Q: Has the Company performed a CCOS study for this case?

A: Yes, the Company performed a CCOS study representative of the Evergy Missouri Metro jurisdiction. A summary of the results of the Company's CCOS studies are attached and marked as Schedules MEM-1 and MEM-2.

Q: Was the study prepared by you or under your direct supervision?

A: Yes, it was. The Company utilized the services of 1898 & Co., a Division of Burns & McDonnell Engineering Company, Inc., who performed the primary CCOS modeling using data provided by the Company.

Q: Has the Company filed a CCOS in previous rate cases?

A: Yes. In all rate cases filed since 2005, the Company has filed a CCOS study.

Q: What is the purpose of the CCOS study?

A: The purpose of the CCOS study is to directly assign or allocate each relevant component of the Company's revenue requirement on an appropriate basis in order to determine the contribution that each customer class makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causative factors of demand, energy and customer.

Q: Would the CCOS study serve as the basis for the determination of increasing or decreasing overall revenue levels for Evergy Missouri Metro?

A: No. Determination of the revenue requirement requested in this case is accomplished using the jurisdictional model sponsored by Company witness Ronald A. Klote. The CCOS model uses the information from the jurisdictional model as an input for the primary purpose of evaluating the possible distribution of costs to the respective classes.

Q: What classes are used as a basis for this CCOS study?

A: The primary classes the Company used in its analysis are Residential, Small General Service, Medium General Service, Large General Service, Large Power Service, and Lighting.

Q: Do these classes conform to the proposed electric rate tariffs?

A: Generally, they do. The Residential class has several rate classifications available to it that include general use, general use and space heat, and time of use. The Small General Service, Medium General Service and Large General Service classes also have general usage rates and all electric rates, plus they can be specific to the voltage level at which the customer receives service. The Large Power Service class is distinguished by the specific voltage at which the customer receives service. In total, the Company has five classes of service (plus Lighting) but has approximately 48 rates to meet the specific needs of the customer and reporting and billing requirements.

Q: What test year was used for the CCOS study?

A: The study is based on a historical test year of the 12 months ending June 30, 2021, with known and measurable changes projected through May 31, 2022.

Q: What general categories of cost were examined and considered in the development of the CCOS study?

A: An analysis was made of all elements of cost as defined by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, including investment (rate base) and expense (cost of service) for the purpose of allocating these items to the customer classes. To achieve this allocation, we begin by functionalizing and classifying costs.

Q: Please explain what you mean.

A: In order to make the appropriate assignment of costs to the appropriate class of customer, it is necessary to first group the costs according to their function. The functions used in the CCOS study were production, transmission, distribution, and other costs. The next step was to classify the costs. Costs are classified as customer-related, energy-related, or demand-related.

Q: What do you mean by customer-related, energy-related and demand-related?

A: Customer-related costs are those costs necessary to provide electric service to the customer independent of any usage by the customer. Some examples of these costs include meter maintenance, customer accounting, billing, and a portion of the investment in distribution plant equipment such as the meter and service line, facilities that are all necessary to make service available. Portions of the distribution facility are separated between the customer costs and the demand costs.

Energy-related costs are directly related to the generation and consumption of energy and consist of such things as fuel and purchased power and certain production operation and maintenance costs.

Demand-related costs relate to the investment and expenses associated with the Company's facilities necessary to supply the customer's full load requirements throughout the year. The majority of demand-related costs consist of production plant (generation), transmission plant and the non-customer portion of distribution plant.

Q: After the above classification of plant investment and operating costs into customer- energy- and demand-related components, what was the next step in the CCOS study?

A: The next step was to allocate each of the three categories of cost to each customer class utilizing allocation factors appropriate for each of the above categories of cost.

Q: How are the allocation factors generally determined?

A: Costs are evaluated to determine the cause driving the cost to be incurred and to establish an allocation method that best distributes the cost based on that causation. Customer-related costs are generally allocated on the basis of the number of customers within each class. Data for the development of the customer-related allocation factors came from Company billing and accounting records. Some of the customer-related accounts were allocated based on a weighted number of customers to reflect the weighting associated with serving those customers.

Energy-related allocation factors were derived on the basis of each customer classes' respective energy (kilowatt hour) requirements. Kilowatt-hour ("kWh") sales to each customer class were available from Company records. The sales data was adjusted to reflect COVID, normal weather, a normal 365-day year, rate switchers, energy efficiency programs, customer growth, and system losses in order to assign the Company's total system output.

Q: How are class demand allocation factors generally determined?

A: The data necessary to develop class demand allocation factors (production and transmission) were derived from the Company's AMI data. Such data consisted of the hour-by-hour use of electricity by each customer class throughout the study period.

Q: Was Evergy Missouri Metro's AMI data used to develop any other allocators?

A: Yes, it was used to develop distribution plant allocators based on customer's non-coincident peak ("NCP") loads within each class.

Q: Are any costs assigned directly to classes?

A: Yes. In instances where the costs are clearly attributable to a specific class, they are directly assigned to that class.

Q: What method do you propose to allocate production plant?

A: Production plant is the single, largest component cost to allocate to the classes within the study. As such, the production allocator has the most impact on the outcome of the CCOS study. After considerable efforts to determine the most appropriate production allocation methodology in the prior rate case, the Company intends to continue to utilize the Energy Weighted approach, specifically the Average & Excess Demand ("AED") allocation method, incorporating a four (4) Coincident Peak ("CP") component (collectively "AED-4CP"). An Energy Weighted approach was viewed to be cost effective, balanced through its incorporation of energy, and less subjective than other methods. Utilization of the AED method is an energy-weighted method of production plant allocation that gives classes a reasonable balance between the energy and capacity function of generating facilities. Use of the AED method is also consistent with the provisions of Section 393.1620(2), RSMo.

Q: Has this allocation method been used before?

A: Yes, the AED-4CP method was used by the Company in the most recent CCOS study filed in its 2018 rate cases.

Q: How were the fuel costs associated with the production plant allocated in the CCOS study?

A: Fuel costs were allocated using a monthly kWh allocator. Based on monthly fuel costs from the Company for the 12 months ended June 30, 2021, each month's fuel costs were allocated to each customer class's corresponding calendar month kWh sales adjusted for losses. These allocated results were summed by rate and major customer class to identify a proxy fuel allocator which was then used to allocate the actual fuel costs shown in the CCOS study. To ensure the allocation was representative of a normal year, an adjustment was made to the fuel costs associated with February 2021 due to the cold weather event that occurred[14].

Q: How were the off-system sales margins that Evergy Missouri Metro receives from its external sales of energy allocated?

A: They were allocated using an energy allocator.

Q: What method did you use to allocate transmission plant costs?

A: Transmission plant costs were allocated AED-4CP allocation method.

Q: What method did you use to allocate Distribution Plant?

A: Depending on the plant account, distribution plant is allocated using either a demand or customer allocation factor. Accounts 360 through 363 are demand-related and allocated using a Non-Coincident Peak ("NCP") demand allocator based on the use of NCP class demands. Accounts 364 through 368 include both a demand and a customer component and use a minimum system method to distinguish the appropriate split between demand and customer-related costs for each account. The demand components are allocated using

[14] The fuel costs for February 2021 were replaced with the average fuel costs in February for 2018, 2019, and 2020.

the Class NCP allocator and the customer component is allocated using a customer allocator. The remaining distribution plant accounts (369-373) were allocated using a customer allocation factor.

Q: What method did you use to allocate Services?

A: Since Account 369 - Services is considered customer-related, these costs were allocated based on the customers receiving service at a secondary voltage.

Q: What method did you use to allocate Meters?

A: Meter costs, recorded to Account 370, are also customer-related and were allocated using an assignment of all meters and metering devices to customer classes.

Q: Did you include any other rate base elements in the study?

A: Yes, multiple rate base elements have been included. Additions to net plant included cash working capital, taxes other than incomes taxes, tax offset from rate base, materials and supplies, prepayments, fuel inventory, and various regulatory assets. The following details their allocation to various functions and classifications:

- The cash working capital component of rate base was developed and allocated on energy, payroll, and plant in service.
- Taxes other than income taxes were developed and allocated on retail revenue and plant in service.
- Tax offset from rate base was allocated on plant in service.
- Materials and supplies were allocated on a mix of production, transmission, and distribution plant allocators.
- Prepayment items were allocated using plant in service and customer allocation factors.

- Fuel inventory was allocated on energy.
- Regulatory assets were allocated on payroll, energy, customer, and demand allocation factors depending on the costs tracked.
- Subtractions to net plant included accumulated deferred taxes, customer advances, customer deposits, gain on SO2 emissions and income eligible weatherization.
- The accumulated deferred taxes were allocated on plant in service.
- Customer advances for construction were allocated on total distribution plant.
- Customer deposits were developed using the data analysis by customer group available from the Company.
- Gain on SO2 emissions allowances were allocated on energy production.
- Income eligible weatherization was allocated by customers.

Q: What revenues did you use for this study?

A: The class revenues were developed under my supervision and were discussed earlier in this testimony. Other sources of revenues such as Miscellaneous Revenues were allocated consistent with the revenue source.

Q: How were Operation and Maintenance ("O&M") Expenses allocated?

A: O&M Expenses were allocated using various methods dependent of the cost causation. O&M for production, transmission and distribution plant were allocated to customer classes following plant. Customer Accounts Expenses, Customer Services and Information Expenses, Sales Expenses, and Administrative and General Expenses were allocated based on the results of individual allocation studies. Administrative & General expenses were primarily allocated on the payroll allocator with the exception of the following:

- Account 924, Property Insurance, which was allocated based on plant in service.

- Account 928, Regulatory Commission expenses, which was allocated on plant in service and energy production.
- Account 929 Duplicate Charges - Credit, which was allocated on customer sales.

Q: What is the next step after the allocations are applied?

A: The next step is to determine the relative return on rate base for each of the classes and rates in the study. The ratio of class revenues less expense (net operating income) divided by class rate base will indicate the rate of return being earned by the Company that is attributable to a particular class. It is necessary to keep in mind that this calculation only represents a snapshot in time. The results of the CCOS study will most likely vary over time. The results of the study will also vary if you apply different allocation factors to the study. By applying different methods to the allocation process, you can change the outcome of the CCOS study.

Q: What were the results of the CCOS study?

A: The overall jurisdictional rate of return was calculated to be 5.9%. Individual classes' rates of return at current rates vary, and based on the current costs, are shown in the following table.

Table 7- The Relative Rate of Return by Rate Class

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting	CCN
2.0%	9.1%	10.1%	10.3%	9.6%	9.6%	-55.49%

Q: If rates were changed so that Evergy Missouri Metro earned the same rate of return from each customer class, how much would each class's rates need to change?

A: To achieve an overall jurisdictional revenue increase of 5.7%, the classes should be adjusted by the percentages in the table below.

Table 8- Rate Increase Needed to Achieve and Equalized Rate of Return

Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Other Lighting	CCN
30.6%	-9.1%	-12.9%	-13.2%	-9.9%	-12.8%	3068.9%

Q: What general conclusion can be made from these results?

A: The results of the CCOS study show that each class of customers recovers the cost of service to that class and provides a return on investment, except the CCN class. The results also show the Residential class revenue is well below the Total Missouri ("MO") Retail rate of return level while the Small General Service, Medium General Service, Large General Service, Large Power Service, and Lighting class revenues are above.

Q: Are you proposing changes to the class revenues based on the results of the study?

A: Yes.

Q: **Are you proposing changes to class revenues that are reflective of an equalized rate of return by class?**

A: No. The exact application of changes in rates that aim for an equalized rate of return by class would have been extremely detrimental to our residential customers and not in line with sound rate design principles. Instead, the Company opted for a gradual approach to adjusting revenues and rates. Utilizing the results from the study prepared based on the Average & Excess production allocation; the Company has identified the following recommended changes to class revenues based on an overall jurisdictional revenue requirement increase of 5.65%.[15]

- Apply a 7.73% (approximately 136% of the jurisdictional rate increase) increase to the Residential class, and
- Apply a 7.53% (approximately 136% of the jurisdictional rate increase) increase to the CCN class, and
- Apply a 4.24% (approximately 75% of the jurisdictional rate increase) equally to the remaining classes

Application of these proposals to the electric rates is discussed further in the rate design section of this testimony.

Q: In proposing class revenue shifts, is there an expectation of rate switchers that should be considered and taken into account?

A: Yes. Revenue losses associated with potential rate switching resulting from the above rate changes are possible. The Company plans to size this impact by the True-up and if possible, sooner.

IV. ELECTRIC RATE DESIGN

Q: Are you sponsoring the electric tariffs filed in this case?

A: Yes, I am.

Q: Please summarize the proposed rate design recommendation for the electric tariffs and any additional proposed changes to the tariffs?

A: The Company is requesting an annual aggregate increase over current revenues reflecting impacts before the rebasing of fuel for the fuel adjustment clause, in the amount of $43.9

[15] This change represents the rate increase including Net Fuel. The overall rate increase excluding Net Fuel is 5.21%.

million (5.21%). The aggregate annual increase over current revenues including the rebasing of fuel for the fuel adjustment clause is $47.6 million (5.65%).

Utilizing the results of the CCOS and the Residential Class relative rate of return relative to other classes, the Company applied approximately 136% of the jurisdictional revenue requirement or 7.73%[16] to Residential class revenues with a proposed customer charge of $16.00. The $16.00 proposed customer charge is based on the results of the CCOS and is consistent with prior Commission approved customer charges. This proposed amount is ***below*** the recommended CCOS customer charge of $17.49 which represents the customer charge inclusive of the jurisdictional rate increase on an equalized basis. The Company opted to propose a lesser amount to help manage the impact to customers but hopes to make continued progress towards the equalized customer charge in subsequent rate cases, consistent with prior Commission approved customers charges. The proposed customer charge not only considers incremental progress towards the alignment of cost, but also seeks consistency across its Missouri jurisdictions (Evergy Missouri Metro and Evergy Missouri West). The intention of the Company is to offer one customer charge with the same pricing across both its Missouri jurisdictions. The remaining revenue shortfall/increase was then applied equally to remaining Residential bill components.

For the remaining classes, (with the exception of CCN) the Company applied 75% of the jurisdictional rate increase[17] or 4.24% to consider the results of the Class Cost of Service study and the C&I class relative rates return. Generally, for the C&I classes, the Company attempted narrow the gap between how costs are incurred and how rates are designed and applied 125% of each class increase to the fixed cost rate components (i.e.

[16] This change represents the rate increase including Net fuel and revenue shifts.
[17] This change represents the rate increase including Net fuel and revenue shifts.

customer charges and demand charges) and 75% to the variable cost rate components (i.e. energy charges). The application of the above increases by class by billing component can be found in attached schedule MEM-5. The summary of revenues and proposed increase by class may be found in Schedules MEM-6. For more details on the reasonableness of the rate increase applied to the CCN class, please see the Direct testimony of Company Witness Darrin Ives.

Q: Describe the rate design recommendation for unmetered lighting and why an increase wasn't applied equally across rate components.

A: The Company's Missouri jurisdictions have established LED streetlights and LED private areas lighting tariffs. As such, all standard municipal street lighting has been converted to LED while the conversion of private area lighting is at the customer's option. In order to highlight the continuing obsolescence of non-LED lighting, the following is reflected in the unmetered Lighting rate design:

- The adder components (i.e., additional poles, wire spans, etc.) that are common between LED and non-LED rates have been equalized.
- Non-LED lighting components were allotted the balance of the increase at 4.7% with the mercury vapor lighting getting the highest percentage increase at 6.25%. As mercury vapor replacements are only available in the used market, the higher increase reflects the lack of availability and reflects favorably towards the energy efficient, LED equivalent.
- LED and traffic lighting were not increased.

Q: Are there any new tariffs being filed as part of this case?

A: Yes, the Company is proposing expansion of Renewables, TOU programs, and rates supportive of Electrification. Company Witnesses Kimberly Winslow and Bradley D. Lutz explain this in detail in both their Direct Testimonies. Finally, the Company is also proposing a Subscription Pricing proposal that is explained by Company witness Ryan Hledik.

- Proposal of New Rates include:
    - Time-Related Pricing tariff (Large C&I Customers)
    - Residential Two Period Time of Use Rate (See Direct Testimonies of Bradley D. Lutz and Kimberly Winslow)
    - Residential Three Period High Differential Time of Use and Separately Metered Electric Vehicle TOU tariff (See Direct Testimonies of Bradley D. Lutz and Kimberly Winslow)
    - Business EV Charging Service Rate (See Direct Testimony of Bradley D. Lutz)
    - Residential Green Pricing Renewable Energy Credit ("REC") Program (See Direct Testimony of Kimberly Winslow)
    - Residential Low Income Solar Subscription Pilot Program (See Direct Testimony of Kimberly Winslow)
    - Residential Battery Energy Storage Pilot Program (See Direct Testimony Kimberly Winslow)
    - Residential Advance Easy Pay Pilot Program (See Direct Testimony of Kimberly Winslow)

- Residential Subscription Pricing Pilot Program (See Direct Testimonies of Bradley D. Lutz, Kimberly Winslow, and Ryan Hledik)

Q: Please summarize the proposed changes to rules & regulation tariffs and/or other non-base rate tariffs.

A: There are multiple changes proposed to existing tariffs. Some changes are proposed to better align the rules & regulations with current costs, planned business practices, and are generally minimal in impact. Others are more impactful. The most significant changes have already been highlighted in this Direct Testimony and others and includes:

- Elimination of rates including:
  - Residential frozen 2 Meter Heat Rate (1RS2A)
  - Residential Other Rate (1RO1A)
  - Eliminate frozen Time of Day Rate (1TE1A)
  - Remove frozen Multi-occupancy provision from the Residential Standard and Residential 1 Meter heat rate calculation (subset of 1RS1A and 1RS6A)
  - C&I frozen 2 Meter Heat Rates (1SGHE, 1MGHE, 1LGHE)
  - C&I frozen Two Part Time of Use Rate
  - C&I frozen provision of special Facilities Demand calculation for certain customers on the Large General Service, Medium General Service, and Small General Service tariffs (subset of rates 1SGSE, 1MGSE and 1LGSE)
  - C&I Real Time Pricing Rate
- Miscellaneous Changes:
  - Changing Summer and Winter dates in all base rate tariffs "Seasons" to align with MO Metro jurisdiction

- FAC (See Direct Testimony of Linda Nunn)
- Income Eligible Weatherization ("IEW") Program (See Direct Testimony of Kimberly Winslow)
- Emergency Conservation Plan (See Direct Testimony of Bradley D. Lutz)
- Solar Subscription Rider Program (See Direct Testimony of Bradley D. Lutz)
- Market Based Demand Response ("MBDR") (See Direct Testimony of Kimberly Winslow)
- Interconnection Study Requirements and Fees – the Company proposed to institute requirements and fees associated with large systems requesting to connect to the Company system. Studies are costly and the fees will defray the cost, avoiding subsidy.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2022-0129

AFFIDAVIT OF MARISOL E. MILLER

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Marisol E. Miller, being first duly sworn on his oath, states:

1. My name is Marisol E. Miller. I work in Kansas City, Missouri, and I am employed by Evergy Metro, Inc. as Senior Manager – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri Metro consisting of forty-seven (47) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

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

Marisol E. Miller

Subscribed and sworn before me this 7th day of January 2022.

Notary Public

My commission expires: 4/26/2025

ANTHONY R. WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2025
PLATTE COUNTY
COMMISSION #17279952

Evergy, Inc. - Missouri Metro
2022 Rate Case - Direct
Test Year 6/30/2021
Cost of Service Summary

Allocation Method: Avg & Excess 4 CP

Sch No.	Line No.	Description	MO Metro Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting	CCN
1	1	**REVENUE REQUIREMENT SUMMARY**								
1	2	Test Year Revenue	$843,129,436	$340,921,856	$68,664,014	$123,594,692	$178,461,467	$121,482,208	$9,930,635	$74,564
1	3									
1	4	Gross Revenue Requirements	$925,823,204	$400,003,717	$65,477,643	$121,808,654	$186,617,488	$141,402,473	$8,870,250	$1,642,979
1	5	Less Other Revenue	($268,188,737)	($91,521,952)	($18,026,409)	($37,981,591)	($64,234,028)	($53,850,584)	($2,552,402)	($21,771)
1	6	Net Revenue Requirements	$657,634,467	$308,481,765	$47,451,234	$83,827,063	$122,383,460	$87,551,889	$6,317,848	$1,621,208
1	7									
1	8	Net Operating Income	$185,494,970	$32,440,091	$21,212,780	$39,767,629	$56,078,008	$33,930,320	$3,612,786	($1,546,644)
1	9									
1	10									
1	11	**RETURN AT PRESENT RATES**								
1	12	Rate Base	$3,153,481,360	$1,590,872,305	$233,637,212	$393,211,025	$543,034,420	$352,376,054	$37,562,935	$2,787,408
1	13	Net Operating Income at Present Rates	$185,494,970	$32,440,091	$21,212,780	$39,767,629	$56,078,008	$33,930,320	$3,612,786	($1,546,644)
1	14									
1	15	Rate of Return at Present Rates	5.88%	2.04%	9.08%	10.11%	10.33%	9.63%	9.62%	-55.49%
1	16									
1	17	Relative Rate of Return	1.00	0.35	1.54	1.72	1.76	1.64	1.64	(9.43)

Evergy, Inc. - Missouri Metro
2022 Rate Case - Direct
Test Year 6/30/2021
Unit Costs of Service Summary

			Equalized Rate of Return @ 7.0325%		
			Customer Costs* ($/bill) Monthly	Energy Costs ($/kWh) Annual	Demand Costs ($/kW) Annual
Sch No.	Line No.	Customer Class			
2	1	Residential	$17.49	$0.0297	
2	2	Small General Service	$18.53	$0.0297	
2	3	Medium General Service	$32.39	$0.0297	$19.26
2	4	Large General Service	$13.35	$0.0295	$20.64
2	5	Large Power Service	$114.77	$0.0286	$22.46
2	6	Lighting		$0.0297	

* Excluding Local Facilities

Notes:
Allocation Method: Avg & Excess 4 CP

SCHEDULES MEM-3 THROUGH MEM-4
CONTAIN CONFIDENTIAL
INFORMATION
NOT AVAILABLE TO THE PUBLIC.

ORIGINALS FILED UNDER SEAL.

	A	B	D	E	F	G	H
1			**Evergy - Missouri Metro**				
2			Large Power Service				
3							
4			**Case No.**	**ER-2022-0129**			
5			**Status:**	**Direct**		4.24%	
6						*INPUT FOR MODEL*	
7			**JURISDICITIONAL INCREASE (%)**			**5.30%**	**3.78%**
8	Ref #	Component	Rate Code	Charge Values	**Current Rates**	**Rates w/Rate Design**	**Proposed Rates**
9	1	Customer Charge	1PGSE; 1PGSF; 1PGSV; 1PGSZ	CUSTOMER CHARGE	1,149.23	1,210.14	1,210.14
10	2						
11	4	Facilities Charge - Block 1	1PGSE	SECONDARY	3.849	4.053	4.053
12	5	Facilities Charge - Block 1	1PGSF	PRIMARY	3.190	3.359	3.359
13	6	Facilities Charge - Block 1	1PGSV	SUBSTATION	0.963	1.014	1.014
14	7	Facilities Charge - Block 1	1PGSZ	TRANSMISSION	-	-	-
15	8						
16	10	Demand - Summer - Block 1	1PGSE	First 2443 KW	14.932	15.723	15.723
17	11	Demand - Summer - Block 2	1PGSE	Next 2443 KW	11.944	12.577	12.577
18	12	Demand - Summer - Block 3	1PGSE	Next 2443 KW	10.006	10.536	10.536
19	13	Demand - Summer - Block 4	1PGSE	All KW over 7329 KW	7.304	7.691	7.691
20	14						
21	15	Demand - Winter - Block 1	1PGSE	First 2443 KW	10.150	10.688	10.688
22	16	Demand - Winter - Block 2	1PGSE	Next 2443 KW	7.920	8.340	8.340
23	17	Demand - Winter - Block 3	1PGSE	Next 2443 KW	6.987	7.357	7.357
24	18	Demand - Winter - Block 4	1PGSE	All KW over 7329 KW	5.379	5.664	5.664
25	19						
26	20	Demand - Summer - Block 1	1PGSF	First 2500 KW	14.589	15.362	15.362
27	21	Demand - Summer - Block 2	1PGSF	Next 2500 KW	11.672	12.291	12.291
28	22	Demand - Summer - Block 3	1PGSF	Next 2500 KW	9.776	10.294	10.294
29	23	Demand - Summer - Block 4	1PGSF	All KW over 7500 KW	7.138	7.516	7.516
30	24						
31	25	Demand - Winter - Block 1	1PGSF	First 2500 KW	9.915	10.440	10.440
32	26	Demand - Winter - Block 2	1PGSF	Next 2500 KW	7.740	8.150	8.150
33	27	Demand - Winter - Block 3	1PGSF	Next 2500 KW	6.827	7.189	7.189
34	28	Demand - Winter - Block 4	1PGSF	All KW over 7500 KW	5.257	5.536	5.536
35	29						
36	30	Demand - Summer - Block 1	1PGSV	First 2530 KW	14.415	15.179	15.179
37	31	Demand - Summer - Block 2	1PGSV	Next 2530 KW	11.532	12.143	12.143
38	32	Demand - Summer - Block 3	1PGSV	Next 2530 KW	9.660	10.172	10.172
39	33	Demand - Summer - Block 4	1PGSV	All KW over 7590 KW	7.054	7.428	7.428
40	34						
41	35	Demand - Winter - Block 1	1PGSV	First 2530 KW	9.800	10.319	10.319
42	36	Demand - Winter - Block 2	1PGSV	Next 2530 KW	7.649	8.054	8.054
43	37	Demand - Winter - Block 3	1PGSV	Next 2530 KW	6.748	7.106	7.106
44	38	Demand - Winter - Block 4	1PGSV	All KW over 7590 KW	5.195	5.470	5.470
45	39						
46	40	Demand - Summer - Block 1	1PGSZ	First 2553 KW	14.291	15.048	15.048
47	41	Demand - Summer - Block 2	1PGSZ	Next 2553 KW	11.429	12.035	12.035
48	42	Demand - Summer - Block 3	1PGSZ	Next 2553 KW	9.572	10.079	10.079
49	43	Demand - Summer - Block 4	1PGSZ	All KW over 7659 KW	6.990	7.360	7.360
50	44						
51	45	Demand - Winter - Block 1	1PGSZ	First 2553 KW	9.712	10.227	10.227
52	46	Demand - Winter - Block 2	1PGSZ	Next 2553 KW	7.580	7.982	7.982
53	47	Demand - Winter - Block 3	1PGSZ	Next 2553 KW	6.688	7.042	7.042
54	48	Demand - Winter - Block 4	1PGSZ	All KW over 7659 KW	5.148	5.421	5.421
55	49						
56	51	Energy - Summer - First 180 HU	1PGSE	First 180 Hours Use per month	0.08949	0.08949	0.09287
57	52	Energy - Summer - Next 180 HU	1PGSE	Next 180 Hours Use per month	0.05319	0.05319	0.05520
58	53	Energy - Summer - Over 360 HU	1PGSE	Over 360 Hours Use per month	0.02552	0.02552	0.02648
59	54						
60	55	Energy - Winter - First 180 HU	1PGSE	First 180 Hours Use per month	0.07586	0.07586	0.07873
61	56	Energy - Winter - Next 180 HU	1PGSE	Next 180 Hours Use per month	0.04838	0.04838	0.05021
62	57	Energy - Winter - Over 360 HU	1PGSE	Over 360 Hours Use per month	0.02527	0.02527	0.02622
63	58						
64	59	Energy - Summer - First 180 HU	1PGSF	First 180 Hours Use per month	0.08744	0.08744	0.09074
65	60	Energy - Summer - Next 180 HU	1PGSF	Next 180 Hours Use per month	0.05199	0.05199	0.05395
66	61	Energy - Summer - Over 360 HU	1PGSF	Over 360 Hours Use per month	0.02492	0.02492	0.02586
67	62						
68	63	Energy - Winter - First 180 HU	1PGSF	First 180 Hours Use per month	0.07412	0.07412	0.07692
69	64	Energy - Winter - Next 180 HU	1PGSF	Next 180 Hours Use per month	0.04726	0.04726	0.04905
70	65	Energy - Winter - Over 360 HU	1PGSF	Over 360 Hours Use per month	0.02469	0.02469	0.02562
71	66						
72	67	Energy - Summer - First 180 HU	1PGSV	First 180 Hours Use per month	0.08642	0.08642	0.08968
73	68	Energy - Summer - Next 180 HU	1PGSV	Next 180 Hours Use per month	0.05137	0.05137	0.05331
74	69	Energy - Summer - Over 360 HU	1PGSV	Over 360 Hours Use per month	0.02463	0.02463	0.02556
75	70						
76	71	Energy - Winter - First 180 HU	1PGSV	First 180 Hours Use per month	0.07328	0.07328	0.07605
77	72	Energy - Winter - Next 180 HU	1PGSV	Next 180 Hours Use per month	0.04671	0.04671	0.04847
78	73	Energy - Winter - Over 360 HU	1PGSV	Over 360 Hours Use per month	0.02440	0.02440	0.02532
79	74						
80	75	Energy - Summer - First 180 HU	1PGSZ	First 180 Hours Use per month	0.08565	0.08565	0.08889
81	76	Energy - Summer - Next 180 HU	1PGSZ	Next 180 Hours Use per month	0.05091	0.05091	0.05283
82	77	Energy - Summer - Over 360 HU	1PGSZ	Over 360 Hours Use per month	0.02442	0.02442	0.02534
83	78						
84	79	Energy - Winter - First 180 HU	1PGSZ	First 180 Hours Use per month	0.07259	0.07259	0.07533
85	80	Energy - Winter - Next 180 HU	1PGSZ	Next 180 Hours Use per month	0.04629	0.04629	0.04804
86	81	Energy - Winter - Over 360 HU	1PGSZ	Over 360 Hours Use per month	0.02417	0.02417	0.02508
87	82						
88	83	Reactive Demand Adj	1PGSE; 1PGSF; 1PGSV; 1PGSZ	KVR	0.96600	1.01720	1.01720
89							
90			LPS Secondary		0.000%	1.94%	4.33%
91			LPS Primary		0.000%	1.74%	4.28%

	A	B	D	E	F	G	H
92			LPS Substation		0.000%	1.21%	4.12%
93			LPS Transmission		0.000%	1.18%	4.11%
94			LPS Overall Change (*)		0.000%	1.606%	4.237%
95			Winter Price Below Summer (SUM-WIN)/SUM		**13.478%**	**13.597%**	**13.509%**
96			Overall Change			1.606%	4.24%
97							
98				Revenue	$ 121,915,793.79	$ 123,873,311.34	$ 127,081,697.30
99				Change in Revenue			$ 5,165,903.51
100							
101				Proposed change per Revenue Summary			$ 5,169,315.00
102							$ (3,411.49)
103							
104				EDR Credit	$ (319,690.03)		
105				Forecasted EE Adjustment	$ (113,895.64)		
106					$ 121,482,208.12		

	B	C	D	E	F	H	J
1			**Evergy - Missouri Metro**				
2			Large General Service				
3							
4			**Case No:**	**ER-2022-0129**			
5			**Status:**	**Direct**		4.24%	
6						*INPUT FOR MODEL*	
7			**JURISDICTIONAL INCREASE (%)**			**5.30%**	**3.85%**
8	Component	Usage	Rate Code	Charge Values	**Current Rates**	**Rates w/ Rate Design**	**Proposed Rates**
9	Customer Charge 1	Secondary/Primary	1LGSE ;1LGSEW ;1LGSF ;1LGSFW ;1LGAE ;1LGAEW ;1LGAF ;1LGAFW ;1LGHE	0-24 KW	118.82	125.12	125.12
10	Customer Charge 2	Secondary/Primary	1LGSE ;1LGSEW ;1LGSF ;1LGSFW ;1LGAE ;1LGAEW ;1LGAF ;1LGAFW ;1LGHE	25-199 KW	118.82	125.12	125.12
11	Customer Charge 3	Secondary/Primary	1LGSE ;1LGSEW ;1LGSF ;1LGSFW ;1LGAE ;1LGAEW ;1LGAF ;1LGAFW ;1LGHE	200-999 KW	118.82	125.12	125.12
12	Customer Charge 4	Secondary/Primary	1LGSE ;1LGSEW ;1LGSF ;1LGSFW ;1LGAE ;1LGAEW ;1LGAF ;1LGAFW ;1LGHE	1000 KW or above	1,014.44	1,068.21	1,068.21
13	Other Meter	Secondary/Primary	1LGHE ;1LGHEW	Separately Metered Space Heat	2.72	2.86	2.86
14							
15	Facilities Charge - Block 1	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGHEW	All KW	3.399	3.579	3.579
16	Facilities Charge - Block 1	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW	All KW	2.818	2.967	2.967
17							
18	Demand Charge - Summer - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGHEW	All KW	6.788	7.148	7.148
19	Demand Charge - Winter - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGHE ;1LGHEW	All KW	3.652	3.846	3.846
20	Demand Charge - Summer - Blk 1	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW	All KW	6.634	6.986	6.986
21	Demand Charge - Winter - Blk 1	Primary	1LGSF ;1LGSFW	All KW	3.569	3.758	3.758
22	Demand Charge - Winter - Blk 1	Secondary	1LGAE ;1LGAEW	All KW	3.382	3.561	3.561
23	Demand Charge - Winter - Blk 1	Primary	1LGAF ;1LGAFW	All KW	3.302	3.477	3.477
24							
25	Energy Charge - Summer - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGHEW	First 180 Hours Use	0.09569	0.09569	0.09938
26	Energy Charge - Summer - Blk 2	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGHEW	Next 180 Hours Use	0.06597	0.06597	0.06851
27	Energy Charge - Summer - Blk 3	Secondary	1LGSE ;1LGSEW ;1LGAE ;1LGAEW ;1LGHE ;1LGHEW	Over 360 Hours Use	0.04248	0.04248	0.04412
28							
29	Energy Charge - Winter - Blk 1	Secondary	1LGSE ;1LGSEW ;1LGHE ;1LGHEW	First 180 Hours Use	0.08793	0.08793	0.09132
30	Energy Charge -Winter - Blk 2	Secondary	1LGSE ;1LGSEW ;1LGHE ;1LGHEW	Next 180 Hours Use	0.05070	0.05070	0.05265
31	Energy Charge -Winter - Blk 3	Secondary	1LGSE ;1LGSEW ;1LGHE ;1LGHEW	Over 360 Hours Use	0.03570	0.03570	0.03708
32							
33	Energy Charge - Summer - Blk 1	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW	First 180 Hours Use	0.09355	0.09355	0.09715
34	Energy Charge - Summer - Blk 2	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW	Next 180 Hours Use	0.06439	0.06439	0.06687
35	Energy Charge - Summer - Blk 3	Primary	1LGSF ;1LGSFW ;1LGAF ;1LGAFW	Over 360 Hours Use	0.04148	0.04148	0.04308
36							
37	Energy Charge - Winter - Blk 1	Primary	1LGSF ;1LGSFW	First 180 Hours Use	0.08592	0.08592	0.08923
38	Energy Charge -Winter - Blk 2	Primary	1LGSF ;1LGSFW	Next 180 Hours Use	0.04949	0.04949	0.05140
39	Energy Charge -Winter - Blk 3	Primary	1LGSF ;1LGSFW	Over 360 Hours Use	0.03500	0.03500	0.03635
40							
41	Energy Charge - Winter - Blk 1	Secondary	1LGAE ;1LGAEW	First 180 Hours Use	0.08455	0.08455	0.08781
42	Energy Charge -Winter - Blk 2	Secondary	1LGAE ;1LGAEW	Next 180 Hours Use	0.04537	0.04537	0.04712
43	Energy Charge -Winter - Blk 3	Secondary	1LGAE ;1LGAEW	Over 360 Hours Use	0.03541	0.03541	0.03677
44							
45	Energy Charge - Winter - Blk 1	Primary	1LGAF ;1LGAFW	First 180 Hours Use	0.08277	0.08277	0.08596
46	Energy Charge -Winter - Blk 2	Primary	1LGAF ;1LGAFW	Next 180 Hours Use	0.04437	0.04437	0.04608
47	Energy Charge -Winter - Blk 3	Primary	1LGAF ;1LGAFW	Over 360 Hours Use	0.03473	0.03473	0.03607
48							
49	Energy Charge - Winter Separate Heat	Secondary	1LGHE ;1LGHEW	All kWh	0.05915	0.05915	0.06143
50							
51	Reactive Demand Adj	Secondary/Primary	1LGSE ;1LGSEW ;1LGSF ;1LGSFW ;1LGAE ;1LGAEW ;1LGAF ;1LGAFW ;1LGHE	KVR	0.85300	0.89821	0.89821
52							
53			LGS Secondary		100.000%	1.47%	4.26%
54			LGS Primary		100.000%	1.33%	4.21%
55			LGS Overall Change (*)		100.000%	1.43%	4.25%
56			LGA Secondary		100.000%	1.39%	4.23%
57			LGA Primary		100.000%	1.25%	4.19%
58			LGA Winter Energy Overall Change	Winter	100.000%	1.65%	4.31%
59			LGA Overall Change (*)		100.000%	1.36%	4.23%
60			Winter Price Below Summer (SUM-WIN)/SUM		**9.157%**	**9.083%**	**9.137%**
61			Overall Change			1.417%	4.24%
62							
63				Revenue[(1)]	$ 179,496,883	$ 182,041,131	$ 187,108,880
64				Change in Revenue			$ 7,611,997
65							
66				Proposed change per Revenue Summary			$ 7,612,406
67							$ (409.19)
68							
69				Manual Bill	($112,625)		
70				Overall Revenue	$ 179,384,258		
71				EDR Credit	($922,787)		
72				Parallel Generation Credit	($3)		
73							
74							
75					$ 178,461,467		
76							
77				Tie-out to Billed Revenue Total	-		
78							
79							
80							
81							
82							
83				[(1)] Values do not include any Manual Bill non-blocked charges or revenue associated.			

	A	B	C	D	E	F	H	J
1				**Evergy - Missouri Metro**				
2				Medium General Service				
3								
4				**Case No.**	**ER-2022-0129**			
5				**Status:**	**Direct**		4.24%	
6							*INPUT FOR MODEL*	
7				**JURISDICTIONAL INCREASE (%)**			**5.30%**	**3.87%**
8	Ref #	Component	Usage	Rate Code	Charge Values	**Current Rates**	**Rates w/ Rate Design**	**Proposed Rates**
9	1	Customer Charge 1	Secondary/Primary	1MGSE ;1MGSEW ;1MGSF ;1MGSFW ;1MGAE ;1MGAEW ;1N	0-24 KW	53.96	56.82	56.82
10	2	Customer Charge 2	Secondary/Primary	1MGSE ;1MGSEW ;1MGSF ;1MGSFW ;1MGAE ;1MGAEW ;1N	25-199 KW	53.96	56.82	56.82
11	3	Customer Charge 3	Secondary/Primary	1MGSE ;1MGSEW ;1MGSF ;1MGSFW ;1MGAE ;1MGAEW ;1N	200-999 KW	109.59	115.40	115.40
12	4	Customer Charge 4	Secondary/Primary	1MGSE ;1MGSEW ;1MGSF ;1MGSFW ;1MGAE ;1MGAEW ;1N	1000 KW or above	935.69	985.28	985.28
13	5	Other Meter	Secondary/Primary	1MGHE ;1MGHEW	Separately Metered Space Heat	2.52	2.65	2.65
14	6							
15	7	Facilities Charge - Block 1	Secondary	1MGSE ;1MGSEW ;1MGAE ;1MGAEW ;1MGHE ;1MGHEW	All KW	3.135	3.301	3.301
16	8	Facilities Charge - Block 1	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	All KW	2.598	2.736	2.736
17	9							
18	10	Demand Charge - Summer - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1MGAEW	All KW	4.102	4.319	4.319
19	11	Demand Charge - Winter - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW	All KW	2.087	2.198	2.198
20	12	Demand Charge - Summer - Blk 1	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	All KW	4.006	4.218	4.218
21	13	Demand Charge - Winter - Blk 1	Primary	1MGSF ;1MGSFW	All KW	2.037	2.145	2.145
22	14	Demand Charge - Winter - Blk 1	Secondary	1MGAE ;1MGAEW	All KW	2.955	3.112	3.112
23	15	Demand Charge - Winter - Blk 1	Primary	1MGAF ;1MGAFW	All KW	2.891	3.044	3.044
24	16							
25	17	Energy Charge - Summer - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1MGAEW	First 180 Hours Use	0.10721	0.10721	0.11136
26	18	Energy Charge - Summer - Blk 2	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1MGAEW	Next 180 Hours Use	0.07333	0.07333	0.07617
27	19	Energy Charge - Summer - Blk 3	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW ;1MGAE ;1MGAEW	Over 360 Hours Use	0.06185	0.06185	0.06424
28	20							
29	21	Energy Charge - Winter - Blk 1	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW	First 180 Hours Use	0.09264	0.09264	0.09622
30	22	Energy Charge -Winter - Blk 2	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW	Next 180 Hours Use	0.05544	0.05544	0.05759
31	23	Energy Charge -Winter - Blk 3	Secondary	1MGSE ;1MGSEW ;1MGHE ;1MGHEW	Over 360 Hours Use	0.04650	0.04650	0.04830
32	24							
33	25	Energy Charge - Summer - Blk 1	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	First 180 Hours Use	0.10465	0.10465	0.10870
34	26	Energy Charge - Summer - Blk 2	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	Next 180 Hours Use	0.07168	0.07168	0.07445
35	27	Energy Charge - Summer - Blk 3	Primary	1MGSF ;1MGSFW ;1MGAF ;1MGAFW	Over 360 Hours Use	0.06043	0.06043	0.06277
36	28							
37	29	Energy Charge - Winter - Blk 1	Primary	1MGSF ;1MGSFW	First 180 Hours Use	0.09046	0.09046	0.09396
38	30	Energy Charge -Winter - Blk 2	Primary	1MGSF ;1MGSFW	Next 180 Hours Use	0.05416	0.05416	0.05626
39	31	Energy Charge -Winter - Blk 3	Primary	1MGSF ;1MGSFW	Over 360 Hours Use	0.04561	0.04561	0.04737
40	32							
41	33	Energy Charge - Winter - Blk 1	Secondary	1MGAE ;1MGAEW	First 180 Hours Use	0.08128	0.08128	0.08443
42	34	Energy Charge -Winter - Blk 2	Secondary	1MGAE ;1MGAEW	Next 180 Hours Use	0.04650	0.04650	0.04830
43	35	Energy Charge -Winter - Blk 3	Secondary	1MGAE ;1MGAEW	Over 360 Hours Use	0.04038	0.04038	0.04194
44	36							
45	37	Energy Charge - Winter - Blk 1	Primary	1MGAF ;1MGAFW	First 180 Hours Use	0.07945	0.07945	0.08252
46	38	Energy Charge -Winter - Blk 2	Primary	1MGAF ;1MGAFW	Next 180 Hours Use	0.04535	0.04535	0.04710
47	39	Energy Charge -Winter - Blk 3	Primary	1MGAF ;1MGAFW	Over 360 Hours Use	0.03962	0.03962	0.04115
48	40							
49	41	Energy Charge - Winter Separate Heat	Secondary	1MGHE ;1MGHEW	All kWh	0.06058	0.06058	0.06292
50	42							
51	43	Reactive Demand Adj	Secondary/Primary	1MGSE ;1MGSEW ;1MGSF ;1MGSFW ;1MGAE ;1MGAEW ;1N	KVR	0.78600	0.82766	0.82766
52								
53				MGS Secondary		**100.000%**	1.35%	4.23%
54				MGS Primary		**100.000%**	1.50%	4.28%
55				MGS Overall Change (*)		**100.000%**	1.35%	4.23%
56				MGA Secondary		**100.000%**	1.42%	4.26%
57				MGA Primary		**100.000%**	1.40%	4.25%
58				MGA Overall Change (*)		**100.000%**	1.42%	4.25%
59				MGA Winter Energy Overall Change	Winter	**100.000%**	1.42%	4.25%
60				MGA Overall Change (*)		**100.000%**	0.00%	0.00%
61				Winter Price Below Summer (SUM-WIN)/SUM		**17.473%**	**17.437%**	**17.46%**
62				Overall Change			1.361%	4.237%
63								
64					Revenue[1]	$ 123,841,828	$ 125,527,078	$ 129,088,729
65					Change in Revenue			$ 5,246,901.64
66								
67					Proposed change per Revenue Summary			5,249,290
68								$ (2,388.36)
69								
70					EDR Credit	($236,613)		
71					Net Metering Credit	($5,663)		
72					Parallel Generation Credit	($4,860)		
73								
74								

Evergy - Missouri Metro
Small General Service

Case No. **ER-2022-0129**
Status: **Direct**

B	C	D	E	F	H	J
					4.24%	
					INPUT FOR MODEL	
		JURISDICTIONAL INCREASE (%)			**5.30%**	**4.07%**
Component	Usage	Rate Code	Charge Values	**Current Rates**	**Rates w/ Rate Design**	**Proposed Rates**
Customer Charge 1	Secondary/Primary	1SGSE ;1SGSEW ;1SGSF ;1SGSFW ;1SGAE ;1SGAEW ;1SGAF ;1SGAFW ;1SGHE ;1SGHEW	0-24 KW	18.18	19.14	19.14
Customer Charge 2	Secondary/Primary	1SGSE ;1SGSEW ;1SGSF ;1SGSFW ;1SGAE ;1SGAEW ;1SGAF ;1SGAFW ;1SGHE ;1SGHEW	25-199 KW	50.40	53.07	53.07
Customer Charge 3	Secondary/Primary	1SGSE ;1SGSEW ;1SGSF ;1SGSFW ;1SGAE ;1SGAEW ;1SGAF ;1SGAFW ;1SGHE ;1SGHEW	200-999 KW	102.38	107.81	107.81
Customer Charge 4	Secondary/Primary	1SGSE ;1SGSEW ;1SGSF ;1SGSFW ;1SGAE ;1SGAEW ;1SGAF ;1SGAFW ;1SGHE ;1SGHEW	1000 KW or above	874.15	920.48	920.48
Customer Charge 1	Secondary/Primary	1SUSE	Unmetered Service	7.63	8.03	8.03
Other Meter	Secondary/Primary	1SGHE ;1SGHEW	Separately Metered Space Heat	2.34	2.46	2.46
Facilities Charge - Block 1	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	First 25 KW	-	-	-
Facilities Charge - Block 2	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	All KW over 25 KW	2.929	3.084	3.084
Facilities Charge - Block 1	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	First 26 KW	-	-	-
Facilities Charge - Block 2	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	All KW over 26 KW	2.860	3.012	3.012
Energy Charge - Summer - Blk 1	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	First 180 Hours Use	0.16225	0.16225	0.16886
Energy Charge - Summer - Blk 2	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	Next 180 Hours Use	0.07701	0.07701	0.08015
Energy Charge - Summer - Blk 3	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	Over 360 Hours Use	0.06859	0.06859	0.07138
Energy Charge - Winter - Blk 1	Secondary	1SGSE ;1SGSEW ;1SGHE ;1SGHEW ;1SUSE	First 180 Hours Use	0.12607	0.12607	0.13120
Energy Charge -Winter - Blk 2	Secondary	1SGSE ;1SGSEW ;1SGHE ;1SGHEW ;1SUSE	Next 180 Hours Use	0.06155	0.06155	0.06406
Energy Charge -Winter - Blk 3	Secondary	1SGSE ;1SGSEW ;1SGHE ;1SGHEW ;1SUSE	Over 360 Hours Use	0.05556	0.05556	0.05782
Energy Charge - Summer - Blk 1	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	First 180 Hours Use	0.15855	0.15855	0.16501
Energy Charge - Summer - Blk 2	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	Next 180 Hours Use	0.07523	0.07523	0.07829
Energy Charge - Summer - Blk 3	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	Over 360 Hours Use	0.06701	0.06701	0.06974
Energy Charge - Winter - Blk 1	Primary	1SGSF ;1SGSFW	First 180 Hours Use	0.12320	0.12320	0.12822
Energy Charge -Winter - Blk 2	Primary	1SGSF ;1SGSFW	Next 180 Hours Use	0.06014	0.06014	0.06259
Energy Charge -Winter - Blk 3	Primary	1SGSF ;1SGSFW	Over 360 Hours Use	0.05427	0.05427	0.05648
Energy Charge - Winter - Blk 1	Secondary	1SGAE ;1SGAEW	First 180 Hours Use	0.11548	0.11548	0.12018
Energy Charge -Winter - Blk 2	Secondary	1SGAE ;1SGAEW	Next 180 Hours Use	0.06155	0.06155	0.06406
Energy Charge -Winter - Blk 3	Secondary	1SGAE ;1SGAEW	Over 360 Hours Use	0.05556	0.05556	0.05782
Energy Charge - Winter - Blk 1	Primary	1SGAF ;1SGAFW	First 180 Hours Use	0.11284	0.11284	0.11744
Energy Charge -Winter - Blk 2	Primary	1SGAF ;1SGAFW	Next 180 Hours Use	0.06014	0.06014	0.06259
Energy Charge -Winter - Blk 3	Primary	1SGAF ;1SGAFW	Over 360 Hours Use	0.05427	0.05427	0.05648
Energy Charge - Winter Separate Hea	Secondary	1SGHE ;1SGHEW	All kWh	0.06752	0.06752	0.07027
On-Peak Adjustment - Summer	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	On-Peak	0.14397	0.14397	0.14983
Off-Peak Adjustment - Summer	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	Off-Peak	0.06179	0.06179	0.06431
On-Peak Adjustment - Winter	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	On-Peak	0.05574	0.05574	0.05801
Off-Peak Adjustment - Winter	Secondary	1SGSE ;1SGSEW ;1SGAE ;1SGAEW ;1SGHE ;1SGHEW ;1SUSE	Off-Peak	0.04810	0.04810	0.05006
On-Peak Adjustment - Summer	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	On-Peak	0.13291	0.13291	0.13832
Off-Peak Adjustment - Summer	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	Off-Peak	0.05837	0.05837	0.06075
					-	
On-Peak Adjustment - Winter	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	On-Peak	0.05408		-
Off-Peak Adjustment - Winter	Primary	1SGSF ;1SGSFW ;1SGAF ;1SGAFW	Off-Peak	0.04668	0.04668	0.04858

	F	H	J
SGS Secondary	100.000%	0.71%	4.23%
SGS Primary	100.000%	0.99%	4.30%
SGS Overall Change (*)	100.000%	0.71%	4.23%
SGA Secondary	100.000%	0.63%	4.22%
SGA Primary	100.000%	0.00%	0.00%
SGA Winter Energy Overall Change	100.000%	0.66%	4.22%
SGA Overall Change (*)	100.000%	0.63%	4.22%
SGS Secondary Space Heat	100.000%	0.00%	0.00%
Winter Price Below Summer (SUM-WIN)/SUM	**17.790%**	**17.619%**	**17.754%**
Overall Change		0.708%	4.235%

	F	H	J
Revenue[1]	$ 68,706,027.50	$ 69,192,163.69	$ 71,615,456.53
Change in Revenue			$2,909,429
Proposed change per Revenue Summary			$ 2,909,743
			($314)
Manual Bill	$274	$274	$274
Overall Revenue	$ 68,706,301.82	$ 69,192,438.01	$ 71,615,730.85
EDR Credit	($15,639)		
Net Metering Credit	($24,776)		
Parallel Generation Credit	($1,873)		
	$ 68,664,014.16		
Tie-out to Billed Revenue Total	-		

[1] Values do not include any Manual Bill non-blocked charges or revenue associated.

	B	C	D	E	F	H	J
1			**Evergy - Missouri Metro**				
2			Residential Service				
3							
4			**Case No:**	**ER-2022-0129**			
5			**Status:**	**Direct**		7.73%	
6						INPUT FOR MODEL	
7			**JURISDICTIONAL INCREASE (%)**			-	3.96%
8	Component	Usage	Rate Code	Charge Values	**Current Rates**	**Rates w/ Rate Design**	**Proposed Rates**
9	Customer Charge	General Use (RESA)	1RS1A ;1RS1AS	One Meter	11.47	16.00	16.00
10	Customer Charge	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	One Meter	11.47	16.00	16.00
11	Customer Charge	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	Two Meters	13.80	19.25	19.25
12							
13	Customer Charge	Other Use (ROU)	1RO1A	One Meter	11.47	16.00	16.00
14	Customer Charge	Time of Day (RTOD)	1TE1A	One Meter	15.96	22.26	22.26
15	Customer Charge	Time of Use (RTOU)	1RTOU	One Meter	11.47	16.00	16.00
16							
17	Energy Charge - Summer - Blk 1/Off Peak	General Use (RESA)	1RS1A ;1RS1AS	First 600 kWh per month	0.13511	0.13511	0.14053
18	Energy Charge - Summer - Blk 2/On Peak	General Use (RESA)	1RS1A ;1RS1AS	Next 400 kWh per month	0.13511	0.13511	0.14053
19	Energy Charge - Summer - Blk 3/Super Of	General Use (RESA)	1RS1A ;1RS1AS	Over 1000 kWh per month	0.14916	0.14916	0.15515
20							
21	Energy Charge - Summer - Blk 1/Off Peak	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	First 600 kWh per month	0.13806	0.13806	0.14360
22	Energy Charge - Summer - Blk 2/On Peak	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	Next 400 kWh per month	0.13806	0.13806	0.14360
23	Energy Charge - Summer - Blk 3/Super Of	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	Over 1000 kWh per month	0.13806	0.13806	0.14360
24							
25	Energy Charge - Summer - Blk 1/Off Peak	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	First 600 kWh per month	0.13806	0.13806	0.14360
26	Energy Charge - Summer - Blk 2/On Peak	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	Next 400 kWh per month	0.13806	0.13806	0.14360
27	Energy Charge - Summer - Blk 3/Super Of	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	Over 1000 kWh per month	0.13806	0.13806	0.14360
28							
29	Energy Charge - Winter - Blk 1/Off Peak	General Use (RESA)	1RS1A ;1RS1AS	First 600 kWh per month	0.12013	0.12013	0.12495
30	Energy Charge -Winter - Blk 2/On Peak	General Use (RESA)	1RS1A ;1RS1AS	Next 400 kWh per month	0.07396	0.07396	0.07693
31	Energy Charge -Winter - Blk 3/Super Off F	General Use (RESA)	1RS1A ;1RS1AS	Over 1000 kWh per month	0.06561	0.06561	0.06825
32							
33	Energy Charge - Winter - Blk 1/Off Peak	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	First 600 kWh per month	0.09703	0.09703	0.10093
34	Energy Charge -Winter - Blk 2/On Peak	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	Next 400 kWh per month	0.09703	0.09703	0.10093
35	Energy Charge -Winter - Blk 3/Super Off F	General Use & Space Heat (RESB)	1RS6A ;1RS6AS	Over 1000 kWh per month	0.06300	0.06300	0.06553
36							
37	Energy Charge - Winter - Blk 1/Off Peak	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	First 600 kWh per month	0.12013	0.12013	0.12495
38	Energy Charge -Winter - Blk 2/On Peak	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	Next 400 kWh per month	0.07396	0.07396	0.07693
39	Energy Charge -Winter - Blk 3/Super Off F	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	Over 1000 kWh per month	0.06353	0.06353	0.06608
40	Energy Charge - Winter Separate Heat	General Use & Separate Meter Heating (RESC	1RS2A ;1RS2AS	All kWh	0.06353	0.06353	0.06608
41							
42	Energy Charge - Winter - Blk 1/Off Peak	Other Use (ROU)	1RO1A	All kWh	0.13949	0.13949	0.14509
43	Energy Charge - Summer - Blk 1/Off Peak	Other Use (ROU)	1RO1A	All kWh	0.17951	0.17951	0.18671
44							
45	Energy Charge - Summer - Blk 2/On Peak	Time of Day (RTOD)	1TE1A	On-Peak	0.21197	0.21197	0.22048
46	Energy Charge - Summer - Blk 1/Off Peak	Time of Day (RTOD)	1TE1A	Off-Peak	0.11809	0.11809	0.12283
47	Energy Charge - Winter - Blk 1/Off Peak	Time of Day (RTOD)	1TE1A	All kWh	0.08729	0.08729	0.09079
48							
49	Energy Charge - Summer - Blk 1/Off Peak	Time of Use (RTOU)	1RTOU	Off-Peak	0.10833	0.10833	0.12037
50	Energy Charge - Summer - Blk 2/On Peak	Time of Use (RTOU)	1RTOU	On-Peak	0.32498	0.32498	0.36112
51	Energy Charge - Summer - Blk 3/Super Of	Time of Use (RTOU)	1RTOU	Super Off-Peak	0.05416	0.05416	0.06019
52							
53	Energy Charge - Winter - Blk 1/Off Peak	Time of Use (RTOU)	1RTOU	Off-Peak	0.10422	0.10422	0.09028
54	Energy Charge -Winter - Blk 2/On Peak	Time of Use (RTOU)	1RTOU	On-Peak	0.26575	0.26575	0.18056
55	Energy Charge -Winter - Blk 3/Super Off F	Time of Use (RTOU)	1RTOU	Super Off-Peak	0.04495	0.04495	0.06019
56							
57							
58			General Use (RESA)	Summer	100.000%	3.004%	6.709%
59			General Use (RESA)	Winter	100.000%	5.465%	8.923%
60			General Use & Space Heat (RE	Summer	100.000%	3.235%	6.918%
61			General Use & Space Heat (RE	Winter	100.000%	4.482%	8.040%
62			General Use & Separate Meter	Summer	100.000%	0.000%	0.000%
63			General Use & Separate Meter	Winter	100.000%	0.000%	0.000%
64			Other Use (ROU)	Summer	100.000%	0.000%	0.000%
65			Other Use (ROU)	Winter	100.000%	0.000%	0.000%
66			Time of Day (RTOD)	Summer	100.000%	0.000%	0.000%
67			Time of Day (RTOD)	Winter	100.000%	0.000%	0.000%
68			Time of Use (RTOU)	Summer	100.000%	3.555%	13.673%
69			Time of Use (RTOU)	Winter	100.000%	5.565%	-7.064%
70			Winter Price Below Summer (SUM-WIN)/SUM		**25.726%**	**24.211%**	**24.532%**
71			Overall Change (*)			4.192%	7.726%
72							
73				Revenue	$ 340,959,745	$355,251,106	$ 367,303,277
74				Change in Revenue			$ 26,343,532.69
75							
76				Proposed change per Revenue Summary			$ 26,347,726
77							$ (4,193.14)
78							
79				Net Metering credit	($37,804)		
80				Parallel Generation Credit	($84)		
81					$ 340,921,856		
82							
83							
84							
85				Tie-out to Billed Revenue Total	-		
86							

	B	C	D	E	F	G	H	I	J	K	L
1	**Evergy - Missouri Metro**										
2	Lighting										
3										6.25%	% for MV
4		Case No.	**ER-2022-0129**					Juris Increase (%) =	3.52%	4.70%	% for all other non-LE
5		Status:	**Direct**							0.00%	% for LED and traffic s
6											
7	Rate			Tariff			Actual	*MRU Count	Current Rate	Current	Proposed Rate
8	Schedule	Lighting Description	Rate Code	Sheet No.	Rate No.	Description	Revenues		Monthly	Revenues	Monthly
9	ML	Municipal Street Lighting Service	1MLLL	35	1.1	5000 Lumen LED (Class A) Type V pattern	$ -	-	$ 20.48	$ -	$ 20.48
10	ML	Municipal Street Lighting Service	1MLLL	35	1.2	5000 Lumen LED (Class A) Type V pattern - Twin	$ -	-	$ 40.96	$ -	$ 40.96
11	ML	Municipal Street Lighting Service	1MLLL	35	1.3	5000 Lumen LED (Class B) Type II pattern	$ 611,454.18	29,856.16	$ 20.48	$ 611,454.18	$ 20.48
12	ML	Municipal Street Lighting Service	1MLLL	35	1.4	5000 Lumen LED (Class B) Type II pattern - Twin	$ -	-	$ 40.96	$ -	$ 40.96
13	ML	Municipal Street Lighting Service	1MLLL	35	1.5	7500 Lumen LED (Class C) Type III pattern	$ 457,827.84	19,871.00	$ 23.04	$ 457,827.84	$ 23.04
14	ML	Municipal Street Lighting Service	1MLLL	35	1.6	7500 Lumen LED (Class C) Type III pattern - Twin	$ 12,165.12	264.00	$ 46.08	$ 12,165.12	$ 46.08
15	ML	Municipal Street Lighting Service	1MLLL	35	1.7	12500 Lumen LED (Class D) Type III pattern	$ 317,890.62	12,938.16	$ 24.57	$ 317,890.62	$ 24.57
16	ML	Municipal Street Lighting Service	1MLLL	35	1.8	12500 Lumen LED (Class D) Type III pattern - Twin	$ 26,191.62	533.00	$ 49.14	$ 26,191.62	$ 49.14
17	ML	Municipal Street Lighting Service	1MLLL	35	1.9	24500 Lumen LED (Class E) Type III pattern	$ 77,459.91	2,909.84	$ 26.62	$ 77,459.91	$ 26.62
18	ML	Municipal Street Lighting Service	1MLLL	35	1.10	24500 Lumen LED (Class E) Type III pattern - Twin	$ 21,083.04	396.00	$ 53.24	$ 21,083.04	$ 53.24
19	ML	Municipal Street Lighting Service	1MLLL	35	2.1	5000 Lumen LED (Class B) Type II pattern	$ 190,429.98	16,897.07	$ 11.27	$ 190,429.98	$ 11.27
20	ML	Municipal Street Lighting Service	1MLLL	35	2.2	7500 Lumen LED (Class C) Type III pattern	$ -	-	$ 13.82	$ -	$ 13.82
21	ML	Municipal Street Lighting Service	1MLLL	35	2.3	12500 Lumen LED (Class D) Type III pattern	$ 1,290.24	84.00	$ 15.36	$ 1,290.24	$ 15.36
22	ML	Municipal Street Lighting Service	1MLLL	35	2.4	24500 Lumen LED (Class E) Type III pattern	$ -	-	$ 17.41	$ -	$ 17.41
23	ML	Municipal Street Lighting Service	1MLLL	35	3.1	4300 Lumen LED (Class K) Acorn Style	$ -	-	$ 64.21	$ -	$ 64.21
24	ML	Municipal Street Lighting Service	1MLLL	35	3.2	10000 Lumen LED (Class L) Acorn Style	$ -	-	$ 65.66	$ -	$ 65.66
25	ML										
26	ML	Municipal Street Lighting Service	1MLSL, 1MLML	35A	8.4	9500 Lumen High Pressure Sodium	$ 22,568.96	1,024.00	$ 22.04	$ 22,568.96	$ 23.08
27	ML	Municipal Street Lighting Service	1MLSL, 1MLML	35A		9500 Lumen High Pressure Sodium - Twin	$ -	-	$ 44.08	$ -	$ 46.15
28	ML	Municipal Street Lighting Service	1MLSL, 1MLML	35A	8.5	16000 Lumen High Pressure Sodium	$ 270.05	11.00	$ 24.55	$ 270.05	$ 25.70
29	ML	Municipal Street Lighting Service	1MLSL, 1MLML	35A		16000 Lumen High Pressure Sodium - Twin	$ -	-	$ 49.10	$ -	$ 51.41
30	ML	Municipal Street Lighting Service	1MLSL, 1MLML	35A	8.6	27500 Lumen High Pressure Sodium	$ 5,637.60	216.00	$ 26.10	$ 5,637.60	$ 27.33
31	ML	Municipal Street Lighting Service	1MLSL, 1MLML	35A		27500 Lumen High Pressure Sodium - Twin	$ -	-	$ 52.20	$ -	$ 54.65
32	ML										
33	ML	Municipal Street Lighting Service	1MLCL	35B	10.1	Code CX [single]	$ 15,413.09	2,849.00	$ 5.41	$ 15,413.09	$ 5.66
34	ML	Municipal Street Lighting Service	1MLCL	35B	10.2	Code TCX [twin]	$ 1,547.26	143.00	$ 10.82	$ 1,547.26	$ 11.33
35	ML										
36	ML	Municipal Street Lighting Service	1MLCL	36B	6.1	8600 Lumen - Limited Maintenance	$ 395.28	36.00	$ 10.98	$ 395.28	$ 11.50
37	ML	Municipal Street Lighting Service	1MLCL	36B	6.4	9500 Lumen - Limited Maintenance	$ 9,091.44	828.00	$ 10.98	$ 9,091.44	$ 11.50
38											
39	ML-LED	Municipal Street Lighting Service	1MLLL (LED)	48A	11.1	Small LED (≤ 7000 lumens)	$ 6,347.52	288.00	$ 22.04	$ 6,347.52	$ 22.04
40	~~ML-LED~~	~~Municipal Street Lighting Service~~	~~1MLLL (LED)~~	~~48A~~		~~Small LED (≤ 7000 lumens) - Twin~~	~~$ -~~	~~-~~	~~$ 44.08~~	~~$ -~~	~~$ 44.08~~
41	ML-LED	Municipal Street Lighting Service	1MLLL (LED)	48A	11.2	Large LED (> 7000 lumens)	$ 589.20	24.00	$ 24.55	$ 589.20	$ 24.55
42	~~ML-LED~~	~~Municipal Street Lighting Service~~	~~1MLLL (LED)~~	~~48A~~		~~Large LED (> 7000 lumens) - Twin~~	~~$ -~~	~~-~~	~~$ 49.10~~	~~$ -~~	~~$ 49.10~~
43											
44			**Optional Equipment**								
45	ML, ML-LED	Municipal Street Lighting Service	1MLSL, 1MLLL	35A, 48A	9.1, 12.1	Ornamental steel pole	$ 56,418.00	36,635.06	$ 1.54	$ 56,418.00	$ 1.54
46	ML, ML-LED	Municipal Street Lighting Service	1MLLL	48A	12.2	Aluminum pole	$ -	-	$ 3.85	$ -	$ 3.85
47	ML, ML-LED	Municipal Street Lighting Service	1MLSL, 1MLLL	35B, 48A	9.2, 12.3	Underground service extension under sod	$ 237,235.88	36,554.06	$ 6.49	$ 237,235.88	$ 6.49
48	ML, ML-LED	Municipal Street Lighting Service	1MLSL, 1MLLL	35B, 48A	9.3, 12.4	Underground service extension under concrete	$ 40,631.16	1,641.00	$ 24.76	$ 40,631.16	$ 24.76
49	ML, ML-LED	Municipal Street Lighting Service	1MLSL, 1MLLL	35B, 48A	9.4, 12.5	Breakaway base	$ 16,613.22	4,693.00	$ 3.54	$ 16,613.22	$ 3.54
50											
51	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		5800 Lumen High Pressure Sodium Unit	$ 154,879.30	6,565.46	$ 23.59	$ 154,879.30	$ 24.70
52	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		8600 Lumen Mercury Vapor Unit	$ 125,108.87	5,042.68	$ 24.81	$ 125,108.87	$ 26.36
53	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		16000 Lumen High Pressure Sodium Unit	$ 242,675.30	8,984.65	$ 27.01	$ 242,675.30	$ 28.28
54	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		22500 Lumen Mercury Vapor Unit	$ 104,958.73	3,456.00	$ 30.37	$ 104,958.73	$ 32.27
55	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		22500 Lumen Mercury Vapor Unit	$ 111,299.97	3,664.80	$ 30.37	$ 111,299.97	$ 32.27
56	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		27500 Lumen High Pressure Sodium Unit	$ 37,497.79	1,305.63	$ 28.72	$ 37,497.79	$ 30.07
57	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		50000 Lumen High Pressure Sodium Unit	$1,506,328.89	48,064.10	$ 31.34	$ 1,506,328.89	$ 32.81
58	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		63000 Lumen Mercury Vapor Unit	$ 117,760.06	2,983.53	$ 39.47	$ 117,760.06	$ 41.94
59	AL										
60	AL		**Optional Charges**								
61	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		Each 30-foot ornamental steel pole installed	$ 4,176.00	576.00	$ 7.25	$ 4,176.00	$ 7.59
62	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		Each 35-foot ornamental steel pole installed	$ 4,730.44	572.00	$ 8.27	$ 4,730.44	$ 8.66

	B	C	D	E	F	G	H	I	J	K	L
63	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		Each 30-foot wood pole installed	$ 56,816.28	10,237.17	$ 5.55	$ 56,816.28	$ 6.83
64	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		Each 35-foot wood pole installed	$ 58,485.09	9,651.00	$ 6.06	$ 58,485.09	$ 7.03
65	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		Each overhead span of circuit installed	$ 113,614.29	27,983.82	$ 4.06	$ 113,614.29	$ 4.06
66	AL	Private Unmetered Lighting Service	1ALDA, 1ALDE	33		Underground lighting unit	$ 3,103.98	998.06	$ 3.11	$ 3,103.98	$ 3.69
67											
68	PL	Private Unmetered LED	1ALLA, 1ALLE	44		4500 Lumen LED (Type A - PAL)	$ 7,566.95	671.42	$ 11.27	$ 7,566.95	$ 11.27
69	PL	Private Unmetered LED	1ALLA, 1ALLE	44		8000 Lumen LED (Type C - PAL)	$ 3,835.54	261.63	$ 14.66	$ 3,835.54	$ 14.66
70	PL	Private Unmetered LED	1ALLA, 1ALLE	44		14000 Lumen LED (Type D - PAL)	$ 6,377.53	330.10	$ 19.32	$ 6,377.53	$ 19.32
71	PL	Private Unmetered LED	1ALLA, 1ALLE	44		10000 Lumen LED (Type C - FL)	$ 32,092.84	2,189.14	$ 14.66	$ 32,092.84	$ 14.66
72	PL	Private Unmetered LED	1ALLA, 1ALLE	44		23000 Lumen LED (Type E - FL)	$ 129,782.71	4,873.55	$ 26.63	$ 129,782.71	$ 26.63
73	PL	Private Unmetered LED	1ALLA, 1ALLE	44		45000 Lumen LED (Type F - FL)	$ 4,012.00	77.47	$ 51.79	$ 4,012.00	$ 51.79
74	PL										
75	PL		**Optional Charges**								
76	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Each 30-foot metal pole installed	$ 562.10	110.00	$ 5.11	$ 562.10	$ 5.11
77	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Each 35-foot metal pole installed	$ 268.85	48.27	$ 5.57	$ 268.85	$ 5.57
78	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Each 30-foot wood pole installed	$ 7,755.03	1,135.44	$ 6.83	$ 7,755.03	$ 6.83
79	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Each 35-foot wood pole installed	$ 8,072.31	1,148.27	$ 7.03	$ 8,072.31	$ 7.03
80	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Each overhead span of circuit installed	$ 12,117.66	2,984.65	$ 4.06	$ 12,117.66	$ 4.06
81	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Breakaway base	$ -	-	$ 3.41	$ -	$ 3.41
82	PL	Private Unmetered LED	1ALLA, 1ALLE	44		Underground lighting unit	$ 494.71	134.07	$ 3.69	$ 494.71	$ 3.69
83											
84	OLS	Off-Peak Lighting Service	1OLSL	45	1.1	Total Watts X MBH X BLF ÷ 1000	$ 12,835.06	156,850.30	$ 0.08183	$ 12,835.06	$ 0.08568
85	OLS	Off-Peak Lighting Service	1OLSL	45	1.2	First 100 Watts X MBH X BLF ÷ 1000	$1,685,541.88	20,598,092.14	$ 0.08183	$ 1,685,541.88	$ 0.08568
86	OLS	Off-Peak Lighting Service	1OLSL	45		Excess over 100 Watts X MBH X BLF ÷ 1000	$ -	-	$ 0.07656	$ -	$ 0.08016
87	OLS	Off-Peak Lighting Service	1OLSL	45	1.3	First 100 Watts X MBH X BLF ÷ 1000	$ 422,254.41	5,160,141.88	$ 0.08183	$ 422,254.41	$ 0.08568
88	OLS	Off-Peak Lighting Service	1OLSL	45		Next 50 Watts X MBH X BLF ÷ 1000	$ 197,530.24	2,580,071.06	$ 0.07656	$ 197,530.24	$ 0.08016
89	OLS	Off-Peak Lighting Service	1OLSL	45		Excess over 150 Watts X MBH X BLF ÷ 1000	$ -	-	$ 0.07391	$ -	$ 0.07738
90	OLS	Off-Peak Lighting Service	1OLSL	45	1.4	First 100 Watts X MBH X BLF ÷ 1000	$ 346,376.08	4,232,874.01	$ 0.08183	$ 346,376.08	$ 0.08568
91	OLS	Off-Peak Lighting Service	1OLSL	45		Next 150 Watts X MBH X BLF ÷ 1000	$ 469,277.54	6,349,310.51	$ 0.07391	$ 469,277.54	$ 0.07738
92	OLS	Off-Peak Lighting Service	1OLSL	45		Excess over 250 Watts X MBH X BLF ÷ 1000	$ -	-	$ 0.06731	$ -	$ 0.07047
93	OLS	Off-Peak Lighting Service	1OLSL	45	1.5	First 100 Watts X MBH X BLF ÷ 1000	$ 458,186.15	5,599,244.16	$ 0.08183	$ 458,186.15	$ 0.08568
94	OLS	Off-Peak Lighting Service	1OLSL	45		Next 300 Watts X MBH X BLF ÷ 1001	$1,130,655.39	16,797,732.73	$ 0.06731	$ 1,130,655.39	$ 0.07047
95	OLS	Off-Peak Lighting Service	1OLSL	45		Excess over 400 Watts X MBH X BLF ÷ 1000	$ 14,759.50	219,276.48	$ 0.06731	$ 14,759.50	$ 0.07047
96	OLS	Off-Peak Lighting Service	1OLSL	45A	2.1	Total Watts X MBH X BLF ÷ 1000	$ 188,845.03	2,307,772.58	$ 0.08183	$ 188,845.03	$ 0.08568
97											
98	TR	Municipal Traffic Contol Signal	1TSLM	37	1	Individual Control	$ 16,787.40	84.00	$ 199.85	$ 16,787.40	$ 199.85
99	TR	Municipal Traffic Contol Signal	1TSLM	37	2A	1-Way, 1-Light Signal Unit	$ 564.84	12.00	$ 47.07	$ 564.84	$ 47.07
100	TR	Municipal Traffic Contol Signal	1TSLM	37	2B	4-Way, 1-Light Signal Unit - Suspension	$ 975.10	17.50	$ 55.72	$ 975.10	$ 55.72
101	TR	Municipal Traffic Contol Signal	1TSLM	37	3	Pedestrian Push Button Control	$ 2,007.24	12.00	$ 167.27	$ 2,007.24	$ 167.27
102	TR	Municipal Traffic Contol Signal	1TSLM	37A	4	Multi-Phase Electronic Control	$ 5,791.56	12.00	$ 482.63	$ 5,791.56	$ 482.63
103	TR										
104	TR		**Optional Equipment**								
105	TR	Municipal Traffic Contol Signal	1TSLM	37A	5	3-Light Signal Unit	$ 10,238.40	360.00	$ 28.44	$ 10,238.40	$ 28.44
106	TR	Municipal Traffic Contol Signal	1TSLM	37A	6	2-Light Signal Unit	$ 3,939.84	144.00	$ 27.36	$ 3,939.84	$ 27.36
107	TR	Municipal Traffic Contol Signal	1TSLM	37A	7	1-Light Signal Unit	$ -	-	$ 8.57	$ -	$ 8.57
108	TR	Municipal Traffic Contol Signal	1TSLM	37A	8	Pedestrian Control Equipment	$ -	-	$ 3.81	$ -	$ 3.81
109	TR	Municipal Traffic Contol Signal	1TSLM	37B	9	12-Inch Round Lens	$ 10,396.12	1,498.00	$ 6.94	$ 10,396.12	$ 6.94
110	TR	Municipal Traffic Contol Signal	1TSLM	37B	10	9-Inch Square Lens	$ 2,263.68	288.00	$ 7.86	$ 2,263.68	$ 7.86
111	TR	Municipal Traffic Contol Signal	1TSLM	37B	11a	Vehicle - Actuation Unit - Loop Detector - Single	$ 853.68	24.00	$ 35.57	$ 853.68	$ 35.57
112	TR	Municipal Traffic Contol Signal	1TSLM	37B	11b	Vehicle - Actuation Unit - Loop Detector - Double	$ -	-	$ 56.44	$ -	$ 56.44
113	TR	Municipal Traffic Contol Signal	1TSLM	37B	12	Flasher Equipment	$ -	-	$ 10.09	$ -	$ 10.09
114	TR	Municipal Traffic Contol Signal	1TSLM	37B	13a	Mast Arm - Style 2	$ 9,075.84	192.00	$ 47.27	$ 9,075.84	$ 47.27
115	TR	Municipal Traffic Contol Signal	1TSLM	37B	13b	Mast Arm - Style 3	$ -	-	$ 46.85	$ -	$ 46.85
116	TR	Municipal Traffic Contol Signal	1TSLM	37C	14	Back Plate	$ 622.08	288.00	$ 2.16	$ 622.08	$ 2.16
117	TR	Municipal Traffic Contol Signal	1TSLM	37C	15	Wood Pole Suspension	$ 240.90	11.00	$ 21.90	$ 240.90	$ 21.90
118	TR	Municipal Traffic Contol Signal	1TSLM	37C	16	Traffic Signal Pole	$ 865.44	72.00	$ 12.02	$ 865.44	$ 12.02
119											
120											
121						Revenue	**$9,973,807.83**			**$ 9,973,807.83**	
122		*MRU/CCB Item Type Duplicates across different rate codes				Change in Revenue					
123											
124											

Evergy - Missouri Metro
Clean Charge Network

Case No. ER-2022-0129
Status Direct

Charge	Rate Code	Season	Tariff Language	Current Rates	Rates with Increase	Proposed Rates	% Change
			JURIS INCREASE (%)		7.53%	0.00%	
					INPUT FOR MODEL		
Energy Charge - Blk 1/ On-Peak	CCN	Summer	Energy Level 2 Charge	0.20000	0.21506	*0.21506*	7.53%
Energy Charge - Blk 2/ Off-Peak	CCN	Summer	Energy Level 3 Charge	0.25000	0.26883	*0.26883*	7.53%
Energy Charge - Blk 1/ On-Peak	CCN	Winter	Energy Level 2 Charge	0.20000	0.21506	*0.21506*	7.53%
Energy Charge - Blk 2/ Off-Peak	CCN	Winter	Energy Level 3 Charge	0.25000	0.26883	*0.26883*	7.53%

CCN	Summer	100.000%	7.53%	7.530%
CCN	Winter	100.000%	7.53%	7.530%
Winter Price Below Summer (SUM-WIN)/SUM		**20.80%**	**22.37%**	**22.37%**
CCN Overall Change			7.530%	7.530%

Revenue	$ 76,456.73	$ 82,214.20	$ 82,214.20
Change in Revenue			$5,757
Proposed change per Revenue Summary			$ 5,763.00
			($6)
	$ 76,456.73		

Tie-out to Billed Revenue Total

1,893

% Because Riders and Surcharges are included in pricing above, straight Revenue calculations from these prices include those extra charges, and thus do not match Billed Revenue total

The SSR rates are calculated from the class rates. Therefore, the SSR must be included in filed cases that involve a change in applicable class rates.
Explanation of calculation metholodgy - reference case ER-2018-0145/0146, B. J. Meyer surrebuttal testimony

KCPL SSR Summary										
SGS Secondary Voltage	**SGS Primary Voltage**	**MGS Secondary Voltage**	**MGS Primary Voltage**	**LGS Secondary Voltage**	**LGS Primary Voltage**	**LPS Secondary Voltage**	**LPS Primary Voltage**	**LPS Substation Voltage**	**LPS Transmission Voltage**	
Standby Fixed Charges										
$110.00	$110.00	$110.00	$110.00	$130.00	$130.00	$430.00	$430.00	$430.00	$430.00	**Administrative Charge**
										Facilities Charge per month per kW of Contracted Standby Capacity
$0.000	$0.000	$0.540	$0.527	$0.894	$0.873	$0.961	$0.940	$0.929	$0.920	Summer
$0.000	$0.000	$0.275	$0.268	$0.481	$0.470	$0.708	$0.692	$0.684	$0.678	Winter
$0.000	$0.000	$0.540	$0.527	$0.894	$0.873	$0.961	$0.940	$0.929	$0.920	**Generation and Transmission Access Charge per month per kW of Contracted Standby Capacity**
Daily Standby Demand Rate - Summer										
$0.206	$0.201	$0.436	$0.393	$0.596	$0.547	$0.655	$0.600	$0.439	$0.368	Back-Up
$0.103	$0.100	$0.218	$0.197	$0.298	$0.274	$0.327	$0.300	$0.220	$0.184	Maintenance
Daily Standby Demand Rate - Winter										
$0.206	$0.201	$0.312	$0.272	$0.403	$0.359	$0.537	$0.484	$0.325	$0.255	Back-Up
$0.103	$0.100	$0.156	$0.136	$0.202	$0.179	$0.268	$0.242	$0.162	$0.127	Maintenance
Back-Up Energy Charges - Summer										
$0.16886	$0.16501	$0.11136	$0.10870	$0.09938	$0.09715	$0.09287	$0.09074	$0.08968	$0.08889	kWh in excess of Supplemental Contract Capacity
Back-Up Energy Charges - Winter										
$0.13120	$0.12822	$0.09622	$0.09396	$0.09132	$0.08923	$0.07873	$0.07692	$0.07605	$0.07533	kWh in excess of Supplemental Contract Capacity

MO Metro - Missouri Jurisdiction Class REVENUE SUMMARY - For Direct filing - ER-2022-0129

Full Increase: 5.65%

Adj Inc Excl Net Fuel: 5.21%

	(B)	(C)	(D)	(E)	F=B-(C+D)	G=(F-E)	H=F*(%)					
MISSOURI RATE GROUP	**Revenue from Existing Rates (Including FAC, DSIM, EDR)(1)**	**FAC Rider/Adjustments**	**DSIM Rider/Adjustments**	**EDR Credits****	**Revenue from Existing Rates less FAC & DSIM adjustments (1)***	**Revenue from Existing Rates grossed up to reflect EDR credits (1)**	**Requested Increase-from Rev Model excluding EDR gross-up (Equal increase)**	**Requested Increase-Including EDR Gross Up**	**Full Requested Increase-Revenue Shifts with EDR gross up**	**Adj Request-excluding Net Fuel**	**Proposed Revenue (1) Reg increase only-excluding Net Fuel**	**Proposed Revenue - Full Increase**
LARGE POWER TOTAL	$122,490,103	$ 431,371	$ 462,629	$ (319,690)	$ 121,596,104	$ 121,915,794	$ 6,868,343	$ 6,886,401	$5,169,315	$4,371,382	$126,287,176	$127,085,109
LARGE GEN SVC TOTAL	$184,475,179	$527,361	$5,486,350	$ (922,787)	$ 178,461,467	$ 179,384,255	$ 10,080,377	$ 10,132,501	$7,612,406	$6,700,169	$186,084,424	$186,996,661
MEDIUM GEN SVC TOTAL	$128,571,457	$315,281	$4,661,484	$ (236,613)	$ 123,594,692	$ 123,831,305	$ 6,981,233	$ 6,994,598	$5,249,290	$4,719,600	$128,550,904	$129,080,595
SMALL GEN SVC TOTAL	$71,336,061	$142,891	$2,529,156	$ (15,639)	$ 68,664,014	$ 68,679,653	$ 3,878,480	$ 3,879,363	$2,909,743	$2,660,701	$71,340,354	$71,589,396
RESIDENTIAL TOTAL	$357,810,782	$714,551	$16,174,375	$0	$ 340,921,856	$ 340,921,856	$ 19,256,935	$ 19,256,935	$26,347,726	$25,111,670	$366,033,526	$367,269,582
MO Metered TOTALS	**$864,683,583**	**$2,131,456**	**$29,313,994**	**$ (1,494,729)**	**$ 833,238,133**	**$ 834,732,862**	**$ 47,065,368**	**$ 47,149,798**	**$ 47,288,480**	**$ 43,563,522**	**$ 878,296,384**	**$ 882,021,343**
MO Lighting TOTAL:	$9,951,318	$20,683	$0	$ -	$ 9,930,635	$ 9,930,635	$ 560,931	$ 560,931	$420,698	$384,793	$10,315,427	$10,351,333
MO TOTAL*	**$874,634,900**	**$2,152,139**	**$29,313,994**	**$ (1,494,729)**	**$ 843,168,768**	**$ 844,663,497**	**$ 47,626,299**	**$ 47,710,729**	**$ 47,709,179**	**$ 43,948,315**	**$ 888,611,812**	**$ 892,372,676**
CCN	$74,563.92	$0.00	$0.00	$0.00	$74,563.92	$74,563.92	$ 4,212	$ 4,212	$5,763	$ 5,763		